Electricity Market Auction Settings in a Future Danish Electricity System
- A Comparison of Marginal Price Setting and Pay-As-Bid

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Synopsis

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Abstract

The long-term political goal for the Danish energy system is to be free of fossil fuels. In order to achieve this, an increased amount of fluctuating renewable electricity such as wind power is expected to be implemented.

The Danish electricity market is part of the Nordic power exchange Nord Pool, which uses an auction setting known as Marginal Price for the day-ahead auctions. This is characterized by the market price being equal to the bidding price of the most expensive auction winning unit. In this setting the fluctuating renewable electricity sources bid with prices of zero or close to zero, resulting in a market price for the hours of fluctuating renewable production to be lower than what they otherwise would be. In turn, this reduces the fluctuating renewable sources' income from market sales, and makes them more dependent on subsidies. As more fluctuating renewable electricity is implemented, this effect will only become greater.

Other auction settings could potentially help to reduce this problem. One of these is the Pay-As-Bid auction setting, where the winning units are paid their own bid, which would result in bids greater than zero from fluctuating renewable energy sources.

The aim of this thesis is hereby to investigate and compare the two auction settings; Marginal Price Setting and Pay-As-Bid, to find whether a change of electricity market auction setting might provide a more suitable auction setting for large amounts of fluctuating renewable electricity. This has been done with two technical setups with different amounts of fluctuating renewable electricity.

From the analysis it is found that the Marginal Price Setting generally is better for the fluctuating renewable electricity sources. The result is, however, very dependent on the base assumptions used for the calculations, and any change in the base assumptions could result in the Pay-As-Bid setting becoming better. None of the investigated auction settings are hereby significantly better for fluctuating renewable electricity sources.

Preface

This Master's Thesis was written in the 4th semester of the master program Sustainable Energy Planning and Management at Aalborg University, Department of Development and Planning. The thesis period from which this report is the result, was from February 2nd 2010 – June 10th 2010.

The report is divided into 7 chapters. Furthermore there are appendixes. One is attached to the report in printed version, this is numbered as A. Ten are attached on a DVD; these are numbered as 1-10. References to appendix are stated as (Appendix X) through the entire report.

In the report the Harvard method has been used for references. In the text the references are written using the authors surname followed by the year of the reference, e.g. (Lund 2006). The full list of references can be found in the end of the report. If a source has the same author and year, then a letter (a, b, c, etc.) is added after the year.

The authors would like to thank our supervisor Poul Alberg Østergaard for his help and input for the thesis. Furthermore the authors would like to thank Manager for energy system analyses at EMD Anders N. Andersen, General Manager for Business Development at Nord Pool Spot Anders Plejdrup Houmøller, System Analyst at Vattenfall A/S Georges Salgi, and Chief Consultant at Energinet.dk Steen Kramer Jensen for making themselves available for interviewing.

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1 Introduction

In Denmark the electricity grid is divided into two separate grids, Western Denmark (DK1) and Eastern Denmark (DK2), which also make up two different price areas for electricity. The two areas are in the process of being coupled together. This thesis focuses on how an electricity market is affected by a large share of renewable energy sources (RES), and therefore the most interesting area to investigate is the current situation of DK1 with its high share of RES, which in 2009 was 29.5% of net production, compared to DK2 with a RES share of 26.3% (Energinet.dk 2010). In order to compare this to other countries the production has to be compared to the consumption, and here wind power production in Denmark in 2007 made up 21.2% of the total consumption, which is the highest share in the EU; Spain had the second largest with 11.8% of consumption in 2007 (Safarkhanlou 2009). For this reason the analyses in this introduction will focus on DK1, since it shows most of the potential challenges an electricity market relying on RES will have to face. The RES in DK1 is especially from wind power production. This high wind power share is seen in Figure 1, which shows the electricity production from different sources in 2009.

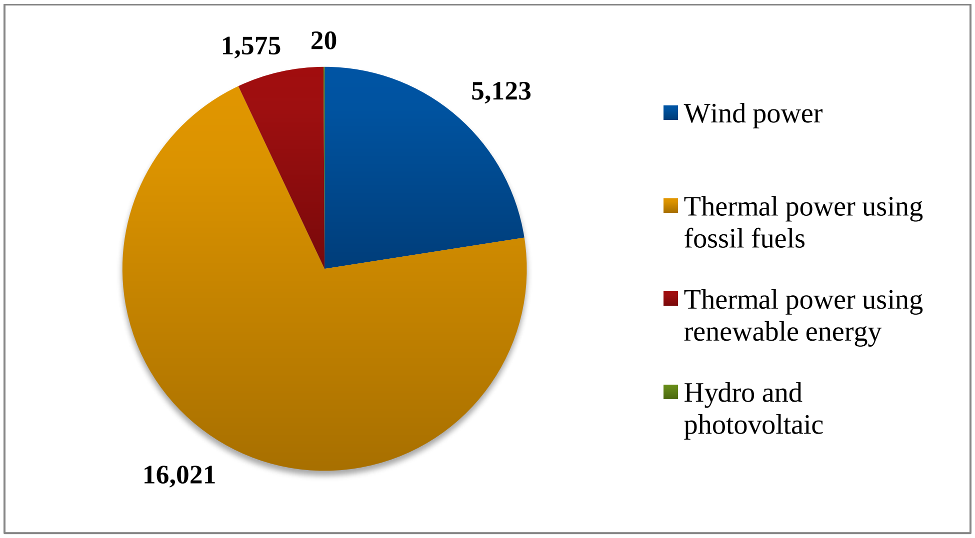

Figure 1: Net electricity production in GWh in DK1 in 2009 divided into sources (Energinet.dk 2010)

As seen, fossil fuel plants do make up the largest source of electricity production in 2009, however wind power is producing quite a significant share of the total production.

Moving from the technical setup of the electricity system to the current market situation. Since January 1st 2003 it has been possible for electricity consumers in Denmark to choose between competing electricity suppliers. This is a part of the liberalization of the European electricity market, which was initiated in 1996 (The European Parliament 1997). The reasons behind the liberalization were to improve efficiency and competition within the European system (Danish Energy Agency n.d.). The existing wholesale electricity exchange market in the Nordic Area is called Nord Pool Spot, and is divided into two markets called Elspot and Elbas. Elspot is the day-ahead market for commercial players, whereas Elbas is an intraday market used for balancing the system, which is needed due to variations between the trading on Elspot and the actual productions and demands. Geographically, Nord Pool covers Denmark, Finland, Sweden, Norway and Estonia. The trading on Nord Pool Spot was around 70% of the total trading in the Nordic countries in 2008, and most of the trading is in the Elspot market, where in 2008, 297.6 TWh of electricity was traded compared to Elbas with only 1.8 TWh (Nord Pool Spot 2009). Wind power is almost only traded on Elspot (Ea Energy Analyses 2007). The focus in this thesis is the Elspot market, since this is where the electricity is mostly traded. The electricity traded on Elbas will, however, most likely increase when more fluctuating electricity sources are used, because of uncertainties with regard to production from e.g. wind power. However, as this market in its current form is used for balancing the forecasted demand and supply of the Elspot with the actual demand and supply, the Elbas market is more a practical necessity rather than a market relevant for the modeling in this thesis.

As a day-ahead auction, the players on the Elspot market who want to buy electricity send in their bids before noon the day before consumption, thus, 12-36 hours before the electricity is delivered. The players who wish to sell electricity also send in their offers 12-36 hours before delivery. At Nord Pool Spot the purchase bids are aggregated into a demand curve and the offers are aggregated into a supply curve for each hour in the day (Houmøller 2009). The resulting price for the hours is the point where the supply and demand curves intersect, and is calculated after noon. When the price is calculated, all of the players get a report informing them how much electricity they have bought or sold for each hour of the next day (Houmøller 2009). This type of price formation is called uniform price setting or marginal price setting (MPS), which means that all the sellers get the same price as the marginal cost for the final kWh produced to satisfy the demand. This type of price formation is illustrated in Figure 2.

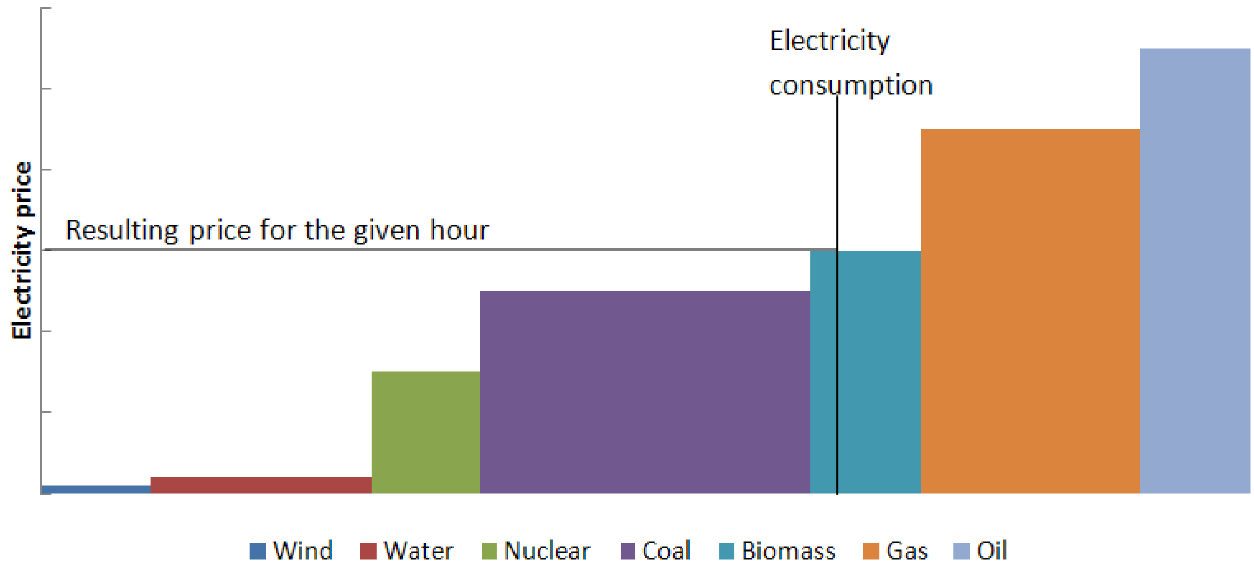

Figure 2: Resulting market price in a marginal pricing setting for one hour in the Nordic area. Inspired by (Ea Energy Analyses 2007)

The figure shows how the different types of production units offer electricity at different costs. The production units with the lowest short-term marginal cost (STMC) are wind, water and nuclear. Included in STMC are the variable costs for producing one extra unit of electricity: e.g. fuel cost, CO_2-qoutas and variable operation and maintenance costs. After these sources are the combined heat and power (CHP), condensing power and peak load capacity facilities, shown as coal, biomass, gas and oil in the figure. The demand is shown as a vertical black line, because it is fairly inelastic on the short run, meaning that it, only to a minor extent or not at all, changes according to the variation in cost within short timeframes (Fridolfsson, Tangerås 2009). In a market system with MPS all of the producers get the same price, even though they offered to sell at a lower price. In theory this means that the production units that are most efficient will earn the most, and the units with the highest STMC will just earn enough to cover their STMC. This also means that if the production units with the lowest marginal costs can cover the whole demand, the price will drop dramatically (Stoft 2002). In DK1 wind power has already forced the price down to zero in some hours, as discussed in the next section. (Nord Pool Spot 2010)

The long term goal of the current Danish Government is that Denmark has to be a society independent of fossil fuels. To reach this goal, the strategy is to focus on energy efficiency and increase the share of renewable energy in the energy system (The Danish Prime Minister's Office 2010). The key source of renewable energy in Denmark is wind power, which produced around 29.5% of the net electricity production in DK1 in 2009 (Energinet.dk 2010). In general, wind power has a reducing effect on the electricity price in hours where the wind blows, since wind power offers electricity at a price close to zero which presses some of the more expensive bids away from the winning bids, resulting in a lower price on the market. It has to be underlined that the price can be both high and low in hours with much wind, but in average, the price decreases with more wind in the system. In 2009, the average price was 37.19 EUR/MWh with a wind production below 750 MW, which occurred in 6,040 hours that year, and 34.46 EUR/MWh with a wind production above 1,750 MW, which occurred for 297 hours (based on data from (Energinet.dk n.d.)). The large amount of wind power made up by 661 MW offshore wind turbines and 2,821 MW on land (Energinet.dk 2010) has also resulted in hours where the electricity price drops to zero. Summarizing these hours gives a total of 28 hours in 2008 and 46 hours in 2009 in which the price went down to zero (Nord Pool Spot 2010). The reason the price dropped down to zero is that the wind production and the heat bound electricity production from CHPs in these hours covered the whole electricity demand and the available transmission capacity out of DK1. CHPs normally do not offer to sell electricity for a price of zero, but due to upstart costs and heat demand in the colder hours of the year, it will sometimes be economically sound for individual CHP plants to run at some hours at prices of zero. Since 30th November 2009 it has been possible for the Nord Pool Spot prices to be negative in some hours, however this is not be investigated in this thesis (Djursing 2009). In the present electricity system these price drops are not a large problem, because they only happen very few hours each year. However, in a future electricity system with larger amounts of wind production it could occur in more hours; since these are also the hours where wind power would have the greatest potential to earn its long-term marginal costs. Having more of these hours could result in poorer income from the electricity market for wind power, and hereby making them depend more on subsidies.

In order to integrate more fluctuating RES into the system, the system would have to be more flexible so other power production units could produce electricity when there is no wind, but also be able to shut down production when there is a lot of wind. Not only the production has to be flexible, but also a more flexible electricity demand is important to utilize the wind production, e.g. with the use of heat pumps (Meibom 2005). However, the potential of a flexible electricity demand can be discussed, as there could be an upper limit to the possibilities of a flexible demand, this will however not be investigated further. This makes it interesting to investigate which technologies are being implemented to meet the future situation, or in other words, which technologies are being invested in.

An important factor when looking at the willingness to invest in new electricity capacity is that a high electricity price will encourage investments in new units producing electricity. But this is not always the case, as it will also depend on whether the investor is new on the market or if it is an old player owning existing production facilities. In most cases, owning other production facilities is an obstacle for investing in new facilities; since the new facility will compete with the old units, and lower the total profitability for the investor. New market players do not run this same risk of competing against their own facilities. Other aspects affecting the willingness to invest are: the competitive situation in the market and how certain the future political framework for the market is. There are different uncertainties in the political framework that are more important than others. The cost of CO_2-quotas is one of them. A high CO_2-quota cost gives advantages to new efficient electricity producing plants, because they have lower fuel consumption per output unit than older and typically more inefficient electricity producing plants. RES also benefit from high CO_2-quota prices. Another important factor is the amount of wind power. A large amount of wind power gives lower electricity prices, as shown before, which makes the profitability of investing in other electricity capacity worse. The worst case for investing in new electricity capacity, besides wind and other RES, is when there is a large amount of wind power in the system and a low CO_2-quota cost. (Morthorst, Grenaa Jensen & Meibom 2005)

When looking at investments in new electricity capacity e.g. new central power plants (PPs) investments in new capacity seem to have stopped in 2001 (Danish Energy Association 2008). Normally PPs have a lifetime of around 30 years; this means that many of the PPs older than 25 years will be gone in the near future (Meibom 2005). When looking at wind power capacity, it has been quite stable from 2001-2008, where the total capacity has been around 3,200 MW. But, unlike central PPs, there has been an ongoing replacement of old wind power capacity (Danish Energy Agency 2009b). It must be assumed that unless the electricity demand drops, there will have to be investments in new capacity. It is therefore relevant to investigate which technologies are most likely to be invested in within the current market system; and especially whether the current system benefits technologies that would help reach an energy system free of fossil fuels, as this is the political goal.

Some of the problems could be due to market design, where e.g. the ability to earn money on investments in new production facilities depends on there being more expensive units winning the auction, so that more than the STMC can be recovered. There are, however, other ways of designing a market than the MPS. One of these is called pay-as-bid (PAB). In such an auction, the bid winners are paid the price that they are asking for, rather than e.g. the price of the most expensive unit. PAB makes each unit less dependent on other units being more expensive, since they are only paid what they offer, and not what a more expensive unit is paid, and they are therefore, in principle, more likely to bid a price that will make them cover their long-term marginal costs plus a desired profit. The long-term marginal costs are understood as the STMC plus the fixed costs of running the facility, making it the total cost of the facility divided by each unit sold throughout the lifetime of the facility. It includes e.g. payback on investments, fixed operation and maintenance costs, taxes on facilities and insurance costs. This would also mean that units will generally not bid a price of zero, since that would not result in any payment. The PAB auction setting is used in the British electricity system. (Tierney, Schatzki & Mukerji 2008)

Summarizing all of these issues gives an understanding of the focus in this thesis. The Danish electricity system is part of the Nord Pool market, which uses MPS as a market design. With more wind energy in the system, this could create a problem regarding the price setting, where more very low or zero price hours are expected in the future. This could result in lower income for the fluctuating RES, leading to a situation in which willingness to invest would be directed towards technologies that would not help reach a fossil free energy system, which is the long term goal of the Danish state. The research question for this thesis is therefore:

> *"In a future Nord Pool Elspot market relying heavily on fluctuating renewable energy, how would different auction settings affect the income from electricity sales for the different production units in the Danish energy system?"*

The analysis focuses on which technologies the market players would want to invest in when analyzing the markets allocation of income and the behavior of the market players. This is done within the context of MPS and PAB using different technical energy system setups with different amounts of fluctuating RES. This approach makes it possible to analyze which of the auction settings will be most appropriate for reaching the goal of a fossil free energy system.

To give an overview of how this research question is investigated, the following section presents the structure of the report.

1.1 Report structure

The report structure can be found in Figure 3.

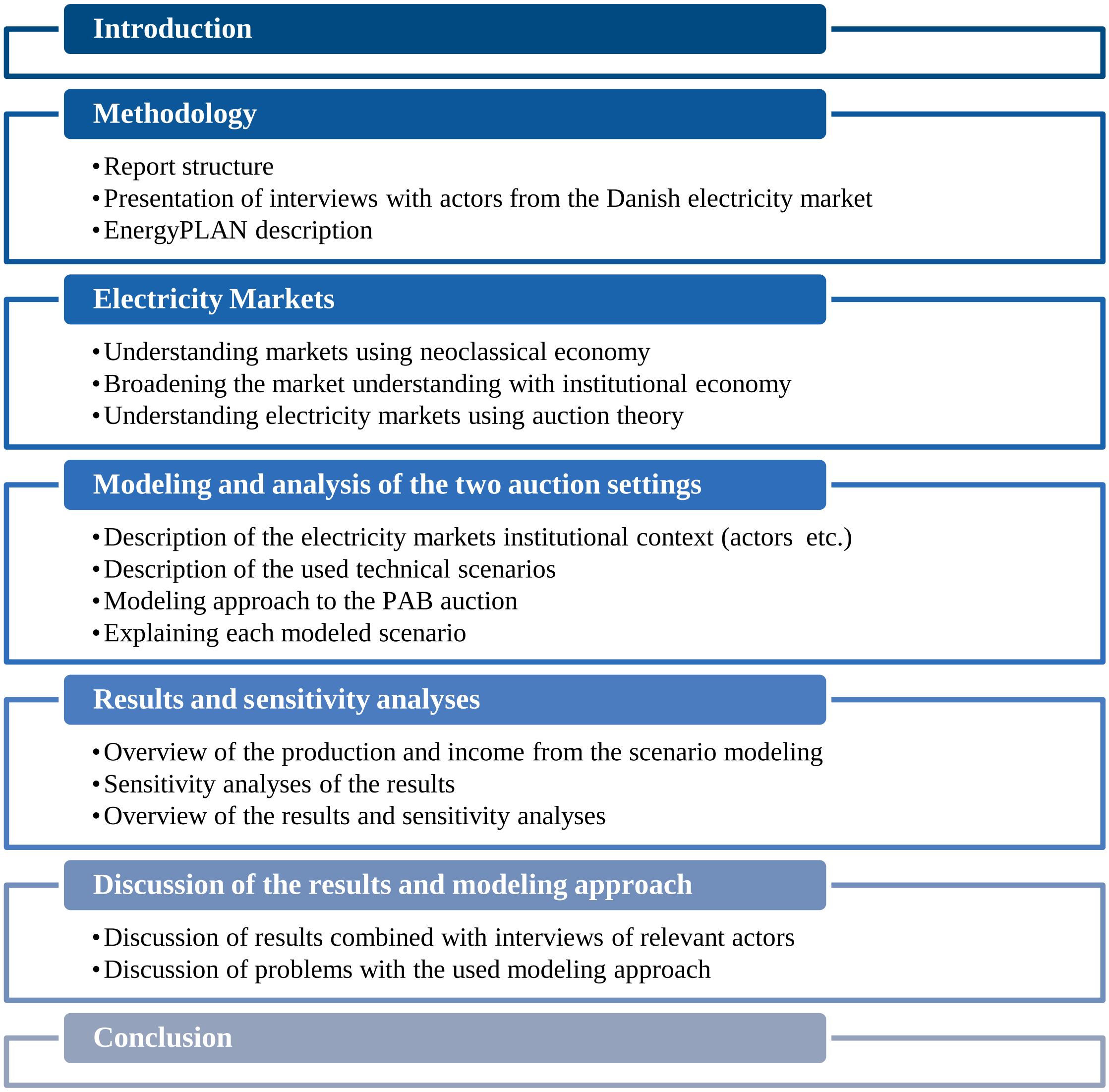

Figure 3: Report structure

The report starts with the introduction which presents the focus of the investigation and the research question. Hereafter, the methods used for analyzing the research question are explained. This leads to the examination and description of how to understand and define electricity markets from a theoretical perspective, where several theoretical approaches are presented. Following this is a detailed explanation of the analyses made in the thesis. The output of the analyses are the results, which are investigated further by making sensitivity analyses on the results in order to find out how much the results depend on certain factors. The results are afterwards discussed and compared with statements gained from interviewing five actors on the Danish electricity market. Following this, the modeling approach's limitations and problems are discussed. Lastly, the conclusion of the thesis is presented.

2 Methodology

This chapter explains the methods used in the thesis. First is a short description of interviews made with several relevant actors on the Danish electricity market. The next and last part of the methodology focuses on the modeling tool used for modeling the Danish energy system, EnergyPLAN, which is explained with focus on the aspects that are relevant for this thesis.

2.1 Interviews with five actors on the Danish electricity market

In order to better reflect on the results of the modeling, interviews with five actors from the Danish electricity market have been made. The interviews were made as semi-structured interviews. These types of interviews are generally characterized by having overall questions, and not necessarily following the exact sequence of the interview schedule. It is also possible for the interviewer to ask follow up questions in reply to what the interviewee replies, making it a flexible interview approach. The context chosen for the interviews differentiated; the ones possible to visit were carried out in person and the rest were made as phone interviews. There are different reasons for preferring face-to-face interviews. One is that it is hard to make phone interviews beyond 20-25 minutes, whereas face-to-face interviews can last much longer. This also was the authors experience with the interviews, where the phone interviews were 15-18 minutes, and the face-to-face interviews were 30-50 minutes. Another reason is that it is easier to observe the interviewees reactions on questions, and make follow up questions. Also it is possible for the interviewee to answer in other ways by drawing or showing diagrams, which gives a better understanding on how they view things. Studies show that there is a tendency to get better quality answers from face-to-face interviews, than phone interviews. On the other hand there are also reasons in favor of phone interviews; most obvious is that it takes fewer resources to make a phone interview, because it takes less time and money to use a phone instead of travelling around to make the interviews. Going on to the questions asked in the interviews; these were characterized by being mostly open questions, where the interviewee could answer however they wished. The advantage of this is that the answer is not forced upon the interviewee, and it opens up for answers that the interviewer has not contemplated. These questions are also good if the researcher wants to explorer new areas in which they have little knowledge. This was especially useful, because the interviews were carried out in the beginning of the project period, as a gateway into how the electricity market players saw the auction setting (Bryman 2008). The specific themes of the questions were: The advantages/disadvantages regarding MPS and PAB, and the bidding strategies in the two auction settings both in the current situation and in a future with more wind power.

The interviewees were chosen in the beginning of the project period and are:

- **Anders N. Andersen**, Manager for energy system analyses at EMD
- **Anders Plejdrup Houmøller**, General Manager For Business Development at Nord Pool Spot
- **Georges Salgi**, System Analyst at Vattenfall A/S
- **Steen Kramer Jensen**, Chief Consultant at Energinet.dk

When selecting these interviewees it was tried to get a broad segment of the actors on the Danish electricity market. Anders N. Andersen works closely with decentral CHPs, and hereby has a good knowledge regarding how these operate on the electricity market. Georges Salgi works for Vattenfall which owns some of the larger CHPs in Denmark, and is one of the major companies on the Danish electricity market. To get a broader understanding of the system, Anders Plejdrup Houmøller was interviewed to get an insight into how Nord Pool Spot themselves see the electricity market. Steen Kramer Jensen was interviewed to get an understanding of how the Danish Transmission System Operators looks at the electricity market. The interviews have as mentioned before been used in the beginning of the project period, to get an idea of how the actors see the electricity market and the future problems addressed in the research question. Also they are used to reflect on the results found in the modeling, to see if the comments from these actors are consistent with the results found in the analyses.

2.2 Description of the computer tool EnergyPLAN

To make the analyses in this thesis a computer model called EnergyPLAN is used. There are several reasons for choosing EnergyPLAN for this purpose. First of all it is important to have a model that is capable of analyzing the whole energy system and not only e.g. the electricity sector. This is relevant because the goal of the thesis is to look at a future situation with a lot of fluctuating energy, and in such systems utilizing electricity in other energy sectors like heat and transport is essential. Another reason is that the Nord Pool day-ahead market is based upon hourly changing electricity prices, and to be able to describe this, a modeling tool that analyses each hour is needed. A third reason for choosing EnergyPLAN is that the calculation time for the model is less than a half minute for simulating a whole year. This is important, because it makes it possible to run more calculations, and hereby making it possible to do more sensitivity analyses on the results, than in a model which have a longer calculating time.

2.2.1 The overall structure of EnergyPLAN

EnergyPLAN is a model that has been under development since 1999. It was originally a spreadsheet model, but has since been reprogrammed into a more user-friendly interface using the coding language Delphi Pascal. The main purpose of the model is to make energy plans on a regional or national level. The energy sectors included are district heating, electricity, transport, industry and individual heating.

It has been developed in order to be able to model the Danish energy system with CHP plants and fluctuating RES like wind power. The model operates on an hour-to-hour basis and calculates for a period of one year defined as 8,784 hours. Another characteristic of the model is the ability to switch between different regulation strategies, making it possible to focus only on e.g. a technical optimisation and not taking market prices into account. However, in this thesis' analyses only the economic regulation strategy is used, which takes production costs and external market prices into account. But to understand how the model operates, the technical part is described. (Lund 2010)

EnergyPLAN is a deterministic model, which in short means that the model always produces the same results, when the same inputs are used. The opposite of this would be a stochastic model, which would be using random events with known probabilities, and would give different results every time (Origlio 2010). EnergyPLAN operates with overall inputs defining the technical system, an economic part and a regulation part. In Figure 4 the overall structure of the technical part of EnergyPLAN is shown.

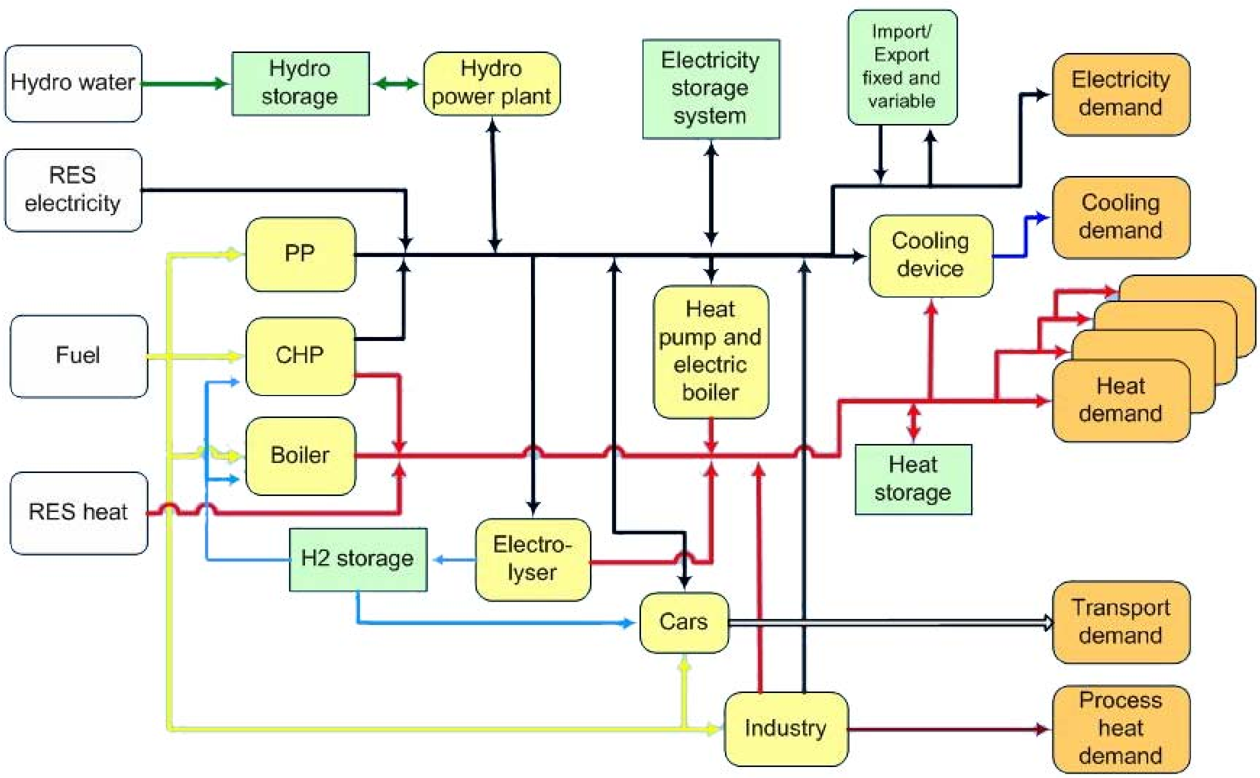

Figure 4: The structure of EnergyPLAN (Lund 2010)

The overall characteristic of EnergyPLAN is that the model operates with aggregated data inputs for the different types of production. This means that for instance PPs are not added separately in the model, but are aggregated into one category; this is the same for all the different types of production.

