Bidding and operation strategies in future energy markets

The transition of small district heating plants into market-based smart energy systems

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Publication date:
2015

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PhD Thesis by

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July 2015

Title: Bidding and operation strategies in future energy markets – The transition of small district heating plants into market-based smart energy systems

1. Edition

July 2015

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Printed by:
Uniprint, DK-9220 Aalborg Ø

The work presented in this PhD thesis is a result of the research activities of the Strategic Research Centre for 4th Generation District Heating (4DH), which has received funding from The Innovation Fund Denmark.

Section 2.4 and 3.2 are based on a rewriting of the co-authored paper:

- Nielsen, Steffen, Peter Sorknæs, and Poul Alberg Østergaard. "Electricity Market Auction Settings in a Future Danish Electricity System with a High Penetration of Renewable Energy Sources – A Comparison of Marginal Pricing and Pay-as-Bid." *Energy* 36, no. 7 (July 2011): 4434–44. doi:10.1016/j.energy.2011.03.079.

Chapter 5 and section 3.3 are based on a rewriting of the co-authored paper:

- Sorknæs, Peter, Henrik Lund, and Anders N. Andersen. "Future Power Market and Sustainable Energy Solutions – The Treatment of Uncertainties in the Daily Operation of Combined Heat and Power Plants." *Applied Energy* 144 (April 15, 2015): 129–38. doi:10.1016/j.apenergy.2015.02.041.

Chapter 6 and section 3.3 are based on a rewriting of the co-authored paper:

- Sorknæs, Peter, Henrik Lund, Anders N. Andersen, and Peter Ritter. "Small-Scale Combined Heat and Power as a Balancing Reserve for Wind." *International Journal of Sustainable Energy Planning and Management* 4 (2014): 31–42.

Resumé

I denne ph.d.-afhandling undersøges de mindre fjernvarmeværker med kraftvarmes potentiale for at deltage i el-balanceringsmarkederne. Dette er relevant, da energisystemer over hele verden er under forandring. Forandringen går på at øge energieffektiviteten samt øge integrationen af fluktuerende vedvarende energikilder (VE), bl.a. i elsystemet. På den ene side resulterer den øgede produktion fra fluktuerende VE i en reduceret elproduktion på kraftvarmeværker, hvilket derved mindsker deres økonomiske grundlag. På den anden side har samfundet et behov for elkapacitet, til når de fluktuerende VE ikke producerer. Derfor er det vigtigt for samfundet at opretholde en kraftvarmekapacitet, men hvordan sikres disse enheder overlevelse, hvis de kommer til at producere væsentligt mindre? Denne afhandling undersøger muligheden for at øge disse værkers indtjening ved at være mere aktive på el-balanceringsmarkederne. Det er undersøgt med fokus på Danmark og Tyskland. Det konstateres, at deltagelse i el-balanceringsmarkeder øger indtjeningen for disse værker, men at forøgelsen er begrænset, og det er usandsynligt, at dette alene vil give tilstrækkeligt økonomisk incitament til at opretholde kraftvarmekapaciteten ved mindre fjernvarmeværker. Derfor bør andre muligheder til at sikre tilstrækkelig kraftvarmekapacitet ved mindre fjernvarmeværker undersøges.

Forandringen af energisystemer med øget fluktuerende VE øger behovet for at det resterende energisystem er fleksibelt, grundet fluktuerende VEs produktionsmønster. Øget fleksibilitet kan opnås ved en øget integration af de forskellige dele af energisystemet, den såkaldte smart energisystem tilgang. Dette øger både fleksibiliteten og øger den samlede effektivitet af energisystemet, samtidig med at omkostningerne til integration af fluktuerende VE holdes lave. En del af denne tilgang betyder også, at enheder er nødt til at deltage mere i balancering af elsystemet, som i nogle lande håndteres gennem markeder. En af de teknologier, der giver mulighed for denne øgede integration mellem forskellige dele af energisystemet er kraftvarme, som traditionelt mest har været benyttet for at øge den samlede effektivitet af energisystemer. Mindre fjernvarmeværker med kraftvarme og store varmelagre kan medvirke til både at øge energieffektiviteten samt lette integrationen af fluktuerende VE. Således er hypotesen i denne ph.d.-afhandling, at en overgang skal initieres fra en forståelse, hvor kraftvarme kun hjælper til at reducere brændstofforbruget gennem sin høje system effektivitet - mod en forståelse, hvor kraftvarme opretholder denne høje system effektivitet samtidig med, at den medvirker til at reducere omkostningerne i forbindelse med integrationen af fluktuerende VE.

Det findes, at kraftvarmekapaciteten ved mindre fjernvarmeværker er relevant for energisystemet, når fluktuerende VE ikke producerer tilstrækkeligt til at dække efterspørgslen for elektricitet, og til at håndtere ubalancer grundet

prognose fejl for fluktuerende VE produktion. Dog forventes der en væsentlig reduktion i driftstimer af kraftvarme, dels som følge af en lavere efterspørgsel efter el-produktionen, men også på grund af en stigning i antallet af forskellige varmeproducerende enheder på de mindre fjernvarmeværker. Disse nye enheder, samt store varmelagre ved mindre fjernvarmeværker, tillader en fleksibel drift af kraftvarmeenhederne på de mindre fjernvarmeværker.

Effekten på den daglige driftsplanlægning af dette skift ved mindre fjernvarmeværker med kraftvarme, med en mere fleksibel drift samt deltagelse på balanceringsmarkeder, er blevet analyseret for Danmark og Tyskland, som er nogle af frontløberne i integrationen af fluktuerende VE.

Mindre danske fjernvarmeværker med kraftvarme har allerede en række forskellige varmeproducerende enheder som medtages i deres daglige driftsplanlægning, hvor især solvarme og elkedler har set en betydelig implementering, og det forventes, at elvarmepumper fremadrettet vil se en øget integration. I de kommende år forventes kraftvarmekapaciteten ved de mindre fjernvarmeværker i Danmark at blive reduceret, på grund af problemer med at holde kapaciteten økonomisk rentabel. Det findes, at i Danmark er det forholdsvis let for mindre fjernvarmeværker at deltage i det vigtigste el-balanceringsmarked, dog identificeres der nogle problemer med organisationen og benyttelsen af dette marked.

I Tyskland er mindre fjernvarmeværker med kraftvarme ikke så udbredte som i Danmark, men den tyske regering har et mål om at øge kraftvarmekapaciteten. I Tyskland sker balancering af elsystemet hovedsageligt gennem et marked, hvor reglerne for deltagelse medfører nogle udfordringer for mindre fjernvarmeværker, som introducerer nogle omkostninger for disse værker, der ikke opleves af rene kraftværker.

Baseret på disse analyser præsenteres i denne afhandling nogle politiske anbefalinger til at lette deltagelsen af mindre fjernvarmeværker i balanceringsmarkeder. Det konstateres, at jo mere fleksibel deltagelse markedet tillader, jo lettere er det for de mindre fjernvarmeværker at deltage.

Det findes at deltagelse i balanceringsmarkeder gør kraftvarme mere økonomisk attraktiv. Dog er gevinsten så lille, at det er usandsynligt, at det i sig selv vil være tilstrækkeligt til at holde den eksisterende kraftvarmekapacitet ved mindre fjernvarmeværker i drift. Eftersom samfundet ønsker denne kapacitet, til når fluktuerende VE ikke producerer tilstrækkeligt, er det relevant at undersøge andre muligheder til at opretholde et tilstrækkeligt niveau af kraftvarmekapacitet i energisystemet.

Abstract

This PhD thesis investigates the potential for small district heating (DH) plants with combined heat and power (CHP) to participate in electricity balancing markets. The subject is highly important since a transition of energy systems is occurring worldwide. This transition includes efforts to improve energy efficiency and increase integration of variable renewable energy sources (RES) in the electricity system. On the one hand, increased production from variable RES results in reduced electricity production by CHP units, thereby reducing their feasibility. On the other hand, society relies on CHP capacity to produce electricity when variable RES does not. Consequently, it is essential for society that the existing CHP capacity be maintained in the system. But, how can these units survive economically if they are going to produce substantially less? This thesis investigates the potential for such plants to increase their earnings by being more active on the new electricity balancing markets. The focus is on the potential in Denmark and Germany. It is found that participation in electricity balancing markets increases the feasibility of these plants, but that the increase is limited and is unlikely to provide sufficient incentives needed to keep the existing CHP capacity at small DH plants in operation. As such, other options for securing sufficient CHP capacity at small DH plants should be investigated.

Due to the inherent production nature of variable RES, the transition of energy systems that incorporate a higher proportion of variable RES require increased flexibility throughout the remaining energy system. Increased flexibility can be achieved by enhanced integration among the different parts of the energy system, the so-called smart energy system approach, allowing some energy to be transferred from one type to another as needed. This increases both flexibility and overall energy system efficiency, while keeping the cost of integrating variable RES low. A consequence of this is also that units have to be more active in the balancing of the electricity system, which in some countries is handled through markets. One technology that allows for this increased interaction between different parts of the energy system is CHP, which has traditionally been used primarily to increase overall energy system efficiency. Small DH plants with CHP units and thermal storage systems can play an important role in both increasing energy efficiency and facilitating the integration of variable RES. As such, it is the hypothesis of this PhD thesis that a transition should be initiated from an understanding in which CHP only helps to reduce fuel use through its high system efficiency – towards an understanding in which CHP maintains this high system efficiency while simultaneously helps to reduce the costs associated with the integration of variable RES.

It is found that the CHP capacity at small DH plants is relevant when variable RES does not produce sufficiently to cover the electricity demand and in order

to handle imbalances due to forecast errors for variable RES production. However, a substantial decrease in hours of operation for these CHP units should be expected, partly due to a lower demand for the CHP electricity production, but also due to an increase in the number of different heat producing units at small DH plants. These new units, alongside large thermal storage facilities, allow for the flexible operation of CHP units at small DH plants.

This shift towards more flexible operational capabilities and increased participation on balancing markets effects the daily operations planning at small DH plants with CHP. The nature and scope of this effect has been analysed in this thesis for Denmark and Germany, which are two of the frontrunners in the integration of variable RES.

Small Danish DH plants with CHP are already dealing with a number of different heat producing units in their daily operation planning, where especially solar thermal panels and electric boilers have seen significant implementation, and it is expected that compression heat pumps will see increased integration as well. The CHP capacity at small DH plants in Denmark is expected to decrease in the coming years, due primarily to problems associated with keeping these units economically feasible. It is found that in Denmark it is relatively easy for small DH plants to participate in the main electricity balancing market, though some issues are identified regarding the organisation and utilisation of the main balancing market.

In Germany, small DH plants with CHP are not as common as in Denmark, though the German government has set a goal of increasing overall CHP capacity. In Germany, most of the electricity system balancing is done through a market where participation poses some challenges for small DH plants; these challenges introduce additional costs for DH plants that are not experienced by traditional power plants.

Based on the analyses herein, several policy recommendations for facilitating the participation of small DH plants in the balancing reserves are presented. It is found that the more flexible the conditions for participation in the market are, the easier it is for small DH plants to participate.

Participation in the balancing markets is found to increase the feasibility of the examined CHP capacity. However, as the anticipated gain is small, it is unlikely that this gain will be sufficient to keep the existing CHP capacity at small DH plants in operation, especially considering the expected decrease in hours of operation. As society relies on CHP capacity to produce electricity when variable RES does not produce sufficient amounts, it is relevant to investigate other possibilities to maintain a sufficient level of CHP capacity in the energy system.

Publication overview

The following publications have been produced during the thesis period.

Primary

- Sorknæs, Peter, Anders N. Andersen, Jens Tang, and Sune Strøm. “Market Integration of Wind Power in Electricity System Balancing.” *Energy Strategy Reviews* 1, no. 3 (March 2013): 174–80. doi:10.1016/j.esr.2013.01.006.
- Sorknæs, Peter, Henrik Lund, Anders N. Andersen, and Peter Ritter. “Small-Scale Combined Heat and Power as a Balancing Reserve for Wind.” *International Journal of Sustainable Energy Planning and Management* 4 (2014): 31–42.
- Sorknæs, Peter, Henrik Lund, and Anders N. Andersen. “Future Power Market and Sustainable Energy Solutions – The Treatment of Uncertainties in the Daily Operation of Combined Heat and Power Plants.” *Applied Energy* 144 (April 15, 2015): 129–38. doi:10.1016/j.apenergy.2015.02.041.

Secondary

- Sorknæs, Peter. “Notat om Hvide Sande Fjernvarmes fordel ved overskudsvarmen - v1 (Memo on Hvide Sande District Heating’s benefit by utilising excess heat – v1).” (October 14, 2014)
- Sorknæs, Peter. “Notat om tilkobling af Højmark til Lem Varmeværk - v1 (Memo on connecting Højmark to Lem District Heating – v1).” (October 16, 2014)
- Sorknæs, Peter. “Notat om varmepumpe ved Troldhede Fjernvarme - v2 (Memo on heat pump at Troldhede District Heating – v2).” (December 18, 2014)

The following publication has been produced before the thesis period:

- Nielsen, Steffen, Peter Sorknæs, and Poul Alberg Østergaard. “Electricity Market Auction Settings in a Future Danish Electricity System with a High Penetration of Renewable Energy Sources – A Comparison of Marginal Pricing and Pay-as-Bid.” *Energy* 36, no. 7 (July 2011): 4434–44. doi:10.1016/j.energy.2011.03.079.

Nomenclature

4GDH = 4^{th} generation district heating

ACER = Agency for the Cooperation of Energy Regulators

BRP = Balance responsible party

CHP = Combined heat and power

CRM = Capacity Remuneration Mechanism

DH = District heating

DSO = Distribution system operator

ENTSO-E = European Network of Transmission System Operators for Electricity

HT = Hochtarif

IPCC = Intergovernmental Panel on Climate Change

MPP = Marginal price principle

Ngas = Natural gas

NHPC = Net heat production cost

O&M = Operation and maintenance

PAB = Pay-as-bid

PCR = Primary control reserve

RES = Renewable energy sources

SCR = Secondary control reserve

TCR = Tertiary control reserve

TSO = Transmission system operator

Contents

1. Introduction

The Earth's temperature has increased recently, with the period from 1983 to 2012 likely to be the warmest 30-year period in the Northern Hemisphere during the last 1400 years. This increase in temperature has resulted in e.g. sea level rise and more extreme weather [1]. The consensus within the scientific community is that this increase in temperature is due to increasing emissions of CO_2 and other greenhouse gasses resulting from human activity [2]. The emission of these gasses increases the greenhouse effect on Earth resulting in a situation where less of the Sun's energy is able to leave the Earth's atmosphere. According to the Intergovernmental Panel on Climate Change (IPCC) the production of electricity and heat contributes about 25% of the total greenhouse gas emissions from human activity, where the burning of fossil fuels for energy purposes are the main contributor to the sector's greenhouse gas emissions [1]. Figure 1.1 shows the world's fuel consumption for electricity generation purposes.

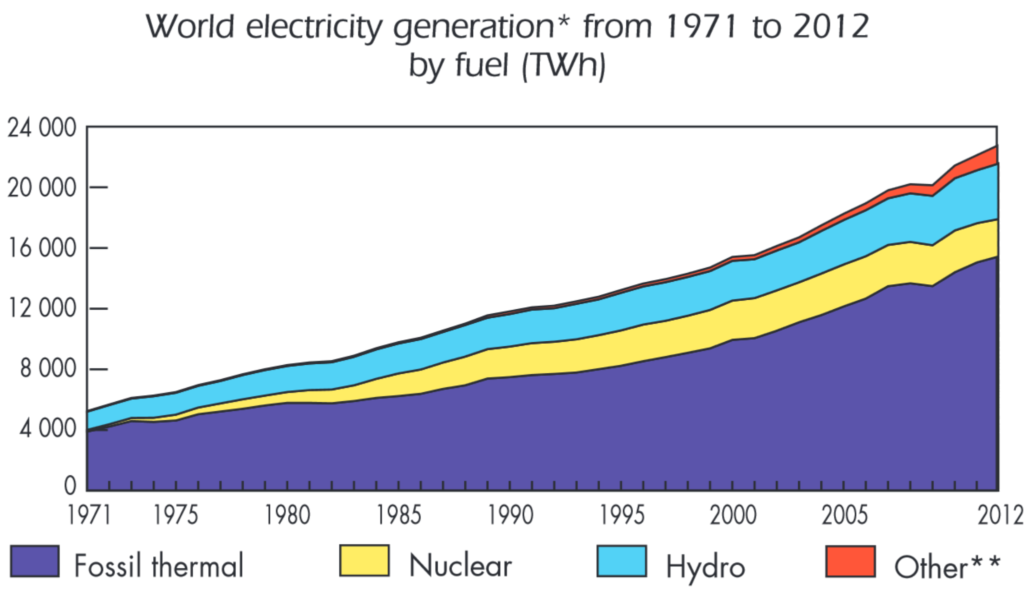

Figure 1.1 – World electricity generation from 1971 to 2012 by fuel in TWh. *Excludes electricity generation from pumped storage. **Includes geothermal, solar, wind, heat, etc. [3]

The issue of global warming has received increasing political attention. On a global scale this can be seen especially in the United Nations Framework Convention on Climate Change (UNFCCC), of which the ultimate objective, according to Article 2, is the:

> *"[…] stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."* [4]

Currently, 195 states are parties to this UN convention [5]. The parties of the UNFCCC meet annually at the Conference of Parties in which, in 1997, the Kyoto Protocol was established. The Kyoto Protocol sets legally binding obligations for developed countries to reduce their greenhouse gas emissions.

This intensified focus on reducing global warming has been a contributor to an increase in political interest regarding the transition of energy systems away from the heavy use of fossil fuels into low- or non-greenhouse gas emitting energy sources. Renewable energy sources (RES) and nuclear power have received attention in this regard. Historically, nuclear has been controversial in many countries, e.g. due to challenges regarding the nuclear waste generated by these plants, alongside the dangers of catastrophic accidents, the latest being the Fukushima nuclear disaster in Japan in 2011, after which many countries either accelerated their nuclear phase-out plans or cancelled planned nuclear power plants, e.g. Germany accelerated its nuclear phase-out plans. That said, increased nuclear power is still seen as a viable way of reducing greenhouse gas emissions in some countries; for example, UK, Finland, China, Russia, India and South Korea are planning to increase their nuclear power capacity [6].

An expected increase in the cost of fossil fuels alongside an expected reduction in the cost of RES [7–9] has also sparked both political and commercial interest in the transition of energy systems away from fossil fuels. The reduced cost of RES has especially sparked political interest in countries that traditionally import a large share of their energy needs due to a lack of traditional energy resources within the country. The reason is that these countries see RES as a possible means of curtailing their need to import energy, both reducing their energy dependency on other countries and improving their balance of payment.

RES is in this thesis defined as:

> *"[...] energy that is produced by natural resources – such as sunlight, wind, rain, waves, tides and geothermal heat – that are naturally replenished within a time span of a few years."* [10]

RES can further be divided into two subgroups: variable sources and dispatchable sources. Dispatchable sources are sources that can be activated on request, such as biomass-fired thermal plants, whereas variable sources are not continuously available for activation due to factors outside the operators' direct control, such as wind and solar energy.

One of the regions with a large proportion of imported energy is the European Union (EU), where in 2012 about 53% of all primary energy consumed within the EU was imported from non-EU countries, up from 43% in 1995 [11]. The

EU has the political goal to increase RES in the energy sector to 20% of the gross final consumption by 2020 [12]. In 2012 RES accounted for 14.1% of the gross final consumption in the EU, increased from 9.3% in 2006, and within the electricity sector it was 23.5% in 2012, up from 15.4% in 2006 [11]. Within the electricity sector, variable RES have experienced a particularly large increase in the EU, where in 2012 18.6% of the total installed electric capacity was comprised of variable RES, up from 5.3% in 2005 [11].

In a grid system, electricity must be produced at the same time as it is consumed in order to keep the electricity system stable. As such, coordinating the time of production with time of consumption is of the outmost importance. For this reason, increasing variable RES imposes a challenge to, or different understanding of, the balancing of the electricity system; RES production, to a larger extent than traditional electricity producers, is dependent on external factors, primarily the weather at any given period. However, this is relevant primarily with respect to the demand for increasing production, as the controlled decrease in electricity production from variable RES is not a technical nor an organisational problem [13], but mainly an economically problem, as variable RES tend to have very low short-term marginal production costs.

Dealing with electricity balancing challenges has also generated interest in the research of smart electricity grids. As argued by Lund [10] there are many ways of defining what precisely is meant by the term smart electricity grids; though generally, definitions of smart electricity grids include using information technology on electricity grids to for example better deal with potential imbalances. The research into virtual power plants [14] is an example of a field within smart electricity grids.

Based on the increasing focus on smart electricity grids, some researchers have argued that the tendency to focus exclusively on the electricity system delimits the research from finding possible solutions and synergies in other energy sectors than the electricity system, such as in the heating sector, transport sector or fuel sector. This more inclusive approach is sometimes referred to as the smart energy system approach [15,16]. The smart energy system approach can be defined as:

> *"[...] an approach in which smart electricity, thermal and gas grids are combined and coordinated to identify synergies between them in order to achieve an optimal solution for each individual sector as well as for the overall energy system."* [10]

The smart energy system approach is explained more in chapter 2.

Besides changes in production technologies, improving energy efficiency has also received attention as a tactic to reduce both fuel dependency and greenhouse gas emissions. This can for example be seen in the EU goal of reducing primary energy consumption by 20% by 2020 [12]. Globally there is a large potential for improving energy efficiency, e.g. with respect to the conversion of primary energy to electric energy. Energy flows in the global electricity system in 2007 can be found in Figure 1.2.

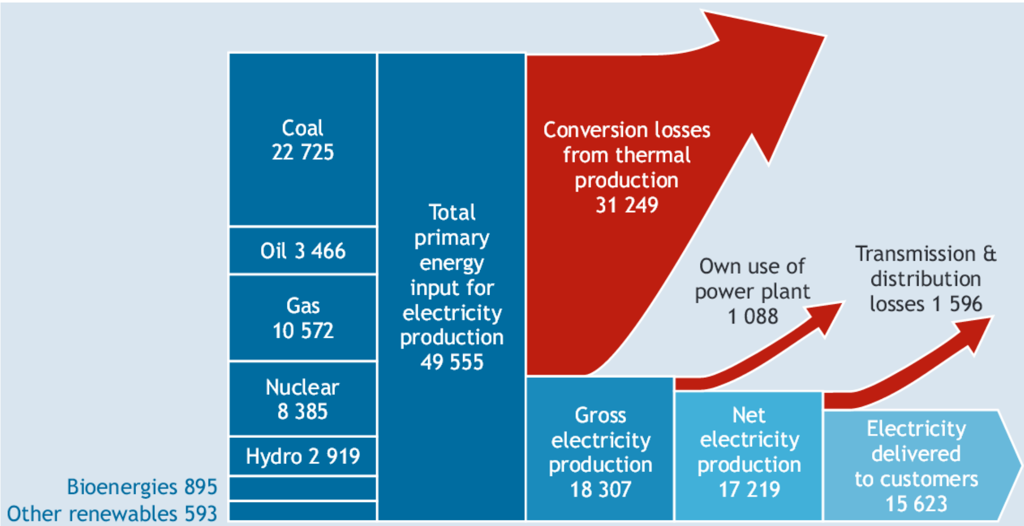

Figure 1.2 - Energy flows in the global electricity system in 2007 (TWh) [17]

As seen in Figure 1.2, in 2007 about 63% of the total primary energy input for electricity production was lost in the conversion process. This large loss of energy takes the form of thermal energy, which in principle could be utilized for e.g. heating purposes. The utilization of this lost heat from the electricity production process is known as combined heat and power (CHP), in which part of the thermal loss in the conversion process is captured and used for a local or regional heat demand. As such, with CHP, otherwise discarded thermal energy can be utilized to replace heat-only units and hence reduce fuel use for heating. Alternatively, using absorption heat pumps with CHP, excess thermal energy can also be used for providing cooling. In many countries CHP is promoted; as part of the EU's goals for reducing primary energy consumption, the EU also promotes CHP production. In energy systems that are not based on fossil fuels it is also expected that CHP can play an important role due to its efficient utilization of primary fuels. The utilisation of biomass for energy purposes is expected in such an energy system; however, due to the fact that biomass is found to be a limited resource with respect to the large global energy demand, and because biomass has other uses such as food, even though biomass is a RES its use should be limited as much as possible [16]. It is hence expected that CHP can play an important role in both the current fossil-based energy system as well as in energy systems based on RES.

It must be noted that for CHP to be a resource effective technology then a thermal demand, or alternatively a cooling demand, has to be found locally or regionally. For this reason, CHP units in many countries tend to be associated with e.g. industry, high-rise buildings or institutions, where one owner has a large localized thermal or cooling demand. Though in some countries, distribution of heat and cooling are done from the owner of e.g. CHP to other independent building owners. In this way, the owner of CHP does not have to utilize heating or cooling for their own purposes, but can instead sell it to consumers on a grid. Such thermal grids are known as district heating (DH). DH is a system that allows for the distribution of centrally produced heat through a network to end consumers in larger areas. DH is especially utilized in e.g. Scandinavia and Eastern Europe. District cooling, however, is currently utilized to a much lower extent than DH.

Within the smart energy system approach, DH has shown promise for integrating variable RES into the energy system. The reason is that DH enables the use of a wider variety of heat sources and increased flexibility in heat production than is found when using individual heating solutions. Production units such as CHP and electric-driven heat pumps enable DH interaction with the electricity system. Lund et al. [18] found that DH should have an increased interaction with the electricity system, as DH can help integrate flexible solutions and improve the energy efficiency of the system. This is supported by studies of different countries' energy systems. Connolly and Mathiesen [19] present a pathway to a 100% renewable energy system, using Ireland as a case. In the pathway, DH is utilized with a high degree of interaction with the electricity system. The Danish governmental appointed Commission on Climate Change [20], The Danish Society of Engineers [21], Lund et al. [22] and Münster et al. [23] all investigate the role of DH in a future sustainable energy system in Denmark. They all find that DH should play an active role and have an increased interaction with the electricity system in order to integrate more variable RES into the Danish energy system. Liu et al. [24] investigate the ability of the Chinese energy system to integrate wind power, and find that an increased interaction between DH and the electricity system can greatly increase the ability to integrate wind power.

The first DH grid was constructed in the USA in the 1880s with steam used as the heat carrier. Steam based DH systems are seen as the first generation of DH. The problem with this first generation of DH are, among others, that heat losses in the grid are substantial, the energy efficiency of production units is low due to relatively low heat condensation and heat production units that do not produce at steam temperatures are not usable. For these reasons, in many countries, DH has developed past this first generation towards using lower temperatures, though first generation DH is still used in some places. The second generation of DH uses pressurised water with supply temperatures usually above 100°C, and the third generation uses pressurised water where the supply temperature is usually below 100°C. This development towards lower supply temperatures has resulted in increased efficiency for production units and reduced grid loss while also allowing sources that produce at lower temperatures, e.g. flat plate solar heating, to be implemented. The third generation of DH is currently utilized e.g. in the Scandinavian countries and is used for replacements of older Eastern European DH systems. It is expected that DH will continue this development towards lower supply temperature, and as such, a future fourth generation DH (4GDH) is expected. 4GDH is expected to have supply temperatures as low as 40-55°C. [18] 4GDH has been defined as:

> *"The 4th Generation District Heating (4GDH) system is consequently defined as a coherent technological and institutional concept, which by means of smart thermal grids assists the appropriate development of sustainable energy systems. 4GDH systems provide the heat supply of low-energy buildings with low grid losses in a way in which the use of low-temperature heat sources is integrated with the operation of smart energy systems. The concept involves the development of an institutional and organisational framework to facilitate suitable cost and motivation structures."* [18]

As seen in this definition, the goal of 4GDH is not only reduction of the supply temperature, but also a further development of 4GDH into the smart energy system approach, where DH should be developed to have an increased interaction with other sectors of the energy system.

Some researchers also expect a change in the types of production units present in energy systems, with a high integration of variable RES predicted. Electricity systems have traditionally been dominated by large central plants, especially in countries where thermal plants have played or are playing a major role. Many of these large thermal production units are inflexible by design, and as such, it is expected that these units will become increasingly unfeasible as the proportion of variable RES rises in an energy system [25]. This is due to the fact that variable RES have lower short-term marginal production costs, and hence, are more economically attractive to operate in place of thermal plants, which require a fuel input to produce electricity. This will lead to a reduction in the hours of operation for these thermal plants, and will require increased flexibility as they will have to alter production levels in line with the production from variable RES. Electricity system balancing has traditionally been provided by large production units, such as hydro power and steam turbines based on fossil fuels and nuclear power. As these large units leave the system, smaller flexible generation units will, to a larger extent, be required to participate in system balancing. Here, the DH plants with CHP or electric heat pumps can play an important role, especially as electricity system balancing is also expected to become increasingly important with increasing integration of variable RES [26–32].

Smaller plants can also be beneficial for balancing the electricity system locally, reducing the need for grid capacity to and from a local area, while also improving local fuel efficiency in towns and villages due to the utilization of CHP, and to a larger extent, can use locally available resources, such as biogas. [33]

For the purpose of this thesis, a distinction between large and small plants is used. Large plants are henceforth defined as plants directly connected to the transmission network, and small plants are defined as plants directly connected to the distribution network. Thus, the distinction is not directly based on the capacity of the plants, though plants connected to the transmission network tend to be plants with a large capacity compared with units connected to the distribution network due to inherent limitations with the distribution network compared to the transmission network. As such, the definition used in this thesis for small plants is similar to the definition used in some instances for distributed generation [33]. However, the focus in this thesis will be on centralized production plants, and as such, micro plants, which are normally plants designed for use in single households, are not included in the discussions within this thesis.

1.1. Research question

Based on the previous description, it is the hypothesis of this PhD project that a transition should be initiated from an understanding in which CHP only helps to reduce fuel use through its high system efficiency – towards an understanding in which CHP maintains this high system efficiency while simultaneously helps to reduce the costs associated with the integration of variable production from RES by improving system flexibility. With this in mind, the following research question is posed:

1. What role can be expected for small CHP plants in future smart energy systems based on RES, and to what extent are they expected to take part in electricity system balancing?

Based on this research question, existing research within this topic is discussed, leading to more specific analysis of existing plans for future energy systems based on RES. This is done in chapter 4.

In order to understand the incentives for centralised small CHP plants to want to participate in electricity system balancing tasks, the research focuses on investigating the daily operation of these plants, specifically when these plants are both selling electricity wholesale while also participating in electricity system balancing. As the concrete institutional conditions are highly dependent on which country the plant is located in, the current concrete institutional conditions of two case countries are used: namely, Denmark and Germany. These two countries both have political goals of integrating large amounts of RES, and have already integrated relatively large amounts of RES in their respective energy systems; furthermore, major parts of the RES in these systems is variable. As argued in chapter 3, despite only investigating these two cases, it is possible to draw general lessons based on these cases. As such, two research questions for the examination of these two countries can be put forward:

2. How can small CHP plants participate in the balancing tasks in Denmark, and what are the daily operational challenges within these concrete institutional conditions?
3. How can small CHP plants participate in the balancing tasks in Germany, and what are the daily operational challenges within these concrete institutional conditions?

Both of these countries' energy systems and concrete institutional conditions are first detailed, followed by simulations of selected cases for small CHP plants, examining both the selling of electricity wholesale while participating in electricity system balancing tasks in the country. The two countries' energy systems, political goals and the simulation of the case plant are described in detail in chapters 5 and 6, respectively. The main bulk of the analyses are done in regards to these two research questions.

Based on the findings of research questions 1-3, the effect of the concrete institutional conditions on the possibility for small CHP plants to participate in electricity system balancing is discussed. The discussion takes its departure from expectations about the needs of future energy systems based on RES, resulting in some policy recommendations for how to facilitate the inclusion of small CHP plants in electricity system balancing. As such, a final research question is set forward:

4. How can the rules for electricity system balancing be set up in order to facilitate participation of small CHP plants in a way that also facilitates a lower integration cost of RES?

However, due to the many challenges faced when examining future market-based smart energy systems, not all of the challenges inherent in research question 4 are dealt with, and the discussion in this thesis is meant to provide further input to the broader discussion.

1.2. Thesis structure

Based on the research questions posed, the following structure is used for this thesis. First, the theoretical understanding of electricity markets alongside relevant international political goals is presented. The methodology utilised is then presented. Afterwards, the balancing needs of energy systems based on large shares of variable RES is explained, followed by a discussion of the role of small DH plants in smart energy systems. This is followed by a detailed description of the Danish energy system including the simulation approach and results for the Danish case plant. The same is then done for the German energy system and the German case plant. This leads to a discussion of the policies relevant for having small DH plants participate in the balancing of the electricity system. Lastly, the overall research and results are summarised in the conclusion. This structure is illustrated in Figure 1.3.