The inputs for EnergyPLAN are therefore less detailed than models that separate the different production facilities. Looking at Figure 4 all the inputs used for calculating the energy system in EnergyPLAN is shown. The white boxes are all the available energy sources, the yellow boxes are the potential conversion technologies and the green boxes are the storage possibilities. The orange boxes are the energy demands. When using the model the first inputs added are the energy demands. It is possible to add demands for electricity, district heating, transport, industry and individual heating. The demands are added as annual demands with an hourly distribution curve for a year. This gives hourly demand curves for all of the different types of energy demands. The next inputs to add are the production units, which have different inputs depending on type of production unit. For example wind power is a fluctuating source, producing according to weather conditions, and therefore this type of production needs to have a distribution curve for their production. Other types of production units are dispatchable, producing according to prices or regulating strategies. For district heating there are three different categories; one without CHP, a second with decentral CHPs and a third with central CHPs. Overall it is though very few details that are needed for the main inputs in the model. (Lund 2005)

When the technical system is designed, the next step is to choose the right regulation strategy for the analysis. EnergyPLAN has three different strategy options:

1. The first strategy is for CHPs only to produce according to the heat demands. For areas without CHPs, solar thermal, industrial CHPs and boilers produce the heat needed. For areas with CHPs the heat production follows this order of priority: solar thermal, industrial CHP, CHP, heat pumps and peak load boilers.
2. The second strategy is for CHPs to produce according to both heat and electricity demands. In this strategy electricity export is minimized by switching heat production from CHPs with boilers and heat pumps. This way the heat consumption is increased while the electricity production is decreased. On the other hand electricity production on condensing power plants is minimised by using CHPs units and heat storages.
3. The third strategy is the economic strategy, which is following a market strategy where electricity is exported when the market price is higher than the marginal production price, and imported when it is lower than the market price. All production units except for fluctuating RES run according to their STMC in this strategy. (Lund 2005)

The third strategy is used in this thesis, because the focus is to look into the electricity market. Some changes to the models code have been made, to make it possible to calculate the PAB setting; these changes can be seen in (Appendix A).

Since the economic part of EnergyPLAN is important for the thesis, the following section is a deeper look into this part of the model.

2.2.2 The market economic optimisation in EnergyPLAN

The focus of this description is how the market economy is being optimized in the model and furthermore a focus on the specific STMC calculations used in the thesis. Since the calculations differ for each technology only those that are important to have a thorough understanding of, is explained in this section.

First of all the market economic strategy is based upon an hourly market price, which is a result of the demand and supply of electricity. The calculations shown next are used continuously when running the market optimization strategy. The first calculation, in the market economic strategy, is to find the difference between the demand and supply; this is called demand net import and is found by using formula 1:

$$\textit{Net-import demand}_{hourly} = \textit{Total demand}_{hourly} - \textit{total production}_{hourly} \quad (1)$$

The net import demand is found by summarizing the demand and production for each hour. Next thing is calculating the external market price for each hour. This is done by using the following formula:

"$p_x = p_i + (p_i/p_0) * F_{ACdepend} * d_{net\text{-}import}$ (2)

- *p_x is the price on the external market*
- *p_i is the system market price*
- *$F_{ACdepend}$ is the price elasticity*
- *P_0 is the basic price level for price elasticity*
- *$d_{net\text{-}import}$ is the trade on the market" (Lund 2010)*

The price elasticity is used to find the influence on the external market price from import/export. This is done continuously, so when the best business economic strategy is found for each plant, the influence on the market price is taken into consideration, using formula (2).

The next step is to identify the STMC. This is done differently for each production unit, but overall the STMC is calculated by using fuel costs, handling costs, taxes, CO_2 costs and variable O&M costs. This gives different STMC in DKK/MWh for producing electricity on each of the production types.

The following is a sequence which is used continuously when making the market optimisation; it is numbered to give a better overview of the procedure.

1. When starting the optimization the starting point for the market prices is found. This is done on the basis of the electricity demands including flexible demands. For district heating the starting point is that the areas are supplied by boilers.
2. Optimising hydrogen and electricity demands for electric vehicles. This is calculated by identifying the lowest cost solutions of buying the minimum electricity needed to supply the demands.
3. Optimising electricity consumption options. This is done according to the highest STMC. The important ones in this thesis are:
   a. Replace boiler with heat pumps in group 2
   b. Replace boiler with heat pumps in group 3
4. Optimising hydro power. Since hydro power not is used in this thesis, it is not explained further.
5. Optimising electricity production options. This is done according to the lowest STMC. Again the important ones are:
   a. Condensing power plants
   b. CHP replacing boilers in group 2
   c. CHP replacing boilers in group 3
   d. CHP replacing heat pump in group 2
   e. CHP replacing heat pump in group 3

   This is done so that it is taking into consideration that the changes in production decreases the price. Also limitations in transmission lines to the external market are considered. If the transmission line capacity is exceeded when importing and demand is still not meet, then condensing PPs will be activated.

6. Optimizing the electrical storages; this is also not used in this thesis.

Since the production units influence the market price, the 6 steps are repeated to find this effect on the optimisation on the consumption units. Also throughout the optimisation critical export is minimised by using different strategies, which are defined in the technical optimisation. (Lund 2010)

The next part of this section goes into detail with how the STMC are calculated for the technologies used later on in the thesis.

Calculating the STMC in EnergyPLAN

An overall thing to notice when calculating the STMC of producing electricity on various production technologies is that the STMC is always calculated according to the input fuels. It is possible to have four types of fuels per technology. This means that in the model the fuels are linked with the same percentage share of each MWh produced. The marginal price for each fuel is calculated as follows in formula 3:

$$\textit{Marginal fuel price} = \textit{Fuel price} + CO_2\,\textit{price} + \textit{handling cost} + \textit{tax cost}\ (3)$$

The price is not always the same as the STMC excluding variable O&M costs, because some technologies like CHPs compare their production costs with that of the boilers or heat pumps, as the heat will have to be produced no matter what, even if the CHPs are running or not. The following gives an overview of how the STMCs used in this thesis are calculated. There is no source in the following sections, because the content is not explained in the EnergyPLAN documentation, it is instead based upon the source code of the program.

Condensing CHPs and power plants

For all the fuels used by the PPs the marginal fuel price is calculated. The sum of these is divided by the electric efficiency of the power plant. Afterwards the output price is found by adding the variable cost input to the marginal fuel price this is shown in formula 4.

$$Price\ power\ plant = Fuel\ costs_{power\ \ plant} + VC_{power\ \ plant}\ \ (4)$$

The price for running the PPs in this situation is the same as the STMC, which is the marginal fuel price plus the variable O&M cost (VC) for the PP.

CHPs replacing boilers in group 2 and 3

For the CHPs the marginal fuel price is calculated and divided by the thermal efficiency of the CHPs. For the boilers the fuel price is calculated and divided by the thermal efficiency of the boilers.

Output price for increasing CHPs and decreasing boilers is then calculated by using formula 5:

$$Price\ incr.CHP\ decr.Boiler = \frac{Fuel\ costs_{CHP} - Fuel\ costs_{boiler}}{\frac{electric\ \ eff_{CHP}}{thermal\ \ eff_{CHP}}} + VC_{CHP} - \left[VC_{boiler} \times \frac{thermal\ \ eff_{CHP}}{electric\ \ eff_{CHP}}\right]\ (5)$$

The reason that the price is calculated differently for the CHPs is that it has to be compared to other technologies for the heat production; in this situation the boiler, since the heat has to be produced to meet the demand. Therefore the price of running the boiler has to be subtracted from the price of running the CHP, which is the last part of formula (5).

The procedure is a general formula, which is used for both calculation in district heating group 2 and 3.

CHP replacing heat pumps in group 2 and 3

When looking at the third type of production, used in later analyses in this thesis, a temporary step has to be taken before going on the final calculation of the price. This is the increase fuel formula shown as formula 6.

$$Increase\ fuel = \frac{\frac{1}{thermal\ \ eff_{\ CHP}}}{\frac{electric\ \ eff_{\ CHP}}{thermal\ \ eff_{\ CHP}} + \frac{1}{COP_{\ hp}}} \quad (6)$$

This increase fuel price takes the different efficiencies of producing on CHP and comparing it to the heat pump. This is then used in the final formula for calculating the price of decreasing heat pumps and increasing CHPs shown as formula 7.

$$Price\ incr.CHP\ decr.heat\ pump = Fuel\ costs_{CHP} \times increase\ fuel \times elec.effiency_{CHP}\ - \left\lfloor (VC_{Heat\ \ pump}\ + Tax_{heat\ \ pump}\ ) \times (1 - increase\ fuel \times elec.effiency_{CHP}) \right\rfloor \quad (7)$$

Similar to formula (5), this one has a saving on taxes and fuels from not using the heat pump, which is the last part of formula (7). The procedure is again a general formula, which is used for both calculation in district heating group 2 and 3.

The following chapter proceeds into a more theoretical description of the thesis' focus, away from the methodology and focusing on electricity markets and auction settings.

3 Electricity markets

This chapter explains the theory used for the modeling in this thesis. First the basic understanding of an electricity market from the neoclassical market economic understanding is explained, which concludes with a more detailed description of electricity markets. Then the institutional economic understanding is explained to expand upon the neoclassical understanding. This leads to explaining auction theory with regards to the theory behind MPS auctions and PAB auctions with focus on electricity markets.

3.1 Understanding markets

First it is relevant to define what is meant when referring to the term "market". This description does not go into detail with the workings of markets, since this is seen as outside the scope of the thesis. However it is used to define important terms and understandings used by the authors.

A market can be defined as:

> *"Any context in which the sale and purchase of goods and services takes place"* ((Stoft 2002) page 449)

This definition provides a quite broad understanding of what makes up a market, since it can include e.g. bilateral deals and auctions, and it shows that market theory is relevant for this thesis' scope, since Nord Pool is a context where the sale and purchase of the good electricity takes place. Therefore this definition is relevant when describing the basic neoclassical understanding of the workings of an electricity market.

In a market there is a demand side, composed of those that wants to purchase a good or service and hence puts a value on it, and a supply side, which are those that are willing to provide this good or service and have a cost for providing it. These two sides of a market are normally shown as two curves that show the marginal change in quantity (Q) for different prices per unit (P), and vice versa, in supply and demand for a certain good or service. Generally speaking, if P for a good increases then it must be assumed that the demand for it will drop, meaning a lower Q is demanded. For the supply side, if P increases then the suppliers will be willing to provide more of a good. The Q and P in a market can then be found by the intersection of the supply and demand, which very simple put can be seen as the point at which both sides agrees on the P and Q. At that point the consumers will not demand more of the good or service, and therefore the suppliers will not want to produce more, since they would not be able to sell more units at that P, and producing anymore would result in a loss for them. The point of intersection is also known as the market equilibrium. (Keohane, Olmstead 2007)

A simple illustration of a market situation is shown in Figure 5, which illustrates a simple electricity market with two suppliers having constant STMCs of respectively 200 DKK/MWh and 400 DKK/MWh, which here also is assumed to be the price the suppliers "bids" in the market. The demand curve (Demand) is here shown as changing incrementally. The market equilibrium in this example is at Q= 10,000 MWh and P= 300 DKK/MWh.

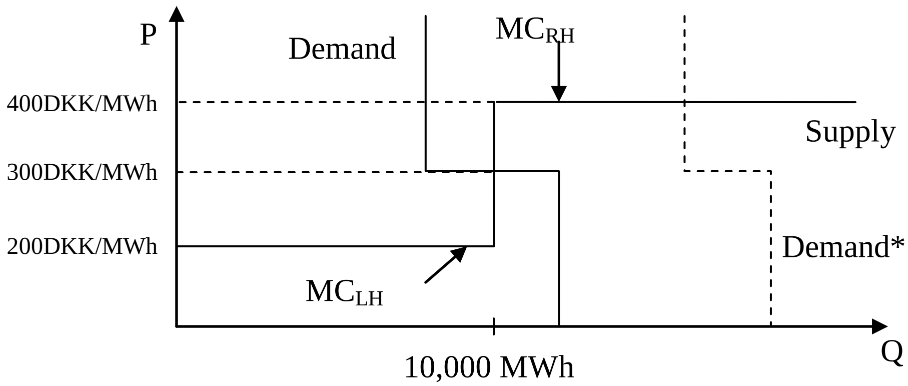

Figure 5: Simple example of an electricity market with demand and supply curve changing incrementally. MC_{LH} = "Left-hand Marginal Cost" and MC_{RH} = "Right-Hand Marginal Cost". Based on figure from (Stoft 2002)

As it can be seen in Figure 5, the demand is meet only by the cheapest unit in the system, which produces with a STMC of 200 DKK/MWh, but the market equilibrium results in a price that are 300 DKK/MWh, since this is the point of intersection between supply and demand. This is an important observation as it shows that the market price not always equals the cost of the last supplier, but instead will be somewhere in the marginal cost range made up by MC_{LH} and MC_{RH}, which is the left (LH) marginal cost that is the possible savings for producing one less unit, and right hand (RH) marginal cost which are the cost of producing one more unit. If the market equilibrium instead occurred at Demand* the market price would however equal the STMC of the last chosen supplier (Stoft 2002). In markets where the demand curve is very steep, meaning that the demand Q will be fairly unchanged no matter the P, also referred to as an inelastic demand, the market equilibrium will most often be equal to the marginal cost of the last producer.

In economic theory it is stated that the market equilibrium will, if several market conditions are meet, provide the most economic efficient outcome (Keohane, Olmstead 2007). With economic efficiency is understood that the good or service is provided by the cheapest supplier, that it is consumed by the consumers willing to pay for it, and the right amount is produced. This must be seen as a desired outcome of a market situation. The market will not always be in an equilibrium, since changes in the market will occur, e.g. change in demand due to new buyer or closing of an old PP, but a competitive market will in principle always approximate it. If e.g. a plant closed down due to old age and no new plant would be built in its place, then, all other things being equal, it would result in an increase in P, which would result in either a new plant being built or a decrease in demand. (Stoft 2002)

The conditions that have to be met in order to achieve an economic efficient outcome of a market are:

- *Many mutually independent suppliers of a product.*
- *Many mutually independent buyers of a product.*
- *Full information regarding quality and prices of products available.*
- *Agents in the market, acting with rational behavior.*
- *Sellers who maximize profits and buyers who maximize utility.*
  ((Hvelplund, Lund & Sukkumnoed 2007) page 596)

In neoclassical market economy understanding, if these conditions are met or approximated, then it would result in the most efficient outcome of a market situation. (Hvelplund, Lund & Sukkumnoed 2007)

These conditions are relevant to discuss with regard to the Nord Pool electricity market. For the Nord Pool market there are many independent suppliers and buyers of electricity, however there are only four major players on the Nord Pool market. These are Vattenfall, Fortum, Statkraft and Dong, but none of these market players have a market share of more than 20%, when considering the whole Nord Pool market. The buyers of electricity are in the end every single household, company etc., and these must also be seen as “many” and “independent”. The small consumers are not directly active on the wholesale market, but they are represented by retailers which they are free to choose. (Fridolfsson, Tangerås 2009)

Buyers and sellers have full access to knowledge regarding the price on the market for each hour, as these data are published for all the price areas. The individual bids are however not publicly available. Electricity on the grid is of the same physical quality for the buyers, however there can be a perceived difference of quality of electricity depending on which type of facility produced the electricity. Electricity in the grid cannot be traced from a consumer to a specific production facility (Stoft 2002), however the consumers can get information on which types of production facilities were producing in any given hour as these are also published.

If the market is not in perfect competition there is a risk of market players, both suppliers and buyers, exercising market power, which is when a player is able to alter prices away from the competitive levels in order to increase their own gain of the market outcome (Stoft 2002). In this thesis it will not be analyzed whether or not market power is being exercised within Nord Pool, however (Fridolfsson, Tangerås 2009) finds that there is no indication of short-term exploitation of market power on Nord Pool.

3.1.1 Understanding electricity markets

Electricity markets should be described separate from traditional markets. This is due to the unique nature of electricity as a product. Electricity is unique in that it is being consumed within 1/10 of a second of it being produced (Stoft 2002). This also illustrates some of the challenges with the fluctuating RES, since it hereby is important to make the market react to possible unexpected increases or decreases in production from these, since the production from fluctuating RES is less predictable than PPs. The unique nature of electricity and the way that electricity consumption is measured at the consumers also provides a problem on the demand side, where in the current context the demand side is fairly inelastic to short-term price changes, since only few large consumers are able to change their electricity consumption in the short term. This demand side flaw provides a problem for the implementation of fluctuating RES, as these would benefit from a flexible demand. (Fridolfsson, Tangerås 2009)

When describing electricity markets it is relevant to understand the traditional division of different types of power producers. Traditionally three overall types of power producing facilities can be identified. These are base-load facilities, intermediate facilities and peaking facilities. (European Wind Energy Association 2009)

- Base-load facilities are characterized by having a low STMC. They normally have a high fixed cost per MW capacity. Base-load facilities can e.g. be efficient coal-fired steam plants, nuclear plants and hydro power. The cost structure of base-load facilities mean that they will be used to run many or nearly all hours throughout a year in order to pay the fixed costs, and hence they provide the base-load for the electricity system. (Leveque 2006)
- Intermediate facilities have many of the same properties as base-load, but they are used fewer hours a year, since they are used to cover high-load hours that are off-peak. Meaning they are normally not used in night time, but will be used in daytime where the demand is higher. This is because they have a higher STMC and a lower fixed cost per MW capacity than base-load. It can e.g. be less efficient coal-fired steam power plants. (European Wind Energy Association 2009)
- Peaking facilities have a different role within the electricity system. They are characterized with having low fixed costs per MW capacity but high STMC, resulting in them only being needed few hours a year. It is e.g. old plants and natural gas plants. They are basically only used when base-load and intermediate cannot cover the demand. (Leveque 2006)

Power production facilities are not bound to act within these three categories, but can act as they see fit. However, this has traditionally been the division of overall types on the power market. The capacity mix of these three traditional types of power producing facilities will from a neoclassical understanding over time be optimal, if the market is competitive. Meaning that if an electricity market is competitive the optimal mix of these will be approximated. (Stoft 2002)

Within the traditional division, the fluctuating RES like wind power, where the production only to some extent can be controlled, will fall into the category of intermediate facilities, since both base-load and peaking facilities requires facilities with a more controllable nature (European Wind Energy Association 2009). The traditional division of types of power facilities does however seem to have some drawbacks when analyzing a possible future energy system, which likely will rely heavily on fluctuating RES. The reason for this is that the fluctuating RES will in periods completely cover the demand on its own, as already is the case for some hours in the price area DK1, and as the amount of fluctuating RES increases this will occur in more and more hours of the year. Hereby these will reduce the economic potential for having traditional base-load facilities. This illustrates the problem with using this division in a system where fluctuating RES are used to a high degree. One way to define the power producing facilities in this future energy system would be to define the energy system around the fluctuating RES, making non-fluctuating power producing facilities a mix between the traditional types of intermediate and peak facilities that would be used to produce potentially needed electricity when the fluctuating RES cannot cover all the demand. Here it is also relevant to underline that more fluctuating RES most likely will increase the need for a more flexible demand side, meaning a more price elastic demand, in order to reduce problems with an excess production of electricity from these fluctuating RES. This will result in a decrease in the need for peak facilities since the demand peaks will be reduced by either moving the demand or storing the fluctuating production in hours of overproduction. Therefore the traditional division will not be used to define the different technologies within energy systems relying heavily on fluctuating RES. A more fitting division would be: fluctuating RES (wind, wave, etc.), non-fluctuating RES (biomass, biogas, etc.) and means for a flexible demand (electricity storages, flexible consumer demand, etc.). It must be reasonable to assume that within the neoclassical understanding, these would approximate an optimal mix if the market is competitive, as the case is with the traditional division.

However since this thesis focuses on which technologies that will be invested in when using different auction settings, it is relevant to further investigate the reasons for making investments in power producing facilities. Overall there can be identified three typical reasons for investors to invest in electricity producing facilities:

1. Less than optimal needed capacity can make it profitable to invest in new capacity, since low capacity will result in increased prices of electricity, making investing in capacity more economically interesting.
2. Some capacity has reached the end of its lifetime and must be replaced with new capacity.
3. The costs of running a facility are so high that it is economically feasible to replace it.
   (List derived from (Leveque 2006))

If the STMC are covered then it does not always make economic sense to build new capacity. This is due to the fact that sunk costs embedded in power producing facilities are relatively high and also that it takes several years to build new capacity, which puts a high degree of uncertainty in the investment decision. This uncertainty drives a wedge in the relationship between the price of electricity and at what point it is economic feasible to enter or leave the market. (Leveque 2006)

These three reasons could all result in there being invested in technologies relevant for a renewable energy system. The choice of which technologies to invest in would depend on the income potential of the different technologies. As it must be assumed that when dealing with technologies with similar production purposes, like producing fluctuating electricity, then the technologies that are chosen by the market players will be the ones with the greatest income potential, based on the assumption that market players will try to maximize their profit. In neoclassical market economy the efficient market outcome will on its own result in the right technology mix. However, since this project focuses on which technologies will benefit from a change of auction setting in different technological energy system setups, it is relevant to introduce institutional economy.

3.2 Using institutional market economy to understand markets

Institutional economy focuses on the institutional setting of the market and how that affects a technological change. Here the auction setting can be seen as an institutional setting for the electricity system, and the change towards more RES in the energy system must be seen as a technological change, and institutional economy is therefore of relevance. (Hvelplund, Lund & Sukkumnoed 2007)

Where neoclassical economy focuses on creating a competitive market with an economically efficient outcome, in which the result is the best outcome for society as a whole, institutional economy instead sees the market as an institutional construct that does not necessarily produce the best outcome for society. The reasoning behind this is that institutional economy sees the neoclassical conditions for a competitive market with an efficient outcome as a utopian situation, which will never occur in the real world. Institutional economy instead treats the market as an institutional construct with the specific institutional context for each market situation, and the institutions of the market can be changed to achieve a more socially desirable outcome. In institutional economy it is hence also of importance to investigate who stand to gain and who stand to lose of a concrete institutional setting. The institutional economy therefore requires a much more concrete modeling of the institutional setting of the market, including the players on the market, their connections and the flow of money. (Hvelplund, Lund & Sukkumnoed 2007)

The general institutional approach for technological change can be seen in Figure 6.

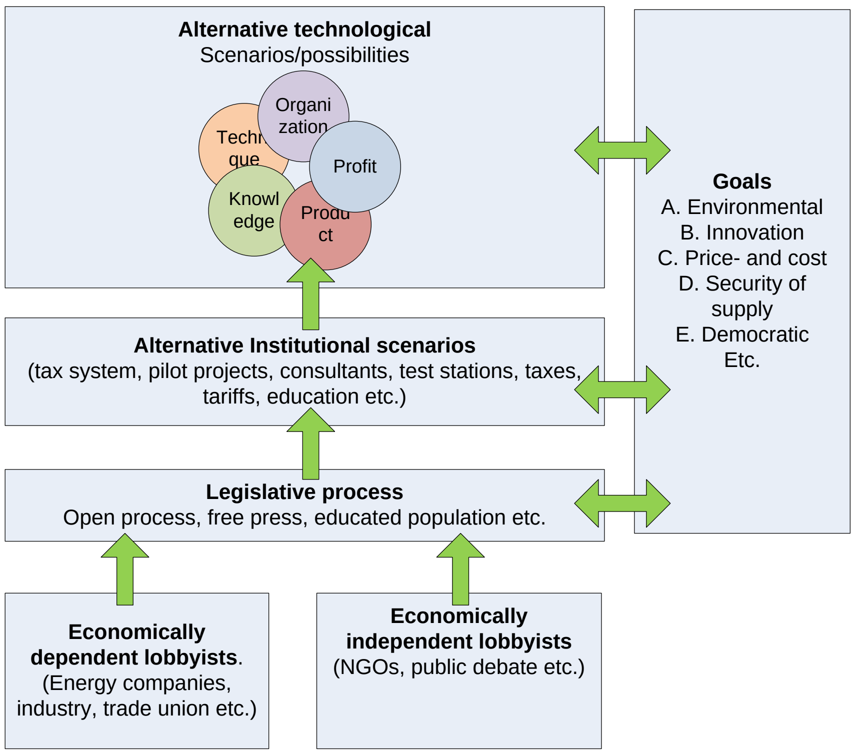

Figure 6: General institutional approach to technological change (Hvelplund 2001)

When making a full institutional economic analysis of a technological change all the parts of the model will have to be analyzed. At the bottom of the model are the different economically dependent and independent lobbyists, who will try to influence the technological change through the legislative process. The legislative process will result in some institutional scenarios, where elements such as the tax system, pilot projects, etc. are analyzed, and these are then hold against the technological scenarios. The legislative process, institutional scenarios and technological scenarios are all developed on the basis of the goals for the technological change.

Parts of the institutional approach to the market are brought into the analysis in section 4.1, where the ownership of the different technologies is discussed. Furthermore the results focus on the flow of money in the different modeled auction settings, as this shows which technologies stand to gain and which stand to lose. The analyses are mainly within the boxes of Alternative Institutional Scenarios and Alternative Technological shown in Figure 6.

3.3 Using auction theory to understand electricity markets

The institutional approach does require a more detailed look into the alternative institutional scenarios, where the goal is to investigate two different auction settings. In order to understand these institutional structures better, another definition of markets is brought into play:

> *"A market is a decentralized collection of buyers and sellers whose interactions determine the allocation of a good or set of goods through exchange"* ((Keohane, Olmstead 2007) page 56)

What is interesting about this definition is that it addresses markets as being decentralized. This keyword is relevant since it makes a distinction between markets and auctions, where auctions are centralized around an auctioneer. (Keohane, Olmstead 2007)

In the context of Nord Pool Spot this distinction is particularly interesting, since this implies that in order to understand the workings of the Nord Pool electricity market it is important to investigate the workings of auctions differently from traditional market theory. However, it must be assumed that the market theory described in this chapter still applies, since auction theory does not supersede market theory, but builds upon market theory by providing a more detailed look into a specific market situation. So a more concrete look at the theoretical workings of auctions is beneficial.

Auction theory is an applied branch of the economic theory known as Game Theory, which focuses on player's behavior in situations, where the player's success is affected by the choice of other players (Klemperer 2004). Basically there are four types of auction settings. These are:

1. **Ascending-bid auction:** Buyers start bidding at a low price and the highest bidder wins and pays the last price bid.
2. **Second-price sealed-bid auction:** The buyers submit sealed bids, and the winner pays the price of the highest losing bid.
3. **Descending-bid auction:** The auctioneer starts with a very high price and progressively lowers the price. The first buyer to accept a specific price wins and pays that price.
4. **First-price sealed-bid auction:** Buyers submit sealed bids, and the winner pays the price that is bid.
   (Klemperer 2004)

These auctions can also be used in reverse in order to sell a product rather than buying it, and can be used for multi-unit auctions, which would be the characteristics of an electricity auction. The two examined auction settings in this thesis are the MPS, which fall under the category Second-price sealed-bid auction, since the all winners are paid the same and the bid is sealed. And PAB must be seen as a First-price sealed-bid auction, since the winners of the auction are paid what they bid and the bids are sealed. (Stoft 2002)

The two investigated auction settings are described in more detail separately in the following sections.

3.3.1 Marginal Price Setting

In Marginal price setting (MPS) auctions all the winners of the auction are paid the same price for the good, which is the price of the most expensive winning bid. This auction is also known as Uniform price auction. (Tierney, Schatzki & Mukerji 2008)

MPS auctions are the most commonly used auction setting in electricity markets (Cramton 2004), and is also the model used by Nord Pool Spot as described in the introduction, chapter 1. As this provides a description of Nord Pool Spot it will not be described again in this section.