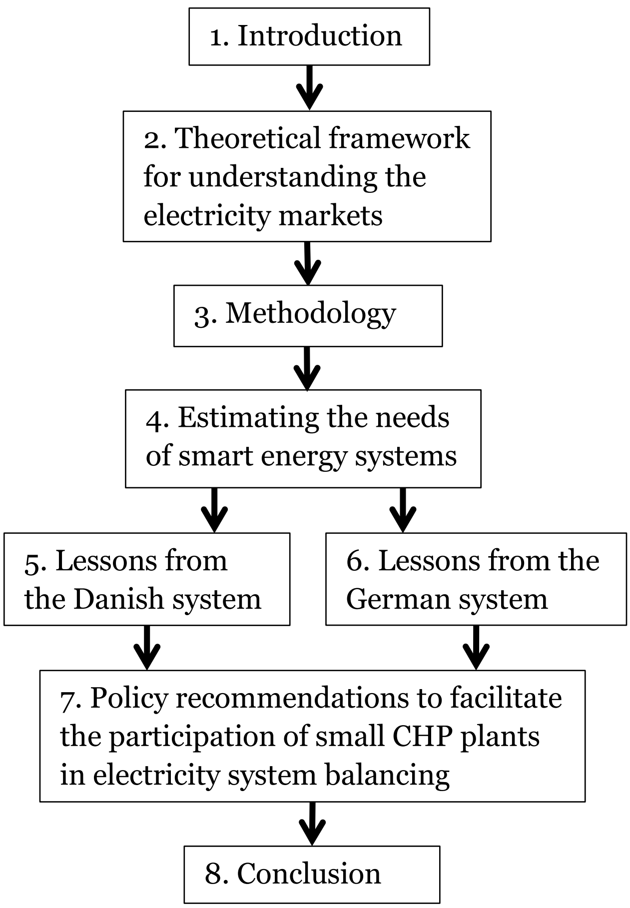

Figure 1.3 – Thesis structure

2. Theoretical framework for understanding the electricity markets

This chapter sets the frame for understanding the applicable functions in the electricity system, and presents the relevant organisational understanding of the institutional context as utilised in this thesis. This understanding is based on the smart energy system approach. As the focus is on market-based systems, the understanding of markets in general and the specifics of electricity markets are also explained. The economic understanding is based on institutional economy. Lastly, as the two case countries are located in the EU, relevant EU rules and goals are presented.

2.1. Smart energy systems

As argued in chapter 1, it is important when conducting energy system analyses using the smart energy system approach to take a coherent approach to the energy system, and include all relevant energy sectors in order to harness the full advantage of potential synergies from different sectors [10,16]. An illustration of the coherent approach to the smart energy system is seen in Figure 2.1.

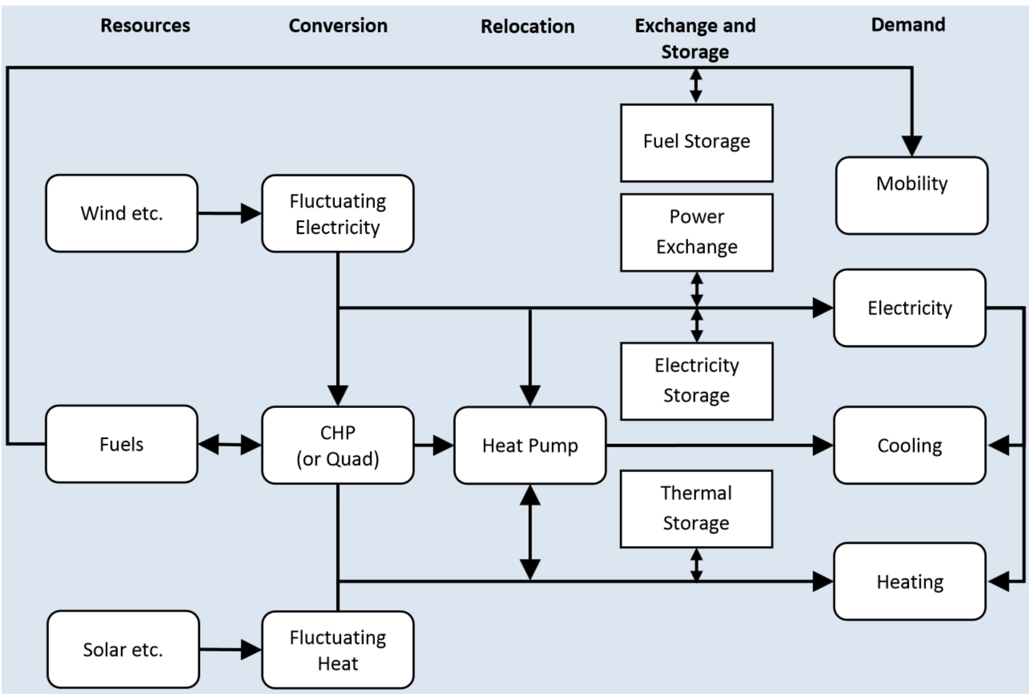

Figure 2.1 – Illustration of the smart energy system approach [34]

As seen in Figure 2.1, the various parts of the energy system are interconnected by different technologies, for example CHP units and heat pumps, in order to transform one type of energy into another, as needed. In this way, with the smart energy system approach, each part of the energy system is interconnected, and therefore must be understood with respect to its relation to the other parts of the energy system. This is necessary in order to exploit synergies that can increase overall system efficiency and reduce total system costs.

In this thesis, the focus is placed especially on the electricity system and its synergies with the heating system through small DH plants. However, as these parts cannot be understood entirely separate from the remaining energy system, other parts of the energy system are included when relevant. As such, this chapter mostly focuses on the electricity system, but also includes some aspects of the heating system.

Likewise, the focus is on the operational organisation of the energy system within a market-based set-up, and as such, market theory that is relevant with respect to this smart energy system approach is included.

2.2. Organisation of electricity systems

The specific organisational structure of electricity systems depends on when and where they are situated in the world, though normally, one or more actors handle the following functions in the electricity system:

- Electricity producer: owns and operates facilities for producing electricity.
- Transmission system operator (TSO): owns and operates the high-voltage electricity grid in an area.
- Distribution system operator (DSO): owns and operates the low-voltage electricity grid in an area.
- System responsible parties: are responsible for keeping the electricity system in balance.
- End user supply and services: includes traders of electricity.
- Related services: such as maintenance services and electricity market places.

  (List based on [35])

Historically, all of these functions in electricity systems have been dominated by national or regional monopolies, where one monopoly could own and operate all functions in an electricity system. Since 1978, however, when the US adopted the Public Utility Regulatory Policies Act that required utilities to buy electricity from "qualified facilities", electricity systems worldwide have increasingly seen a change towards deregulated system set-ups. Chile for example, in 1982, allowed large electricity users to choose their own supplier of electricity, and England and Wales made the first central electricity market in 1990 [35]. This trend of increasing marketization of the electricity system has occurred worldwide [35], though, the specific market set-up depends on the specific conditions in the country or region [36]. It is hence the purpose of this chapter to establish the frame used for understanding electricity markets within this thesis.

2.3. General market understanding

Generally, markets can be defined as:

> *"Any context in which the sale and purchase of goods and services takes place"* [37]

This definition of markets is very broad, and as such, it cannot form the basis of a market understanding. However, it is useful in order to qualify that the term "market" is wide-ranging, and it is hence relevant to further clarify how markets are understood in the context of this thesis. A detailed description of different theoretical understandings of markets lies outside the scope of this thesis; instead, a short explanation of the theoretical market understanding utilised in this thesis is presented here.

In this thesis, the economic understanding applied is in line with institutional economy. Within this understanding, markets are embedded in a historical and political context that differs from country to country and changes over time as a result of market participants and politicians. As such, in order to comprehend a market, an understanding of the historical and political context in which the market is embedded is required, alongside a description of the organisation of the market and its participants. This economic perspective differs from that of, for example, neoclassical economy, which does not include institutions during analyses. [38–40]

Within the understanding of institutional economy, markets are seen as constructs that do not necessarily provide the politically desired outcome, and markets should be adjusted in order to facilitate political goals for the society, as adjustments to the market may be required in order to facilitate radical changes. [38–40]

This institutional perspective is especially useful for electricity markets; due to the nature of trading electricity via large grids, it is only possible to have a well-functioning electricity system by establishing very clear market rules in order to keep the frequency stable. As such, the trading of electricity is hugely dependent on the specific organisation of the respective electricity market. Within this understanding of a market, it is important to describe its historical development, political goals for the future and the relevant market actors. This is done for both the Danish and German energy systems. It is also within the scope of analysis to estimate how well-organised the electricity markets are for facilitating reaching political goals for the future energy system.

2.4. Organisational aspects of electricity markets

Within the electricity system two overall types of markets can be identified, wholesale markets and balancing reserves:

- Wholesale markets represent the context in which trading occurs between market participants. In wholesale markets, both purchase volumes and sale volumes are defined by participations on the market in advance of time of delivery.
- Balancing reserves are different in that the demand in these is set partly by the expectations of potential imbalances between traded supply and demand, and partly by the specific imbalances. Balancing reserves are typically procured by the system responsible party.

Wholesale markets are organised to handle the main bulk of sales and purchases, while balancing reserves are organised to keep the electricity system in balance in real-time. Market players that settle imbalances with the system responsible party are normally referred to individually as a balance responsible party (BRP). In this thesis the term "electricity markets" is used as a term for all electricity wholesale markets and balancing reserves that are organised in a market set-up.

The specific aspects of electricity markets are highly dependent on specific market conditions; however, only general aspects are presented in this chapter. These general aspects will be utilised in chapters 5 and 6, where more detailed explanations of the two case countries are presented.

2.4.1. The overall market structure

In general, two contrasting electricity market structures can be identified; centralised market structures and decentralised market structures. A centralised market structure is often based on a single central market place where the main bulk of electricity is traded. Balancing reserves are normally set-up in centralised market structures, as they are organised and utilised by the system responsible party. Decentralised market structures do not have a single central auction; instead, it is left to the participants in the market to self-organise trading. Bilateral trading between two or more market participants is quite common in such market structures. That said, trading can still occur via auctions, but the auctions are set-up by market participants, and the auction will not benefit from special rules or legislation that compels participants to trade on them, e.g. if selling to or buying from parts of the market or import/export of electricity were only possible through one or more auctions. [41,42]

In praxis, these two market structures represent extremes, and normally a specific market set-up is neither one of these in totality, but some mixture of the two. An example of a mostly decentralised market structure is the current UK electricity wholesale market, where most of the trading is done via bilateral agreements, and several electricity auctions exist, which are set-up by the market participants rather than by a central organisation. The current electricity market structure in Denmark is an example of a more centralised structure, where most trading is conducted via the central wholesale electricity auction, Nord Pool Spot. Though it is not compulsory to trade on this central market, it is encouraged through market rules.

2.4.2. The specific organisation of an electricity market

When describing a specific electricity market, several aspects are relevant for a participant. The following are further described:

- The product traded, including the period of delivery.
- Requirements for being allowed to participate.
- Settlement principle.
- Approach for participation, incl. gate closures.

The product traded

It is important to define the product that is being traded. Generally on electricity markets, two different products are traded: capacity and energy.

- Capacity is the offering of available capacity; this can e.g. be balance reserve capacity available for the system responsible party.
- Energy is payment for the amount of energy delivered or subtracted from the electricity system.

Some electricity markets provide a payment for both, and some only pay for one. Besides the product, it is also important to identify what period the product has to be offered for, e.g. a single hour or all weekdays for an entire month.

Requirements for participation

Requirements for participation are most often important for balancing reserves, as the requirements in wholesale markets tend to be less restrictive. Requirements differ, but a commonly encountered requirement is that a certain minimum amount must be offered in order to participate on the market, for example, 10 MW. When describing an electricity market it is important to include the relevant minimum requirements, as they can completely exclude the possibility to participate in the market. That said, in some cases it might still be possible to participate through proper organisation, for example, minimum limits can sometimes be managed by allowing participants to pool several units together in order to reach the required minimum amount.

Settlement principle

Another important aspect to define regarding electricity markets is how the market is settled, meaning how winning participants are determined. For electricity markets, the settlement rule tends to be guided by either the marginal price principle (MPP) or the pay-as-bid (PAB) principle.

In markets based on the MPP, each winning participant in the market is cleared based on the most expensive winning bid. As this settlement principle requires several bids in order to function, it requires a market place to handle the settlement process. With this settlement principle, a participant's profit depends on a more expensive unit also winning. Existing research into MPP tends to find that the optimal strategy when submitting bids is to submit a bid equal to or close to the short-term marginal cost of participation, assuming that no one in the market is exercising market power [43]. The reason for this is that with such a bid, the short-term marginal cost is covered in case the bid is accepted, any potential extra income can be used to cover fixed costs, etc.

If someone is able to exercise market power, then due to the MPP settlement rule they will be able to increase the market price, e.g. by withholding production capacity from the market, resulting in increased gains for all producers. Examples of this have been seen in the former MPP system used during the 1990s in the UK [44] and in California in 2000-2001 [45]. Even though the MPP settlement rule carries this inherent risk, the settlement principle is normally preferred in many markets. This is due to the fact that, in the absence of market power being exerted, the optimal bidding strategy normally results in units with the lowest short-term marginal costs being employed first; the market is therefore known for keeping total system costs low, assuming no one is exercising market power. It has also been described as a fair settlement principle, as all participants are settled at the same price, and it appears easier for small participants to do well, as only knowledge of own costs are needed in order to provide an optimal bid [43]. As such, this market is widely utilised within for example the EU and USA [36]. However, in the future energy system it is uncertain whether MPP will be as useful as it is currently found to be. The reason is that variable RES, such as wind power and photovoltaic, have very low short-term marginal costs, in some cases close to zero or even negative, and as these variable RES become predominant in electricity systems, they will increasingly become the most expensive winning bids. As earnings are only achieved by having more expensive units win, some researchers find that, at some point, variable RES will represent the most expensive winning bid frequently enough that variable RES will no longer be feasible in the electricity market under this settlement principle. This problem is often referred to as the merit order problem [46]. The issues related to MPP are discussed further in chapter 7.

In markets based on the PAB principle each winning participant is settled according to that participant's bid. Thus, with this settlement rule, participants' incomes are less dependent on the other participants' bids, as long as at least one winning bid is more expensive. Research into the PAB principle tends to find that the optimal strategy is to guess at the most expensive winning bid, and then submit a bid that is slightly cheaper, provided that the expected most expensive bid is higher than the participant's short-term marginal costs [43]. In practice this strategy can prove difficult to utilise, especially for small participants, as they tend to lack sufficient manpower to accurately analyse what the most expensive winning bid might be. Bidding too high will result in no bid being won, while bidding too low will either result in an economic loss for the participant, or making less profit than other market participants. For this reason this settlement principle is often found to favour larger participants [43]. However, the settlement principle of PAB does not have the same inherent challenges with the potential influence of market power, though market power can still be exercised in these markets, albeit at a lower level than in the MPP setup. Bilateral contracts can be seen as a form of decentralised PAB payments.

The principle settlement approaches for MPP and PAB, respectively, are illustrated in Figure 2.2.

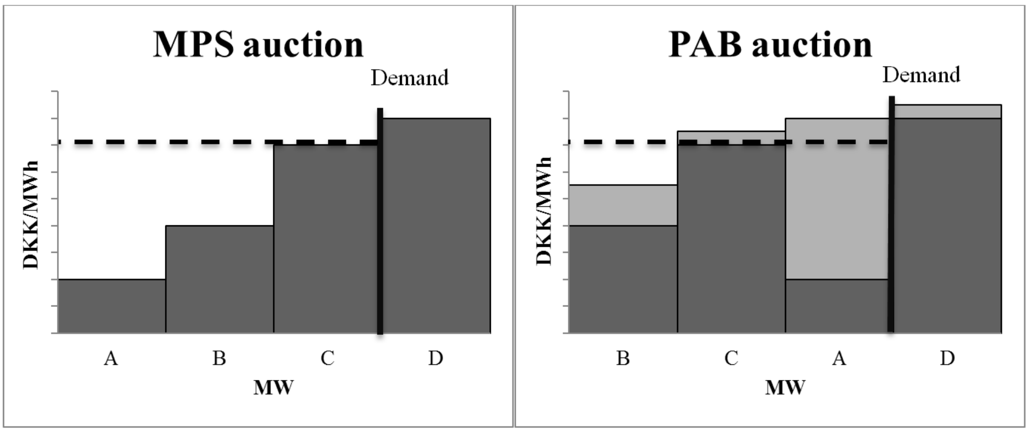

Figure 2.2 - Principle illustration of the settlement approach for market prices with MPP (MPS in figure) and PAB settlement principle. Dark grey is the short-term marginal cost of the units and light grey is the difference between the PAB bids and the short-term marginal cost. The dashed black line shows the resulting average market price. Figure from Nielsen et al. [43], originally inspired by Tierney et al. [47].