In MPS there is a link between the STMC and the bids of the suppliers. This is because it will be the preferred strategy of the market players to bid close to their own STMC and have the highest possible chance of winning the auction, and then hope for more expensive bids to also win, rather than not winning the bid at all, and thereby not selling the good. Therefore this auction setting provides a framework similar to the efficient market where the suppliers with the lowest costs are chosen first. This is however only true when there is no collusion in the market, which is when players either explicitly or tactically work together to increase their own gains, which a repeating auction is particular vulnerable to. Since auctions on electricity markets are repeated every day they are particular vulnerable to collusion. MPS auctions are particular in risk of collusion since all winning bids affect the resulting price. The risk of collusion in an auction is however reduced when there is a competitive market; since this will make the players compete instead of collude. (Klemperer 2004). Any possible collusion on Nord Pool will not be investigated, but as stated the market seems to be competitive, and collusion is similarly assumed not to be a concern in the current Nord Pool electricity market. Therefore it can be assumed that the bidding price for the players in the MPS auction will be fairly close to their STMC.

The auction setting is widespread particular because it is seen as fair, since all winners are paid the same no matter their bid (Cramton 2004). Also it is fairly easy to enter the auction, since new market players will only need to know the market price and their own STMC, whereas in PAB one will need more market information regarding what other players bid in order to do well on the market. (Klemperer 2004)

3.3.2 Pay-as-bid auction

In Pay-As-Bid (PAB) auctions the winners of the auction are paid the price that they are asking for their good, without taking other winning bids into account. This auction setting is also known as "discriminatory auctions", since the winners are paid differently depending on what they bid. (Tierney, Schatzki & Mukerji 2008)

Where the MPS auctions resulting market price is similar to that shown in Figure 5, PAB auctions finds the resulting market price by the average price of the winning bids. The general difference of these two approaches can be seen illustrated in Figure 7.

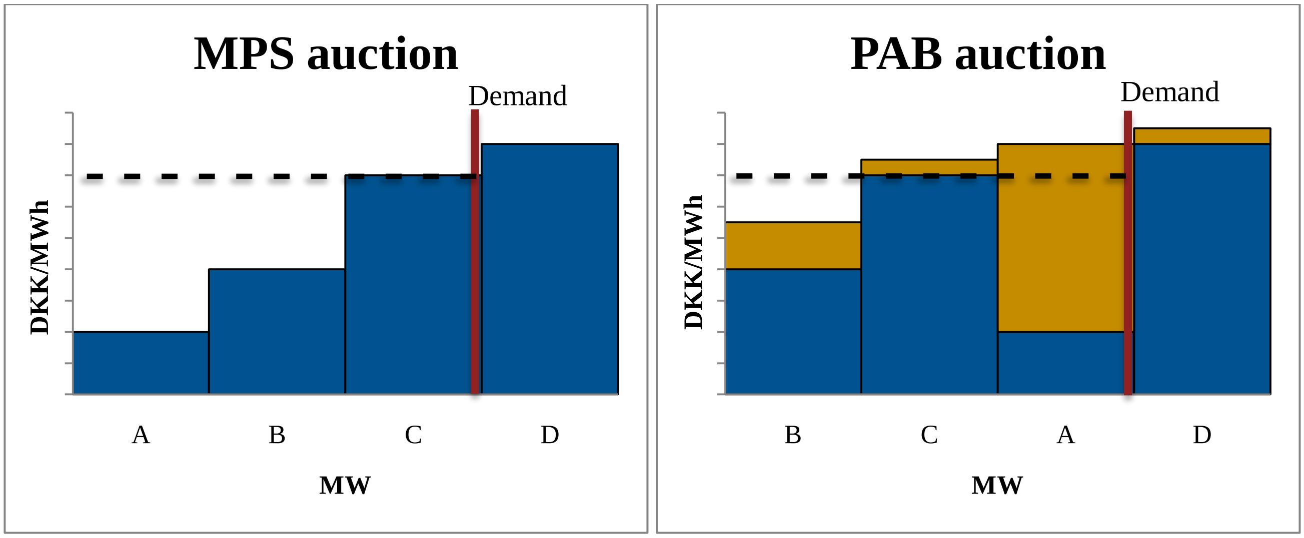

Figure 7: Approach for finding the resulting auction prices in the MPS and PAB auctions. Blue is the STMC of the units and yellow is the difference between the PAB bids and the STMCs. Inspired by figure from (Tierney, Schatzki & Mukerji 2008)

The difference between STMC and the PAB bidding prices is discussed later in this section.

There are only few examples of PAB being used in electricity markets. PAB has been used in the electricity regulating market in Denmark until December 1st 2009, but because of the harmonization of the Nordic balancing market it was changed to MPS (Energinet.dk 2009). It has not been possible to find any information regarding whether the change was due to flaws in the auction setting. Instead it seems as if the main reason was that the other Nordic countries in Nord Pool used MPS for the regulating markets, making it easier to have the Danish market use this auction setting as well.

In most markets PAB is only used in submarkets if used at all, however the electricity market covering England, Scotland and Wales (is here referred to as the English system) went from a MPS electricity market to a PAB electricity market. This change occurred due to the institutional market setting in the English electricity market. Originally the English electricity market was privatized in 1990 with the former state owned generation and transmission company being split up into four companies. The fossil fuel power generation was divided into the companies National Power and Powergen, and the nuclear power facilities were collected under the company Nuclear Electric. The transmission grid became National Grid Company, and was owned by the 12 regional electric companies (RECs) until 1995, where it then became an independent institution. These existing 12 RECs handled distribution and retail in 12 regions and were also privatized in 1990. (Anderson 2009). With this privatization a new market system was also introduced with a day-ahead MPS auction as one of the major parts of the new market, where the producers and consumers gave bids to this auction for the day after, and an algorithm calculated the electricity price for each half hour the next day. (Federico, Rahman 2003)

The then newly privatized market had a lot of problems linked to the competition on the market. The details of these problems will not be described here, but some of the main problems were:

- Not having a clear division between generation and retail/distribution companies, where the RECs were bought by the generation companies and the RECs also themselves had some generation facilities. This resulted in problems with market power in some regions.
- Different government decided protection schemes resulted in more than 95% of the consumed electricity was not competing on the central auction. An example of one of these schemes was state subsidies to nuclear power which meant that half the income of the nuclear power plants came from subsidies, resulting in Nuclear Electric having no incentive to compete on the auction, making National Power and Powergen the only active big players on the market.
(Thomas 2006)

The institutional setting was an important part of the reason for the change of market system, since the MPS that were set up in 1990 were perceived as operating in favor of those generating electricity. This meant that the wholesale prices did not fall in the period in which the auction setting was in place; despite that both the electricity producers cost of generation was halved along with the general efficiency of the PPs increased in the period. Therefore the government decided to change the system to reduce the potential for exercising market power, and getting a more competitive market system for electricity. (Ofgem 2002)

This occurred in March 2001 with the "New Electricity Trading Arrangements" (NETA) that changed the system of England and Wales from a MPS to a PAB market structure. It was done by completely abolished the day-ahead auction and only having a central PAB balancing market, which was preceded by bilateral contracting or trading on private power exchanges (Federico, Rahman 2003). In this new setting 98 % was in 2002 traded by bilateral contracts or on private exchanges, and only 2 % was traded at the balancing market (Ofgem 2002), with most traded bilaterally and only a small amount traded on the private exchanges. E.g. in January 2004 the typical amount traded on the private exchanges was less than 1% of the total demand of the system. (Thomas 2006)

Another important factor in NETA was allowing generation companies to own retail companies. This meant that in 2003 the 12 RECs were controlled by companies that also owned generation of electricity. Five of the main generating companies did not own any of these, and they all went bankrupt or close to it. The nuclear power companies were however not allowed to fail, due to waste issues. (Anderson 2009). This vertical integration is also important for the amount of bilateral trades on the electricity market, since many of the major players own both generation and retail, and hereby only produce electricity for their own customers in their retail branches. (Thomas 2006)

Considering the conditions for an efficient market outcome, the English electricity market seems to have problems with keeping buyers and suppliers mutually independent by letting companies have both the selling and buying on the wholesale market in one company, making it possible to only trade internally within the companies. Also the very small amount of open trade seem to be problematic with regards to full information about the market prices, since the open trade price most likely does not reflect the actual electricity price on the market.

These very specific conditions for the English electricity system make it extremely difficult to base a possible Nord Pool PAB system upon the English system. However, an important fact is that the Nord Pool power exchange is more successful in that significantly more of the total demand is traded on it than on the English private exchange (Thomas 2006), where in 2008 71% of the consumption of electricity in the Nord Pool area was traded via Nord Pool Spot (Houmøller 2009). Also that PAB can be used in power exchanges is an important takeaway. But as there is no well functioning electricity markets based on the PAB auction setting, providing a detailed description of how PAB could be implemented as the basis for the Nord Pool Spot would be difficult and time-consuming, and will not be discussed in detail in this thesis. However, it is assumed that a potential Nord Pool PAB still is able to function using the current exchange system, with the difference being how the price is calculated as the average price of the winning bids, and that each winning bid is paid their bid.

PAB is also sometimes brought up in discussions in USA during times with high electricity prices. This is due to an argument that this auction setting will make sure that consumers do not get overcharged for the good they purchase, since it will make sure that no producers are overcompensated for their production, as could be the case with MPS, where the highest cost determine the cost for all other units, and hereby one expensive unit could result in a high compensation to all cheaper units. (Laffer, Giordano 2005)

However, the counter-argument is that PAB auctions will not result in lower consumer prices, since the bidders will try to increase their profit by guessing the final marginal auction price resulting in them bidding just below this price, instead of bidding based on their costs (Tierney, Schatzki & Mukerji 2008). Also this is only really a potential behavior for the major players, since only these have the resources to make these assessments and the financial power to take these risks of gambling on the market. The small players and potential small newcomers will to a lesser extent be able to gamble on the market, since they have fewer resources and less information about the market to do so and thereby will get less profit than the major players in a PAB setting, and the major market players will thereby have an advantage. The market players in MPS only need information regarding their own costs in order to make a bid. (Vázquez, Rivier & Pérez-Arriaga 2001)(Klemperer 2004)

Another important argument against PAB's potential for reducing consumer prices is that the low bids in MPS will have to account for their fixed costs in the bidding price, which will result in them bidding their long-term marginal cost plus profits instead of their STMC. And this will especially increase the bids from base-load facilities and intermediate facilities when comparing to MPS. Though it must also be concluded that the production facilities with a low STMC, which normally also will have high fixed costs, will try and keep the bid low enough to ensure a sale, since they would be quite dependent on winning many hours a year in order to recover their fixed costs. This could result in these types of facilities to get lower revenue than plants with lower fixed costs, since they would be more able to gamble on the market, and thereby this would in the long-run result in more investments placed in the low fixed costs facilities. (Tierney, Schatzki & Mukerji 2008) (Stoft 2002)

PAB is however very useful to avoid potential collusion in a market. This is due to the nature of PAB, where one's bid only affects one's own income, whereas in MPS one bid sets the price for all other winning bids, and where all lower bids also affect the price (Klemperer 2004). These arguments regarding PAB provides two different types of potential bidding behavior for PAB auctions. First and foremost it is assumed that all players will try and bid with a price that will both cover their long-term marginal costs, and also provide a profit for selling electricity. Therefore one potential bidding behavior would be one, where all players will bid into the market with a bid that will make them able to cover these long-term marginal costs and get a profit. The other bidding behavior would be one where the major players will try to gamble on the market with some of their units, in order to improve their gain.

The next chapter provides a description of how the two auction settings are modeled and analyzed.

4 Modeling and analysis of the two auction settings

First part of the analysis is a description of the ownership structure of the Danish electricity market to show which technologies in the current electricity system are owned by the major players. This is done to estimate who has most resources to gamble on the market in a PAB setting. The second part is a description of the two technical setups used as a foundation for the analysis. This description gives an overall understanding of which technologies and the sizes that are used for electricity production and consumption. The third part provides a walkthrough of the different costs used in the modeling. This is followed by a description and discussion of how to model the different auction settings, which leads into a more detailed description of the different modeled MPS and PAB scenarios.

4.1 Institutional context of the Danish electricity market

As stated in the section 3.2 it is in these analyses seen as relevant to investigate the ownership of the technologies within the electricity system in Denmark, as this is relevant when modeling PAB auctions. This section describes the ownership structure in all of Denmark's electricity system, meaning that DK1 and DK2 are described as one.

The Danish electricity system is dominated by two large generation companies. These are DONG Energy and Vattenfall, which are the two only significant market players, and they are therefore in this project separated from all other players, which are referred to as "Others". The ownership structure is analyzed by investigating four main generating components of the Danish electricity system. These are offshore wind power, onshore wind power, central thermal facilities and decentral thermal facilities, where the central in a classical understanding are the ones that are centrally dispatchable. The border between central and decentral however changes over time, since new technology makes it possible to control more facilities from the TSO's side. Technologies with very small capacities, such as photovoltaic that had a capacity of 3 MW in 2008, and hydro power that had a capacity of 9 MW in 2008, are not investigated. Also the producers with electricity production as a side-income of their main activity e.g. waste treatment companies and electricity from industrial companies are not investigated, as they are not bidding actively on the market. They had a total capacity of 679 MW in 2008. (Danish Energy Agency 2009b)

The central thermal facilities are defined as 18 named larger facilities in Denmark, and the decentral facilities are the rest of the thermal facilities where the main activity is the production of heat and power. The Danish electricity system is characterized by the electric generation from thermal production being closely connected to heat production, where in 2008 79.7% of the district heating and 55.4% of the thermal electricity production were produced by CHPs. Therefore most of the central and decentral thermal facilities also have CHP capability, and are connected to district heating grids. Of the central facilities only facilities with a combined capacity of 558 MW out of a total central capacity of 7,558 MW in 2008 did not have some heat producing capability, and the central facilities also produce the main portion of the district heating in Denmark. (Danish Energy Agency 2009b)

The ownership of the electric capacity for the central and decentral thermal production is shown in Figure 8 and Figure 9. These figures have been produced using data from different sources, and might be imprecise due to possible differences in date of registration, but should provide a general overview.

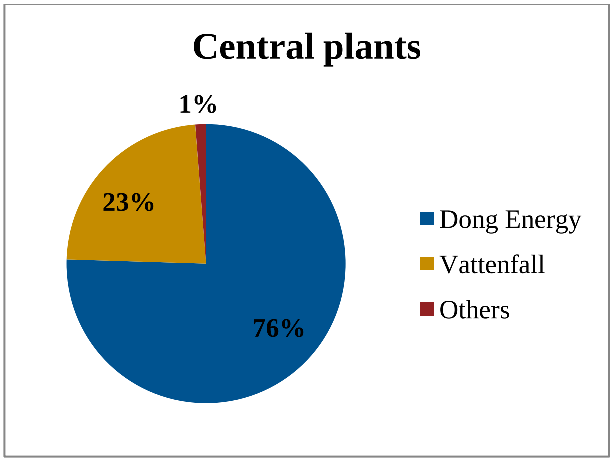

Figure 8: Ownership percentage of the total central electric capacity in Denmark in 2010 (Dong Energy n.d.)(Vattenfall 2010)(Energinet.dk 2010)

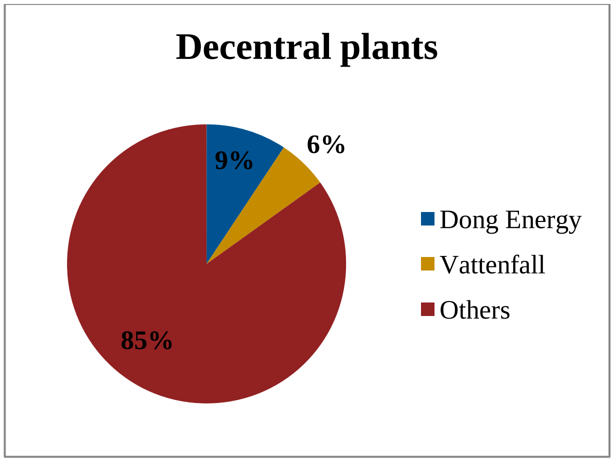

Figure 9: Ownership percentage of the total decentral electric capacity in Denmark in 2010 (Dong Energy n.d.)(Vattenfall 2010)(Energinet.dk 2010)

As can be seen in Figure 8 almost all the central thermal capacity is owned by DONG Energy and Vattenfall. The last 1% is owned by the company “Østkraft”, which only operates on the small Danish island Bornholm. It is hereby clear that the two major players are the only market players on the Danish market that have any significant central plant capacity, and here DONG Energy clearly has the largest capacity.

The picture is however completely different for the decentral plants, as seen in Figure 9. Overall DONG Energy and Vattenfall only owns about 15% of the electric capacity of the decentral plants. The majority of the plants are owned by smaller market players. The owners of the other decentral plants are other energy companies, local authorities and co-operatives (Danish Energy Association 2008).

The decentral CHP units and the central CHPs are all connected to district heating grids, where the heat produced is sold to consumers connected to the grid. These district heating grids are by Danish legislation to sell the heat at a price corresponding to the cost of producing and distributing (Danish Energy Agency 2009a). The district heating provider does not necessarily own the connected CHPs, this is the case with several of the central plants; however these CHPs will have an agreement with the local heating grid owner regarding the price they get for producing heat, and these agreements will hereby be different for each plant.

As mentioned in the introduction, chapter 1, a large share of the electricity production comes from wind energy. This can be categorized into onshore and offshore wind power. The ownership in these categories is very different. This is shown in Figure 10 and Figure 11.

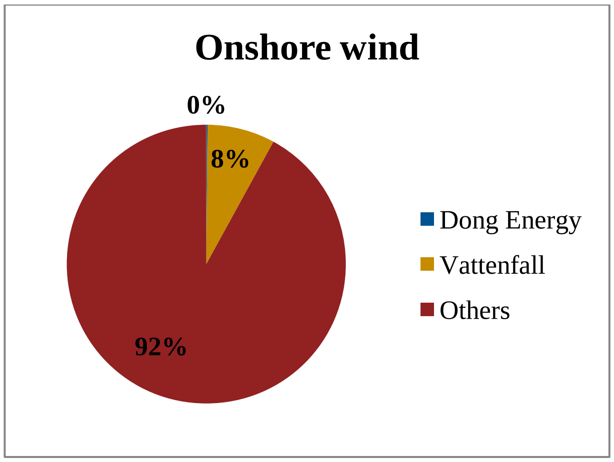

Figure 10: Ownership percentage of the total onshore wind power capacity in Denmark in 2010 (Dong Energy n.d.)(Vattenfall 2010)(Energinet.dk 2010)

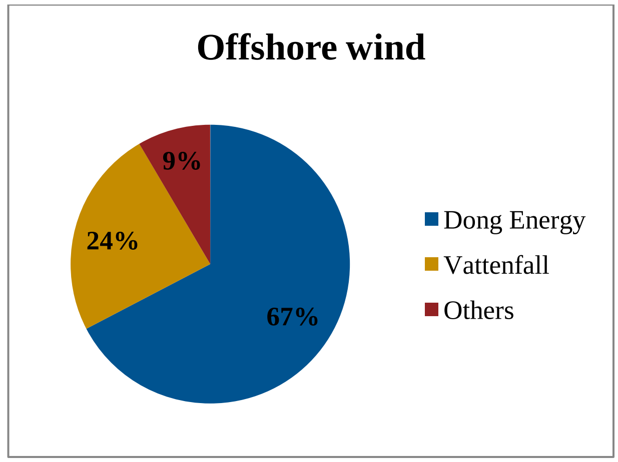

Figure 11: Ownership percentage of the total offshore wind power capacity in Denmark in 2010 (Dong Energy n.d.)(Vattenfall 2010)(Energinet.dk 2010)

From Figure 10 and Figure 11 it is clear that the two major players own only a small part of the onshore wind capacity, but instead owns most of the offshore wind power. The other owners of wind power are a mix of single-persons and co-operatives (Danish Wind Turbine Owners' Association 2009). Again it has to be noted that the numbers in the figures are from different sources, and may not be from the same point in time, but to give an overall idea about the ownership structure in Denmark, the numbers are sufficient.

The previous shows that in the current electricity system the central thermal plants and offshore wind power are primarily owned by the only two major market players. The decentral thermal plants and the onshore wind is however owned by a larger number of smaller market players. This is of relevance when determining possible bidding strategies for the different technologies in the PAB setting, as the bidding strategy could depend on the owner of the technology, because the larger owners have more resources to run the risk of gambling on the market.

For the modeling of the auction settings two technical setups are used, and these are explained in the next section.

4.2 The two technical setups used for the analysis

To make an analysis of the effects of changing the auction setting, two technical setups are used. The first is to represent a system similar to the present situation in Denmark, and another is to show a possible future situation with a larger share of wind power. Instead of designing these two systems specifically for this thesis, it has been chosen to use the cases that The Danish Society of Engineers (IDA) uses in a project named "The IDA Climate Plan 2050". The IDA Climate Plan focuses on three different scenarios which are in the years 2015, 2030 and 2050. The difference between the scenarios is the amount of RES in the system, where 2015 is more or less like the present situation and 2050 is a 100% RE system. Each of the IDA cases is improvements of reference systems forecasted by the Danish Energy Agency (DEA). To represent the present energy system in the analyses it has been chosen to use the basic reference scenario DEA2030 with 30.7% RE of all energy produced. To represent an energy system with more RES, it has been chosen to use the IDA2030 case with 45.7% RE of all energy produced. The following sections describe the characteristics of these two energy systems setups. Since the focus in this thesis is the electricity market, the focus is on the type of technologies and capacities utilized for electricity production and also the electricity demand. This differs from the IDA Climate Plan where a more holistic approach is used, by looking into all the energy sectors. (Danish Engineer's Association 2009)

The DEA2030 setup is as mentioned a basic forecast for 2030 made by the DEA from 30th of April 2009, this means that it is based on the assumptions regarding fuel prices, emission prices, economic growth, tax rates, subsidies, etc. Also it is based on an interpretation of the political initiatives, and their effects on the energy consumptions and productions. The IDA2030 setup uses the same prices, taxes, etc., but looks into different technological setups than in the DEA2030. The technologies used in the IDA2030 setup arise from a lot of different steps looking into how to make a flexible energy system, and minimize resource use. These steps include CHP regulation, large heat pumps, flexible electricity demands, electric vehicles and fuel cells. Hereby the IDA2030 incorporates demand flexibility means, which as stated in chapter 3 is relevant when implementing fluctuating RES. In Figure 12 the capacities of different technologies used for electricity generation in both DEA2030 and IDA2030 are shown.

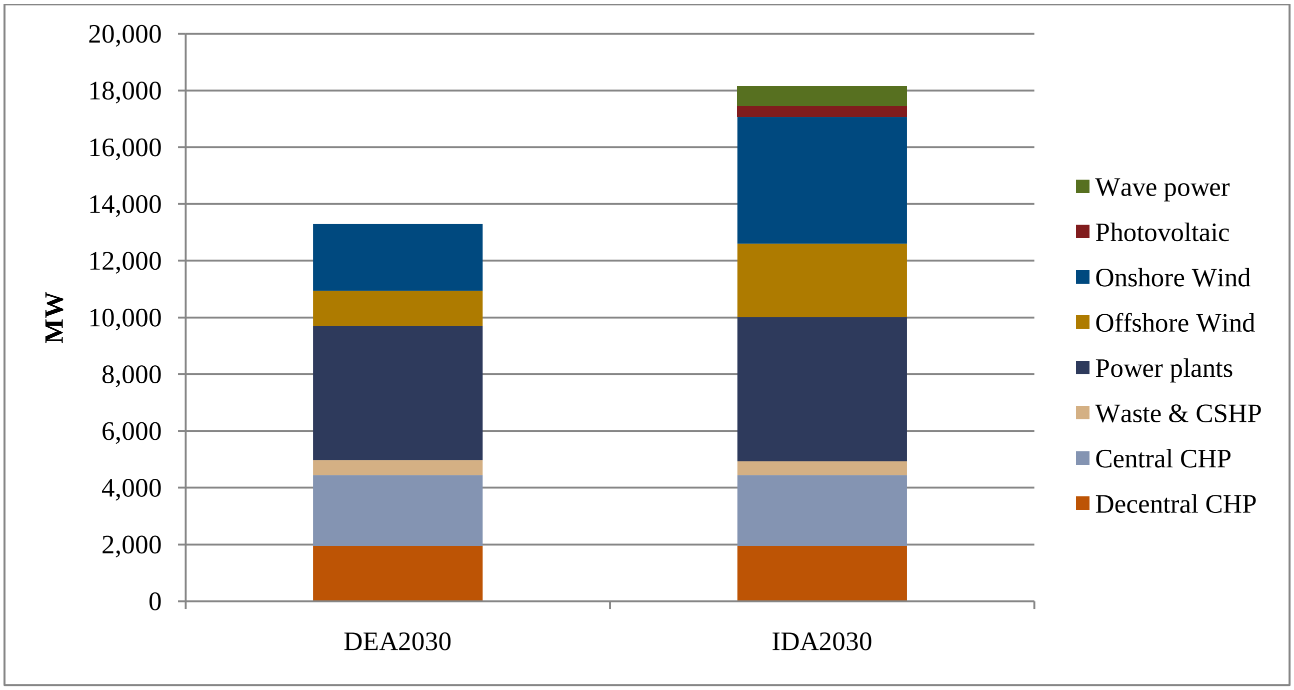

Figure 12: Electric capacities in the two setups from the IDA Climate Plan used in this thesis. CSHP = Industrial CHP (Appendix 1) (Danish Engineer's Association 2009)

In the DEA2030 situation there is a large share of central CHPs with an electric capacity of 8,552 MW with an electric efficiency of 35% and in condensing mode 42%. The capacity is based on the peak electricity consumption added 20%. For decentral CHPs the electric capacity are 1,945 MW with an electric efficiency of 37%. Also a 534 MW share of waste and industrial production capacity is available. In DEA2030 there is an onshore wind power capacity of 2,350 MW and an offshore capacity of 1,239 MW. For the wind production different full load hours are used, for onshore 32% full load hours and for offshore 45% full-load hours. (Danish Engineer's Association 2009)

Looking at IDA2030 the onshore capacity is increased to 4,454 MW with 32% full load hours and the offshore to 2,600 MW with 45% full-load hours. In DEA2030 there are no photovoltaic, but in IDA2030 this is implemented with a capacity of 683 MW with 15% full-load hours. Similarly wave power is also introduced in IDA2030 with a capacity of 400 MW and full-load hours around 40%. The overall waste incineration electrical efficiency is increased from 23% to 27%, which results in a capacity of 484 MW. The largest share of electric capacity is still the CHPs and PPs in IDA2030, but the fuel cell technology is introduced making these more efficient. The overall capacity is again calculated from the peak electric demand which combined with flexible demand gives a condensing CHP and PP capacity of 7,578 MW in total and a decentral CHP capacity of 1,950 MW. In total approximately 3,500 MW fuel cells are used for CHP and PP. This gives the average electrical efficiencies of 45.6% for central CHP plants with 50.2% in condensing mode operation, and 46.6% for the decentral CHP plants. (Danish Engineer's Association 2009)

Not shown on the graph is that the transmission capacity for import/export in both cases is 2,500 MW and no bottlenecks exist between DK1 and DK2 in the setups, since the plan covers both price areas. (Danish Engineer's Association 2009)

In the IDA Climate Plan’s EnergyPLAN modeling of DEA2030 and IDA2030 different fuel consumptions have been used for the two setups. For DEA2030 the focus has been to approximate the modeled fuel consumption with the DEA forecasted fuel consumptions. In order to achieve this the fuel biomass has been kept as a fixed fuel amount in the EnergyPLAN modeling, which means that the biomass fuel in the DEA2030 is modeled as a yearly fixed cost, and are not part of the STMC. This approach is useful for approximating a forecasted future, but it is not a desired modeling strategy for this thesis, as it leaves out an important part of the foundation for the hourly choice of technologies. For this reason the fuel modeling for DEA2030 has been changed in order to get the biomass fuel from being a yearly cost to be part of the STMC. Remodeling in order to achieve the fuel consumption forecasts of DEA would be an extensive task, which also is the reason for it being fixed in the original DEA2030. IDA2030 is however modeled with biomass as a variable fuel consumption, meaning that it is part of the EnergyPLAN calculated STMC. The fuel consumption for modeling IDA2030 in EnergyPLAN has therefore been applied to DEA2030, and the DEA2030 presented throughout this thesis does hereby differ from the one presented in “The IDA Climate Plan 2050” by having different fuel consumptions for the technologies.

This change of fuel, the capacities and the efficiencies have been used in the EnergyPLAN modeling in combination with hourly distribution files for demands and non-thermal production. Both are calculated with the market economic strategy selected in EnergyPLAN, this is done to include trade on the external electricity market, for a thorough explanation of the strategy see section 2.2. It has to be noticed that the costs used for this initial analysis also are different from the ones used in the original IDA climate plan, since the DEA has updated their forecasts in April 2010 (Danish Energy Agency 2010). The new costs used for the modeling can be seen in section 4.2.1. One of the overall outputs is the annual electricity production and consumptions for the two setups, which is shown in Figure 13.

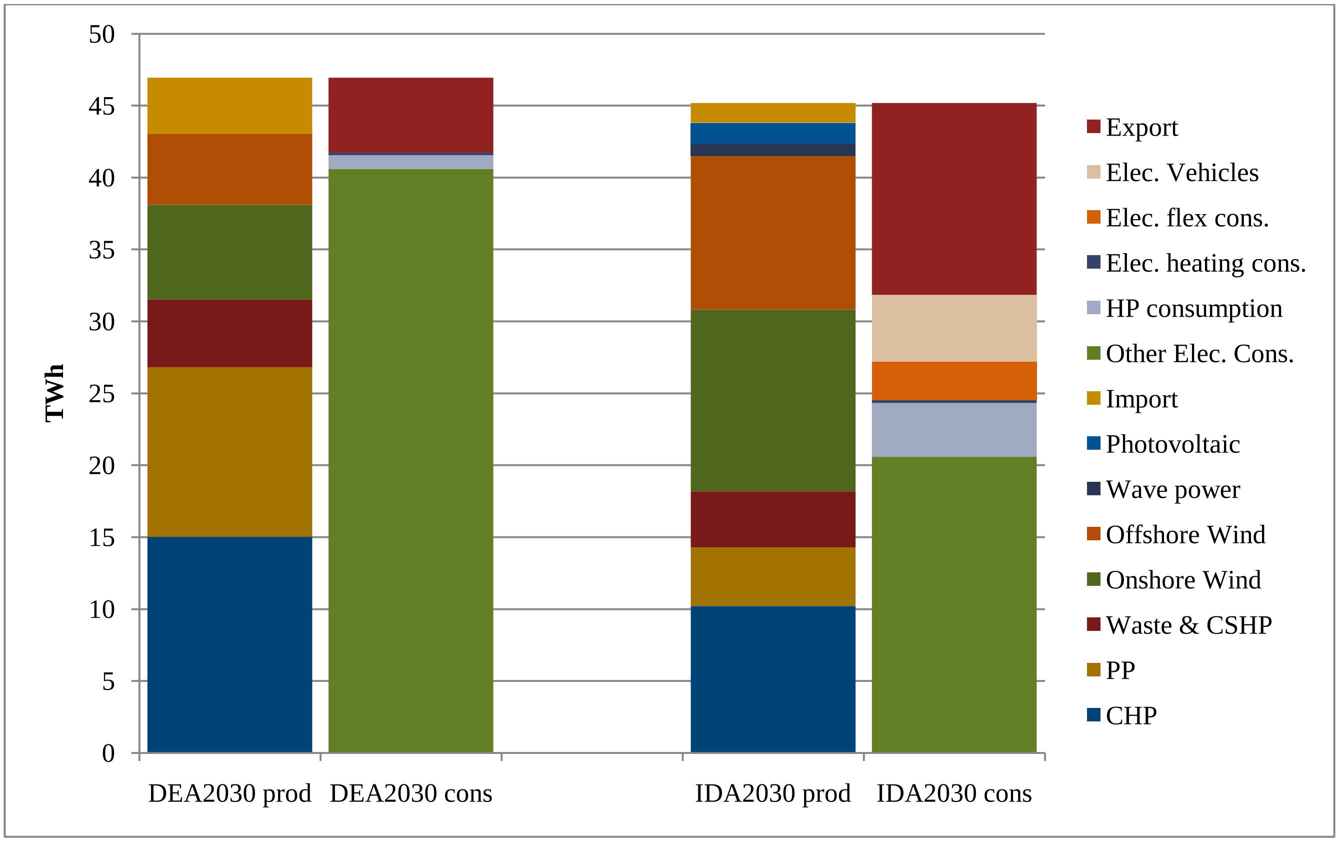

Figure 13: Electric production and demand in DEA2030 and IDA2030 scenarios. HP = Heat Pump (Appendix 1)

Some of the productions and consumptions are based upon the STMC for running the different production units in each hour, where the model chooses those with the lowest STMC first; this is the thermal production units like CHP and PP. Other units like wind, wave and photovoltaic produce according to the hourly distributions for each energy type. Looking at the amounts in Figure 13 for DEA2030, which represent the present energy system, it can be seen that the production is based mainly upon CHP, PP, Waste and CSHP which produce 32 TWh/year. The rest is produced by wind power, which is around 12 TWh/year. The electricity consumption in DEA2030 is mostly non-flexible consumption except for small amounts of export and heat pump consumptions. Going on to IDA2030 this gives a whole different system; the key element in the production is the wind power consisting of around 23 TWh/year. The CHP, PP, Waste and CSHP produce only 18 TWh/year. Also small amounts of wave and photovoltaic units are introduced producing around 2 TWh/year. This system gives a more fluctuating production for each hour than the DEA2030 setup, therefore the demand side also needs to be more flexible. In order to achieve this, new technologies are introduced on the demand side: electric vehicles, larger amounts of heat pumps and other flexible consumption. Combined flexible consumption amounts to around one third of the consumption or 11 TWh/year. Another important difference between the two systems is the exported electricity which is around 5 TWh/year in DEA2030 and larger in IDA2030 with 13 TWh/year.

As mentioned earlier these productions are results of the market economic optimization strategy used in EnergyPLAN. An important part of this is the different costs used for each technology, therefore the next sections is about the different costs for fuels, handling, transport, CO_2 and O&M.

4.2.1 Fuel and CO_2 costs used for the modeling

The fuel costs used for the modeling are the ones from "DEA - April 2010", as shown in Table 1. These costs are not the ones used in the original IDA Climate Plan, but the updated predictions from the DEA. It has been chosen to use these, because they are the newest estimations, and therefore are more up to date.

	DEA - April 2010
(DKK/GJ)	$117/barrel
Crude oil	119.8
Coal	26.5
Natural gas	80.7
Fuel oil	83.9
Diesel fuel/Diesel	149.7
Petrol/JP	159.3
Straw	39.5
Wood pellets	85.8

Table 1: Fuel costs used in the scenarios (Danish Energy Agency 2010)

There is also handling costs linked to the different fuels; these are shown in Table 2.

Additional costs(DKK/GJ)	Coal	Natural gas	Fuel oil	Diesel fuel/Diesel	Petrol/JP	Biomass
Power plants	0.53	3.38	1.8			12.92
Decentralized CHP, district heating & industry	0.53	8.86	14.85			8.65
Individual households	0.53	22.29		22.59		47.6
Road transport		22.29		24.5	33.09	12.92
Aviation					5.41	

Table 2: Additional costs (Danish Energy Agency 2010)

The fuel handling costs are also the new prices from the basic forecast made by the DEA in April 2010. These are important, because they add to the STMC for production. Hence if these are different for e.g. the PPs and decentral CHPs, this have an effect on which type of technologies are used for production.

On the environmental side, for the CO_2-quota cost the DEA April 2010 forecast for 2030 is used again with a 290 DKK/ton CO_2. This is higher than the one used in the IDA Climate Plan, but again more up to date with what the DEA expects. (Danish Energy Agency 2010)

There are also added taxes on parts of the fuel use; these are shown in Table 3.

Taxes (DKK/GJ)	Coal	Natural gas	Fuel oil	Diesel fuel/Diesel	Waste	Biomass
Individual households				60		
Boilers	72.6	86.4	70.6		42.6	1.75
CHP units	26.5	24.5	25.8		34.6	1

Table 3: Taxes on fuel consumption (Danish Engineer's Association 2009)

The taxes are the same as used in the IDA Climate Plan. The taxes are important, since they affect the STMC for the production units. It has to be noticed that there is not used taxes on fuel consumption for PPs, as this is not done in the IDA Climate Plan.

4.2.2 Operation and maintenance costs

The last thing adding to the STMC for a production unit is the variable operation and maintenance costs (O&M) shown in Table 4.

	Variable O&M
	DKK/MWh-e
Onshore wind	0
Offshore wind	0
Wave power	0
PV	0
Decentral CHP	20
Central CHP	20
PP	15

Table 4: Variable O&M costs (excl. fuel costs) for electricity producing units (Danish Engineer's Association 2009)

For wind, wave and photovoltaic the variable O&M cost is set to zero, because these have very low variable O&M costs. The CHPs and PPs on the other hands have some variable O&M costs linked to producing, the CHPs with 20 DKK/MWh electricity and the PPs with 15 DKK/MWh electricity.

Next section discusses how to approach the modeling of the different auction settings, and especially how to model the new auction setting PAB.

4.3 The modeling of the auction settings

In order to discuss the modeling of PAB, the modeling of the MPS auction setting must first be explained as it sets the basis for the PAB settings. In the modeling of MPS it is assumed that the technologies bids close to their STMC for producing electricity, which as described in chapter 3, is the preferred strategy when there is no collusion on the market. In the analyses it is assumed that there is no collusion on Nord Pool Spot. It is also assumed that the technologies in the scenarios are able to earn enough to at least cover their yearly long-term marginal costs by bidding their STMC in the MPS, since the players otherwise should make higher bids. This is linked to how the bidding price is calculated in EnergyPLAN, where the bids are linked to the STMC, and does not take into account the payback time for the long term investment in the bidding price. This can be assumed since the analysis will not include the business economic feasibility of each technology in the found scenarios, as the modeling only focuses on Nord Pool Spot, where the income potential from e.g. heat production and ancillary services are not included in the modeling. Also potential subsidies for production are not included. This makes it impossible to make any assessments on the economic balance of a technology in the modeling. However, this is not seen as a problem as the aim of the modeling is to find any difference in the money flow to each technology in the two auction settings, and any increase in the money flow out of the total money flow is seen as an improved situation for that technology.

Where technologies in MPS can be assumed to bid their STMC, this is not the case within a PAB setting, as stated in section 3.3. In PAB it must be assumed that the technologies will bid higher than their STMC, as they will need to pay off their long-term costs with the size of their own bid. However, as stated in this section, the modeling does not include all income potentials for the technologies, since it only covers the income from Nord Pool Spot. For this reason the long-term marginal costs cannot be used as the basis for the PAB bids, as other income sources also will be used to cover these costs, and if the long-term marginal costs were used as basis for the bids, then the bids would be too high for especially the CHP units. Instead by using the assumption used in MPS, that the technologies are able to earn enough to cover all their costs with the income they receive in the MPS settings. The bidding price in PAB is therefore based on the difference between the income in MPS and the MPS production. As this income is a yearly sum it has to be divided out on a price per MWh based on an expected electricity sale per year. This is done based on the production hours found in the MPS scenarios. The authors are aware that this is a very simplified way to make the calculation. In reality the technologies might bid differently during the year, earning more in some hours than others. But by using a model like

EnergyPLAN it is only possible to bid one price during the whole year. So making more detailed bidding structures in PAB would require a more detailed model, and more resources to make the analyses. So to give an overall idea about how the different technologies would be affected, the more simplified version is chosen.

This provides a PAB setting where none of the producers will try to gamble on the market, however gambling can occur in PAB as described in section 3.3.2. The technologies that might try to gamble would be those owned by the major players on the market, as the major market players have the largest potential to gamble successfully, since they are more risk-neutral than the smaller players. This is because they have more resources to estimate the market price for each hour, and they will also have more capital to take the risk of having to shut down facilities due to a failed gamble. As described earlier in this chapter the only two major players on the current Danish electricity market, DONG Energy and Vattenfall, owns almost all the central plants and most of the offshore wind power. The ownership of the technologies in the two chosen future setups is unknown, and it is therefore assumed that the ownership structure will be fairly unchanged, meaning that the major players will, in the two technical setups, own most of the offshore wind power and central plants. This must be a reasonable assumption, due to the high minimum investment costs of these technologies compared to the decentral plants, onshore wind power, etc. For this reason, the offshore wind power and the central plants potential to maximize their profits by taking a more risk-neutral approach to their bids, is analyzed. This analysis only focuses on their short-term profits and not their long-term potential to exclude other market players by undercutting the market during a longer period. On the basis of these analyses a new PAB situation, where the major players gamble, is found.

From this three different bidding strategies is found; one for MPS and two for PAB. These bidding strategies are all analyzed by using both of the technical setups. This modeling process is summarized into Figure 14, which shows the overall structure of the modeling.

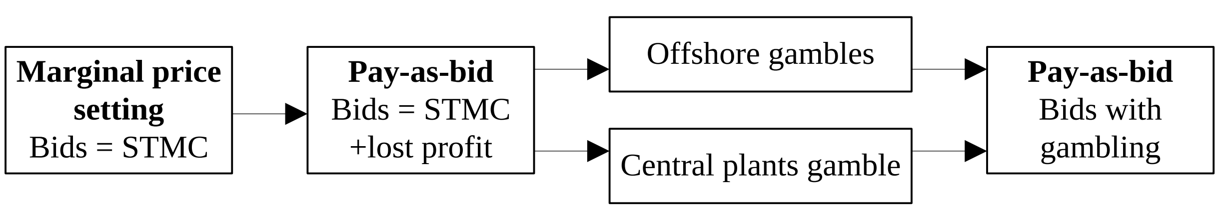

Figure 14: Approach for making the auction settings

In Figure 14 it can be seen that the MPS makes up the basis for the modeling of PAB. In the first PAB setting the bids will equal the STMC plus the profit gained in the MPS. From this basis the gambling potential for offshore wind power and central plants in the PAB setting is found, which results in a

PAB setting where the major players tries to gamble with their bids on the market in order to maximize their gain.

4.3.1 Changes to EnergyPLAN

To make the calculations and thereby the analyses of the PAB auction setting possible, some changes to the EnergyPLAN model have been made by the authors. This means that the version of EnergyP-LAN used for all the calculations in this thesis, is a modified version called "EnergyPLAN PAB", which is only accessible on the Appendix DVD. In (Appendix A) it is possible to find a describing of the most important changes made in the PAB-version. The following description is a shortened version of the appendix description.

Different variable O&M cost inputs have been added to the model, making it possible to add the variable costs for all the technologies relevant when modeling PAB. The first input added is linked to the central CHPs. This is added because in the normal version of EnergyPLAN only a single input is possible for CHPs in the menu. This is separated in the PAB-version into decentral and central CHPs. For fluctuating RES it is not possible to add a bidding price in the normal version of EnergyPLAN, therefore these are also given variable O&M cost inputs, so that bidding prices can be added in these.

For the calculation of the STMC everything else besides fluctuating RES takes fuel, handling, taxes and CO_2 costs into account, see section 2.2.2 for a description of this. In the PAB-version the only new STMC calculations are for the fluctuating RES, and since these do not have any of the before mentioned costs, the resulting STMC is the same as the variable O&M input for RES. It has to be underlined that the RES still produce according to their distribution files even though a price is added in the PAB-version, so if there is a small amount of wind in an hour, it is not possible to produce more than this amount, even if wind power is the cheapest solution.

To calculate when a technology gets to produce according to the prices on the market, a procedure is needed. Since the fluctuating RES are added in the PAB-version, these also need procedures for calculating when they produce according to the prices on the market. Therefore four new procedures are created for this purpose. When choosing which technology that should be used for electricity production each hour, the one with the lowest STMC is chosen. If for example onshore wind power is the cheapest, then the newly created procedure for onshore wind power is activated, finding out how much electricity onshore wind can produce in the given hour.

The named changes are the most important changes made to the EnergyPLAN model in the PAB-version. There are also some smaller additions, which are mostly linked to what outputs the model presents. The outputs added and used in the PAB-version are:

- Hourly electricity consumption for the heat pumps.
- Fuel prices in DKK/GJ for all fuels.
- Annual fuel usage for PPs, CHPs and boilers.
- Annual fuel costs for PPs, CHPs and boilers.
- Efficiencies for PPs, CHPs, heat pumps and boilers.
- Fuel distribution for PPs, CHPs and boilers.
- Lifetime, investment costs and fixed O&M for PPs, CHPs, boilers, RES and heat pumps.

Next section describes each of the modeled scenarios in more detail.

4.4 The different modeled scenarios

In order to easily distinguish between the different scenarios, a naming system has been chosen. Each of the scenarios has a name consisting of two parts, where the first part is the auction setting and bidding strategy. For the Marginal Price Setting it is MPS, for the first Pay-As-Bid it is PAB, and for the Pay-As-Bid with gambling it is PAB2. The second part represents the technical setup, where it is either DEA or IDA. This means that the names of the scenarios end up being: MPS-DEA, MPS-IDA, PAB-DEA, PAB-IDA, PAB2-DEA and PAB2-IDA. These are described in the named order.

As a further comment on these scenarios, there are some general characteristics about the bidding prices in all the scenarios:

- There is only one bidding price for each technology, which is the same all year.
- The CHPs base their bidding prices on both heat and electricity production costs.

This approach for making the bids is a simplified version of how it would be done in reality, where the bids are changed every day, depending on the different situations occurring during the year.

4.4.1 MPS-DEA

The first scenarios are the MPS-scenarios; these are similar to the ones in the IDA2050 climate plan. The next sections explain how the bidding prices used for the modelling are calculated. The formulas for the MPS bidding prices are described in the 2.2.2. This section explains how the resulting bidding prices are found by using the different costs in the formulas. In Table 5 the three different parts for calculating the bidding price for MPS-DEA are shown.

Unit	Fuel costs	Variable O&M	Saved VC/Tax	Marginal bid
	DKK/MWh	DKK/MWh	DKK/MWh	DKK/MWh
Incr. CHP2 decr. HP2	611.2	14.6	-182.2	**443.6**
Incr. CHP3 decr. HP3	587.7	13.9	-207.4	**394.2**
Incr. CHP2 decr. B2	384.0	20.0	-1.3	**402.7**
Incr. CHP3 decr. B3	296.9	20.0	-1.5	**315.3**
Condensing power	499.1	15.0		**514.1**
Incr. B2 decr. HP2	1228.0	0.3	-677.0	**551.3**
Incr. B3 decr. HP3	1246.3	0.3	-677.0	**569.6**

Table 5: The marginal bidding price for the MPS-DEA scenario. VC = variable costs. (Appendix 2)

The first part is the STMC for only the fuels, which includes the price for fuel, handling, taxes and CO_2-quota costs. These costs are the main part of the STMC and all of them are calculated according to the variable distribution of fuels used in the scenario for each technology. The next part is the variable O&M costs, which are the costs that are linked to the production of each MWh. The third part is an important factor when looking at how EnergyPLAN calculates these STMC, and is linked to the district heating production; this is the saved variable costs and taxes by using one technology instead of another. There are three types of these:

- Increase CHP and decrease heat pump
- Increase CHP and decrease boiler
- Increase boiler and decrease heat pump

This results in different savings per MWh which are linked to the different efficiencies of the technologies. The savings for increasing the CHPs while decreasing the boilers are around 200 DKK/MWh, while the increasing of CHPs instead of boilers are only around 1.5 DKK/MWh. The most saved per MWh is by increasing boilers and decreasing heat pumps, this is due to a high tax on the heat pumps of 675 DKK/MWh. It has to be noticed that the saving is per MWh electricity used, so the high saving has to be compared to using a boiler, which has to produce approximately three times as much heat with the same input, this is also why the fuel costs for boilers in the last two rows are so high. In the last column of Table 5 the MPS bidding price is shown, which is the price EnergyPLAN uses when selecting the technologies for each hour. Not shown in the table is wind power, which in this scenario has a bidding price of zero. The second lowest is the central CHPs with a bidding price of 315 DKK/MWh, followed by the decentral CHPs with a bidding price of 402 DKK/MWh. The highest bidding price belongs to the condensing CHPs and PPs which offer to produce electricity for 514 DKK/MWh.

4.4.2 MPS-IDA

The next scenario is the MPS-IDA scenario. In Table 6 the biddings prices for this scenario are shown.

Unit	Fuel costs	Variable O&M	Saved VC/Tax	Marginal bid
	DKK/MWh	DKK/MWh	DKK/MWh	DKK/MWh
Incr. CHP2 decr. HP2	533.9	16.0	-136.0	**413.9**
Incr. CHP3 decr. HP3	514.6	15.6	-147.6	**382.6**
Incr. CHP2 decr. B2	359.5	20.0	-0.9	**378.6**
Incr. CHP3 decr. B3	310.6	20.0	-1.0	**329.6**
Condensing power	420.8	15.0		**435.8**
Incr. B2 decr. HP2	1228.0	0.3	-677.0	**551.3**
Incr. B3 decr. HP3	1246.3	0.3	-677.0	**569.6**

Table 6: The marginal bidding price for the MPS-IDA scenario (Appendix 3)

The MPS bids are calculated in exactly the same manner as the MPS-DEA scenario. The reason that the costs are different from the MPS-DEA scenario is that there are different efficiencies in the two scenarios; these are described in section 4.2. Still RES are not shown in the table, as it is bidding 0 DKK/MWh. In the MPS-IDA scenario wave power and photovoltaic are added as RES. The central CHPs are the ones bidding lowest with 329.6 DKK/MWh followed by the decentral CHPs bidding 378.6 DKK/MWh. The most expensive production units are again the condensing CHPs and the PPs, which bid 435.8 DKK/MWh.

4.4.3 PAB-DEA

As stated the first PAB setting is found with the MPS as the basis. This has been done by assuming that the wanted profit in the MPS equals the wanted profit in the PAB for all the technologies. Therefore the PAB bids are found by adding the MPS bid and the average difference between the market price and MPS bid. This average difference can also be seen as the potential lost income, if changing to PAB without changing the bid of the technology. When doing this it is assumed that the amount of electricity sold will remain approximately the same for each technology in MPS and PAB. This might of course not be the case; however it will provide a reasonable approximation of how the bidding prices would change from MPS to PAB.

In Table 7 can be seen the bidding prices for MPS-DEA, the “Potential lost income” and the new bids for PAB-DEA, based on the assumption of unchanged size of production and unchanged wanted profit per unit sold.

Unit	MPS-DEA bid	Potential lost income	PAB-DEA bid
	DKK/MWh	DKK/MWh	DKK/MWh
Incr. CHP2 decr. HP2	444	55	499
Incr. CHP3 decr. HP3	394	98	492
Incr. CHP2 decr. B2	403	76	479
Incr. CHP3 decr. B3	315	141	456
Condensing power	514	2	516
Incr. B2 decr. HP2	551	0	551
Incr. B3 decr. HP3	570	0	570
Onshore wind power	0	455	455
Offshore wind power	0	458	458

Table 7: Bidding prices for MPS-DEA, the found potential lost income and the resulting PAB-DEA bids (Appendix 4)

It can be seen that this approach especially changes the bidding prices of the wind power, which makes sense due to their former MPS bid of 0. The condensing power, which also covers the PPs, is the electricity producer that changes its bid the least, which is due to it being the most expensive unit in the system, and the market price rarely increases above its STMC. Also interesting is that the PAB bids are much closer to each other than those in the MPS.

4.4.4 PAB-IDA

The PAB-IDA bids are found using the same approach as for PAB-DEA, but using the data from MPS-IDA as the basis. The PAB-IDA bids can be seen in Table 8.

Unit	MPS-IDA bid	Potential lost income	PAB-IDA bid
	DKK/MWh	DKK/MWh	DKK/MWh
Incr. CHP2 decr. HP2	414	12	426
Incr. CHP3 decr. HP3	383	30	413
Incr. CHP2 decr. B2	379	15	394
Incr. CHP3 decr. B3	330	39	369
Condensing power	436	1	437
Incr. B2 decr. HP2	551	0	551
Incr. B3 decr. HP3	570	0	570
Onshore wind power	0	313	313
Offshore wind power	0	326	326
Wave power	0	339	339
Photovoltaic	0	346	346

Table 8: Bidding prices for MPS-IDA, the found potential lost income and the resulting PAB-IDA bids (Appendix 5)

These PAB-IDA prices show much of the same tendencies as those of the PAB-DEA. Again the greatest change of the bids is for the fluctuating RES, and the smallest change of bid, for the electricity producing units, is the condensing power.

4.4.5 PAB2-DEA

As stated the bids in the first PAB settings are used to find new PAB settings, in which the major players gamble with their bidding price in order to increase their gain. The major players are assumed to have ownership of the offshore wind power, the central CHPs and the PPs. In order to analyze these three technologies they are analyzed separately, where the CHPs in condensing mode and the PPs are analyzed together, as their bids and production output are similar. In order to find more optimal bid strategies for these technologies, a range of different bids have been modeled for each of them by changing only the bid of one technology at a time, and with all other things being equal. The results of this are then summarized into a graph for each technology, where the bids effect on the technology's yearly income or yearly profit is shown. For offshore wind power and central CHPs the yearly income has been used. Offshore wind power has a variable cost close to zero; this cost can therefore be discarded to find its optimal strategy. The central CHPs is seen as using the income made on the electricity market as a way to decrease the price of the district heating, and the optimal strategy can hence be seen as the situation where the income from the electricity market is greatest. The CHPs bid referred to here are the bid for increasing CHP and decreasing the boiler. For condensing CHPs and PPs the yearly profit, which is the yearly income minus the yearly variable costs, are used as these technologies will want to achieve the point where the difference between these are the greatest.

Figure 15 shows the effect of changing the bidding price for offshore wind power. Also other selected technologies bids are added to see their effect.

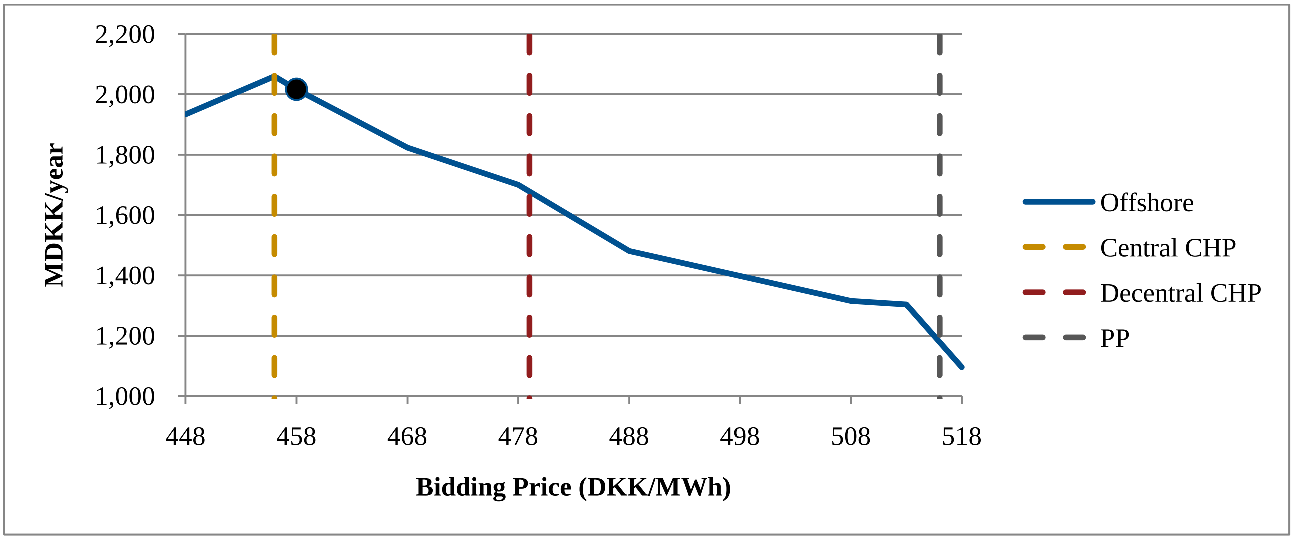

Figure 15: Yearly income from electricity sales for offshore wind power for a range of bidding prices. The black dot represents the starting point being the PAB-DEA bid. (Appendix 6)

In Figure 15 it can be seen that an increase of the offshore wind powers bid results in a loss of yearly income. A small decrease in the bidding price to equal the central CHPs bidding price could result in a small increase in income. However, as the bid of central CHPs also is changed, this small increase is not seen as a relevant option for the offshore wind power. The bidding price of offshore wind power in the PAB2-DEA scenario will stay unchanged compared with the PAB-DEA bid.

In Figure 16 is shown the effect of changing the bidding price of the central CHPs.

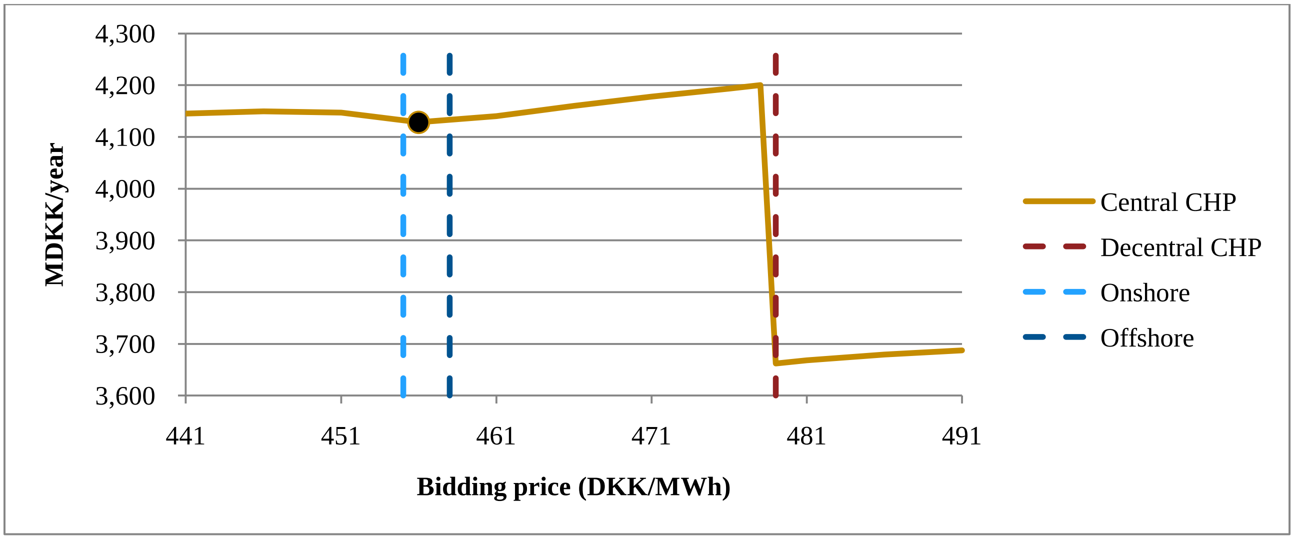

Figure 16: Yearly income from electricity sales for central CHPs for a range of bidding prices. The black dot represents the starting point being the PAB-DEA bid. (Appendix 6)

Figure 16 shows that the central CHPs increases their income by increasing their bid to about 478 DKK/MWh, where it starts to be outbid by the decentral CHPs. This happens due to the two technologies having the same distribution for the production of district heating, and these two technologies therefore compete in the same hours. It will hence be optimal for the central CHPs to bid just below the decentral CHPs to maximize their income from electricity sales. Any reduction of the bid compared with the starting point will only increase the income slightly, as it will start to outbid onshore wind power. The optimal strategy for central CHPs will in PAB2-DEA therefore be 478 DKK/MWh, as this will be just below the bidding price of the decentral plants, and the point with the highest yearly income.