Approach for participation

The approach for participation is understood here as the procedure by which bids are submitted each time a plant participates. As such, this point includes the information that the market needs from a bidder, what the deadline for participation is, when the market is cleared, bid increments, etc. As this can be fairly detailed, only the aspects that affect the simulations of small DH plants' participation are described in the detailed descriptions.

2.5. Relevant EU goals and rules for the energy system

The European Commission's goal for the energy system in the EU is to create what they call an Energy Union. The overall aim of this Energy Union is to create an integrated EU-wide energy system where energy flows freely between countries in order to bring secure, sustainable, competitive and affordable energy [48]. In order to reach this, the European Commission sets forth five dimensions of this Energy Union:

> *"- Energy security, solidarity and trust;*
> *- A fully integrated European energy market;*
> *- Energy efficiency contributing to moderation of demand;*
> *- Decarbonising the economy, and*
> *- Research, Innovation and Competitiveness"* [48]

For the purpose of this thesis it is especially relevant to note the focus on competition and markets in these goals. But, the goals for energy security, energy efficiency and decarbonising are also interesting, as one of the advantages with DH systems is the possibility to provide improved energy efficiency by allowing the utilisation of otherwise discarded heat, for example when using CHP for electricity production. Improved energy efficiency also contributes positively towards energy security. The current goal for energy efficiency in the EU is to reduce primary energy consumption by 20% in 2020 compared with a projected use of primary energy [49]. As such, the EU has also promoted DH and CHP as energy efficiency measures through the Energy Efficiency Directive (Directive 2012/27/EU) [49].

As also shown, the EU has a political goal to create a common market for energy. As such, there is a goal to create a common market for electricity within the EU, known as the internal electricity market. The EU has put forward several directives in order to create the political framework for this. The first is Directive 96/92/EC from 1996; the reason for an internal EU electricity market is described in that directive as follows:

> *"(4) Whereas establishment of the internal market in electricity is particularly important in order to increase efficiency in the production, transmission and distribution of this product, while reinforcing security of supply and the competitiveness of the European economy and respecting environmental protection;"* [50]

The Directive 96/92/EC has been updated twice, first with Directive 2003/54/EC [51] and latest with Directive 2009/72/EC [12]. As part of this effort to secure an internal electricity market, the EU sets rules for when unbundling of functions in the electricity system must be done, and how securing non-discriminatory access to the electricity system should be approached. Because the EU finds that the current rate of development of the internal electricity market is not progressing fast enough, it is one of the priorities of the current European Commission to further this development process [48]. Though common rules do exist, the specific organisation still differs from country to country.

2.5.1. Balancing reserves in the EU

Within the EU, the function of system responsible party normally falls to the TSOs, though it is possible for member states to appoint an independent system operator as the system responsible party [12]. In accordance with the EU Directive 2009/72/EC, the system responsible party has to obtain balancing reserves through market-based procurements that are transparent and non-discriminatory [12].

As part of Directive 2009/72/EC, the EU created the Agency for the Cooperation of Energy Regulators (ACER), and gave legal mandates to the European Network of Transmission System Operators for Electricity (ENTSO-E), which represents 41 TSOs in 34 EU countries. This was done in order to further progress the completion of the internal electricity market. ACER's overall mission is to complement and coordinate the work of national energy regulators in order to work towards the EU's internal electricity market goals. That said, ACER acts by means of recommendations and opinions, and as such, they have very little decision making power. The European Commission has suggested that ACER should be granted more decision making power in order to speed up the creation of an internal electricity market [48].

Some of ENTSO-E's main tasks are to draft network codes, make pan-EU network plans and create the cooperation between the TSOs in the EU [52]. As part of this, ENTSO-E defines three types of balancing reserves [53], which are also used in this thesis:

- Primary control reserve (PCR): used to gain a constant containment of frequency deviations. It is expected by ENTSO-E that 50% or less of the total PCR capacity has to be able to activate within 15 seconds, and the remaining has to be active within 30 seconds. This reserve is also known as frequency containment reserve.
- Secondary control reserve (SCR): used to restore frequency after sudden system imbalances. The activation time of units will typically be up to 15 minutes. This reserve is also known as frequency restoration reserve.

- Tertiary control reserve (TCR): used for restoring any further system imbalances. The activation time of units will typically be from 15 minutes to one hour. This reserve is also known as replacement reserve.

The principle behind these three balancing reserves and their connection is also illustrated in Figure 2.3.

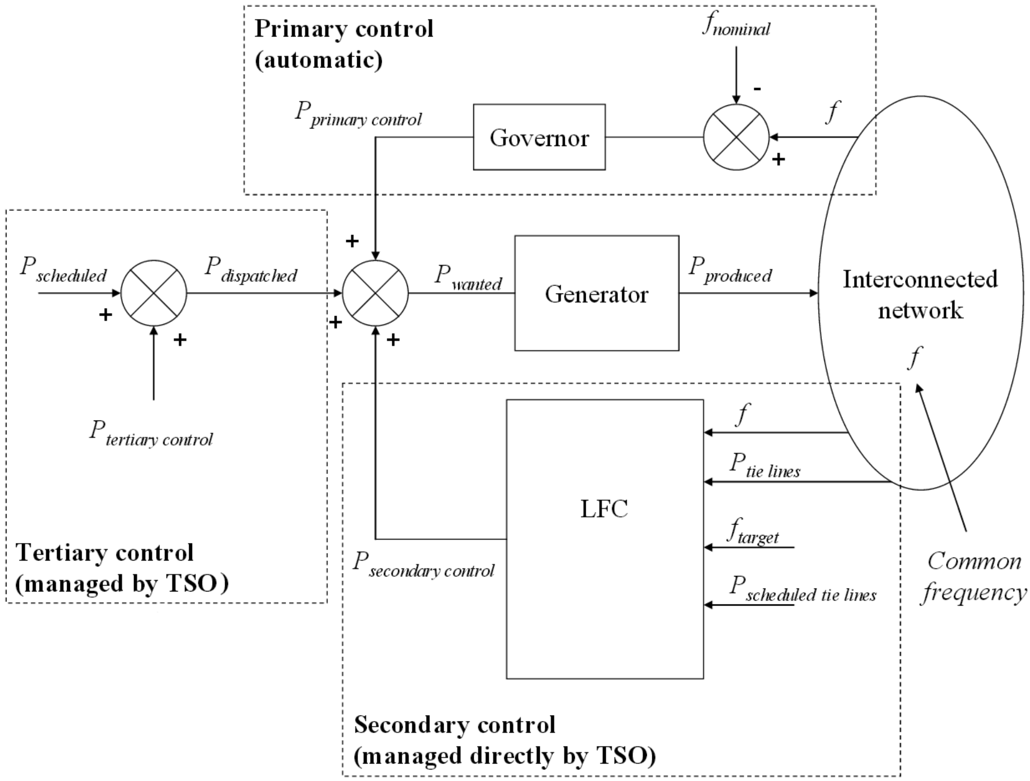

Figure 2.3 - Principle of the three balancing reserves and their connection. LFC = Load-Frequency Control. Slightly adjusted figure from Rebours and Kirschen [54].

As seen in Figure 2.3, the PCR responds locally to changes in frequency, while the SCR and the TCR are managed centrally by the TSO, although the SCR is automatically activated while the TCR is manually activated.

The specific organisation and utilisation of these three balancing reserves changes from country to country, though the needed PCR for the synchronously interconnected system of continental Europe is set by ENTSO-E at 3,000 MW, with each country contributing an agreed amount of capacity [53]. Both case plants are located within the synchronously interconnected system of continental Europe. As can also be interpreted from the short description, the SCR and TCR are where the main bulk of balancing energy is delivered, while the PCR is only used to contain deviations for a short period. The focus of this thesis is on balancing reserves where the largest energy amounts are activated;

these balancing reserves are seen as most relevant for the integration of variable RES, as discussed further in chapter 4. Thus, the focus is on the SCR and TCR, and the organisation of the PCR in the two case countries will not be detailed. In the analysis of the two case plants, the simulation will be done for the balancing reserve where the largest energy amounts are activated.

2.5.2. Small DH plants in the EU

As explained previously, the EU's political goals are to further implement both DH and CHP in the European energy system, while also using a market-based organisational approach towards an energy system utilising a higher share of RES.

These political goals can also be seen in the development of small DH plants with CHP interaction with the electricity system. Lund and Andersen [55] defined this development in 2005 as a four-stage process:

1. Electricity being settled by a fixed price and subsidy, where the payment does not vary in time.
2. Electricity being settled according to a tariff structure, where the payment varies in time.
3. Electricity traded on electricity wholesale markets, where the price varies e.g. hourly.
4. Electricity traded on international electricity wholesale markets where variable RES has a major influence on the market price.

In this thesis a fifth stage is proposed:

5. Electricity traded on international electricity wholesale markets and balancing reserves where variable RES has a major influence on the market price.

This fifth stage is similar to stage four, as stated by Lund and Andersen [55], but in this fifth stage the small DH plants with CHP also participate in the balancing reserves. These stages also show that the plants' transition towards participation in market-based smart energy systems represents a development of these plants' operational conditions, where the traditional understanding of their operation should also develop over time. As argued by Sorknæs et al. [56], this development has also changed the challenges related to the daily operation of these plants, where each new stage introduces more uncertainties and operational challenges for the plants. This thesis focuses on small DH plants that are in this fifth stage.

3. Methodology

In this chapter the overall methodology of the thesis is presented. First, the use of case studies is explained. Thereafter, the simulation tool utilised for analysing the future role of small DH plants is described. The simulation tool chosen is EnergyPLAN, which is found useful among other due to being an hourly simulation model. Lastly, the general methodology for simulating the two case plants is presented. The simulations of the case plants are based on the approach of the tool energyPRO, though some adjustments are made as needed.

3.1. Case studies

The market understanding utilised in this thesis, as explained in chapter 2, makes it relevant to investigate markets from a bottom-up perspective, as opposed to top-down. In a bottom-up analysis the investigation starts by analysing the lowest levels and works upward from the analysis of these. Within the focus of this thesis, the lowest levels are the participants in, and the specific organisation of, the electricity markets. The use of this approach is also clear from the research questions posed in this thesis, as the focus is on specific market participants, namely small DH plants in the two case countries.

Investigating the operation of all small DH plants in both countries would be a daunting task, and it would also be unnecessary, as most of the challenges occurring due to the set-up of the electricity markets are expected to be similar for all small DH plants. Though some plants of course have challenges specific to them, such as possible low back-up capacity, bottlenecks in the DH grid, etc., these specific challenges are not the focus of this thesis. It has been decided to use one small DH plant as a case for Denmark and one for Germany. As such, the analyses are based on case studies. As argued by Flyvbjerg [57], the use of relevant cases can be used to highlight and provide a deeper understanding of relevant research questions. In this thesis, the case study approach is seen both in the choice of the two countries, where each country can be considered as an extreme and critical case for an energy system being developed towards market-based smart energy systems based on variable RES, and also in the choice of case plant. The purpose of an extreme case is:

> *"To obtain information on unusual cases, which can be especially problematic or especially good in a more closely defined sense."* [57]

And the purpose of a critical case is:

> *"To achieve information that permits logical deductions of the type, "If this is (not) valid for this case, then it applies to all (no) cases."* [57]

Though both countries represent such a case, the specific context for each country is different, and as such, each country uses a different approach to reach such a system, as explained in chapters 5 and 6. For this reason it is relevant to investigate both countries, as it is expected that the information gained by analysing these cases can be used for the purpose of acquiring specific knowledge about what is generally needed for small DH plants to be active participants in market-based smart energy systems based on variable RES. As is also shown in chapters 5 and 6, the case of Denmark is of particular interest, as this country has, for a longer period, dealt with high shares of variable RES and has a relatively higher share of its capacity coming from small CHP units; as such, the primary focus is on the Danish case. That said, due to the differences in organisation and type of production units, the German case is also of interest, but due to time constraints the main focus has been on the Danish case.

While the countries' situations can be seen as critical cases, the choice of a small DH plant, within the context of these countries, can instead be seen more as typical cases. However, in the global context these case plants can also be seen as extreme and critical cases, as the description in chapters 4, 5 and 6 indicates.

3.2. Tool for simulating the energy system

As part of the analyses in this thesis, it is discussed what role small DH plants should play in a future smart energy system based on variable RES. As part of this discussion, the deterministic hour-to-hour energy system simulation tool, EnergyPLAN, is utilised. This is done in chapter 4.

The first version of EnergyPLAN was released in 1999, and it has been maintained and continuously developed by the Sustainable Energy Planning Research group at Aalborg University in collaboration with PlanEnergi and EMD International A/S. The current version of EnergyPLAN is version 12. The aim of EnergyPLAN is to provide a simulation tool that can be used to simulate smart energy systems, primarily on a regional or national level. As such, EnergyPLAN incorporates many different parts of the energy system along with their interaction with each other, which it simulates for one year based on one hour steps. An overview of the current structure of EnergyPLAN can be seen in Figure 3.1. The white boxes are the available energy sources, the yellow boxes are the available conversion technologies and the blue boxes are the storage possibilities and import/export to the modelled energy system. The orange boxes are the energy demands. [58]

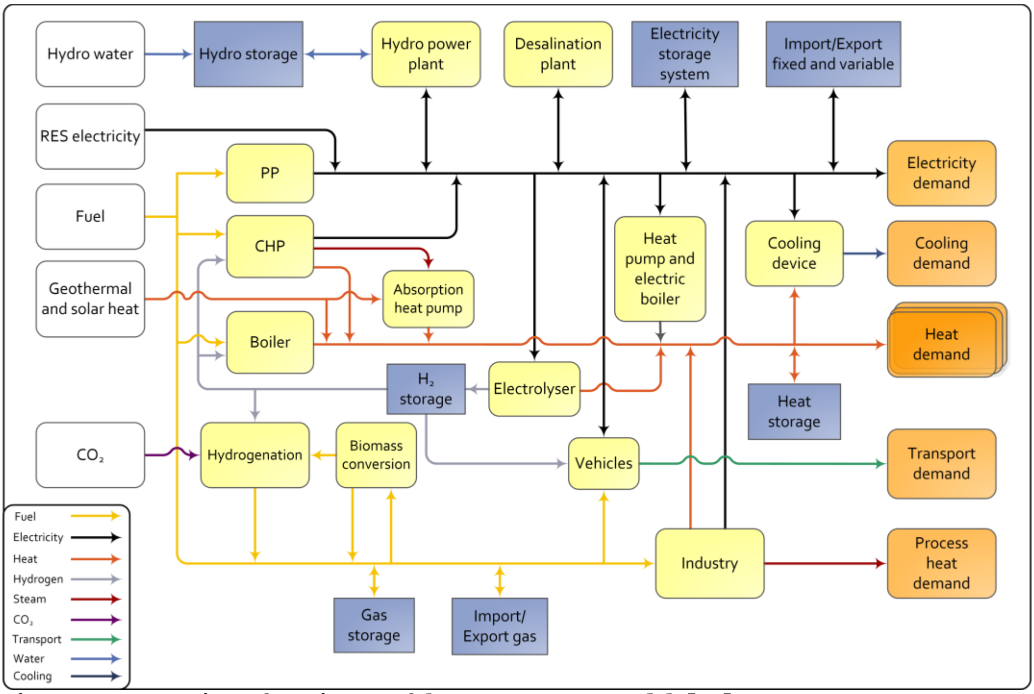

Figure 3.1 – Overview of version 12 of the EnergyPLAN model. [58]

EnergyPLAN is characterised by operating with aggregated data inputs for the different types of production, demands and energy sources within the modelled energy system. This means that, for instance, power plants (PP in Figure 3.1) are not added separately in the model, but are aggregated into one category. The inputs for EnergyPLAN are therefore less detailed than models that separate the different production facilities. However, within DH three different categories exist; DH with heat-only units, small DH plants and large DH plants. As such, it is possible to identify the aggregated production of the small DH plants, even though it is not possible to gain knowledge of individual units. The aggregated approach also means that EnergyPLAN treats the simulated energy system as having no internal transmission and distribution bottlenecks. Instead, bottlenecks only exist for the external electricity transmission. As such, it is not possible to utilise EnergyPLAN to estimate balancing that occurs due to bottlenecks in the internal transmission and distribution networks. Likewise, being a deterministic model imbalances due to breakdowns of e.g. plants cannot be simulated with EnergyPLAN.

EnergyPLAN is chosen because it is useful for the simulation of smart energy systems due to its coherent simulation approach to the energy system. For the analysis needed in this thesis, it is also relevant that EnergyPLAN simulates small DH plants separately from the large DH plants, and that it is possible to export the energy system simulation results on an hourly basis, as this is valuable in order to understand small DH plants on a detailed level. This provides the possibility to conduct further detailed analyses than would otherwise normally be done with this simulation tool.