In Figure 17 the effect of changing the bids of the condensing CHP production and the PPs are shown. For these the optimal strategy is where the difference between the yearly income from electricity sales and the yearly variable costs of producing electricity is the greatest. Therefore the bidding price is compared with the difference between the yearly income and the yearly variable costs for the production.

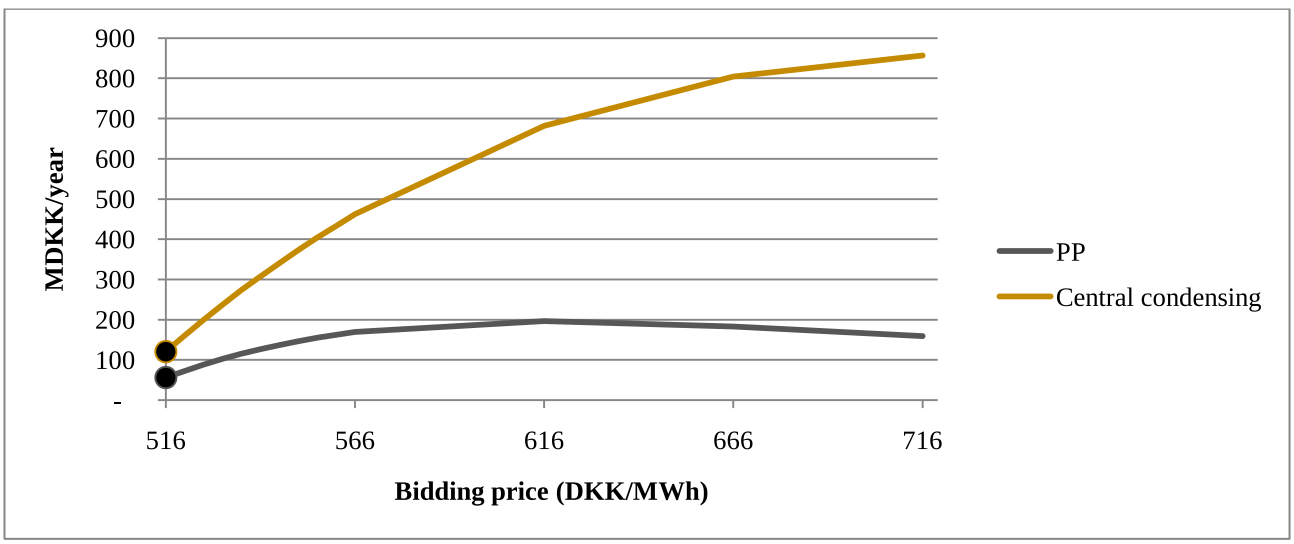

Figure 17: Yearly profit (income minus variable costs) from electricity sales for condensing CHPs and PPs for a range of bidding prices. The black dot represents the starting point being the PAB-DEA bid. (Appendix 6)

As the condensing CHP and PPs are the most expensive units in the modeled system, they in principle can increase their bidding price more or less indefinitely, and thereby continue to increase their combined profit, since they already are mostly chosen when there are no other production facilities able to produce, and the import capacity is fully used or more expensive. However, this can only be seen as a short-term optimal strategy, as increasing the price indefinitely will lead to more competing capacity being built, and this would not be the optimal situation for the existing major players. But it must be assumed that these two technologies still will try and maximize their profit, and the choice of bidding price will therefore be chosen as the point where either the PP or condensing CHP first starts to lose profit. From Figure 17 this point is found to be about 616 DKK/MWh, where the PPs profits are maximized. The bidding price for the PPs and condensing CHPs will hence be 616 DKK/MWh in PAB2-DEA.

4.4.6 PAB2-IDA

The gambling bidding prices for PAB2-IDA are found using the same approach as in PAB2-DEA, where the difference is the used technical setup. The technologies that might gamble are still assumed to be offshore wind power, central CHPs and condensing CHP/PPs, and still only one technology's bidding price is changed at a time.

Figure 18 shows the effect of changing the bid for offshore wind power in the PAB-IDA scenario.

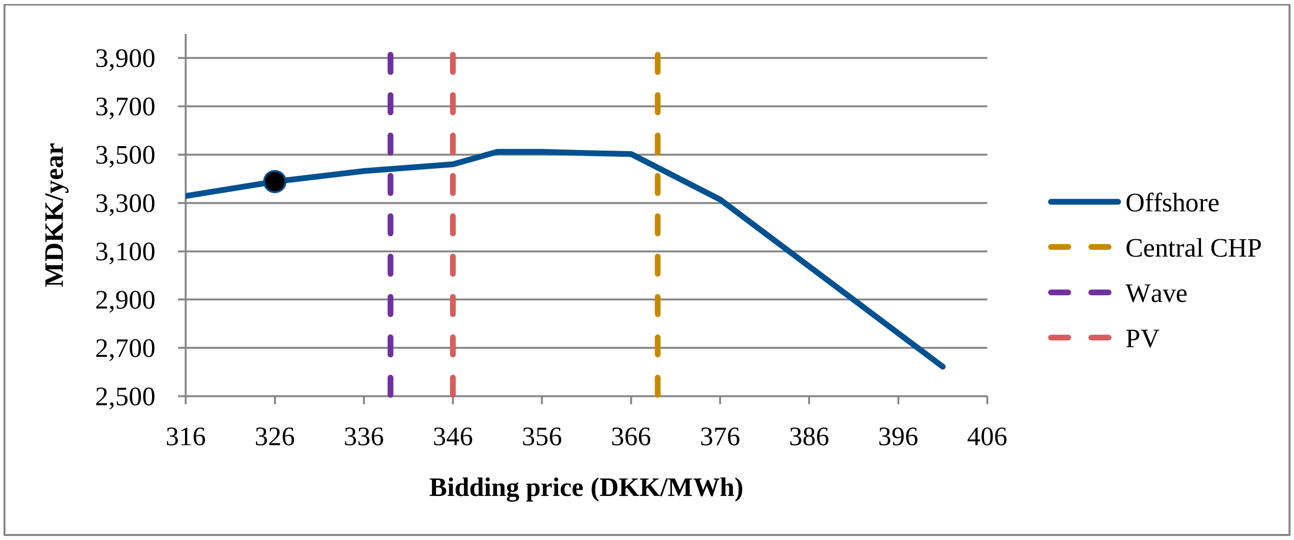

Figure 18: Yearly income from electricity sales for offshore wind power for a range of bidding prices. The black dot represents the starting point being the PAB-IDA bid. (Appendix 7)

From Figure 18 it can be concluded that offshore wind power will see an increase in yearly income until the bid nears that of the central CHPs'. However, the change in yearly income flattens out around a bidding price of 351 DKK/MWh. Due to this flattening there is no reason for increasing the bidding price of offshore wind power to more than 351 DKK/MWh, and this is therefore used for PAB2-IDA. Another observation is that the wave power and photovoltaic seem to have nearly no effect on the offshore wind powers income, which is due to the relative small capacities of these technologies, but also because they only compete to a minor extent in the same hours.

In Figure 19 is shown the change of income when the bidding price of central CHPs is changed.

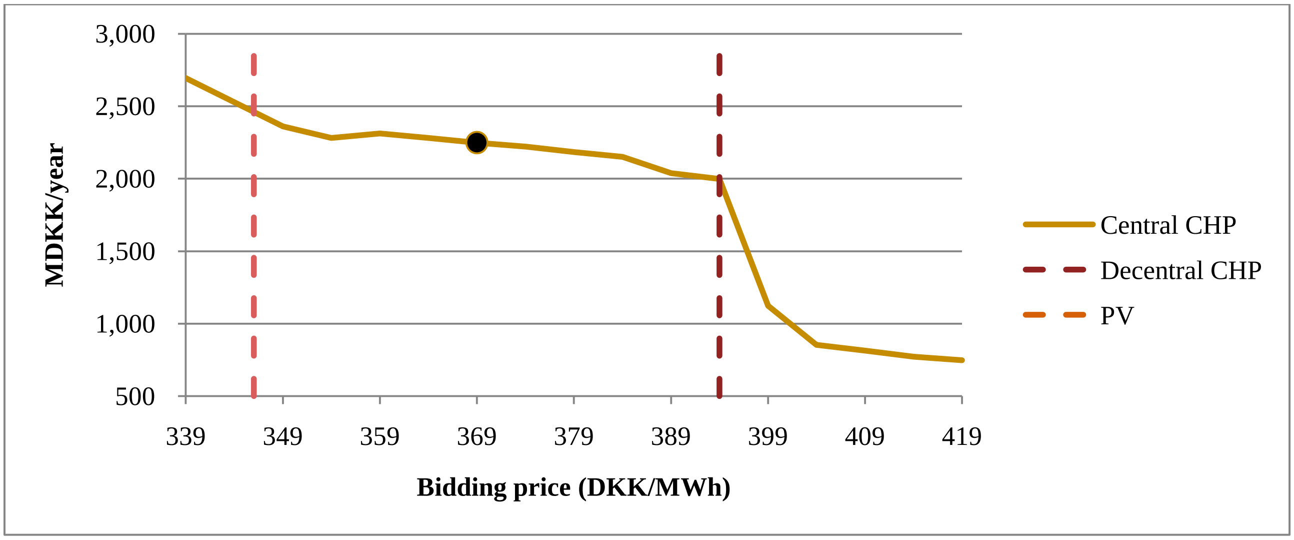

Figure 19: Yearly income from electricity sales for central CHPs for a range of bidding prices. The black dot represents the starting point being the PAB-IDA bid. (Appendix 7)

Figure 19 does not provide a clear optimal bidding price for the central CHPs, as there is no income peak. However, it can be seen that central CHPs would increase their income by reducing their bidding price, rather than increasing it. But just decreasing the bidding price without concern to former bid changes does not seem an optimal strategy, as it is assumed that the owners of the central CHPs are the same as the owners of the offshore wind power, and decreasing the bid for central CHPs below the found bidding price of the offshore wind power, would only move the income from offshore wind power to central CHPs. So by cutting the graph at 351 DKK/MWh the highest peak for the central CHPs income would be at 359 DKK/MWh, which would be a reduction of the bidding price of 10 DKK/MWh compared with PAB-IDA, but would still be above the STMC of the central CHPs, and this price will hence be used as the bidding price in PAB2-IDA.

Figure 20 shows the effect on the yearly profit for condensing CHPs and PPs by changing their bids.

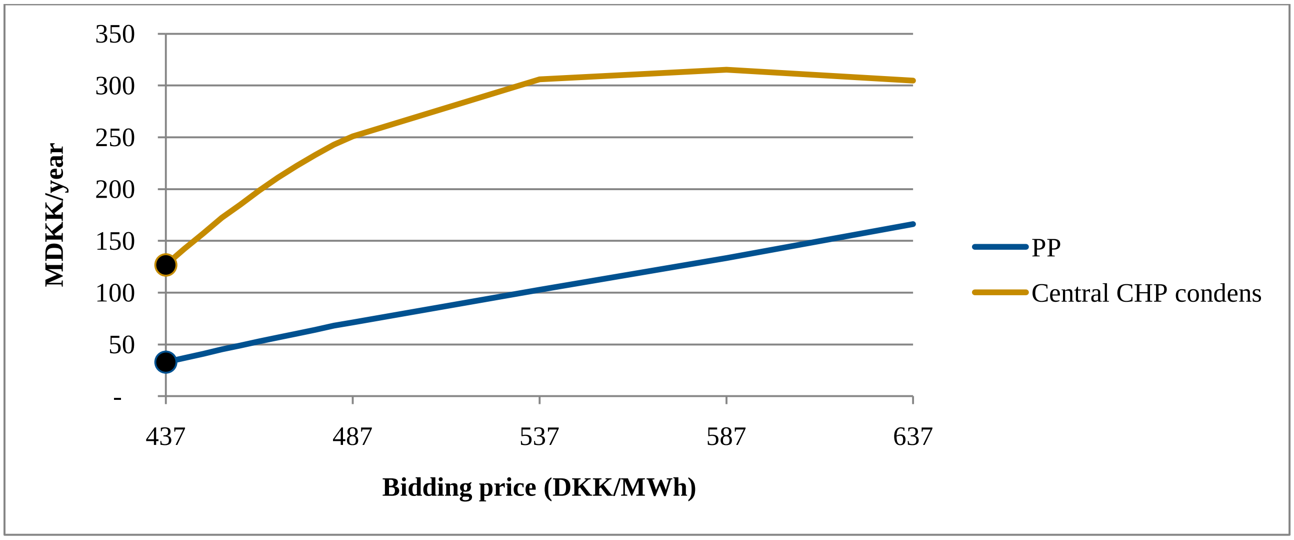

Figure 20: Yearly profit (income minus variable costs) from electricity sales for condensing CHPs and PPs for a range of bidding prices. The black dot represents the starting point being the PAB-IDA bid. (Appendix 7)

Again the PPs and central condensing CHPs are the most expensive units on the market, and the price could be increased more or less indefinitely, and still provide a greater combined profit for these two technologies, since only the short-term effects are analyzed. So again the price is chosen for the bid where the yearly profit peaks for either of the technologies. In Figure 20 it can be seen that the condensing CHPs profit peaks around 587 DKK/MWh. This price is hereby used for the PPs and central condensing CHPs in PAB2-IDA.

4.4.7 Final bidding prices for the six scenarios

Summarizing the previous sections, the main difference between the scenarios is the difference in bidding prices. In Figure 21 the bidding prices for the three DEA scenarios are shown.

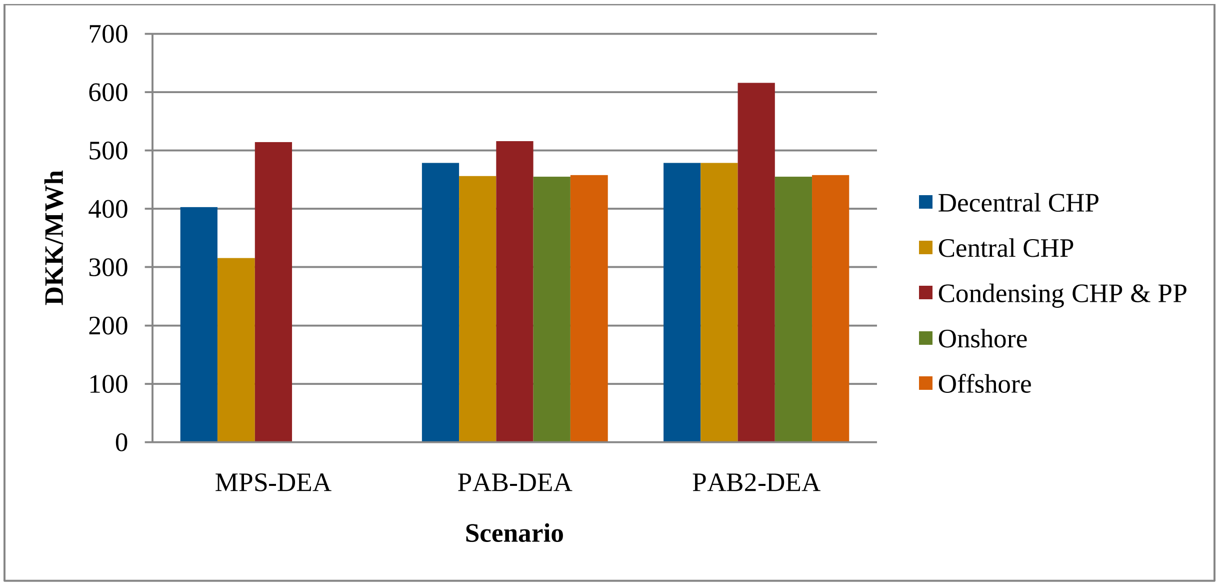

Figure 21: Bidding prices for the DEA-scenarios (Appendix 2, 4 & 6)

From the left the initial MPS-DEA scenario is shown, where onshore and offshore offer their electricity at zero. The CHPs and PPs offer prices around 300-500 DKK/MWh. When going on to the PAB setting, there are some major changes in the bidding prices. The CHPs and fluctuating RES increase their bids, so they are much nearer to the PPs. The order from lowest to highest bid is still the same, where RES are bidding lowest, followed by central CHPs, followed by decentral CHPs and still highest are the PPs. Going on to PAB2, where the major players try to find the bid where they get the largest gain from the electricity sale. This makes the condensing CHPs and the PPs bid 100 DKK above their initial PAB bid, increasing it to around 600 DKK/MWh. The central CHPs also increase their bid with 22 DKK/MWh, so it is close to the price offered by the decentral CHPs. Looking at the overall tendency of the three scenarios, the next move of the CHPs and RES could be to make their bids closer to the condensing CHPs and PPs fairly high bid in PAB2. This behaviour would make an upward spiral increasing the bidding prices over time. The authors are aware of this possible tendency, but focusing only on the short run, it is assumed that the condensing CHPs and PPs will try to maximise their profit only as described.

Going on to the IDA scenarios shown in Figure 22, which is similar to the previous figure except for the difference that wave power and photovoltaic are added to the technologies.

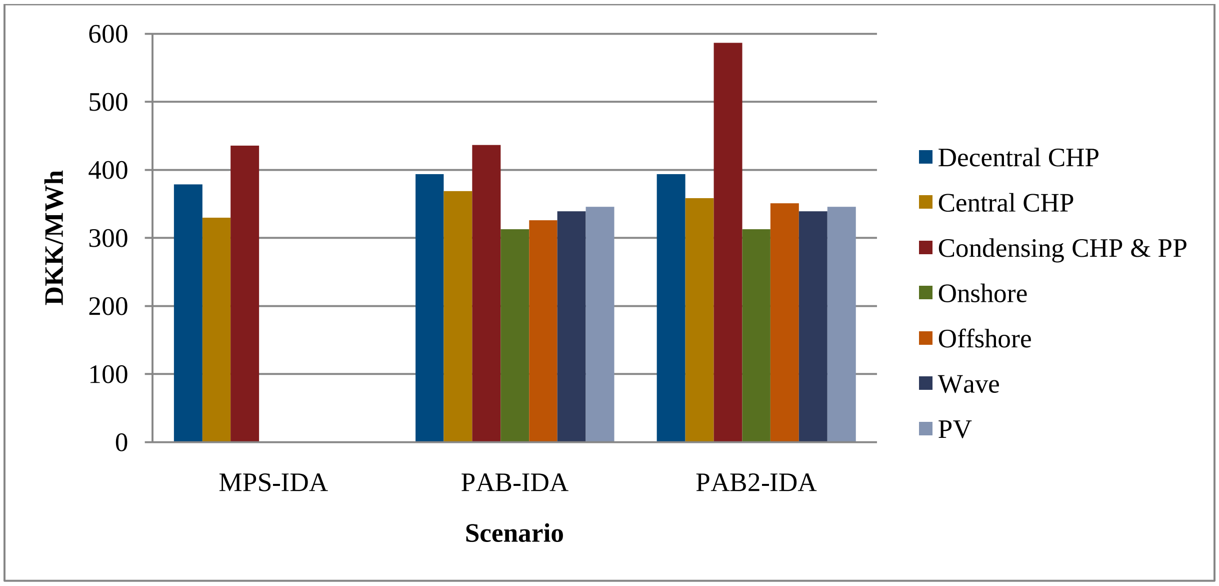

Figure 22: Bidding prices for the IDA-scenarios. PV = photovoltaic (Appendix 3, 5 & 7)

The figure shows much of the same tendencies as with DEA, where in the MPS the fluctuating RES is bidding with zero as their offer, while the CHPs and PPs bid more according to their STMC, making the central CHPs bid lowest and the PPs bid highest. In the PAB-IDA scenario the other technologies try to get as close as possible to the condensing CHPs and PPs without losing income. This leads to the RES bidding close to each other with onshore wind power lowest, going through offshore wind power and wave, to photovoltaic which is the highest of the RES biddings. Both the central and decentral CHPs also increase their bids to get close to the PPs, but the central CHPs keep their bids below the decentral CHPs. The last scenario is the PAB2-IDA scenario, where the major players again try to increase their gain by adjusting their bids. Offshore wind power bids 25 DKK/MWh higher than the PAB-IDA bid. The condensing CHP and PP increase their bid with 150 DKK/MWh giving a bidding price close to 600 DKK/MWh.

The next chapter shows the results of the modeling approach described in this chapter.

5 Results and sensitivity analyses

This chapter contains the results of the modeling, and the analysis of these for the different scenarios described in the previous chapter. First the results of the six modeled scenarios are presented and analyzed. This is done separately for the DEA and IDA scenarios. After this follows a section focusing on sensitivity analyses of different factors effect on the results, which then is used to make conclusions regarding the sensitivity of the modeling. In the end of the chapter there is an overview of the results, comparing the main results and the sensitivity analyses.

5.1 Modeling results

The results of the modeling are presented by showing yearly values for each technology's production of electricity, production of heat, income for electricity sale and profit of electricity production. Furthermore, the import and export are shown alongside the technologies, as they vary with the bidding strategies. The tables also show the differences of going from one auction setting to another in order to easily identify the effects of an auction setting. The DEA- and IDA-setups are presented separately as the results of these cannot directly be compared, due to the difference in mix of technologies.

5.1.1 Results for the DEA-scenarios

Table 9 shows the yearly electricity production for the different technologies together with the import and export of electricity.

TWh/year	MPS-DEA	*MPS → PAB*	PAB-DEA	*PAB → PAB2*	PAB2-DEA	*MPS → PAB2*
PP	3.86	*-0.13*	3.73	*-2.15*	1.58	*-2.28*
Onshore	6.58	*-0.89*	5.69	*-*	5.69	*-0.89*
Offshore	4.93	*-0.52*	4.40	*0.06*	4.46	*-0.47*
CHP condensing	7.94	*0.07*	8.01	*-2.46*	5.55	*-2.39*
Central CHP	9.86	*-0.81*	9.05	*-0.27*	8.78	*-1.08*
Decentral CHP	5.18	*-0.89*	4.29	*-0.08*	4.21	*-0.96*
Import	3.91	*2.47*	6.38	*2.35*	8.73	*4.82*
Export	5.22	*-0.71*	4.51	*-2.54*	1.97	*-3.25*

Table 9: Change in yearly production of electricity in the different auction settings (Appendix 8)

As it can be seen in Table 9 all the technologies, except CHP condensing, experience a decrease in electricity production when going from MPS to PAB setting in the DEA setup. Also the import increases significantly. This increase in import occurs due to the increase in prices for especially the cheapest technologies, which results in the prices not going as low as in MPS, and since the external market remains unchanged the external market is modeled as still using the MPS and hereby low prices in many hours. For this reason the import increases when changing from MPS to PAB and PAB2. This fact especially results in reductions in wind power production, as this in MPS had a bidding price of zero, and after being changed it is outbid by the external market in many hours. But also the CHPs experience a decrease in production due to the external market being cheaper in many hours. The problem with the external market is examined in the sensitivity analysis in section 5.2.2.

Moving from the PAB-DEA to the PAB2-DEA scenario results in an increase in electricity import. The offshore wind power experiences a small increase in production, which occur due to the increase in bidding price of the central CHPs. The onshore wind power has an unchanged production, whereas the rest experience a drop in yearly production. Again this is mainly due to the import being cheaper in many hours, where especially condensing CHPs and PPs losses production due to a large increase in bidding price.

Table 10 shows the heat production for the district heating systems connected to the central and decentral CHPs. This is relevant due to the heat production being so dependent on the electricity production in Denmark.

TWh/year	MPS-DEA	*MPS → PAB*	PAB-DEA	*PAB → PAB2*	PAB2-DEA	*MPS → PAB2*
Central CHP	15.24	*-1.25*	13.98	*-0.41*	13.57	*-1.67*
HP3	-	-	-	-	-	-
Boiler3	0.08	*1.26*	1.33	*0.41*	1.74	*1.67*
Decentral CHP	6.67	*-1.14*	5.53	*-0.10*	5.43	*-1.24*
HP2	-	-	-	-	-	-
Boiler2	0.54	*1.14*	1.68	*0.10*	1.78	*1.24*

Table 10: Change in yearly production of heat for the different auction settings (Appendix 8)

As heat cannot be imported or exported, and the demand being completely inelastic in the model, the heat demand is unchanged for each electricity auction setting. It can be seen on Table 10 that when changing MPS-DEA to either PAB-DEA or PAB2-DEA it results in an increase of the boiler production for both of the district heating systems. This occurs due to the decrease in CHP production, which is being outbid by the external market. From an engineering efficiency point of view it is best to have the CHPs producing as much as possible, as the simultaneously production of heat and power gives the most fuel efficient outcome. So in this case, any change from the current system results in a less optimal situation for the heat production, when using the explained modeling approach.

Returning to the electricity production again; the income from selling the produced electricity is of great relevance for this thesis, as the income from electricity production is one way of illustrating which technologies benefit and which losses from changing the auction setting. Table 11 shows the yearly income from electricity production for the electricity producing technologies, together with the import and export of electricity.

MDKK/year	MPS-DEA	*MPS → PAB*	PAB-DEA	*PAB → PAB2*	PAB2-DEA	*MPS → PAB2*
PP	1,991	*-68*	1,923	*-949*	974	*-1,017*
Onshore	2,991	*-404*	2,587	*-*	2,587	*-404*
Offshore	2,256	*-239*	2,017	*27*	2,043	*-212*
CHP condensing	4,091	*42*	4,134	*-714*	3,420	*-672*
Central CHP	4,498	*-370*	4,128	*72*	4,200	*-298*
Decentral CHP	2,478	*-425*	2,053	*-36*	2,017	*-461*
Import	1,738	*1,314*	3,052	*1,674*	4,726	*2,988*
Export	2,572	*-257*	2,315	*-1,174*	1,142	*-1,430*

Table 11: Change in yearly income for electricity sales in the different auction settings (Appendix 8)

The change from MPS-DEA to PAB-DEA shows the same overall tendencies as with the electricity production, which are that condensing CHPs seem to benefit from the change, and the other technologies are increasingly outbid by the external market. Going from PAB-DEA to PAB2-DEA shows the same tendencies as with the production, the only major difference being that central CHPs seems to increase the yearly income in PAB2. This is due to central CHPs changing their bid to maximize profit in the PAB2 auction system. Again it is clear that PAB-DEA and PAB2-DEA are very much affected by the hours of low prices on the external market. All in all the modeling shows that wind power production is going to lose income if the auction setting is switched to PAB, when using the explained modeling approach.

The income does however not by itself show the change in economy for the technologies, since many of them also have costs associated with each MWh electricity produced, and these costs should be earned back each year. For this reason Table 12 is presented, where the yearly income minus the yearly variable costs of producing are presented as the yearly profit per MW installed electric capacity. This is also the part of the income that is available for paying off the investments. Only the CHPs and PPs are presented, as wind power is modeled as not having STMC for producing.

MDKK/MW/year	MPS-DEA	*MPS → PAB*	PAB-DEA	*PAB → PAB2*	PAB2-DEA	*MPS → PAB2*
PP	0.012	*-0.000*	0.012	*0.029*	0.041	*0.029*
CHP condensing	0.045	*0.004*	0.048	*0.226*	0.275	*0.230*
Central CHP	-1.589	*0.134*	-1.455	*0.121*	-1.333	*0.255*
Decentral CHP	-0.997	*0.173*	-0.824	*0.015*	-0.809	*0.188*

Table 12: Change in yearly profit for electricity sales for the thermal facilities per MW in the different auction settings (Appendix 8)

In Table 12 it can be seen that by changing from MPS to PAB all the technologies, besides the PPs, increase their yearly profit when changing the auction setting. However, for condensing CHPs going from MPS to PAB only results in a fairly small increase. For decentral CHPs going from PAB to PAB2 also only provides a fairly small increase. An important observation is the negative profits for the CHPs, which is due to the income of the heat produced simultaneously with the electricity not being accounted for in these results. But overall changing the auction setting from MPS to PAB and PAB2 does increase the yearly profit for the thermal facilities.

5.1.2 Results for the IDA-scenarios

For the IDA-scenarios similar results have been calculated. Following the structure from before, the first result to look at is the electricity production, which is shown in Table 13.

TWh/year	MPS-IDA	*MPS → PAB*	PAB-IDA	*PAB → PAB2*	PAB2-IDA	*MPS → PAB2*
PP	0.77	*0.10*	0.86	*-0.28*	0.59	*-0.18*
Onshore	12.63	*-0.12*	12.50	*0.02*	12.53	*-0.10*
Offshore	10.67	*-0.28*	10.39	*-0.38*	10.01	*-0.66*
Wave	1.41	*-0.18*	1.23	*0.02*	1.25	*-0.16*
Photovoltaic	0.90	*-0.05*	0.85	*0.01*	0.86	*-0.04*
CHP condensing	3.30	*0.04*	3.34	*-1.95*	1.39	*-1.91*
Central CHP	7.29	*-1.19*	6.10	*0.40*	6.50	*-0.80*
Decentral CHP	2.93	*-0.34*	2.59	*0.01*	2.61	*-0.32*
Import	1.39	*0.63*	2.03	*0.18*	2.20	*0.81*
Export	13.33	*-1.47*	11.86	*-1.94*	9.92	*-3.41*

Table 13: Change in yearly production of electricity in the different auction settings (Appendix 8)

Going from MPS-IDA to PAB-IDA increases the PPs and condensing CHPs productions. These increases occur because of different situations in the two scenarios. In some hours there are lower prices on the external market, which result in the capacity to the external market being fully utilized, which activates the PPs and condensing CHPs. Others situations are due to how filled the heat storages are at times with high prices on the external market, where the PPs in some situations produce because the heat storages are filled, and there is no need for heat production from CHPs in those hours. The import increases, again due to the many hours where the price is low on the external market, caused by using an external market price distribution based on a MPS auction system. This also results in a small reduction of electricity production for all of the RES and CHPs, and an increase in export.

From PAB-IDA to PAB2-IDA the small increase for PPs and condensing CHPs is lost due to an increased production from the RES and CHPs. This increase is only when comparing PAB-IDA and PAB2-IDA, going from MPS-IDA to PAB2-IDA a decrease is seen for everything, except the import.

The heat production for the IDA-scenarios is shown in Table 14.

TWh/year	MPS-IDA	*MPS → PAB*	PAB-IDA	*PAB → PAB2*	PAB2-IDA	*MPS → PAB2*
Central CHP	7.12	*-1.16*	5.95	*0.39*	6.34	*-0.78*
HP3	5.55	*0.21*	5.77	*-0.08*	5.68	*0.13*
Boiler3	1.40	*0.95*	2.36	*-0.30*	2.05	*0.65*
Decentral CHP	2.57	*-0.29*	2.28	*0.01*	2.29	*-0.28*
HP2	3.03	*0.07*	3.11	*0.01*	3.12	*0.09*
Boiler2	3.03	*0.22*	3.25	*-0.02*	3.23	*0.20*

Table 14: Change in yearly production of heat in the different auction settings (Appendix 8)

From MPS-IDA to PAB-IDA there is an increase in heat pump and boiler production. This is due to a decrease in heat production from CHPs, caused by the decrease in electricity production from CHPs, which are being outbid by the external market. Looking at the step from PAB-IDA to PAB2-IDA this is slightly improved, because the CHPs bid a lower price and are hereby able to compete more with the external market.

Returning to the electricity market again, the yearly income is shown in Table 15.

MDKK/year	MPS-IDA	*MPS → PAB*	PAB-IDA	*PAB → PAB2*	PAB2-IDA	*MPS → PAB2*
PP	323	*54*	377	*-33*	344	*21*
Onshore	3,946	*-32*	3,914	*7*	3,921	*-25*
Offshore	3,478	*-89*	3,389	*126*	3,515	*37*
Wave	479	*-63*	417	*8*	425	*-55*
Photovoltaic	311	*-16*	295	*3*	297	*-14*
CHP condensing	1,429	*29*	1,459	*-642*	817	*-613*
Central CHP	2,692	*-443*	2,249	*81*	2,329	*-362*
Decentral CHP	1,153	*-133*	1,020	*6*	1,026	*-127*
Import	530	*258*	788	*234*	1,022	*492*
Export	4,581	*-311*	4,270	*-685*	3,585	*-996*

Table 15: Change in yearly income for electricity sales in the different auction settings (Appendix 8)

Focusing on the first step from MPS-IDA to PAB-IDA, the income is linked to the production shown earlier, where the PPs and condensing CHPs increased their production, which leads to a larger income for these. The RES all lose income when switching to PAB, which is a combination of getting less production and only getting their bidding price, and not the higher price set by the last produced unit of electricity, that would be received in MPS.

Going from PAB-IDA to PAB2-IDA the picture changes. The PPs and condensing CHPs lose a lot of their income, where the PPs still increase their income compared to MPS-IDA. The condensing CHPs lose more than a third of their income by going from MPS to PAB2. The CHPs increase their income going from PAB-IDA to PAB2-IDA, but compared to MPS-IDA, this is not enough to make the change positive on the income side. In fact the offshore wind power is the only production unit, except from PPs, to get an increased income by switching from MPS to PAB2. This is again because the import increases due to the lower unchanged prices on the external market.

As in the DEA-scenarios the yearly aggregated STMC, for producing electricity on the thermal facilities, has to be subtracted from the income to find the profit per installed MW electric capacity for the electricity sale. The profit is shown in Table 16.

MDKK/MW/year	MPS-IDA	*MPS → PAB*	PAB-IDA	*PAB → PAB2*	PAB2-IDA	*MPS → PAB2*
PP	0.004	*0.003*	0.006	*0.020*	0.026	*0.023*
CHP condensing	0.046	*0.005*	0.051	*0.077*	0.128	*0.082*
Central CHP	-0.868	*0.145*	-0.723	*-0.074*	-0.797	*0.071*
Decentral CHP	-0.435	*0.050*	-0.385	*-0.002*	-0.386	*0.048*

Table 16: Change in yearly profit per MW for electricity sales for the thermal facilities in the different auction settings (Appendix 8)

The yearly profit from electricity sale for the thermal facilities is increasing for all of the technologies when going form MPS-IDA to PAB-IDA. When going from MPS-IDA to PAB2-IDA all of the technologies increase their profit. However, going to PAB2-IDA from PAB-IDA the CHPs decrease their profits.

The results shown in this section cannot stand alone, as they are based on a range of assumptions. Therefore, the next section focuses on the important factors that might affect the results. When these are changed it is possible to see how sensitive the above mentioned results are to the different factors. This provides a better understanding of which aspects are important for the different auction settings.

5.2 Sensitivity analyses

Due to the many factors and assumptions used to make the modeling of the PAB settings, it is of relevance to investigate how changes in these factors and assumptions would affect the results. Four overall factors are seen as relevant to investigate. These are:

- Fuel costs. Where the cost of fuels are changed by using both lower and higher fuel costs. Also a changed CO_2-quota price is investigated, as it is a cost affecting production using fossil fuels. Making these changes in fuel costs will also result in changed MPS and PAB bids for the units using the fuels.
- External market. The external market clearly had a significant impact on the results, as the results show an increased import with PAB. It is in the sensitivity analyses investigated what the

effects of a changed average external market price, difference transmission capacity and price distribution on the external market.

- Wind power distribution. Due to the importance of wind power in the system, another wind distribution is used in order to examine this factor.
- Heat demand. As the heat demand is especially important for the CHPs production, it is investigated what a change in the yearly district heating demand means for the results.

Each of these factors is analyzed separately, and everything else is kept unchanged when changing a factor.

5.2.1 Fuel costs

The fuel costs are changed using both low and high fuel costs, and are the same as used in the IDA Climate Plan for sensitivity analyses. The low cost is the basic price forecast for 2030 that the DEA made in February 2008. The high cost is the actual costs from spring/summer 2008. These low and high fuel costs can be found in Table 17 together with the used DEA – April 2010 fuel prices.

(DKK/GJ)	Low price $60/barrel	DEA - April 2010 $117/barrel	High price $132/barrel
Crude oil	67.3	119.8	134.8
Coal	14.8	26.5	51.3
Natural gas	41.7	80.7	105.3
Fuel oil	47.2	83.9	94.1
Diesel fuel/Diesel	84.1	149.7	168.3
Petrol/JP	89.6	159.3	179.1
Straw	27.3	39.5	47.6
Wood pellets	66.3	85.8	86.2

Table 17: Fuel costs used. Low (Danish Energy Agency 2008). High cost (Danish Engineer's Association 2009)

Changing the fuel prices also results in a change of the modeled bidding prices for the facilities using these fuels, since the modeling automatically incorporates these in the STMC, which is part of the modeled bids for all the auction settings. This means that the low fuel prices result in a decrease of the bids for the facilities using fuels, and the high fuel prices results in an increased bid. Since most fuels are traded on a global market, in reality these changes of the fuel costs would also affect the prices on the external market, however for these analyses the external market are kept unchanged. The effect of having lower fuel costs can be seen in Figure 23.

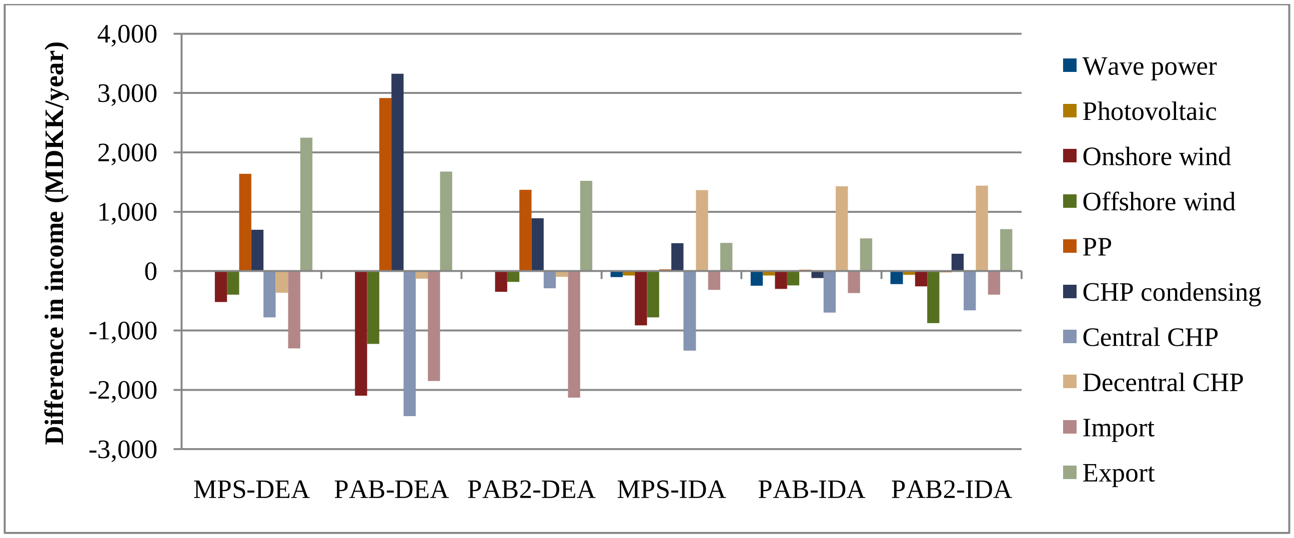

Figure 23: Difference in yearly income between using DEA – April 2010 prices and using the low fuel prices (Appendix 9)

In Figure 23 it can be seen that when using lower fuel prices the condensing CHPs and PPs increase their income in all the DEA-scenarios, and here especially in PAB-DEA. This is because the bidding price for these drops below the bids of both the central CHPs and wind power in the PAB-DEA scenario. The increase is hereby at the expense of wind power and central CHPs, where offshore wind power drops down to 790 MDKK/year and onshore down to 490 MDKK/year (Appendix 9). But as condensing CHPs and PPs also becomes lower than the external market price in an increased amount of hours the import decreases and the export increases. For the IDA-scenarios the tendencies are not as extreme as in the DEA-scenarios. This is especially due to the already low bids of the wind power, which ensures that wind power is not outbid in the same way as in the DEA-scenarios. The wind power does however seem to lose income in the MPS-IDA scenario, but that occur due to the generally lower market prices, because of the lower fuel prices. In the IDA-scenarios it is clear that the low fuel prices do benefit the decentral CHPs instead of the central CHPs, which occur mainly due to the natural gas being halved in price, which is the primary fuel for decentral CHPs, and in the IDA-scenarios this makes the decentral CHPs bid drop below that of central CHPs, which mainly use coal.

In Figure 24 the effect of using the high fuel prices, presented in Table 17, is shown.

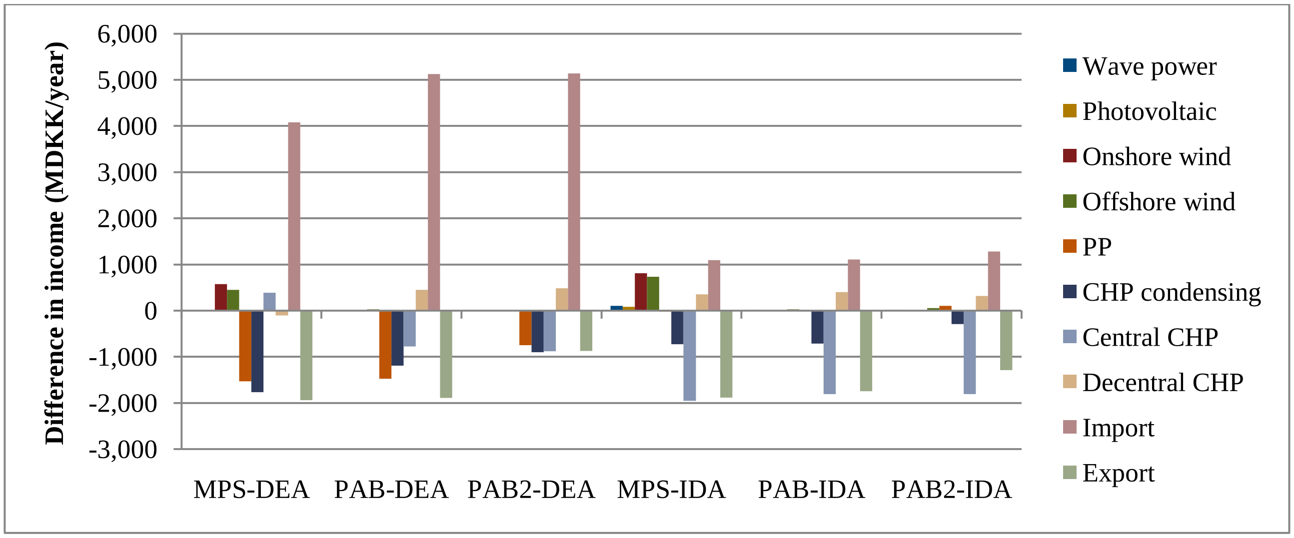

Figure 24: Difference in yearly income between using DEA – April 2010 prices and using the high fuel prices (Appendix 9)

For the DEA-scenarios it is clear that the higher fuel prices only increases the import. The wind power does however also increase in income in MPS-DEA, which is due to increased market prices. The extra import only decreases the thermal units' income, except decentral CHPs, since they are experiencing increased prices and thereby increased bids. In the IDA-scenarios the effects of changing fuel costs are again significantly smaller compared with the DEA-scenarios, but again the greatest increase in income is for the import category, whereas the central CHPs and condensing CHPs are the only that experiences decreased income. Decentral CHPs do increase their income to the same extend as in the DEA-scenarios. The wind power also experiences an increase in income in the MPS scenario and remains unchanged in the PAB scenarios.

It is clear that the wind power's income is very dependent on their bid matching changes in fuel prices, if they do not respond to a decreasing fuel price they risk being outbid. On the other hand they are not as vulnerable to an increase in fuel prices, but only benefits from it in MPS. In a real PAB setting this would not be the case, as it must be assumed that the owners of wind power will vary their bids according to the changes in the market, but the major players will most likely be able to respond faster on these changes than the smaller players. This advantage for the major players is however minor, as changes in fuel cost occur relatively slow compared with other factors on the electricity market.

CO_2-quota price

Another relevant factor for fuel prices is the CO_2-qouta price, as this affects the price of the fossil fuels while keeping the biomass prices unchanged. In these analyses it is examined what a high CO_2-qouta price means for the results. It is chosen to use a doubling of the used CO_2-quota price of 290 DKK/ton

CO_2, which gives a price of 580 DKK/ton CO_2 in the sensitivity analyses. The effect of making this change compared with the lower CO_2-quota price can be seen in Figure 25.

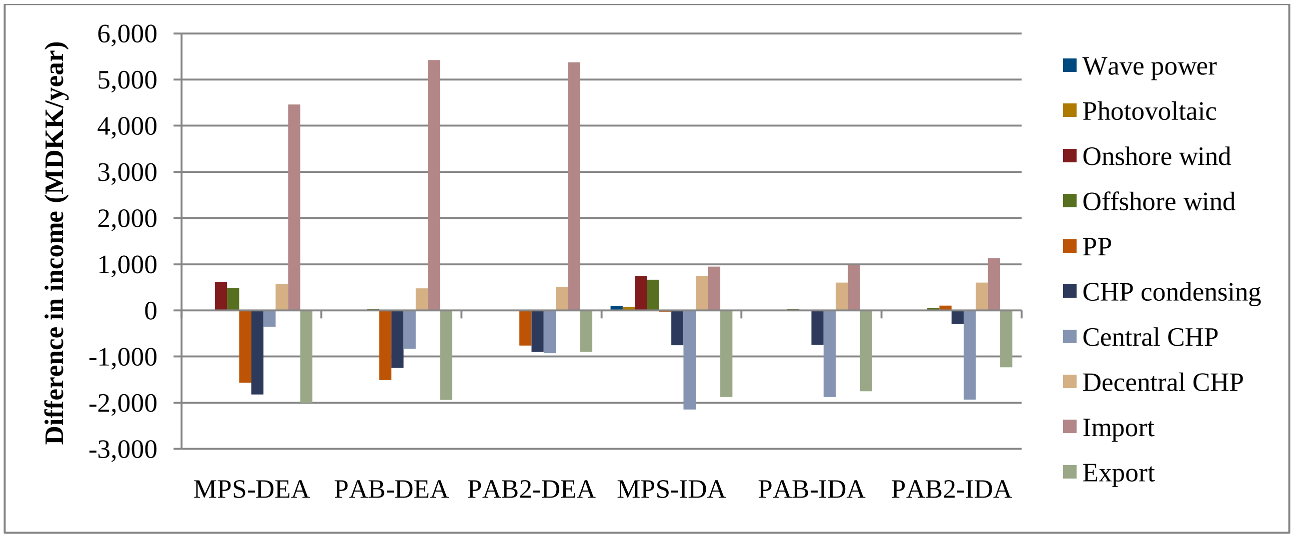

Figure 25: Difference in yearly income between using a CO_2-quota price of 290 DKK/ton CO_2 and 580 DKK/ton CO_2 (Appendix 9)

Again this higher fuel cost results in an increased import, and the central CHPs and PPs are experiencing a drop in income. The decentral CHPs do get a small increase in their income compared with the effect of the high fuel costs, which is due to their fuel input relying more on biomass. Overall increasing either the CO_2-quota price or the fuel prices affects the results similarly. Here it should also be noted that the fuel input of the DEA and IDA setups have been modeled as being the same, and therefore the same tendencies for the CO_2-quota price and fuel prices can be identified in either of these technical setups.

5.2.2 External market

As stated earlier, it is of relevance to make sensitivity analyses on the external market, as this in the initial modeling is kept unchanged. However, it must be assumed that when changing the electricity auction setting within Denmark it will be a change occurring in all of the Nord Pool area, and in this modeling the rest of Nord Pool makes up the external market. A detailed analysis of what a change from MPS to PAB means for the prices in the rest of Nord Pool has not been made in this thesis, as it falls outside this thesis' scope to further investigate the mix of electricity generating technologies and ownership of these on the external markets. This limitation has been made due to time constraints. Instead three important aspects of the external market are investigated. These are:

- The price on the external market, which either could increase or decrease. In order to see the effect clearly a +/-20% change of the yearly average external price of 497 DKK/MWh has been used, giving a low and high average external price.
- The transmission capacity to the external market. Here it is assumed that the transmission capacity only will increase over time, when disregarding possible temporary transmission line breakdowns. A doubling of the transmission capacity of 2,500 MW has been used, giving a new transmission capacity of 5,000 MW.
- The price distribution on the external market, which is used to simulate how the external market price changes during a year. In the initial modeling this distribution has been kept unchanged, which basically means that it has been modeled as a MPS market. PAB seems to even out the price differences by mostly increasing the bids of the lowest MPS bidders and by using the average price of the winning bids as the market price. For this reason more smoothened price distributions is produced in order to simulate an external PAB market.

These factors are analyzed separately, and are presented in the named order.

Average external market price

The effect of using a lower average external market price is found in Figure 26.

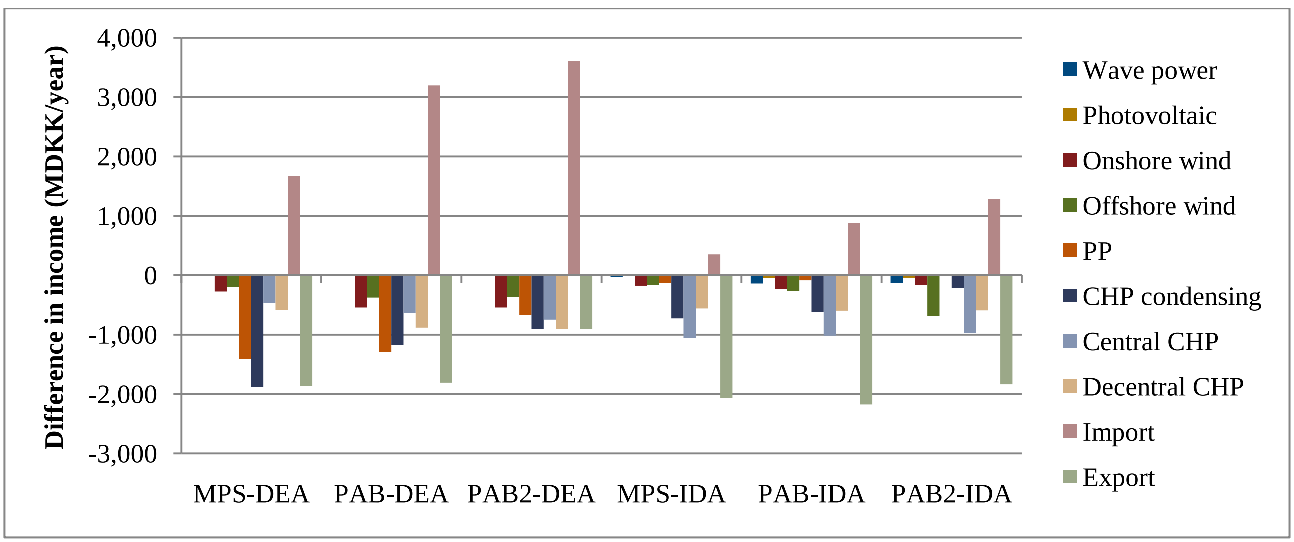

Figure 26: Difference in yearly income between using an average external market price of 497 DKK/MWh and 397 DKK/MWh (Appendix 9)

It is clear from Figure 26 that a lower yearly average external market price increases the import while decreasing the export, and hereby decreases the income of all the facilities in Denmark. The condensing CHPs' and PPs' decrease in income is however smaller in the PAB-scenarios than in the MPS.

Wind power and decentral CHPs seem to experience a larger decrease in income in the PAB scenarios than in the MPS, with the exception of offshore wind power in PAB2-IDA, where the offshore wind power experience the largest decrease due to its increased bidding price.

The effect of increasing the average external market price can be seen in Figure 27.

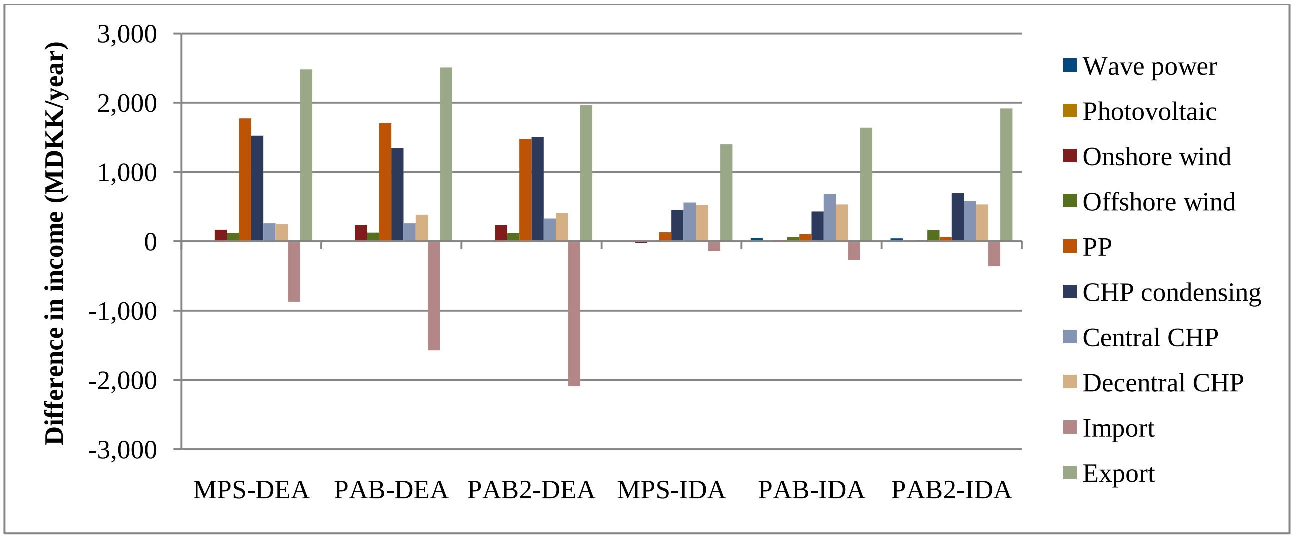

Figure 27: Difference in yearly income between using an average external market price of 497 DKK/MWh and 596 DKK/MWh (Appendix 9)

The figure shows that an increased average external market price results in increased export, decreased import, and an increased income for all facilities. However, onshore and offshore wind power are generally the units that benefit the least of this increase, and this seems to be the same in either of the MPS, PAB and PAB2 settings. The most expensive units, condensing CHPs and PPs, are clearly the units that benefit most from this in the DEA-scenarios, while in the IDA-scenarios it is instead the CHPs and condensing CHPs that benefit the most.

From this it is clear that the average external market price is important for the income potential for all the technologies, but the income potential for the technologies does not seem to be that depend on which auction setting is used. The technical setup is clearly more important in this context. However in the DEA scenarios the change in income is less in the PAB and PAB2 settings than in MPS, though there is not a significant difference.

Transmission capacity

The transmission capacity sets the maximum limit for the import and export in any given hour, and thereby is restricting the competition of the external producers on the Danish market, but also the Danish producers' competition on the external market. For this reason it is relevant to investigate how important this restriction is to the results. The authors do not expect the transmission capacity to the external markets to be reduced over time, instead it is assumed only to increase, and for this reason only an increase in the transmission capacity to the external market is investigated. More precisely it is chosen to double the modeled transmission capacity from 2,500 MW to 5,000 MW. The effect of this doubled transmission capacity is found in Figure 28.

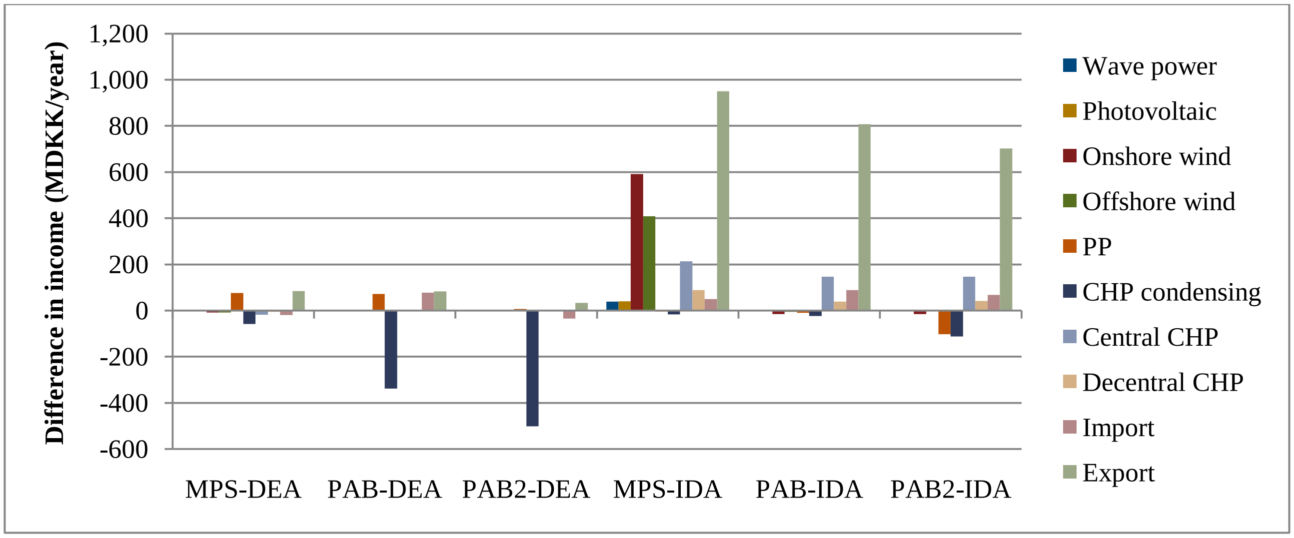

Figure 28: Difference in yearly income between using a transmission capacity of 2,500 MW and 5,000 MW (Appendix 9)

For the DEA PAB scenarios the change of transmission capacity seems to only affect the condensing CHPs, as they experience a significantly greater change in income than any other units. This is due to the condensing CHPs being outbid more by the external market, since the import can replace the condensing CHPs in more hours. The payment for the import does however not increase to the same extent as the condensing CHPs decrease, which is because there are not any units on the Danish market, to increase the payment for the import, and the import payment is calculated as MPS. In all the IDA-scenarios the changed transmission capacity results in the export increasing. However this only significantly increases the income of any of the technologies in the MPS-IDA scenario, since the payment for electricity here is dependent on which hour the production occurs; whereas in PAB only the amount produced affect the income. The wind power production only changes by up to 10 MWh/year in the IDA-scenarios. So the wind power only experiences the benefits of an increased transmission capacity with increased possibility for export in the MPS, but only when there is a significant amount of wind power in the system, as the case is with the IDA-scenarios.