EnergyPLAN has been used for a number of future energy system analyses worldwide e.g. Ireland [19], China [59] and Denmark, where especially the research project Coherent Energy and Environmental System Analysis (CEESA) [16] is of relevance to this thesis. CEESA presents scenarios for future smart energy systems based on variable RES for the Danish energy system. It is not the goal of this thesis to create new scenarios for a future smart energy system based on variable RES; instead, existing scenarios from CEESA are utilised as part of the discussion regarding what role small DH plants are expected to play in such a system. CEESA is described in chapter 4. As no equivalent relevant analysis in EnergyPLAN is available for Germany, this part of the analysis focuses only on Denmark as a critical case.

3.3. Tool for simulating the operation of the DH plants

To simulate the operation of the two case plants, the techno-economic simulation tool energyPRO v4.2 has been utilized. The software energyPRO is developed and maintained by EMD International A/S. The first version came out more than 20 years ago. It was originally made to simulate the operation of Danish small DH plants in order to evaluate investments in these facilities; thus, energyPRO has been used for the design of most of the small DH plants with CHP in Denmark [55]. The possibilities in energyPRO have mainly been developed alongside the changes in operation of these plants, though alternative facilities have also been implemented, such as cooling and electric vehicles. As a German version of energyPRO also exists, energyPRO has been adjusted to include rules specific for small German DH plants. The software energyPRO is a deterministic project system model, where a period is simulated by default on an hour-by-hour basis, but can be done down to 5-minute intervals. [60]

The software energyPRO has been used for a number of simulations of DH plants in research. Streckienė et al. [61] use energyPRO to investigate the feasibility of CHP plants with thermal storage systems in the German spot market. A similar analysis was made for the UK by Fragaki et al. [62], also using energyPRO. Fragaki and Andersen [63] use energyPRO to find the most economic size of a gas engine and a thermal storage system, for CHP plants that are traded aggregately in the UK electricity system. Nielsen et al. [64] use energyPRO as part of an investigation into how excess solar heat production from buildings would affect the local DH systems. Lund et al. [65] investigate how boiler production in DH in Lithuania can be replaced by CHP units using energyPRO. Østergaard [66] uses energyPRO to analyse the effect of different energy storage options for a local energy system with 100% renewable energy. Connolly et al. [67] uses energyPRO to evaluate the technical and economic consequences of supplying an urban area with heat using either DH or individual heat pumps when heat savings are implemented.

With respect to the simulation needs in this thesis, energyPRO v4.2 can simulate the energy consumption and production of a DH plant trading on several electricity markets and fuel markets, while utilizing a number of different units, e.g. CHP units, electric boilers, fuel boilers, solar collector fields and thermal storage units. The technical simulation of energyPRO is based on energy amounts. The simulation objective of energyPRO is to reduce the net heat production cost (NHPC) of the modelled DH plant. energyPRO does this by splitting a simulation period into blocks, down to five minutes each, and for each of these blocks the NHPC of each production unit is calculated. Afterwards, the production units are utilized non-chronological within a period of a month or year until the heat demand is reached, starting with the unit and block with the lowest NHPC, taking into account the minimum operation time of units, thermal storage units, and the heat demand of the blocks [60].

energyPRO only simulates a planning period chronologically on a monthly or yearly basis, where months or years are treated as one simulation period. The exception to this is if a period shorter than a month is simulated, for example a week, then that period is simulated non-chronological. As such, the default simulation approach of energyPRO does not make it possible to conduct chronological simulations on a weekly or daily basis. This is an important point, as it is not possible to simulate the challenge of potential non-reversible daily decisions without a sufficient detailed chronological approach, where lack of knowledge about the future, which can result in less than optimal decisions, can be included. This is especially relevant when simulating participation on several electricity markets where trading occurs at different points in time, and where the trading is done for shorter periods than months. For the purpose of the simulations made in this thesis, it is therefore important to make a more detailed chronological approach in the simulation. The chronological approaches, while still using energyPRO as the simulation model, are done differently for each of the two case plants; as such, the specifics on this are described in chapters 5 and 6, respectively.

4. Estimating the needs of smart energy systems and the role of small DH plants

The aim of this chapter is to provide an understanding of the future needs of small DH plants in the energy system focusing on the balancing of the electricity system. The chapter begins by presenting the expectations regarding the balancing needs in energy systems that have a large integration of variable RES. Following that is a discussion about what role small DH plants should play in a smart energy system based on RES. It is found that with increasing integration of variable RES, the need for flexible units used for balancing is expected to increase with small DH plants being able to play an important role, especially with CHP units and compression heat pumps. Although, due to increased variable RES production and competing heat production units, CHP units at small DH plants will experience relatively few hours of operation.

4.1. Balancing needs in future smart energy systems

As described in section 2.5.1, the focus of this thesis is on market-based balancing reserves, specifically on where the largest energy amounts are activated, the SCR and the TCR. As such, properties relevant to maintain power system stability, such as short-circuit power, continuous voltage control and inertia [68], are not included in the analyses of this thesis. With this focus, the most important causes of imbalances relevant for this thesis can be identified as:

- Operation problems and outages of components in the electricity system, e.g. cables and power plants.
- Forecast errors for demand and production.
  (Inspired by Holttinen [69])

In a future market-based smart energy system based on variable RES it is generally expected that a larger share of the imbalances will occur due to forecast errors. This is a change from the more conventional electricity system paradigm with e.g. large central thermal power plants, as in this system, forecast errors mostly occur on the consumption side due to the dispatchable nature of the traditional production units. As such, the forecasting of variable RES production has received some research attention [70,71]. In this section, existing research into the changing needs for balancing reserves due to increased variable RES integration is presented. The estimation for balancing reserve needs in a future smart energy system based on variable RES is based on reviews of existing research.

In 2009, Albadi and El-Saadany published a review of existing research regarding the impact of large amounts of wind power in the electricity system [26]. The review includes studies of wind power integration up to a maximum of

67% of peak wind power production compared with peak demand. In the review it is found that large amounts of wind power are technically possible, but that increasing wind power integration also leads to increased balancing costs due to increased costs associated with ramping as well as increased costs for starts and stops of plants used for balancing. That said, the actual increase in balancing costs is highly dependent on the energy system in which the variable RES is integrated; for example, the flexibility of existing dispatchable units and the transmission capacity to other areas affect costs. As such, the total increased balancing costs were found to vary from about 0.5 EUR/MWh_{wind} to about 4 EUR/MWh_{wind} depending on the system and study. It was likewise found that the cost is not solely dependent on the level of wind power integration, though increasing integration in a system was found to increase balancing costs.

Albadi and El-Saadany [26] include some early results from Holttinen et al. [27]. In Holttinen et al. [27] case studies from a number of different countries are used to investigate the variable nature of wind power's effect on the reliability of and costs for the electricity system. The cases include both Denmark and Germany. Due to the availability of data in those cases, the study focuses mostly on systems with wind power integration up to about 20% of gross electricity demand. In the study it is found that increasing integration of wind power increases the need for balancing reserves, with the need being at its highest when wind power production is at its highest. It is likewise determined that the impact on balancing reserves is mostly seen within a time-scale of 10 minutes to several hours. At this level it is found that wind power contributes to an increased need for balancing reserves amounting to between 4-18% of the total installed wind power capacity. This is a point that is supported by Hedegaard and Meibom [28] who investigate wind power's effect on system balancing with different time scales using the case of Western Denmark with a wind power penetration of 57%. They found that wind power has a very small effect on the system balance within a period of seconds. The most significant timescale for wind power's effect on system balancing is found to be in periods of one hour to one day, and are primarily due to forecast errors. The balancing of wind power on timescales of several days and seasonally is also found to be relevant, though this is not due to forecasting errors, but rather due to the inherent variability of wind power production.

Holttinen et al. [27] also finds that, depending on the system, the uncertainties and variability of wind power incur an increased balancing cost of about 1-4.5 EUR/MWh_{wind} for integration of wind power up to 20% of gross electricity demand due to increased costs of ramping up production and for starts and stops of plants. This cost is less than 10% of the determined wholesale value of wind power. Holttinen et al. [27] also finds that larger balancing areas and greater aggregation of wind power helps to reduce this cost, as this reduces the system impact of these forecast uncertainties. It is also found that having a deadline for participation on wholesale markets that is closer to the time of operation further reduces the uncertainties that must be handled in the balancing reserves.

The effect of larger balancing areas is also supported by Huber et al. [29], who assess the flexibility requirements of units used for balancing the variable RES in Europe within an operational timescale of 1-12 hours. They found that the flexibility requirements are dependent on three parameters: the penetration of variable RES, their generation type mix and the geographical system size. It is determined that with integration of variable RES above 30% of the annual electricity consumption, the need for balancing flexibility increases dramatically. It is also found that flexibility requirements strongly increase in systems with a large share of both wind power and photovoltaic, though larger geographical areas are found to decrease the need for flexibility of the balancing units.

The increasing demand for balancing reserves at increasing levels of variable RES is also supported by Tarroja et al. [30], who present an array of metrics used to evaluate the effect of variable RES on the balancing of an electricity system. These metrics are used on the case of the existing electricity system in California; it is found that increasing variable RES will increase the need for balancing units, especially when fast ramping units are needed. This is a point that Puga [31] also finds important when discussing the relevance and type of balancing required alongside large-scale integration of wind power. Puga [31] suggests that fast-ramping combined cycle and steam cycles are relevant for the balancing of wind power. Although, Puga [31] also notes that due to these facilities' high operation costs, it is important that the payments to these balancing units be set accordingly.

This problem is also analysed by Klinge Jacobsen and Zvingilaite [72]. They find that an increasing amount of wind power reduces the market price for electricity, reducing the payment for both wind power and alternate units needed when there is no prevailing wind, making both less profitable. This problem is especially relevant for CHP units, as these units are seen as a good match for wind power from a system perspective, especially when CHP is used alongside large thermal storage units.

To sum up, research into this field suggests that increasing integration of variable RES results in increasing turnover within the balancing reserves utilised in the time-scales covered by the TCR and the SCR. This increase is mostly due to uncertainties in the production forecast of variable RES, with improved forecast methods this uncertainty could be reduced. These uncertainties related to variable RES are also found to increase the costs of ramping up production and of starts and stops of plants, though the size of this increased system cost depends mostly on the energy system in which the variable RES is integrated, where the presence of more flexible balancing units reduces the severity of this increase in costs. Technologies that are useful for balancing in time-scales of 10 minutes to several hours are especially relevant for the balancing of variable RES. However, most research focuses on wind power at the existing integration levels of about 20% of gross electricity demand, and at this level it is seen that costs increase within the range of 0.5-4.5 EUR/MWh_{wind}, and the increase in required balancing reserves is 4-18% of total installed variable RES. The geographical size of the balancing area is also important, where larger areas seem to keep costs lower. Likewise, wholesale markets with deadlines closer to the time of operation are also found to reduce costs.

4.2. The role of small DH plants in market-based smart energy systems

In order to examine the role of small DH plants in future smart energy systems based on variable RES, a departure point has been taken using an existing smart energy system analysis that presents a smart energy system with 100% RES, where a large share comes from variable RES. This analysis is from the research project CEESA [73], as also mentioned in section 3.2.

The CEESA project is interdisciplinary, and includes 20 researchers from seven different research institutions in Denmark. In CEESA it is analysed how the Danish energy system can be based 100% on RES by 2050. CEESA includes the electricity demands, thermal demands, industrial energy demands and transport demands of the energy system. Several scenarios for how to achieve this are presented, though CEESA ultimately recommends one scenario. This scenario is shown in Figure 4.1.

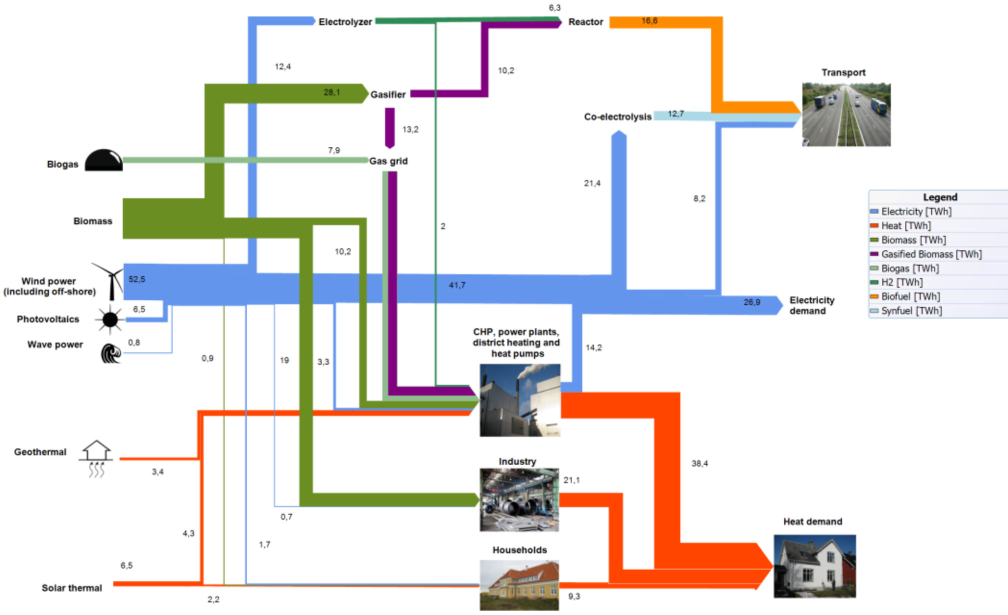

Figure 4.1 - Sankey diagram of the recommended CEESA 2050 100 % RES scenario. [73]

As seen in Figure 4.1, variable RES makes up a large share of the primary energy supply to the energy system, though biomass is also used extensively. A total of 14.2 GW wind power and a total of 5 GW photovoltaic are installed in the system. It can also be seen in the figure that CEESA represents an analysis based on the smart energy system approach with the different energy sectors being highly integrated by e.g. CHP units, heat pumps and gasifiers. DH is used extensively in the recommended CEESA scenario.

In this scenario, the total variable RES electricity production is about 60 TWh/year. Assuming that the increase in required balancing reserves is 4-18% of the total installed variable RES capacity and that the increased ramping and start/stop costs are about 0.5-4.5 EUR per MWh of electricity produced from variable RES, with the scenario's proposed level of variable RES integration the increase in required balancing reserves would be 0.8-3.5 GW and the increased ramping and start/stop costs would be 30-270 million EUR/year. However, these numbers are based on energy systems operating in the early phase of variable RES integration, and as this system has a number of flexible options for the potential balancing of variable RES, it is likely that the balancing amounts and increased costs in this system would be at the lower end of the spectrum, even though there is a very high integration of variable RES. Also, considering the EU goals of continued integration of the electricity system, it is likely that balancing in the future will, to a much larger extent, be done on a transnational or EU scale. As stated earlier, a larger geographical balancing area is also expected to reduce the effect of uncertainty with variable RES. Improved forecasting methods could also reduce uncertainties; as such, the actual balancing reserve demands and system costs due to the uncertainty of variable RES are highly questionable for this 2050 scenario, though, based on the literature review it is expected that balancing reserves will continue to play an important role in such a system.

The energy flows presented in Figure 4.1 are based on simulations made in EnergyPLAN. As such, it is possible to more closely examine the operation of small DH plants in the system, as explained in section 3.2. In the CEESA scenario, the total DH demand including grid loss at the small DH plants is 11.1 TWh/year, corresponding to about 16% of total heat demand in the system. Grid loss for the small DH plants in the scenario is 15% of total DH demand. The heat from small DH plants is primarily produced by CHP units, compression heat pumps, solar thermal panels and fuel boilers. A relatively large capacity of electric boilers are also installed at these plants, but these units are only used in very few instances, and only as balancing for the electricity system; as such, they only deliver a minor contribution to yearly heat production. To balance the heat production with heat demand, a total of 40 GWh thermal storage units are installed at the small DH plants.

Fuel use by CHP units at the small DH plants is partly based on waste incineration and partly on gas. The waste incineration CHP units are modelled with an average electric efficiency of about 27% and a thermal efficiency of about 77%. In the CEESA scenario, these waste incineration plants operate based on the input of waste, which is assumed to be constant throughout the year. The gas-fired CHP units are made up of a mixture of engines, fuel cells and gas turbines, with an average electric efficiency of 47% and a thermal efficiency of 39%. In the simulation, these gas-fired CHP units operate depending on the needs of the energy system as a whole, and as these units are flexible, they are also used for the balancing of variable RES. Figure 4.2 shows the load duration curve for gas-fired CHP units at small DH plants.