External market distribution

In order to change the external market's price distribution to approximate a PAB external market, the existing MPS external market price distribution is used as a base, as it shows the price fluctuations through the year. However, this price distribution reflects the marginal price on the external market, rather than the average price for each hour, as would be the case in a PAB setting and for this reason a more smoothened external price distribution is required. Making this new distribution is done by finding the average prices for each week throughout the year, and comparing it with the yearly average external market price, where the comparison then has been multiplied on each hour in any given week. The concrete calculation of the comparison for each hour depends on whether the hourly price is higher or lower than the corresponding weekly average price, as this will determine whether the price shall be decreased or increased. Furthermore it must also be found whether the weekly average price is greater than the average yearly price or vice versa, as this will decide how to decrease or increase the hourly price. This has been done using the following formulas:

If $P_{average(week)} \leq P_{average(year)}$ and $P_{hour} < P_{average(week)}$, or if $P_{average(week)} > P_{average(year)}$ and $P_{hour} \geq P_{average(week)}$, then:

$P_{hour\ (new)} = P_{hour} * \frac{P_{average\ \ (year\ )}}{P_{average\ \ (week\ )}}$, else: $P_{hour\ (new)} = P_{hour} * \frac{P_{average\ \ (week\ )}}{P_{average\ \ (year\ )}}$

Where: P_{hour} = MPS price in each hour; $P_{average(week)}$ = weekly average price; $P_{average(year)}$ = yearly average price; $P_{hour(new)}$ = hourly price for a more smoothened external price distribution

$P_{hour(new)}$ still have hours where the price is too low and too high when considering the higher minimum bids in PAB and the averaged electricity price. For this reason it is found necessary to remove the lowest and highest prices of the produced hourly prices. This has been done by removing the prices that greatly differentiate from the weekly average prices. Since there are no definite way to define these tops and bottoms of the distribution, without having to investigate the external markets technologies in detail, two external distributions have been created. One where all prices greater than $P_{average(week)}$+200 DKK and lower than $P_{average(week)}$-200 DKK have been removed, this is referred to as PAB external market (high spread), and another where prices greater than $P_{average(week)}$+100 DKK and lower than $P_{average(week)}$-100 DKK have been removed, which is referred to as PAB external market (low spread). These two new external market distributions can be seen in Figure 29 alongside the original MPS external price distribution.

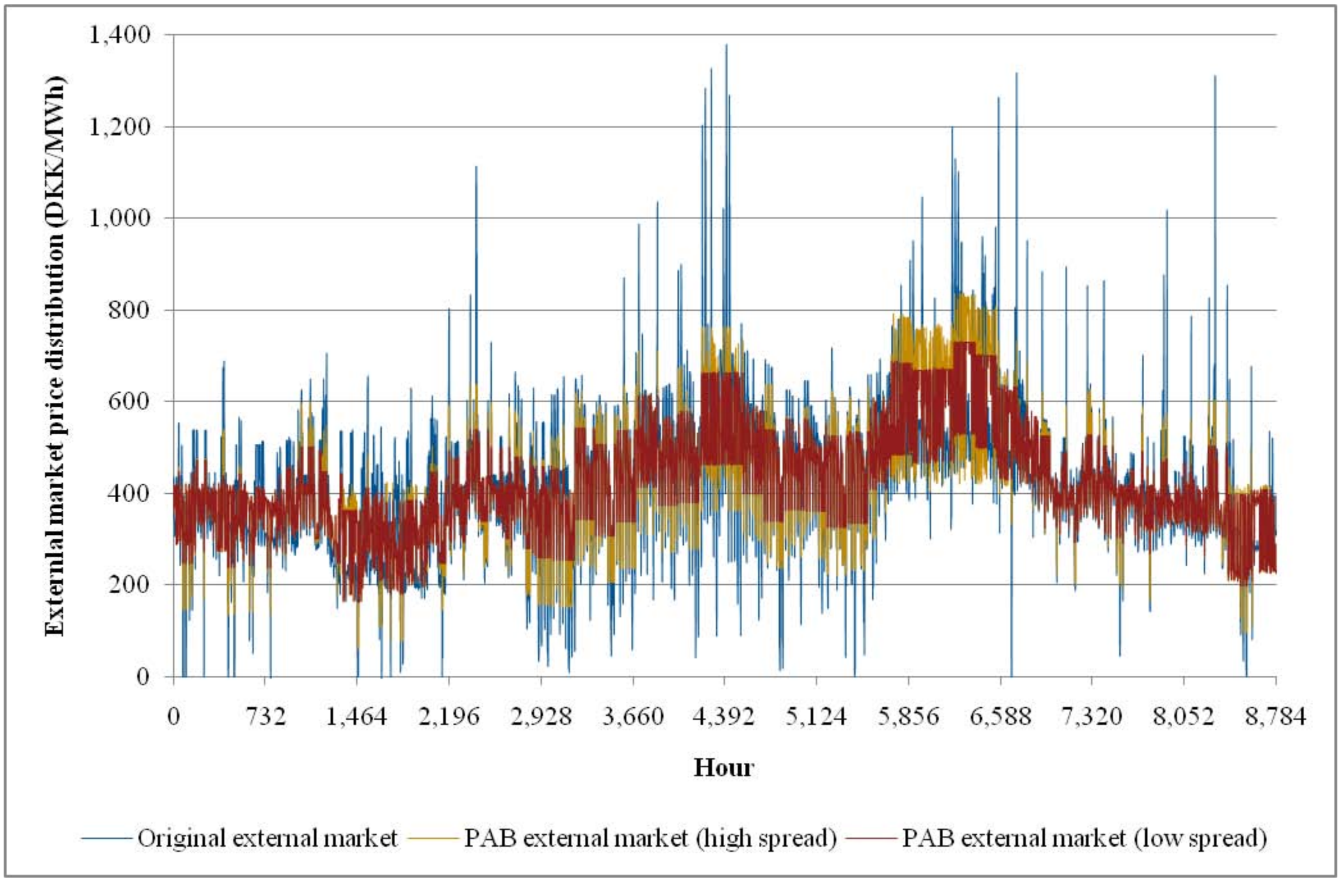

Figure 29: The original external market price distribution alongside the two external market PAB approximations (Appendix 10)

As the figure shows, the two modeled PAB external market price distributions have the same yearly fluctuations as the MPS, however the highest and lowest prices are removed.

The results of using the PAB external market (high spread) distribution compared with the original MPS external market distribution can be seen in Figure 30, where only the PAB scenarios are being presented, as it is assumed that the MPS scenarios do not have this external PAB distribution.

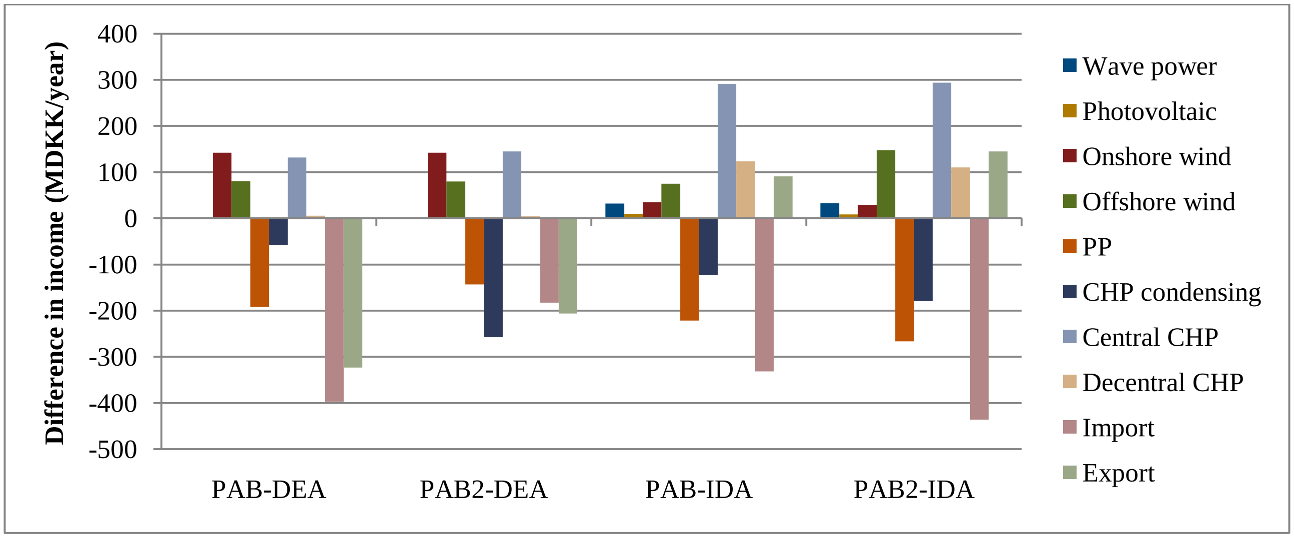

Figure 30: Difference in yearly income between using the original external market distribution and the PAB external market (high spread) distribution (Appendix 9)

From Figure 30 it is clear that by using a smoothened price distribution the import decreases, compared with the original price distribution where the import increased in all the PAB scenarios. This shows that the increase in import when going from MPS to PAB are, at least partly, due to the hours of low external market prices, which occurs in the original external market distribution, but occurs less in the new PAB external market (high spread) distribution. In the DEA-scenarios the export also decreases, which is due to many of the high external market prices being removed. In all the scenarios wind power experiences increased income, since it now is not outbid in as many hours as previous. The condensing CHPs and PPs loose income in all the scenarios because of fewer hours with high external prices. In the IDA-scenarios the decentral CHPs are experiencing increased income. Using the distribution with a lower price spread gives the results shown in Figure 31.

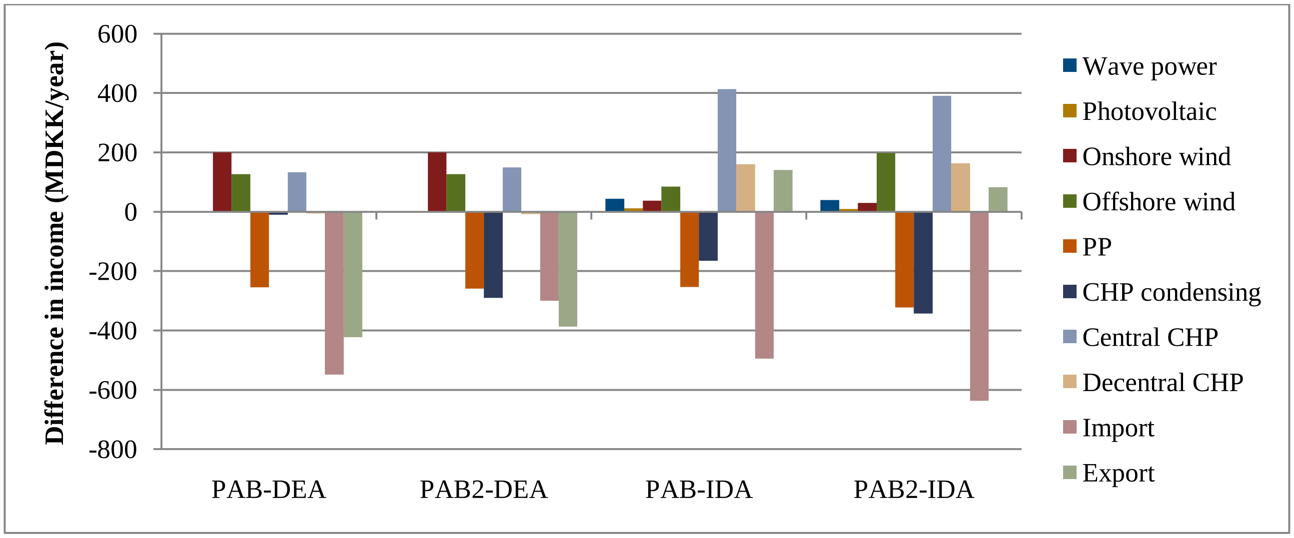

Figure 31: Difference in yearly income between using the original external market distribution and the PAB external market (low spread) distribution (Appendix 9)

The figure shows that using the low spread distribution has the same tendencies as with the PAB external market (high spread) distribution, however the results are here even clearer, as the changes in income are greater for all the units. It is hereby clear that when using an external market price distribution, which is more in line with what may be expected in the PAB auction setting, then the increase in import for going from MPS to the PAB scenarios is reduced, and wind power experiences increased income compared with the original external market distribution.

5.2.3 Wind power distribution

The distribution for the fluctuating RES production is relevant to investigate, and here especially the distribution for wind power, since this is by far the largest share of RES electricity production. For the initial modeling a wind distribution for the year 2001 is used. This year was not as good a wind year as the year 2000, and therefore a sensitivity analysis with the wind distribution for year 2000 is made. The results of this sensitivity analysis are shown in Figure 32.

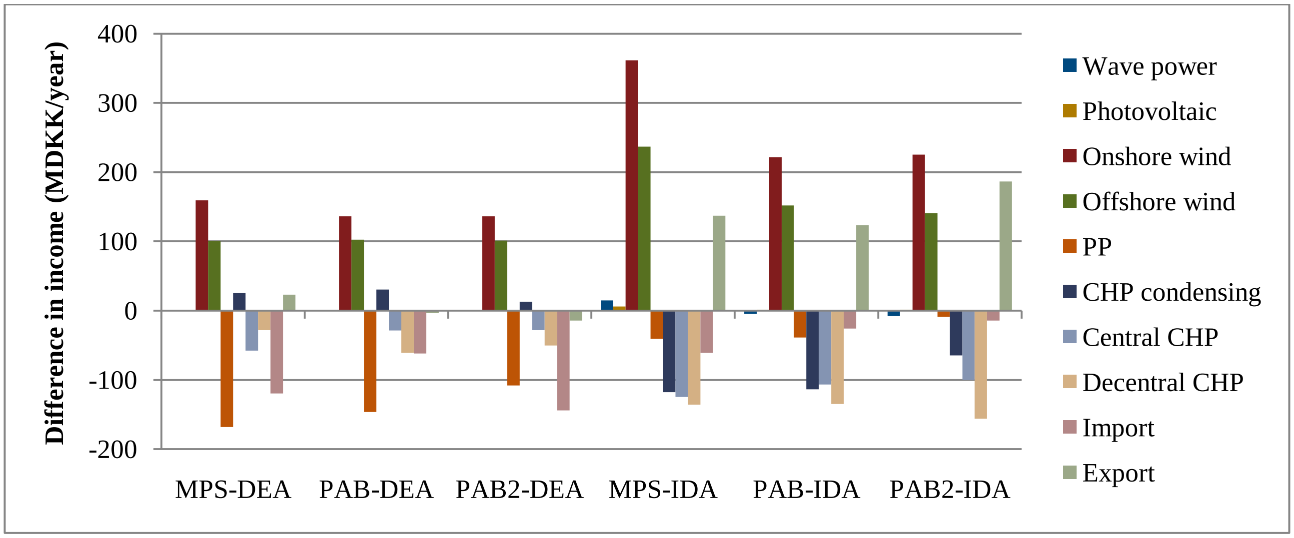

Figure 32: Difference in yearly income between using the original and a different distribution of wind (Appendix 9)

Overall the income is increased for wind production in all scenarios, which is a logical result of using a better wind year for the wind distribution. Because there is a larger capacity of wind power in the IDA-scenarios than the DEA-scenarios, the wind power in these scenarios has a greater increase in income. This also leads to a large decrease in the income for the CHPs, PPs and condensing CHPs in the IDA-scenarios. With this in mind the MPS-IDA scenario is by far the best system for wind power, where the wind gets the largest income. In PAB-IDA and PAB2-IDA wind power is outbid in more hours and getting less for the electricity sale than in MPS. The export is also larger in the IDA-scenarios, which is linked to the large amount of wind production. In the DEA-scenarios there are not any significant changes in the export. When looking at the DEA-scenarios there are a decrease in import, especially in MPS-DEA and PAB2-DEA. As an overall conclusion a year with more wind increases the income for wind power, but it also has to be kept in mind that years with less wind occur, having the opposite effect on the income of wind power. This of course also has an effect on the rest of the technologies, making the yearly income in MPS unpredictable the more fluctuating electricity there is in the system.

5.2.4 Changed annual heat demand

Since the Danish heating system is based on a large share of district heating supplied by CHPs, and as this heat demand affects the CHPs' bidding price by always comparing it with the cost of instead producing the heat using boilers, the heat demand in these areas has an effect on how much electricity production from other units is needed. Therefore a sensitivity of the heat demand is made by looking into the effect of increasing and decreasing the heat demand in the district heating areas by 10%. In Figure 33 the results of increasing the heat demand are shown.

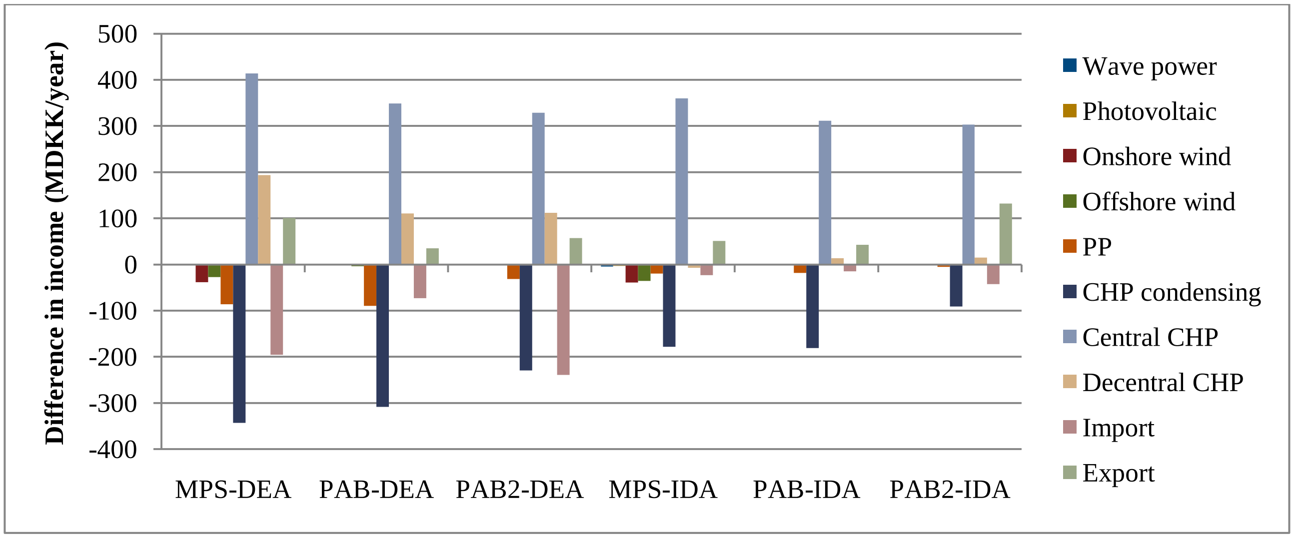

Figure 33: Difference in yearly income when increasing district heating demand 10% (Appendix 9)

An increase in heat demand increases the income for the central CHPs in all scenarios, but for the de-central CHPs the income only increases in the DEA-scenarios. This is because in the IDA-scenarios heat pumps are implemented, and the extra heat demand is instead being covered using these. In all scenarios this leads to a decrease in condensing CHPs and PPs. In the DEA-scenarios there also is a change in the import which decreases; this is due to the extra production from CHPs. This however is not seen in the IDA-scenario because of the already low import in this scenario. Looking at the RES there is a tendency that their income decreases; this is however mostly in the MPS-scenarios, and is caused by a lower price in hours where the CHPs run instead of PPs.

In Figure 34 the opposite situation is shown, where the district heating demand is decreased 10%.

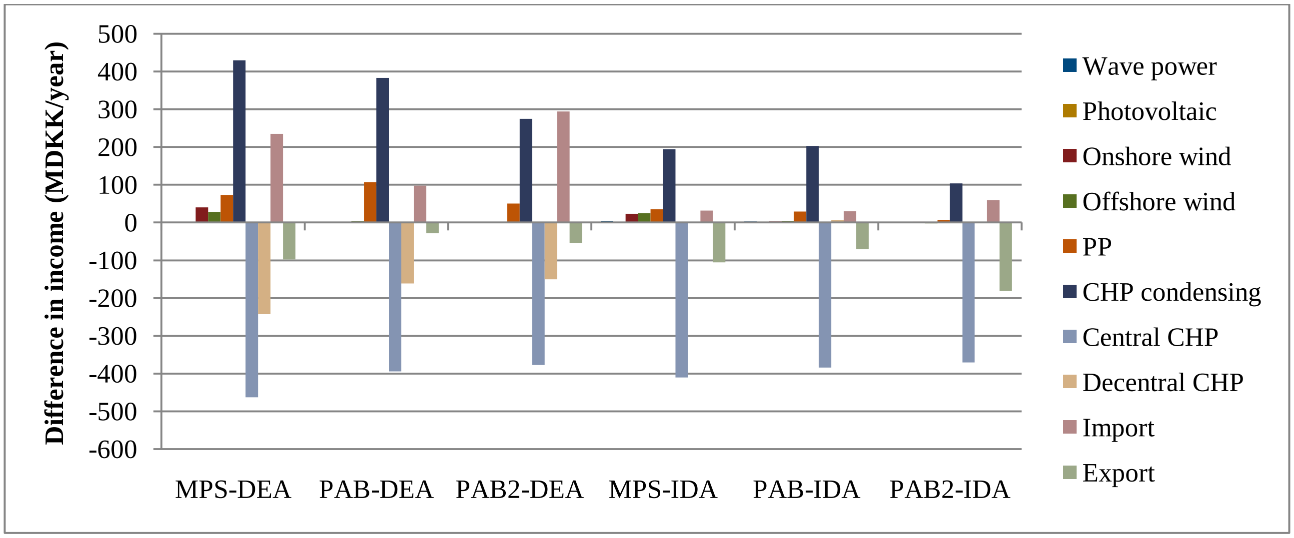

Figure 34: Difference in yearly income when decreasing district heating demand 10% (Appendix 9)

Decreasing the heat demand makes the central CHPs decrease their production, leading to less income for these. This leads to an increase in the use of CHPs in condensing mode, which increases the price on the internal market, leading to more import and a small increase in income for the wind power. Basically it is the opposite of the situation where the heat demand was increased.

Looking at both increasing and decreasing the district heating demand shows that this does not change the situation for the RES, but is important for the CHPs and in the DEA-scenarios for the import. The next section summarizes all of the results from the previous section, and compares these with the sensitivity analyses made in this section.

5.3 Overview of the results and sensitivity analyses

The overview of the results is divided into the DEA-scenarios and the IDA-scenarios. The overview includes a short description of the initial results found using on the base assumptions, and the results of the sensitivity analyses. Also included is which technologies prefer a different auction setting compared to the initials result, if some of the factors in the sensitivity analyses are realized.

5.3.1 The DEA-scenarios

In the DEA-scenarios the overall tendency is that the MPS is the best setting for most of the production units, by getting to produce most electricity in this auction setting. The only technology, for which the PAB setting is better, is the condensing mode CHPs which have the largest production in PAB-DEA. The import is the only category increased in PAB2-DEA compared to the other scenarios; this is linked to the lower prices on the external market. When looking at the income from the electricity sale it is the same situation as with the electricity production, MPS-DEA is the best situation for everything except import, which is highest in PAB2-DEA. On the other hand when looking at the profit for the thermal units, this is highest in PAB2-DEA.

In Table 18 an overview of the sensitivity analyses of the DEA-scenarios is shown.

	MPS-DEA		PAB-DEA		PAB2-DEA	
	Increases	Decreases	Increases	Decreases	Increases	Decreases
Fuel price low	PP & Exp.	Imp.	**PP**, Cond. & Exp.	Wind, CHP3 & Import	**PP**, Cond. & Exp.	Imp.
Fuel price high	**Imp.**	PP, Cond. & Exp.	**Imp.**	PP, Cond. Exp	**Imp.**	PP, Cond. Exp
CO2 cost	**Imp.**	PP, Cond. & Exp.	**Imp.**	PP, Cond. & Exp.	**Imp.** & CHP2	PP, Cond. & Exp.
Ex. Price low	Imp.	PP, Cond. & Exp.	**Imp.**	PP, CHP2, Cond. & Exp.	Imp.	PP, CHP2, Cond. & Exp.
Ex. Price High	PP, Cond. & Exp.	Imp.	PP, Cond. & **Exp**.	Imp.	**PP**, Cond. & **Exp**.	Imp.

Table 18: Overview of the DEA-sensitivity, income changes larger than 25%, bold text is larger than 100%. Based on data from (Appendix 9)

The overview only shows the changes in income that are larger than 25% compared with initial income from electricity sale results. The sensitivities of wind distribution, heat demands, external distribution and external capacity are not shown in the table, because the changes in these categories do not change the overall results more than 25%. If in the sensitivity analyses for e.g. the heat demand were increased 25% instead of only 10% the effects could have been higher, and they would be in the table. Looking at Table 18 there are two overall tendencies; the first being increasing the fuel price, either directly by increasing fuel price or CO_2-quota price, or indirectly by decreasing the external price. These all result in an import increase of more than 100% from the initial results and a decrease in PP, condensing CHPs and export. In the PAB-scenarios there also are a decrease in income for the decentral CHPs when lowering the external prices. The second situation is where the relative electricity prices are lowered directly or indirectly by making the external prices higher, here the opposite occur where import is decreased and PPs, condensing CHPs and export are increased.

Another way to look at the sensitivity analyses is to see which sensitivities results in the technologies changing their preferred setting when only considering their income from electricity sale. By switching to the low fuel price PAB is the best for PPs, and PAB2 is the best for offshore and central CHPs. All had the MPS as their initial best when looking at the income from electricity sales. If switching to the high fuel price this makes PAB and PAB2 the best settings for the decentral CHPs. A low cost on the external market makes PAB the best setting for PPs. The last important point to notice is that condensing CHPs change their best to MPS if there is a high external cost, even more than when changing external distribution, higher export capacity or having a lower heat demand.

5.3.2 The IDA-scenarios

When looking at the electricity production in the IDA-scenarios the pattern is somewhat different from the DEA-scenarios. The MPS-IDA scenario is best for RES, CHPs and the export. The PAB-IDA is best for PPs and condensing mode CHPs. And PAB2-IDA has the highest import. When looking at the income for these technologies it follows the production, except for offshore wind which actually has the highest income in PAB2-IDA. The highest profit for PPs and condensing CHPs are in PAB2-IDA, whereas for the CHPs it is in PAB-IDA.

The sensitivity analyses for the IDA-scenarios are shown in Table 19.

	MPS-IDA		PAB-IDA		PAB2-IDA	
	Increases	Decreases	Increases	Decreases	Increases	Decreases
Fuel price low	Cond. & **CHP2**	CHP3 & Imp.	**CHP2**	Wave, CHP3 & Imp.	Cond. & **CHP2**	Wave, CHP3 & Imp.
Fuel price high	PV, CHP2 & **Imp.**	CHP3, Cond. & Exp.	CHP2 & **Imp.**	CHP3, Cond. & Exp.	PP, CHP2 & **Imp.**	CHP3, Cond. & Exp.
CO2	CHP2 & **Imp.**	CHP3, Cond. & Exp.	CHP2 & **Imp.**	CHP3, Cond. & Exp.	PP, CHP2 & **Imp.**	CHP3, Cond. & Exp.
Ex. Price low	Imp.	PP, CHP, Cond. & Exp.	**Imp.**	Wave, CHP, Cond. & Exp.	**Imp.**	Wave, CHP, Cond. & Exp.
Ex. Price High	PP, CHP2, Cond. & Exp.	Imp.	PP, CHP, Cond. & Exp.	Imp.	PP, CHP3, Cond. & Exp.	Imp.
Ex. Dist. High						PP & Imp
Ex. Dist. Low				PP		PP & Imp
Ex. Cap.						PP

Table 19: Overview of the IDA-sensitivity, income changes larger than 25%, bold text is larger than 100%. Based on data from (Appendix 9)

The table again only shows the changes in income that are larger than 25%, where the sensitivities of wind distribution and heat demand are not shown, due to small changes in income. The sensitivity in Table 19 gives a more diffuse picture than in the DEA-scenarios. Increasing the fuel prices still increases the import more than a 100%, but in the IDA-scenarios also the decentral CHPs benefit from this. Decreasing the external price however only increases the import. Increasing the prices on the external market benefits the PPs, condensing CHPs and export in all the IDA-scenarios. But for the CHPs there are differences between the scenarios, where in MPS-IDA the decentral CHPs benefit, in PAB-IDA both CHPs benefit and in the PAB2-IDA the central CHPs benefit. Also it seems like the external distribution has more impact in the IDA-scenarios, where changing this decreases PPs in PAB-IDA and in PAB2-IDA the PPs and import are decreased. The external capacity also has an effect on the PPs income, which decreases in PAB2-IDA.

As with the DEA-scenarios, it is interesting to see which sensitivity analyses changes the preferable scenario for the different technologies. If the fuel price is low a lot of the technologies switch their preferred scenario; for condensing CHPs MPS is now better than PAB, offshore wind is now in PAB instead of MPS and onshore and central CHPs has PAB2 as their preferred scenario instead of MPS. PPs are better off in PAB2 instead of PAB when there is an increase in fuel price, CO_2-quota price or a decrease in external price. A high price on the external market results in both onshore and offshore wind power switches from MPS to PAB2. Changing the distribution for the external market also makes PAB2 preferable for offshore wind power, but in the same time make PPs and condensing CHPs switch to MPS as their preferred scenarios. If the heat demand is higher the onshore and offshore wind power again prefers PAB2.

Overall it can also be found from the results that the technical setup do have an effect on the results, where the PAB setting fared better in the IDA setup than in the DEA setup. This is especially due to the wind power bidding lower in the IDA setup, where it is more likely to outbid the external market and the CHPs than in the DEA. Also the more flexible demand side in the IDA setup, with e.g. heat pumps and electric vehicles, is relevant in this context, as the demand here can move over time and from electricity to other energy usages such as heat to a much higher degree than in the DEA setup.

The next chapter features a discussion of the results and the modeling approach.

6 Discussion of the results and modeling approach

This chapter contains a discussion of the results and the approach used for the modeling. First a reflection and discussion of the modeling results, set up against interviews with several actors on the Danish electricity market, is presented. Following this the auction settings' effect on consumer prices are investigated. Hereafter the different problems with the modeling are discussed in regard to their importance and effect on the results.

6.1 Reflecting on the modeling results using interviews of market actors

As mentioned in section 2.1, interviews were made in the beginning of the project period with actors from the Danish electricity market. Some of these are used in this section to give a better understanding of the problems linked to the MPS and PAB, and especially the considerations made when modeling the settings.

Throughout the modeling one of the greatest challenges has been how to estimate the bidding prices for the electricity producers. The first strategy was to try and include the long-term costs in the bids by finding annual costs based on the investment, fixed O&M, lifetime and an interest rate. This however made the bids extremely high, and also made another problem clear; most of the production units have other incomes than the spot market, such as district heating sales and ancillary services, making it an odd approach to try and pay for all the expenses, by only using the income from the spot market. The problem with the bidding prices is also addressed by Georges Salgi from Vattenfall when interviewed; he mentions that e.g. wind production would have to somehow guess the prices in a PAB setting, making it much more uncertain what to get for the electricity. Anders N. Andersen from EMD also states that in MPS the smaller actors can cover their expenses by assuming that there is a more expensive unit running and setting the price higher. In a PAB setting it would not be possible to have this strategy, since they would get paid the bidding price. In the modeling in this thesis the solution for the bidding strategies, for each of the technologies, have been to assume that the money earned now on the spot market with MPS were enough to cover their long-term costs, therefore the assumption for the bidding prices have been that the bids in PAB would be the average selling price for each unit. By doing this it is possible to model the different systems, but also makes the PAB setting very static, as bids for each technology are the same all year. In reality the production units would try and adjust their bids over time resulting in more competition. To try and capture this dynamic the PAB2-scenarios were made, but even though it gives an idea about how the bids could be, it is still very static, having the same bids throughout the year and being sure that the nearest competitor does not decrease their bid just below one's own. This strategic approach to the bidding behavior is in line with the economic game theory, where the success of a player's choice depends on the choices the other players make. A more detailed game theoretic investigation could most likely provide better bid assumptions.

Another problem linked to PAB is seen in the results for the PAB-scenarios. There is a tendency that the RES do not produce electricity in all the hours they are capable of, because the bids are too high. This problem is addressed by Anders N. Anders in the interviews, where he sees it as a problem that they will have to bid a price above their STMC, and in some hours lose the bid. Anders Plejdrup Houmøller, Nord Pool Spot, also addresses this problem for the wind power, and says that the wind power in PAB risk not getting sold if bidding too high and risk losing income if bidding too low. Also there is the discussion made in chapter 1 for the thesis regarding the price going down to zero in MPS; even though EnergyPLAN is not perfect for looking at this, as many of these hours are linked to cost of cold starting a CHP or PP, it is possible from the outputs to see that in MPS-DEA there are no hours with a price of 0 DKK/MWh on the Danish market. Going on to the MPS-IDA plan there are 510 hours with a price of 0 DKK/MWh, and 350 hours of these are because the RES production exceeds the consumption and max export capacity. This is also what Georges Salgi from Vattenfall expected in the interview, where he states that this could be an increasing problem in a MPS if wind power is increased. Anders Plejdrup Houmøller from Nord Pool Spot agrees that it will increase, but does not see this as a problem as long as there is good competition on the market. Anders N. Anders from EMD also does not see a problem in the many hours where the price goes to zero and few hours with high prices, because then the production units with a higher fuel cost can produce in these few hours. One problem linked to the PAB auction setting is that all the producers have to bid higher than their STMC, therefore all of the lower price spikes known from MPS are eliminated in this system. This makes it harder to implement a more flexible energy demand that could help remove some of the peak demands. In the view of many of the interviewees this is one of the important solutions to utilize the fluctuating RES better. This hereby could be a problem in the PAB setting. For example Anders N. Anders talks about this, saying that a functioning market should send signals that incent to invest in intelligent electricity demands, when the prices drops down. Steen Kramer Jensen from Energinet.dk also mentions the flexible demand as an important factor, saying that it is important to make incentives for the consumers to move their electricity usage away from the high price periods. However, as stated in section 1, there is a limit to the potential of this.

6.2 The auction settings effect on consumer prices

Not modeled in this thesis, but still relevant to discuss, is how the consumers' price would be affected by a possible change of auction setting. As stated in the chapter 3 the effect on consumer prices of using PAB instead of MPS is subject to extensive discussions, where one side proclaims that PAB will result in lower consumer prices and the other side proclaims that it will not lower the consumer price and that it might even increase the consumer price over time. In this thesis the consumer price has not been the focus of the results, however an indication of how this might be affected can be found by summarizing the incomes for all the technologies. This gives an indication of whether the yearly average electricity price increases or decreases, based on the assumption that any change in the overall income for the producers will directly be experienced by the consumers.

The payment for electricity has been found by summarizing the income for all the producing technologies and adding the net import payment, in order to account for the income gained from consumers on the external market. It is hereby only the consumer price on the internal market that has been examined, and shows the total payment for the electricity used on the domestic market. The total yearly income plus net import can found in Table 20.

(MDKK/year)	MPS-DEA	PAB-DEA	PAB2-DEA	MPS-IDA	PAB-IDA	PAB2-IDA
Total payment	17,470	17,578	18,825	9,760	9,637	10,111

Table 20: Total yearly income for all producer incl. net import using the base assumptions (Appendix 8)

The electricity payments in Table 20 are those found for the calculations using the base assumptions. It can be seen that in both the DEA and IDA setups the change from MPS to PAB only changes the total payment for electricity slightly with around 1%, where it is slightly increased for the DEA setup and slightly decreased for the IDA setup. Hereby it must be concluded that there are no indications in these results that a change in the auction setting from MPS to PAB in itself changes the consumer price significantly. Going from MPS to PAB2 clearly increases the payment for electricity in both the technical setups, where the change from MPS to PAB2 increases the total payment with close to 8% in the DEA setup and close to 4% in the IDA setup. As the PAB2 setting focuses on the possibility of major players gambling on the market, this effect is most likely due to the lack in equal short-term competition between the market players.

The payment for the produced electricity is also only a part of the consumers' current electricity payment. At the beginning of 2009 the average electricity price for a household with an annual consumption of 4,000 kWh was 2.10 DKK/kWh, and of this 0.56 DKK/kWh was the payment for both the energy and the subscription to the electricity supplier (Danish Energy Association 2009). As the electricity price hereby makes up a relatively small portion of the total electricity price, any changes in the price on the Nord Pool Spot will only to a minor extend be experienced by the end consumers in Denmark.

Another important thing when discussion the results, is the whole modeling approach in the thesis. This is discussed in the next section.

6.3 Problems with the modeling approach

This section deals with the identified problems and restrictions regarding the modeling approach used in this thesis. The aim is to identify which aspects of the modeling approach could be improved with further work on the thesis, and discuss how the results most likely would differ if these problems and restrictions were addressed.

6.3.1 Limitations of EnergyPLAN

The EnergyPLAN model has been used to model the markets choice of technologies in each hour, however EnergyPLAN is a model made for the modeling of a MPS auction setting. This gives some problems when making the modeling of a PAB setting, as many of the technologies uses the calculated MPS price for each hour, as is the case with heat pumps where the model's decision of running the heat pumps depends on the MPS price for each hour. The authors' changes to the EnergyPLAN model has mainly been the adding of variable O&M costs for the fluctuating RES, and hereby making it possible to give these a bidding price in PAB, and the overall procedure of the model has therefore not been altered. This gives an approximation of a PAB setting, where the resulting incomes have been modeled outside of EnergyPLAN. However, in order to make the EnergyPLAN model more in line with a PAB setting, units such as heat pumps should instead of using the marginal production cost as a basis for when to produce, be using the average of the winning bids, as this would be the resulting buying price in PAB, and hereby the price these would have to pay for the electricity. This would require more changes in the economic regulation strategy of EnergyPLAN. The effect of this problem in the modeling is not seen as a significant problem, as the average price does not differentiate to a high degree from the marginal production cost, as the used bidding prices in PAB in general are relatively close to each other.

Another restriction of using EnergyPLAN for the modeling is that it models each type of technology as one aggregated single unit. Meaning that all the PPs are modeled as one big PP, all central CHPs are modeled as one big central CHP, etc. This is also the case with the external market, which is modeled as one, however the price would vary depending on whether it being Germany, Sweden or Norway. This results in no difference in the bidding within each technology category and external market, as would be the case in reality, where the difference in age of facility, fuel input, etc. would result in difference of bids. The used bids in EnergyPLAN are to be seen as yearly average bids, and some would bid less than this and some would bid higher, and also the bids could in reality change through the year. The aggregated units also mean that possible costs of shutting down or powering up units are not taken into account. This lack of detailed modeling makes the modeling kind of an all or nothing approach to the production facilities which would not be the case in reality, and when analyzing on the basis of each hour, as has been done in this thesis, this does introduce a source of error. However the advantage of the EnergyPLAN model is that it is easier and faster to make changes in the model than if a more detailed model were used, and the sensitivity analyses are hereby used to reduce this problem of the aggregated modeling.

In the EnergyPLAN model there are also procedures which mostly satisfy a technical justification rather than an economic one. One of these is when the import transmission has reached its maximum and the electricity demand is still not met. In this case the model will activate the PPs and make the resulting market price the marginal cost of producing on the PPs, even though cheaper units such as CHPs could produce in these hours, and the CHPs could reduce the boiler production or fill the heat storage in these hours. This means that the PPs are activated in more hours than would be the case if other units could be activated in the same situations. This is especially relevant in the results where the import increased significantly.

6.3.2 Possible improvements to the modeling

A minor rounding error in the modeling has been identified, however it has been found late in the project period and for this reason has not been possible to correct. The problem occurs when going from MPS to PAB bidding prices. Here the MPS bids and hourly production of each technology are compared with the market price produced by EnergyPLAN in each hour, and the result of this comparison is the profit each technology has in each hour. This hourly profit is used for calculating what profit the technologies are expected to want in PAB, and are used for making the PAB bids. However, a minor error has been found in this. The MPS bidding prices used in these calculations has been calculated within Excel spreadsheets, and hereby this number is precise down to the decimals Excel can handle. But this number is being compared with the output number of EnergyPLAN, which is rounded off to the closest whole number, and hereby there is a difference in the size of these two numbers. The difference is quite small and only has a significant impact in the hours where the market price equals the whole number of a technology's MPS bid. This error can be corrected by changing the MPS bids in the Excel modeling to whole numbers. The result of doing this for the initial modeling of PAB bids are shown in Table 21.

Unit	Used PAB-DEA bid	Corrected PAB-DEA bid	Used PAB-IDA bid	Corrected PAB-IDA bid
	DKK/MWh	DKK/MWh	DKK/MWh	DKK/MWh
Incr. CHP2 decr. HP2	499	**500**	426	**427**
Incr. CHP3 decr. HP3	492	492	413	**414**
Incr. CHP2 decr. B2	479	**480**	394	**395**
Incr. CHP3 decr. B3	456	456	369	**370**
Condensing power	516	516	437	**438**

Table 21: Used PAB bids alongside PAB bids corrected for the rounding error (changing bids has been made bold)

As seen in Table 21 this error only changes the PAB bids to a very small degree, and it can hereby be concluded that this error does not affect the overall conclusions of the analyses.

6.3.3 Bidding prices

Probably the most important aspect of the modeling approach is the way the bidding prices for the auction settings have been found, as these bids sets the basis for the modeling of each setting and the main difference between them, hereby also providing the greatest possible source of error.

One way of improving on the bids could be to make sensitivity analyses on these. This could be done by finding the optimal bidding strategy for each unit, which would result in new bids for all the units, as has been done for finding the PAB2 setting. This would optimally then have to be repeated several times until the bids are as optimal as possible for all units, as changing the bid for one unit could result in new optimal bids for all other units. This could also provide better insight into how changing the bids of the different units would affect the other units in the system. This process would however require longer time than are allocated for this thesis, as making these analyses would take a long time with the used modeling approach. Another possible approach could be to use a different energy system modeling tool than EnergyPLAN or make changes to EnergyPLAN, so that it would be possible to get the model to calculate the optimal bidding strategy for each technology, by running the energy system modeling recursively until the optimal strategy for each unit were found. The PAB2 setting can to some extend be seen as a sensitivity on the bidding strategy of several of the technologies, and if a model capable of making this recursive modeling were used, several other possible bidding behaviors could be found.

Another approach that could have been used would be to model an approximation of all the possible incomes that each technology receives from other markets. Using this approach, the bids could more accurately be in line with what is needed to cover the long-term marginal costs of each technology. However, it must be assumed that the incomes would remain more or less the same in both the MPS and PAB settings, and it is therefore doubtful that this would change the difference between these auction settings significantly, compared with the current approach.

7 Conclusion

The long-term political goal in Denmark is to be free of fossil fuels; if this goal is to be reached, the Danish electricity system will be increasingly dependent on sources of fluctuating renewable energy sources (RES), especially wind power. These energy sources currently are selling electricity on the Scandinavian electricity market, Nord Pool Spot, where they submit bids with prices close to zero, which means that the hours of high wind power production also have very low electricity prices. As more fluctuating RES enters the market, more hours of high production will occur, which will cause the price to further decrease. This price drop will increase these sources' dependency on subsidies, because they will be earning less via sales on Nord Pool Spot during the hours of high production. Furthermore, these sources both decrease the market price and increase the fluctuations in price as their total capacity grows; this results in a higher risk on the market, thereby potentially reducing the willingness to invest in new production capacity needed for achieving an energy system less dependent on fossil fuels.

For these reasons it is relevant to investigate whether another market setting would reduce these potential problems. The current Nord Pool Spot is based on an auction setting known as Marginal Price Setting (MPS), in which the most expensive auction winning unit sets the market clearing price together with the demand for electricity. In this setting, the units optimally bid with a price close to their short-term marginal cost of production. This system is normally used in electricity markets; however, other usable auction settings exist. One of these is the so called Pay-As-Bid (PAB) auction setting, where the winning units are paid their own bid no matter what other winning units are paid. This auction setting forces units to bid what they want for their production, rather than their short-term marginal costs, thereby forcing the units bidding very low in MPS to bid higher. This makes the PAB an interesting alternative auction setting to investigate for an energy system relying more on fluctuating RES, as these units will have to bid somewhat higher than now. Where the modeling of MPS is done using the short-term marginal costs of the units, this cannot be done for PAB, and two different bidding strategies have been identified for PAB. One is called PAB where the bids equal the short-term marginal cost plus the profit gained in the MPS setting; another is referred to as PAB2, where major players optimize their gains by adjusting their bids according to the optimal situation for each technology.

In order to analyze these two electricity auction settings, two technical setups are used, which both are modeled for an energy plan made by The Danish Society of Engineers (IDA) named "The IDA Climate Plan 2050". In this plan several future energy system setups are modeled, but only two of these are used in this thesis. The first of the two chosen technical setups is the so called DEA2030, which is based on a forecast made by the Danish Energy Agency (DEA) for 2030; in this thesis it is used as a technical setup similar to the current energy system in Denmark. The other technical setup is the IDA2030, which is a setup with more RES together with electric vehicles, heat pumps, and other demand changing technologies; in this thesis it is used to simulate a system relying more on fluctuating RES. Each of these technical setups has been modeled using the two different auction settings. This gives a total of six different scenarios, which all have been modeled hourly for one year. Sensitivity analyses of the results have been carried out for all of the scenarios.

The results of the analysis show that when introducing PAB, wind power producers risk being outbid by other technologies or the import from the external market, and thereby risk to be forced to shut down in hours where they would normally produce in MPS. This makes PAB problematic if the highest possible wind power production is wanted.

When looking at the results for the DEA2030 technical setup, then all the modeled technologies have their highest yearly electricity production and income from electricity sales in the MPS. However, when considering their profit for selling, which here is defined as the difference between the yearly income and the yearly cost of producing, then all the thermal units have their highest yearly profit in PAB2. These results are, however, very dependent on the included factors; e.g. on the fuel cost, as reducing the cost of fuel makes the power plants more likely to prefer PAB, and makes the offshore wind power and central CHPs more likely to prefer the PAB2 setting. A high fuel cost however makes decentralized CHPs prefer both PAB and PAB2 instead of MPS. This high dependency on the included factors makes it difficult to give a firm final conclusion from the analyses. However, based on the modeling results, the MPS seems to be the best overall option for the DEA2030 technical setup when considering the goal for the energy system to be free of fossil fuels, as the fluctuating RES seem to gain the most in this auction setting. But, this statement is again very dependent on the external market price, fuel costs, etc.

The results for the IDA2030 technical setup are even less clear than those for the DEA2030. All the fluctuating RES and all the CHPs have the highest production in the MPS, and all of these technologies, with the exception of offshore wind power, also have the largest income in this setting. Offshore wind power has its highest income in the PAB2 setting. The power plants and condensing mode CHPs have their highest production in PAB, but their highest income and profit in PAB2. The CHPs have their greatest profit in the PAB setting. However, this is again dependent on e.g. the fuel costs, where lower fuel costs makes PAB better for offshore wind power and PAB2 better for onshore wind power and centralized CHPs, but also changes to the external market and the heat demand alter the results. Using the base assumptions on costs, etc., the MPS generally is the best setting for most of the fluctuating RES; however, if just one of the factors changes, the PAB or PAB2 setting could be the preferred setting for these technologies.

Which auction setting would be preferred for achieving an energy system free of fossil fuels depends to a high degree on the base assumptions for fuel prices, heat demand, etc.; and this makes it somewhat difficult to conclude which auction setting would be best to facilitate this change. However, the MPS seems to be generally more preferable for the fluctuating RES in either of the technical setups, as their income and production is highest in the MPS more often than in the PAB. Though for the system having a lot of fluctuating RES, IDA2030, the PAB settings are better than MPS in more analyses than in DEA2030. As this thesis uses an aggregated modeling approach, where e.g. all power plants are modeled as one big power plant and the bid of each unit remains the same throughout the year, then using a more detailed modeling approach, where the modeling of each facility bidding behavior is possible, could provide some clearer results. Also, it would be beneficial for the results to further investigate other possible bidding strategies within the different auction settings, as this would provide a broader understanding of the possible effects of changing auction settings.

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Appendix A – EnergyPLAN changes in PAB-version

As described in the main report, some changes to the EnergyPLAN model have been made. This is done to make it possible to calculate the PAB auction setting in the model. This appendix gives an overview of the most important changes in the PAB version of EnergyPLAN. Most of the description is based on excerpts from the Delphi Pascal code, in which EnergyPLAN is programmed, and are explained according to this code.

The first things added to the model are some new variable O&M inputs and outputs, linked to the marginal cost calculation in the model. The additions are shown in Figure 35.

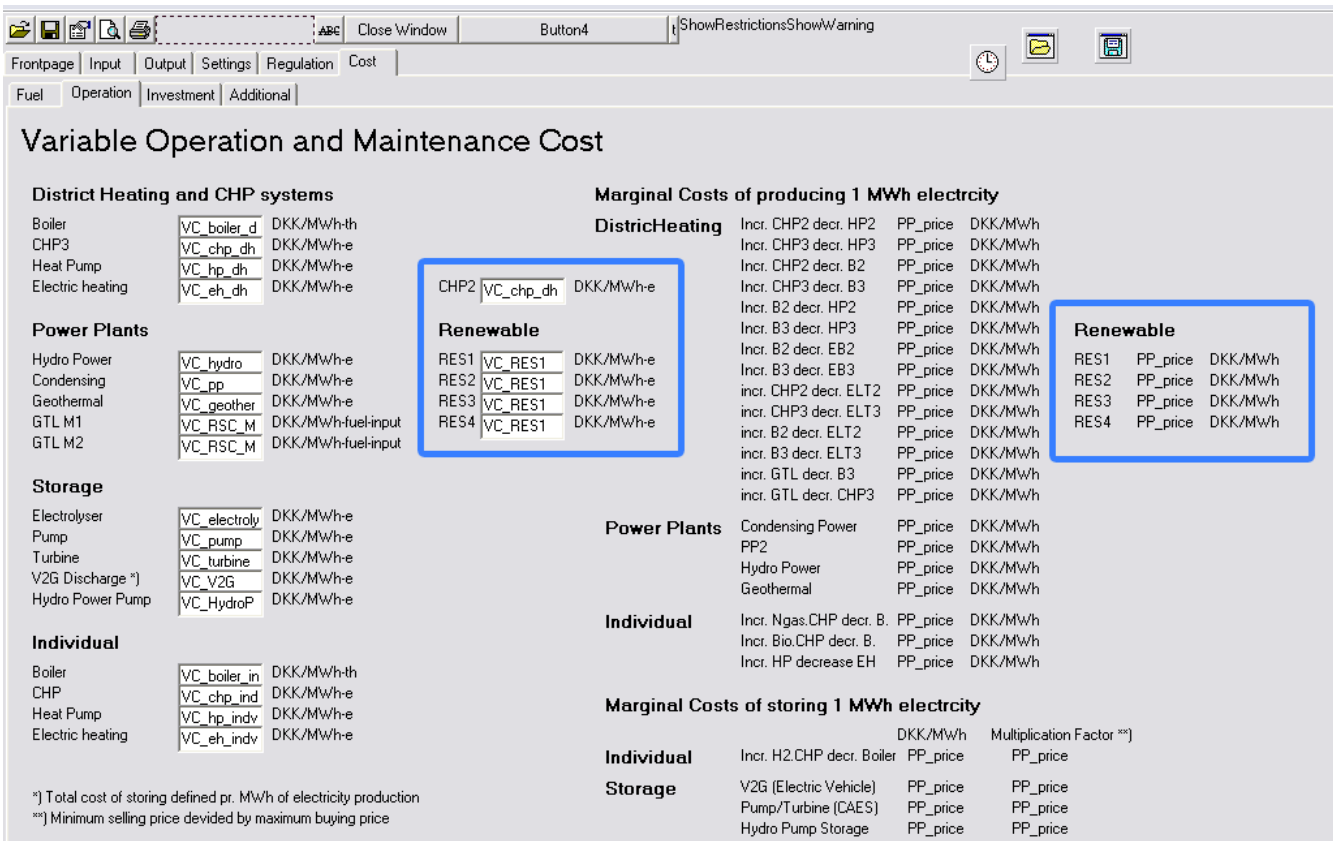

Figure 35: Additions to EnergyPLAN in PAB version

The first input added is linked to the CHPs variable O&M costs. This is done because in the normal version of EnergyPLAN only one input is possible for CHPs. These are separated in the PAB version into CHP2 and CHP3. The new input created for this purpose is called:

VC_chp2_dh: TEdit;

The other important addition is the adding of the possibility to put a cost on renewable energy. In the normal version of EnergyPLAN this is not possible; here the renewable energy just produces according to the distribution files. In the PAB-version they produce according to the distribution files, but also take the cost into account. If a variable cost of zero is added in the PAB model, it calculates the RES exactly as the normal version of EnergyPLAN. The new input boxes created for renewable energy shown in the middle of Figure 35, and are called:

VC_RES1: TEdit;
VC_RES2: TEdit;
VC_RES3: TEdit;
VC_RES4: TEdit;

For the calculation a resulting marginal price for production is needed. This is the prices shown on the left in the figure. For everything else than RES; fuel, handling, taxes and CO_2 costs are taken into account in this price. But in the PAB version the additions are only for the RES, and since they do not have any of these costs, the resulting marginal price is the same as the input in VC_RES1-VC_RES4. The output boxes that are added:

RES1_price: TStaticText;
RES2_price: TStaticText;
RES3_price: TStaticText;
RES4_price: TStaticText;

In the PAB-version some changes to procedures have been made. The first one is linked to the calculation of electricity production from offshore wind power, called RES2. In the normal version of EnergyPLAN the production for RES1 and RES2 are calculated in the same procedure called; Calculate_RES1_production**.** In the PAB-version this is separated into two procedures calculation the production for each of them. The procedures in EnergyPLAN are called:

Calculate_RES1_production
Calculate_RES2_production

To calculate the market economy of each technology a procedure is needed. Since the renewable sources are added in the PAB-version, these also need to be a procedure for calculating their market economy. Therefore four new procedures are created, these are:

Calculate_Market_RES1
Calculate_Market_RES2
Calculate_Market_RES3
Calculate_Market_RES4

Each of them is exactly the same, except for the RES-number. Only the procedure for RES1 is shown here:

```
Procedure Calculate_Market_RES1;
var xx : integer;
    factor, diff : double;
Begin
calculate_RES1_production;
For xx:=1 to 8784 do
 begin
  CalculateNettoImportAndSystemPris(xx);
  if input_import_bottleneck_addprice_factor<>0 then factor:=input_depend_fac * (hourarray_nordpool_prices[xx]/input_import_bottleneck_addprice_factor)
  else factor:=input_depend_fac * hourarray_nordpool_prices[xx];
  if factor<>0 then diff:= -((output_RES1_price  - hourarray_nordpool_prices[xx]) / factor  - NettoImport)
        else diff:=hourarray_RES1[xx];    “”
  If diff < 0 then hourarray_RES1[xx]:=hourarray_RES1[xx]+diff;
  If Hourarray_RES1[xx]< 0 then Hourarray_RES1[xx]:=0;
 end;
end;
```

First thing that happens, is that the procedure calculating the production runs, before taking price into account. This is done for all hours in one year. After this the prices for import/export is calculated together with the system price. If there are any bottlenecks these are also calculated. Afterwards the difference between the market price and the price for RES1 is found, and the resulting production is calculated.

However EnergyPLAN also needs to know when to run these market price calculations. This is done using another procedure called:

Calculate_Market_economy

Here are the additions in the PAB version, which are linked to the RES.

First step of the procedure is to set the marginal cost as equal to the output text from Figure 35:

```
MC_RES1:= output_RES1_price;
MC_RES2:= output_RES2_price;
MC_RES3:= output_RES3_price;
MC_RES4:= output_RES4_price;
```

The next time in the procedure that these are relevant, is when it is chosen which technology that should be used for production in an hour.

This is done by looking at the minimum of all the marginal costs. The formula looks like this:

Minimum:=Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(Min(MC_chp2b2, Min(MC_pp, 99998)), MC_chp2hp2) , MC_chp2elt2), MC_chp3b3), MC_chp3hp3),MC_chp3elt3), MC_NgasCHP_indv), MC_nuclear),MC_BioCHP_indv),MC_pp2),MC_RscB3),MC_RscCHP3),**MC_RES1), MC_RES2), MC_RES3), MC_RES4)**;

The four RES, marked with bold text, are the additions in the PAB-version. The technology that is available for that hour, with the lowest cost, is chosen first. If RES1 is the cheapest the following calculation is run, and this is again the same for RES2, RES3 and RES4:

```
If Minimum=MC_RES1 then
   begin
    If input_RES1_capacity > 0 then
    begin
     EPLANMainMenu.Button4.Caption:='RES1';
     Calculate_Market_RES1;
    end;
    MC_RES1:=99999;
end;
```

If there is a capacity larger than zero the market calculation for RES1 is activated, which is the one mentioned above.

Appendix DVD - List

1. IDA 2050 Climate Plan overview
2. MPS-DEA (Marginal Price Setting – DEA2030)
3. MPS-IDA (Marginal Price Setting – IDA2030)
4. PAB-DEA (Pay-As-Bid Setting – DEA2030)
5. PAB-IDA (Pay-As-Bid Setting – IDA2030)
6. PAB2-DEA (Pay-As-Bid Setting with gambling– DEA2030)
7. PAB2-IDA (Pay-As-Bid Setting with gambling – IDA2030)
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