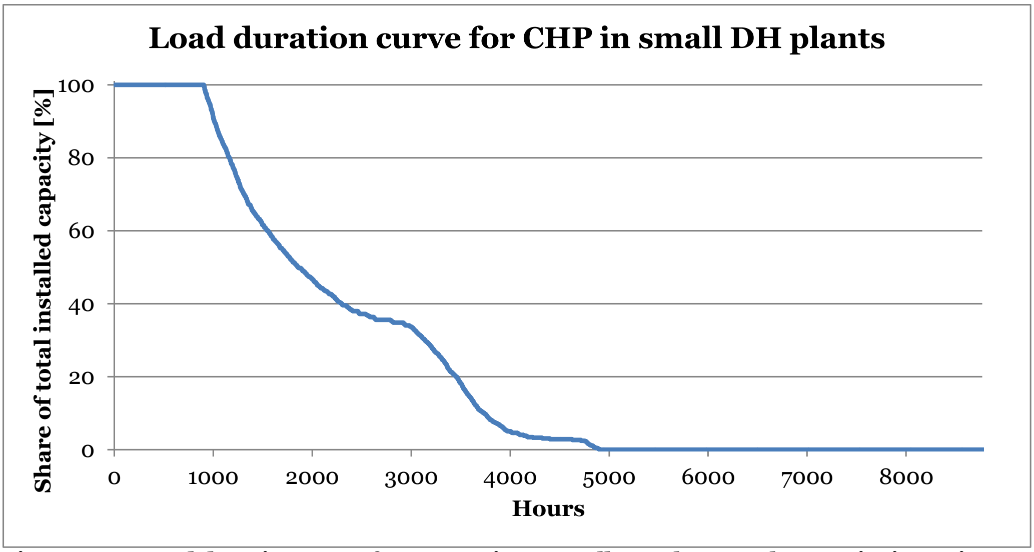

Figure 4.2 – Load duration curve for CHP units at small DH plants excl. waste incineration units in the CEESA 2050 recommended scenario.

As shown in Figure 4.2, the capacity of gas-fired CHP units at small DH plants is fully utilised for less than 1,000 hours/year, and more than 50% of the total installed capacity is used for less than 2,000 hours/year. The average full load hours are 2,230 hours/year. It is hence clear from Figure 4.2 that the gas-fired CHP units at small DH plants can only expect relatively few hours of operation per year. The reason they are included in the CEESA scenario is that their electric capacity is needed when variable RES is not producing. The yearly electricity production of these gas-fired CHP units is about 4.3 TWh and the yearly production of heat is 3.6 TWh. The total fixed annual cost for all these gas-fired CHP units at small DH plants is about 262 million EUR, corresponding to a fixed annual cost of about 33.1 EUR/MWh-produced, when using the energy content method [74]. However, this cost is a socio-economic cost, and it is not necessarily one that must be covered exclusively by the selling of electricity and heat.

The compression heat pumps at small DH plants in the CEESA recommended scenario are assumed to have a yearly average COP of 3.5. The load duration curve for compression heat pumps at small DH plants are shown in Figure 4.3.

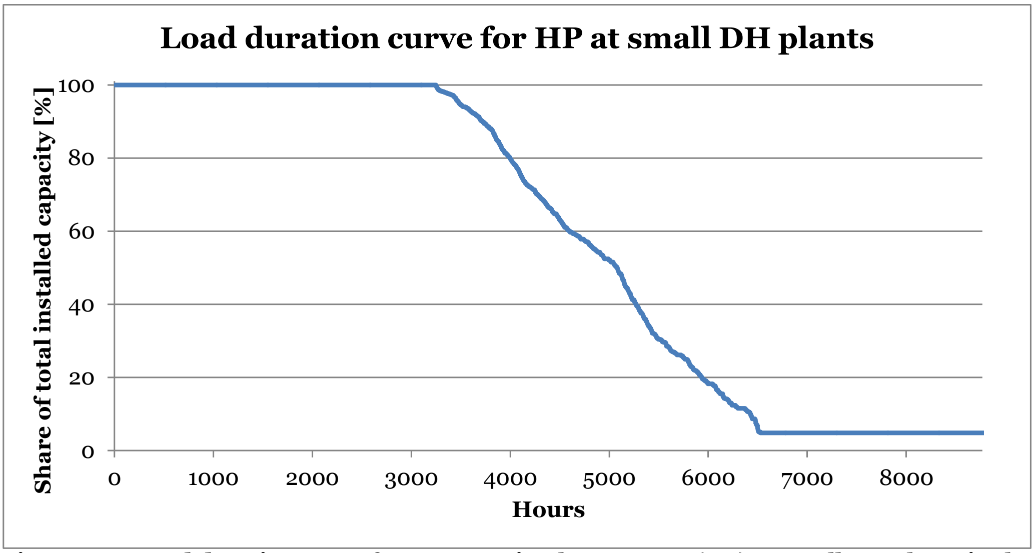

Figure 4.3 - Load duration curve for compression heat pumps (HP) at small DH plants in the CEESA 2050 recommended scenario.

As seen in Figure 4.3, the compression heat pumps at small DH plants are expected to operate at full load to a much larger extent than the CHP units, with the full installed capacity operating for more than 3,000 hours/year. For 5,000 hours/year, more than 50% of the installed capacity is found to be in operation. The average full load hours are about 5,080 hours/year. Yearly heat production from the compression heat pumps at small DH plants is about 3.6 TWh. The total fixed annual cost for all these compression heat pumps is about 45 million EUR, corresponding to a fixed annual cost of about 12.6 EUR/MWh_{heat}.

Considering the results of the CEESA project, it is hence found that small DH plants can play an important role in a future market-based smart energy system based on variable RES, but that heat production will be provided by a number of different energy conversion units and that their operation is linked to the operation of the energy system as a whole. For example, compression heat pumps will be used when the electricity production from variable RES is high, and CHP units with a high electric efficiency will be used in periods when the electricity production from variable RES is low. However, it is found that CHP units at small DH plants should expect relatively few hours of operation, and as such, their fixed annual costs should be covered with income derived from these relatively few hours of operation, or in some other way.

5. Lessons from the Danish system

In this chapter, the Danish energy system along with its relevant historical development and political goals for the future system are presented. This is followed by a description of the current organisation of the electricity system balancing reserves and wholesale markets. Lastly, the simulation of the examined case with results is presented. It is found that Denmark has a long tradition for DH, CHP and wind power integration in the energy system, and that all these play an important part in the current Danish energy system. It is also found that small DH plants with CHP are an important part of the current Danish energy system, though, due to increased integration of wind power and the removal of a capacity subsidy, it is expected that the CHP capacity at small DH plants will decrease. From the simulations it is found that small DH plants can increase their income by about 5% by providing balancing for the electricity system.

5.1. The Danish energy system

The description of the Danish energy system focuses on the electricity system and the DH system.

5.1.1. Historical development

Historically, the Danish energy system has been based on fossil fuels with the electricity system being dominated by a few large central power plants while the heating system was mainly based on individual oil boilers. DH has historically existed in Denmark, and since the 1950s, had seen an expansion in its use [75], it was mainly based on boilers [76]. Since the 1970s, the Danish energy system has experienced a development away from this structure. This important change in Danish policy came with the first oil crisis in 1973, as before this the Danish electricity and heating system consisted of large consumers of imported oil, e.g. oil-fired steam-turbine plants accounted for about 85% of the electricity production, and most residential heating was also based on oil [76]. However, the oil crisis showed that this reliance on imported oil represented a great risk for the energy system. Thus, a change in Danish energy policy occurred, including an increased focus on energy efficiency and efforts to substitute oil with other energy sources. This led to a shift from individual oil boilers towards the increased use of collective systems, namely DH and natural gas (Ngas) systems that utilized gas extracted from Danish waters. This change in policy can be seen in e.g. the first national energy plan, Danish Energy Policy 1976 and the Heat Supply Act from 1979, which among other things, required municipalities to make plans for the organisation of local heating supplies, including the mapping of existing heating demands and existing surplus heat sources that could be used for heating purposes. This helped spark interest in CHP, as many of the large power plants were located in or close to major cities where large heating demands were found, and many power plants were subsequently converted to CHP plants [76]. In the early 1980s many power plants were also changed from oil to coal, and since then coal has been an important fuel in the Danish electricity system. In 1985 the Danish parliament decided that domestic energy sources should be given priority, alongside this, energy taxes on coal and oil were increased in order to prevent falling fuel prices from affecting consumer prices. [75]. The use of high taxes on undesired energy sources has been an important energy policy in Denmark, as this has shown to help increase energy efficiency [76]. Nuclear power was considered in early national plans, but due to strong public opposition the nuclear plans were abandoned in 1985 [77]. The first small CHP units in a DH grid were built in the early 1980s using Ngas, though these were pioneer plants. Small CHP in DH saw increased implementation in towns and villages beginning in the 1990s, with production being based on Ngas-fired plants with CHP. This was made possible by the development of the Ngas grid and a political agreement in 1990 regarding the expansion of CHP use with Ngas [78].

The Danish energy system today is still characterized by a relatively high share of energy coming from fossil fuels, though the amount of RES has increased, especially since the early 2000s. This development of the electricity system can be seen in Figure 5.1, which shows the gross electricity production by energy source for each year since 1994.

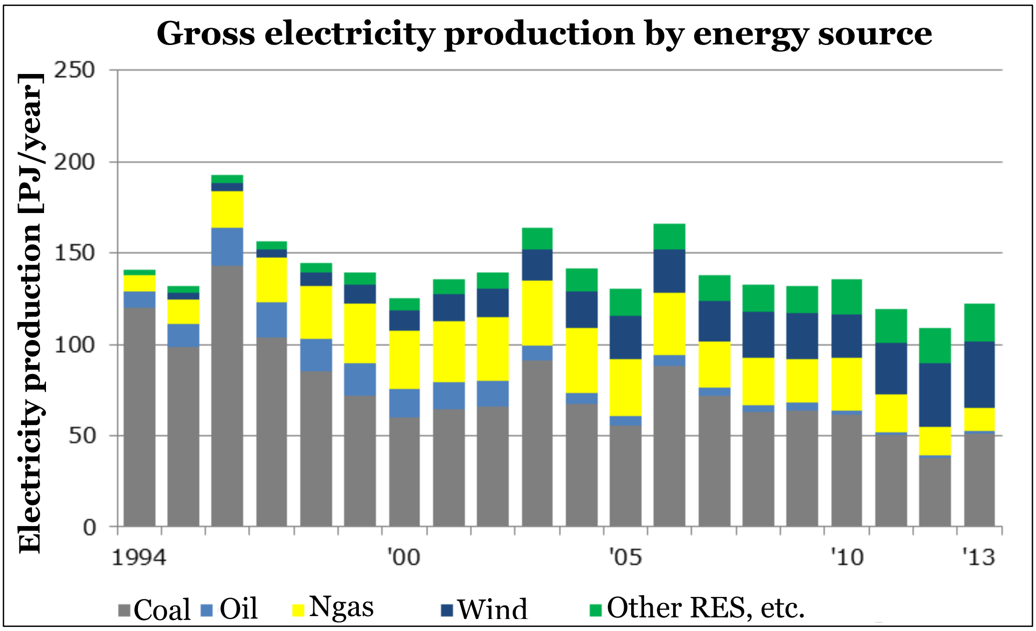

Figure 5.1 - Yearly gross electricity production by energy source in Denmark. [79]

As shown in Figure 5.1, Danish electricity production has historically been dominated by coal, though this is currently changing, with especially wind power taking over as the dominant source of electricity. It can also be seen that

Ngas has played an important role, particularly in the period from the late 1990s to around 2010, but the use of Ngas for electricity production has been on the decline over the last couple of years. Other RES as shown in Figure 5.1 is mainly biomass. The amount of electricity imported or exported is not shown in Figure 5.1.

Due to historical reasons, Danish statistics for the energy system present the consumption and production from small and large units separately, alongside their power only production and CHP production. Figure 5.2 shows the yearly gross electricity production based on the type of producer alongside the climate adjusted final electricity consumption in Denmark.

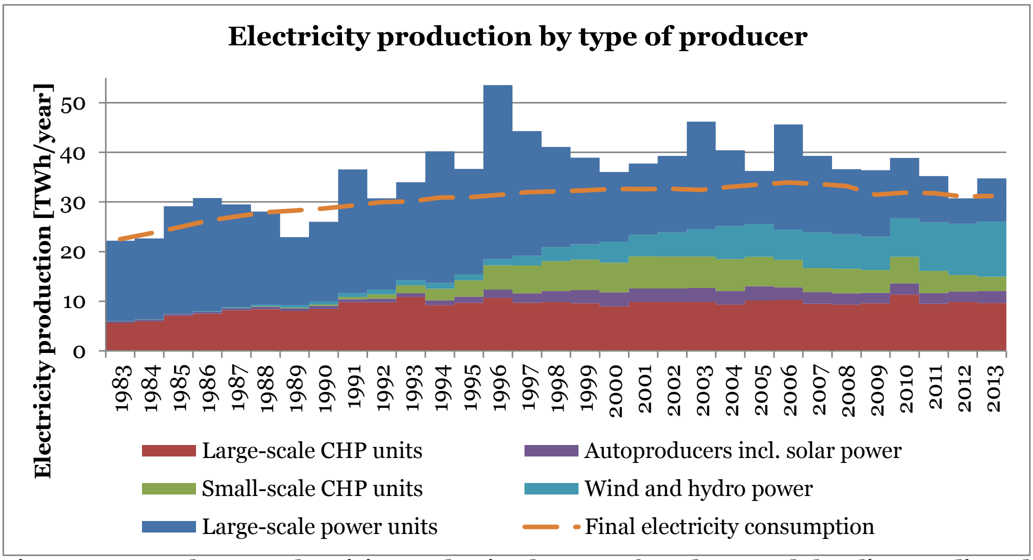

Figure 5.2 - Yearly gross electricity production by type of producer and the climate adjusted electricity consumption in Denmark. Based on data from [79].

As seen in Figure 5.2, the increase in wind power production seems to have mostly reduced electricity production from large power units, but also small CHP units have seen a decrease in line with the increase in wind power. Production from large CHP units has been mostly unchanged by this increase in wind power production. The main reason for this difference in the change of production between small and large CHP units is that the small CHP units have mostly been based on Ngas, whereas the large CHP units have mostly been based on coal. As the price of coal has been lower than the price of Ngas, the small CHP units have been outcompeted in the electricity market, as described in more detail in section 5.2. But, the fact that the large CHP units' production has been more dependent on local heat demand is also an important factor. As can also be seen, the electricity production can vary significantly from year to year, which is due to cross-border electricity trading. Autoproducers are electricity producers whose main activity is not the production of electricity, such as industry with CHP.

Figure 5.2 also shows the key point for understanding the Danish energy system, namely that the electricity and heating systems have historically been highly integrated due to a relatively high share of CHP in the energy system, and most of this CHP capacity is connected to DH systems. In 2013, about 62% of all households were connected to DH, and the final DH consumption in households was about 18.9 TWh, corresponding to about 37% of households' final energy consumption. For industry, the final DH consumption was about 1.7 TWh in 2013, corresponding to about 5% of the final energy consumption in industry, and for commercial and public services the final DH consumption was about 8.7 TWh, corresponding to about 38% of this sectors' final energy consumption. As such, the Danish DH sector is characterised as a major player in the energy system; it primarily delivers heat for both households and commercial and public services, and is used extensively for space heating demand and hot water consumption. [79]

Figure 5.3 shows the gross DH production in Denmark by type of producer.

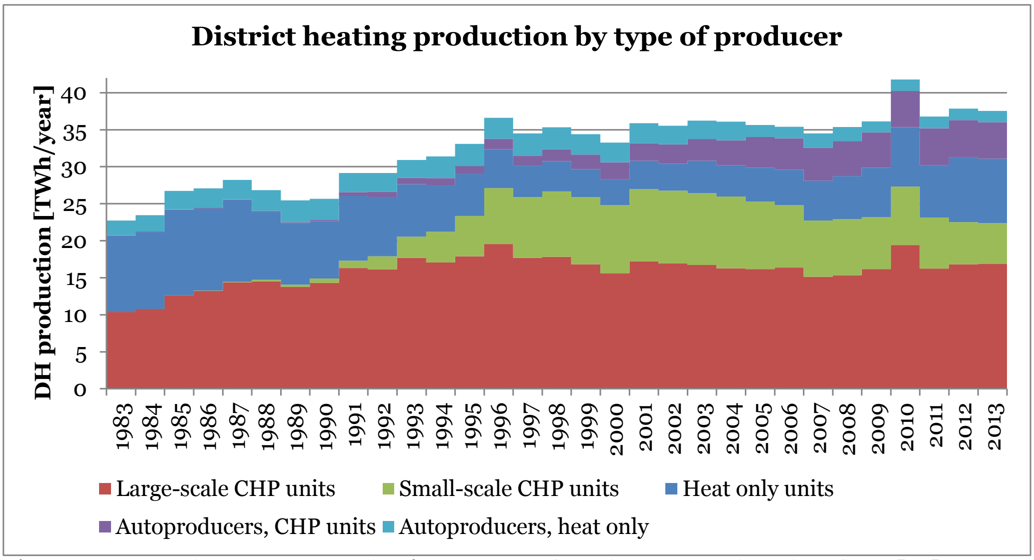

Figure 5.3 – Yearly gross DH production by type of producer. Based on data from [79].

As seen in Figure 5.3, most Danish DH production comes from CHP units, and in 2013 CHP production accounted for about 72% of total DH production [79]. DH production from heat only units mainly consists of biomass boilers and Ngas boilers, respectively comprising about 44% and 34% of the heat only units' DH production in 2013 [79]. The increase in DH production from heat only units corresponds with the decreasing production from small CHP units. The main fuel used in DH in 2013 was biomass, with about 41% of the total gross DH production coming from biomass fired units, coal made up about 24% and Ngas about 22%.

Though production from small CHP units has decreased, a relatively large share of the electricity capacity is still made up of small units, as seen in Figure 5.4. The small units shown in Figure 5.4 are almost exclusively CHP units. In 2013, 85% of the large units' capacities were CHP units. A large share of this is extraction steam turbines.

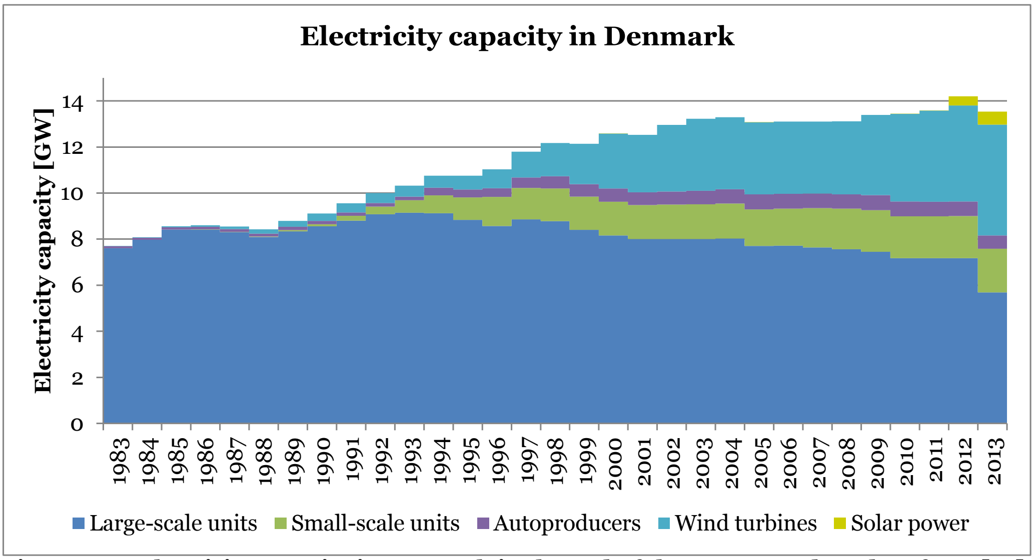

Figure 5.4 - Electricity capacity in Denmark in the end of the year. Based on data from [79]. Hydro power is excluded.

As seen in Figure 5.4, the capacity of wind turbines in Denmark has increased significantly, and in 2013, 35.5% of all electricity capacity in Denmark was wind turbines. With the increasing share of wind turbines, the capacity of large units has seen a continuous decrease, with a large drop from 2012 to 2013 of about 20%. Capacity of small CHP units has, on the other hand, been mostly stable for a number of years. In 2013 a total of 637 small CHP units (excl. autoproducers) were in operation, having a total of 1.89 GW electric capacity and 2.33 GW heat capacity [79].

5.1.2. Future of the Danish energy system

As part of the EU, Danish political goals are affected by EU goals, as described in section 2.5. In this section only the national goals are presented.

In The Climate Change Act from 2014 [80] it is stated that the long-term political goal in national Danish energy policy is to be a "low emission society" in 2050. The "low emission society" is defined as a resource efficient society with an energy system based on RES and significantly lower greenhouse gas emissions from other sectors. The Climate Change Act was passed by a large and broad majority in the Danish parliament, and it is expected that this goal will not be affected by a change in government, as all parties that traditionally hold power in government are part of this majority. The current government has also set some medium term goals, for instance, all oil for heating purposes and coal should be phased out by 2030, and all electricity and heating demands should be covered 100% by RES in 2035 [81]. These medium term goals are, however, not as certain as the long-term goal of an energy system based on RES for 2050, as these are only the politic of the current government.

Specific political goals for 2050 do not exist, however, the current national Danish energy policy takes its departure in an agreement between, at that time, all parties in the parliament except for the Liberal Alliance party, which currently holds 9 out of 179 seats in the Danish parliament. This agreement was made in March 2012; it stipulates plans and goals for the Danish energy system in the period from 2012-2020. The agreement states that the overall goal is to achieve a 40% reduction of greenhouse gas emissions in 2020 compared with 1990 levels. For the electricity system, an important part of this agreement is that wind power should increase by a total of 2 GW, with 1 GW offshore, 500 MW near-shore and a net increase of 500 MW onshore, as it is expected that 1.3 GW onshore will be taken down and 1.8 GW will be built. With an installed wind power capacity of 4.8 GW at the end of 2013, wind power is hence expected to be an important part of the Danish energy system. Another important part of the agreement is the aim to incentivise large CHP units using coal to shift to biomass. The agreement also includes e.g. increased energy efficiency, improved conditions for biogas and steps to reduce the use of individual oil boilers. The agreement also showed an interest in increased installation of heat pumps in the DH system. [82]

Based on e.g. the political goals, input from market participants, current tax and subsidy rules and expectations about future costs and prices, the national Danish TSO, Energinet.dk, published a set of analysed assumptions for the expected development of the Danish energy system until 2035, which Energinet.dk uses in their own analyses. These analysed assumptions are based heavily on current plans, they are therefore primarily relevant for the short-term, and should mostly be used as means to understand in which way the energy system could develop in the medium and long-term. The state-owned Energinet.dk is an important organisation in the Danish energy system, as it is system responsible for both the electricity and Ngas systems. In the analysed assumptions from September 2014, Energinet.dk expects that the transmission capacity to other countries will increase from 5.8 GW export and 5.1 GW import in 2014 to 8.8 GW export and 8.4 import in 2035. For traditional power and CHP plants, the expectations regarding the development of capacity and fuel use can be seen in Figure 5.5. [83]

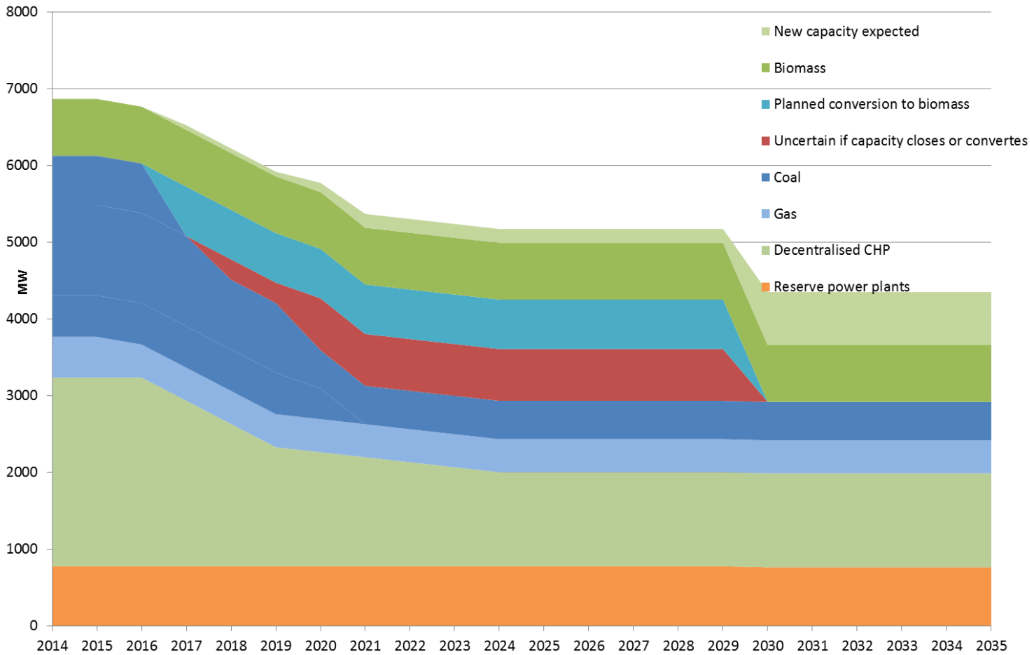

Figure 5.5 – Energinet.dk's expectations to development of power stations 2014-2035 [83].

As seen in Figure 5.5, Energinet.dk expects an overall decrease of traditional power and CHP plant capacity in Denmark, where especially coal-fired capacity and small (decentralised) CHP capacity is expected to see a reduction in the coming years. Some of the coal-fired capacity, though, is expected to be converted to biomass. The decrease in the capacity of small CHP is expected, as many of these plants were built in the 1990s, and with a worsening economy in some of these plants, due to lower electricity prices, increasing taxes on Ngas and the removal of a capacity subsidy in 2018, it is expected that many of these facilities will not reinvest in their CHP capacity. Energinet.dk notes that the future for small CHP plants is very uncertain, as, for example the Ngas-fired CHP are not allowed by law to shift to e.g. a biomass boiler, which is more economically attractive due to significantly lower taxes on biomass. [83]

For variable RES, Energinet.dk expects wind power capacity to reach about 8.2 GW in 2035, corresponding to a yearly production of about 31 TWh. Photovoltaic is expected to increase from 0.56 GW, corresponding to a production of 0.48 TWh in 2014, to 1.7 GW with a production of 1.48 TWh in 2035. Energinet.dk expects other variable RES to have a very low degree of implementation during the examined time period. [83]

Consumption-wise, electricity demand is expected to increase from 32.5 TWh in 2014 to 39 TWh in 2035, with the largest part of this increase expected to be electric vehicles, heat pumps and electric boilers. Energinet.dk expects that large heat pumps and electric boilers will be further integrated into the DH system, and that a large share of individual heating will shift to heat pumps. [83]

5.2. Electricity market setup

The Danish electricity system is part of two separate synchronous grid areas, where everything west of the Great Belt (DK1) is part of the Continental European Synchronous Area, and everything east of the Great Belt (DK2) is part of the Nordic Synchronous Area. The setup of the wholesale markets is the same in both areas, but the setup of balancing reserves differs between DK1 and DK2. As the Danish case plant is located in DK1, the setup of electricity markets in DK1 is described.

5.2.1. Wholesale markets

Denmark is part of the electricity exchange Nord Pool Spot. Nord Pool Spot mainly operates in the Nordic and Baltic countries, being Denmark, Finland, Norway, Sweden, Estonia, Latvia and Lithuania. For the purpose of this thesis, this area will be referred to as the Nord Pool Spot area. Nord Pool Spot also operates electricity markets in the UK and an intraday electricity market in Germany. The origin of Nord Pool Spot dates back to 1971, to a power exchange that was used for Norwegian hydropower in order to trade surplus electricity. In 1993 the market was opened for all producers and consumers in Norway [84]. In 1996 Sweden joined the exchange and was followed by Finland in 1998, Denmark in 2000, Estonia in 2010, Lithuania in 2012 and Latvia in 2013 [85]. In 2013 the market share of Nord Pool Spot within the Nord Pool Spot area corresponded to 84% of the area's electricity consumption. [86]

The main market within Nord Pool Spot is Elspot, on which 349 TWh were traded in 2013 [86]. Elspot is a day-ahead wholesale market. Trading on Elspot occurs daily and starts with each TSO in the Nord Pool Spot area informing the market about the capacity on interconnectors available for trade on Elspot for the following day. This occurs at 10 a.m. The gate closure for bidding on Elspot is at 12 noon, and bids have to cover full hours. A single hourly bid can either be price dependent or price independent. It is possible to pool a period of at least three hours into a single price dependent bid, called a block bid, where the average price in the block is used to determine whether the bid is won or not. The market prices for each hour of the following day are revealed before 1 p.m., and the participants are contacted. At this point, the expected electricity production is equal to the expected electricity consumption for each hour of the following day. Elspot is a MPP auction, where the market is cleared based on the most expensive winning bid.

As stated, the Nord Pool Spot area is divided into separate price areas, with Denmark consisting of two price areas, DK1 and DK2. If there are no transmission bottlenecks within the Nord Pool Spot area then the Elspot market price is the same in all price areas. This market price is also known as the system price. If transmission bottlenecks occur for one or more price areas, separate market prices are calculated for each of these areas, with the remaining price areas setting the system price. The monthly average Elspot system price alongside the price in the Danish price areas, DK1 and DK2, can be found in Figure 5.6. The spot prices shown are in nominal prices, and as such, do not account for general inflation.

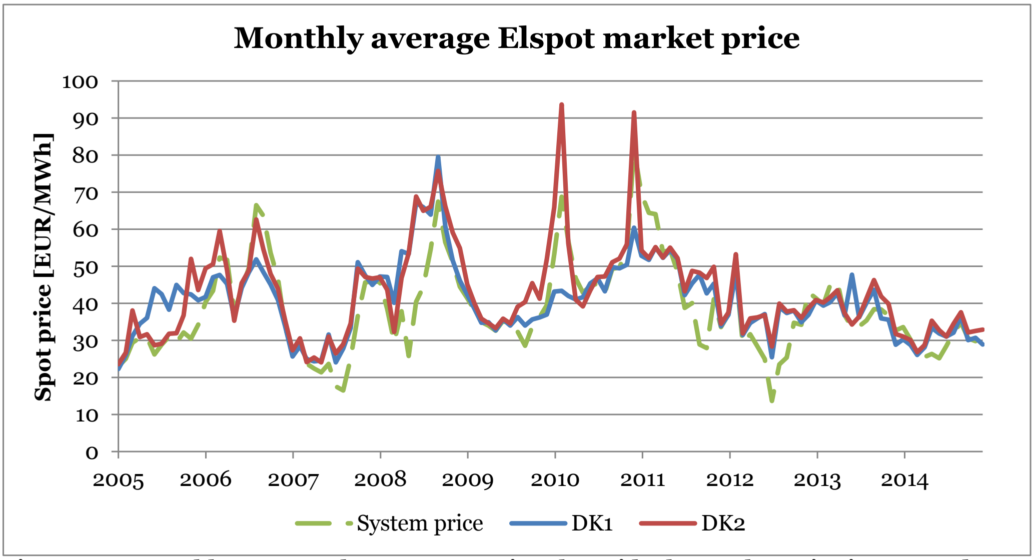

Figure 5.6 - Monthly average Elspot system price alongside the market price in DK1 and DK2, respectively. Spot prices are in nominal terms. Based on data from [87].

From Figure 5.6, it can be seen that the Elspot market price in DK1 and DK2 follow the system price trend, though there have been periods where the area prices differed from the system price. It can also be seen that the price has decreased since 2010, though the price in nominal terms has been down to similar levels before, albeit for a shorter period. This price decrease is due to several reasons, though the increased capacity of variable RES, especially wind power, has been proven to decrease spot prices [88].

Trades on Elspot are binding, but it is still possible to trade expected imbalances on the wholesale intra-day market, Elbas, until one hour before the operating hour. In 2013, 4.2 TWh was traded on Elbas, thus Elbas is a significantly smaller market than Elspot, though its turnover has increased from 3.2 TWh in 2012 [86]. On Elbas, bids are settled similarly to a bilateral contract, meaning one participant submits a bid to the market, and another participant can choose to accept the bid from the market. Therefore, Elbas functions differently than Elspot, e.g. by not having one specific time were all bids are settled, and it functions as a PAB rather than an MPP.

5.2.2. Balancing reserves

In Denmark the national TSO is the system responsible for the electricity system. The Danish TSO is called Energinet.dk, and is 100% owned by the Danish state.

Organisation of the TCR

The Nordic regulating power market is the balancing market for TCR, which Energinet.dk uses to replace activated SCR [53]. On the Nordic regulating power market, a market participant can, for each hour, offer to be both available for regulation the day before, and to be activated as regulation. The maximum technical response time to participate in the market is 15 minutes. The gate closure for availability bids for the following day is at 9:30 a.m. Winning availability is not a requirement for offering activation. However, if availability is won, the participant has to offer the corresponding type of activation in those hours. [89]

Like Elspot, the market is asymmetric, and it is hence possible to offer either downward regulation, activated when there is excess electricity in the system, or upward regulation, activated when there is a lack of electricity in the system. Bids on the regulating power market cover full hours; however, the period of activation can be shorter than one hour. Only activation periods longer than ten minutes are settled according to the market price at that hour. In case of activation periods below ten minutes, the activation payment is settled according to the PAB principle, meaning that the participant must pay for activation according to the participant’s bid, and not the market price. The market price is equal to the bid of the marginal unit in the dominant activation direction in that hour, meaning that the market is normally settled according to the MPP. If activation occurs in the direction that is not dominant, the unit is settled according to the PAB principle. [89]

When a participant is activated as upward regulation, the participant is paid by the TSO, and if downward regulated, the participant has to pay the TSO. Activation can also occur due to special balancing needs, such as local congestion in the transmission grid. This type of activation is called special regulation and is settled using the PAB principle. The length of activations and the chance of being activated are not known to the participants at gate closure. The gate closure for activation bids on the regulating power market is 45 minutes before the operating hour, and the minimum bid size is 10 MW. It is possible to pool several participants into one bid in order to reach this minimum requirement. [89]

After the gate closure for Elbas trading, any imbalances between scheduled production and consumption are penalised using the activation prices on the TCR, the Nordic regulating power market. Imbalances in production are settled according to a two-price principle, where individual imbalances that correspond to the direction of the system's imbalance are settled according to the activation price on the TCR, and individual imbalances that are opposite to the direction of the system imbalance are settled according to the Elspot price. Consumption, however, is instead settled according to a one-price principle, where all individual imbalances are settled according to the activation price on the TCR. In case no TCR activation price is found for a specific hour, the Elspot price is used instead. [89]

Wind power, since 2012, has been able to participate in downward TCR on equal terms as other participants. [13]

Organisation of the SCR

The SCR explained here only covers DK1, as another balancing reserve is used in DK2.

Currently, the SCR is traded monthly with Energinet.dk setting the demand for SCR, though this demand is based on the agreement with ENTSO-E of +/- 90 MW. Offers on the SCR are symmetric, meaning that the participant has to be able to deliver the amount in both directions, and the delivery period covers the entire month. The full capacity must be supplied within 15 min., though part of this must be delivered within 5 min. by units already in operation. The SCR is primarily provided by units already in operation, though it is possible to make a bid with a combination of both fast-start units and units in operation through the period. After bids are submitted, Energinet.dk evaluates each bid and may negotiate with participants that offer SCR, if Energinet.dk deems this relevant. [89]

Winning participants are paid for both capacity and energy, where capacity is settled according to the PAB principle. Upward regulation of energy is settled at the hours' Elspot price plus 100 DKK/MWh, though never lower than the activation price on the TCR. Downward regulation of energy is settled at the hours' Elspot price minus 100 DKK/MWh, though never higher than the activation price on the TCR. [89]

At this writing, this is the current organisation of the SCR in DK1, though in combination with the installation of the new transmission connection, Skagerak 4, between Norway and Western Denmark in 2015, Energinet.dk has decided to purchase +/-100 MW SCR from Norway for the following five years, meaning that essentially all the SCR will be delivered from Norway. [90]

The utilisation of balancing reserves

According to their balancing reserve strategy, Energinet.dk aims to utilize the TCR as much as possible for balancing. This is partly due to the fact that this reserve sets the costs for imbalance for the BRPs, meaning that the real costs of imbalances are, for the most part, paid for by those that cause the imbalance. Though, costs associated with the PCR, SCR and capacity payments in the TCR are, of course, then not paid by those that cause the imbalance. As participation on the TCR is less restrictive than the SCR, the focus on using the TCR as much as possible for balancing the system also makes it possible for more units to participate.

Figure 5.7 shows the monthly average purchase of SCR and TCR capacity. Note that it is not required for participants of the TCR to win capacity in order to offer activation, and as such, Energinet.dk does not purchase capacity for downward TCR.

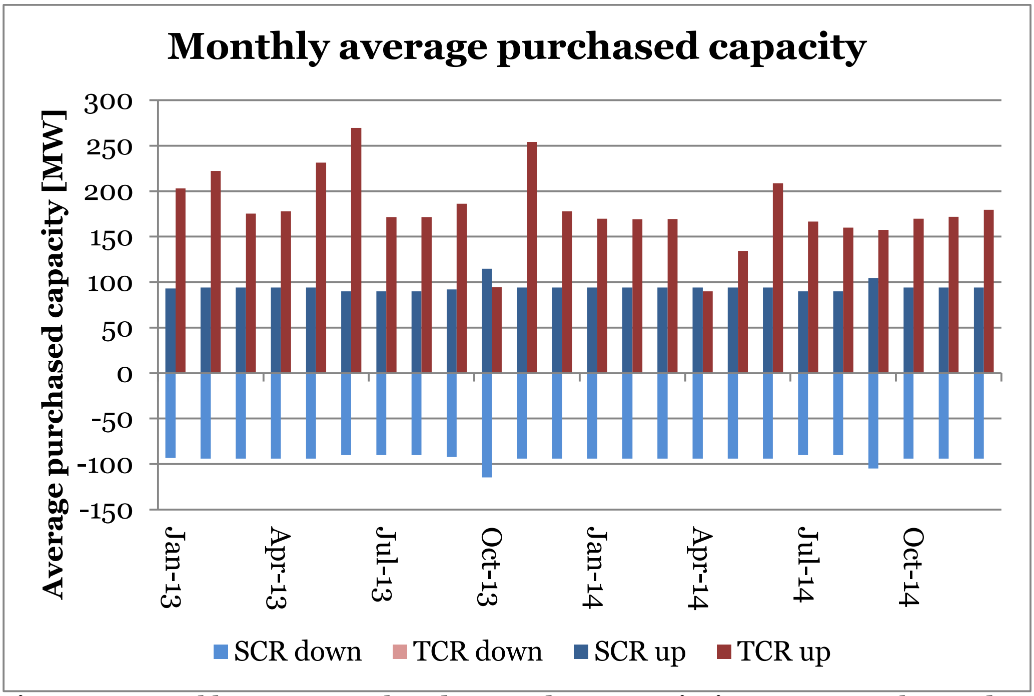

Figure 5.7 - Monthly average purchased SCR and TCR capacity in West Denmark. Based on data from [87] and [91].

Energinet.dk does not publish the energy amounts activated in the SCR, but only the hourly amounts of activations made in the TCR within each area. However, Energinet.dk has, since 1st of January 2013, published the total need for activation of balancing reserves in each hour for the price area DK1. As TCR is traded on a Nordic market, it is possible for Energinet.dk to cover balancing needs with activations in other Nordic countries when there is free capacity on the transmissions, and it is hence not possible to calculate the activated SCR in DK1 based solely on the needed balancing and the activated TCR in DK1, as the import and export amounts for these are unknown. According to Henning Parbo, Chief Economist at Energinet.dk, plants in DK1 only deliver TCR balancing for other countries less than 3% of the time [92]. Hence, most of the TCR activation of plants in DK1 is due to Danish balancing demands. Table 5.1 shows the yearly amounts of activated TCR within DK1, and the total need for balancing in DK1.

[MWh/year]	**2013**	**2014**	**Total**
Activated downward regulation in DK1	-201,145	-172,128	-373,274
Need for downward in DK1	595,578	494,675	1,090,253
Activated in % of need	34%	35%	34%
Activated upward regulation in DK1	194,725	287,210	481,935
Need for upward in DK1	-988,383	-883,587	-1,871,970
Activated in % of need	20%	33%	26%

Table 5.1 – Yearly amounts activated in the regulating power market in DK1 and the TSO's need for balancing in DK1. Based on data from [87].

Based on Table 5.1, and assuming activations in the SCR only contribute with small amounts of energy, it can be concluded that a large share of the DK1 demand for balancing is delivered from other price areas. According to Henning Parbo, DK2 has an even higher degree of balancing import, and as such, it can be concluded that most of the Danish balancing needs are covered using plants in other countries [92].

An important aspect of the TCR's utilisation is the use of special regulation. Energinet.dk does not provide the background data for special regulation, but have addressed the issue in their newsletter [93]. In the newsletter it is stated that the amount of activated special regulation compared with the total activated amount of TCR differs substantially between each month, though special regulation of downward regulation tends to occur more than for upward in DK1. It is also interesting that in some months more than one third of all activation in the TCR occurs as special regulation, meaning more than one third is settled according to the PAB principle. This presents an interesting dilemma for participants on the TCR, as the bidding strategies for MPP and PAB are substantially different, where a bid on a PAB market would normally be higher if produced, or lower if consumed, than on a MPP market, as was also argued in section 2.4.2. This has created a situation in which participants tend to calculate bids for the TCR as they would for a market based on MPP, while the reality is that the market is increasingly being settled according to the PAB principle. Participants will therefore have to change their bidding strategy to account for this shift in market conditions, resulting in increased bids. This, in turn, will put Danish participants on the TCR in an even worse position when competing with participants on the TCR from other countries.

5.2.3. Small CHP plants in the Danish electricity markets

Danish CHP plants with a capacity larger than 5 MW_e have, since 2007, been required to trade on market terms; thus, most of the small CHP plants in Denmark trade on market terms [94]. Prior to being forced to operate on market terms, small CHP plants were managed according to the so-called triple tariff, where three different tariff rates were set according to Danish regulations [95]. Units smaller than 5 MW_e have been allowed to stay on the triple tariff, though as part of a 2014 political agreement the triple tariff is expected to end before 2016, requiring the last remaining units to also trade on market terms [96]. The triple tariff operates with low payments for electricity on the weekend, which originally incentivised the plants to acquire thermal storage systems that could store heat from the CHP over the weekend. Therefore, small CHP plants in Denmark have, for the most part, installed thermal storage systems.

Originally, the small CHP plants operating on market terms participated almost exclusively on Elspot, but as the organisation of the other electricity markets changed, it became easier for them to participate on these, and a number of small CHP plants now participate on several electricity markets, though an exact amount is difficult to determine. Generally, the TCR has shown to be relevant for small CHP plants due to flexible participation conditions and relatively large traded amounts [56]. The SCR has, with its monthly symmetric bids, which basically require participants to be in operation all month, been primarily relevant for large CHP plants that can guarantee an entire month of operation; with the SCR mostly being bought from Norway in the coming years, it is not of relevance for the Danish plants. With the increasing amounts traded on Elbas, this market has also received increasing interest.

Many of the small CHP plants were built around the usage of Ngas, and due to Danish law they are basically only allowed to switch from Ngas if the new capacity is also CHP, though electric boilers, heat pumps and surplus heat from e.g. industry are also allowed. Another possibility, which many small CHP plants have utilised, is installing large solar collector fields in order to reduce the use of Ngas, which is increasingly used in boilers, as shown in section 5.1.1. In Denmark Ngas is particular expensive when used for heat-only production due to energy duties, where energy duties make up about half of the NHPC of a Ngas boiler in a small DH plant. In 2007, the total installed solar collector field area in DH systems was less than 50,000 m^2. In 2013, this had increased to nearly 400,000 m^2, and more collector fields are expected in the future [97]. Besides reducing the need for heat production by Ngas boilers, it also decreases the need for production by CHP units, especially in the summer period. Due to the intermittent production nature of solar collector fields, it also increases the uncertainties in daily operation planning.

Another development in small CHP plants is the increased installation of electric boilers, which are mostly installed in order to consume electricity when electricity market prices are very low, and in order to deliver PCR. Currently, about 44 electric boilers are installed throughout Denmark with a total installed capacity of about 400 MW_e, with most of this capacity existing in small DH plants [98]. With the PCR operating at only about 10-30 MW/h in DK1, and with large capacities being offered on the PCR and the demand remaining unchanged, the market price has dropped significantly [87]. This has reduced interest in delivering PCR, though the installed electric boilers are still used for participation in other electricity markets, especially the TCR, where the market price, by design, is more extreme than in Elspot. They are hence used only for a few hours, and are mostly used for providing balancing for the electricity system. Some plants' electric boilers were also installed as extra backup for the DH system, as they have relatively low investment costs and high operation costs.

5.3. Case: Ringkøbing District Heating

Based on the considerations described in section 5.2.3, and the CEESA scenario for a Danish energy system in 2050 presented in section 4.2 a case plant has been chosen, which is representative of the described system development, in order to analyse how this development is affecting the daily operation of small DH plants in Denmark. The case plant used is Ringkøbing District Heating (RDH).

RDH delivers heat for space heating and hot water consumption to approximately 4,000 consumers in the town of Ringkøbing. RDH is situated in DK1. In 2013, the total sale of heat was 97,356 MWh and the heat loss in the grid was 19.1%. The primary fuel is Ngas, which is used in the production units listed in Table 5.2. The efficiency shown for the engine is when operating at full load. For the Ngas boilers, the average efficiencies are presented.

Production unit	**Electric capacity**	**Heat capacity**	**Total efficiency**
	MW	*MW*	*%*
Engine	8.8	10.3	96
Boiler 1	-	7.0	103
Boiler 2	-	11.5	105
Boiler 3	-	10.0	91
Boiler 4	-	11.5	105

Table 5.2 - Ngas-fired units currently in operation at RDH.

Besides the Ngas-fired units, the plant also has a 12 MW_{th} electric boiler and two similar solar collector fields, each with 15,000 m^2 of solar panels and a peak capacity of 11 MW_{th}. The first of these fields was established in 2010 and the second was established in early 2014. The efficiency of the electric boiler is assumed to be 100%. Furthermore, the plant also has three thermal storage units. The first storage unit has a net storage capacity of 250 MWh_{th}, and is utilized by the engine and electric boiler. The second and third unit each have net storage capacities of 60 MWh_{th}, and they are both primarily used for storing heat from the solar panels.

The months June, July and August have been simulated in order to understand the daily operational challenges during the period when these challenges are most prevalent, being when solar production is at its highest. In the simulated period, RDH participated on Elspot and the TCR. As RDH is not large enough to participate directly on these markets on their own, RDH trades through an aggregator that conveys the bids onto the markets. Every day at 10 a.m., RDH's aggregator provides them with a forecast of the hourly prices on Elspot for the following five days. Daily trading on the Elspot market at RDH is carried out at around 11 a.m. At this time, a rough estimation of the following day's heat demand and solar heating production is also made based on the weather forecast for the area and the current heat demand and production. RDH's aggregator only offers the plant the ability to submit block bids and price independent single hourly bids on Elspot. RDH does not offer availability on the TCR. Instead, upward regulation is offered if the engine has not won trade on Elspot. Downward regulation is offered if the engine has won trade on Elspot or the electric boiler has not won trade on Elspot.

In the simulated period, RDH's price of Ngas was settled based on the price listed on the gas exchange NetConnect Germany. The Ngas price for RDH is settled on a daily basis on the day after operation, and RDH does not have a gate closure for trading on this market. Thus, the plant does not know the price of Ngas until the day after it has been used. For the Ngas price forecast, RDH uses the price from the day before as a forecast for the following days.

5.3.1. Simulating the daily operation of RDH

The objective of the simulations is to approximate the daily operation of RDH. As argued in section 3.3, the simulation approach should account for the chronological decision time aspect and the use of forecasts in the decision process. As also described in that section, energyPRO is used for simulation of the case plants, though a more detailed chronological approach than the default in energyPRO is made for each simulated plant. For the simulation of RDH, the chronological simulation approach is achieved by dividing each day into 24 separate simulations, one for each hour, all beginning at the starting point of each hour. These are, in this section, referred to as simulation steps. Each of these simulation steps represents a decision point in the daily planning process, corresponding to the gate closures on the TCR. The simulation steps are then run chronologically so that decisions in earlier simulation steps affect later steps. All simulation steps cover a simulation period of 6 days, the first representing the day of operation and the next five representing the days following the day of operation. Each day's 24 simulation steps can be divided into four different periods:

- At 12 a.m., midnight, the forecasts for Ngas price, heat demand and solar collector production are updated. The Elspot price forecast from the day before is used. At this point, trading only occurs on the TCR.
- In the period from 1-11 a.m. the Elspot price forecast from the day before is used. In this period, trading only occurs on the TCR.
- At 11 a.m., the forecast for the Elspot prices is updated. Trading occurs both on the TCR for the following hour and on Elspot for the following day.
- In the period from 12 noon to 12 midnight, the actual Elspot prices for the following day are used instead of the forecasted prices. The production won on Elspot for the following day are locked. In this period, trading only occurs on the TCR.

At the end of the six-day period for each simulation step, the thermal storage units will be set at a level equal to the content at the beginning of the respective period. The only exception is if the forecasted solar collector production and any heat production from units already traded on any electricity market are greater than the forecasted heat demand. In that case, any surplus heat increases the thermal storage units' content at the end of the respective period by that surplus amount.

Each electricity market bid is calculated using the method described by Andersen and Lund [99] to calculate bids. Using this method, the electricity market bids are calculated as the change in total forecasted NHPC for the following days, taking into account the content in the thermal storage units. More specifically, the bid price is found as shown in Eq. (1).

$$B = (NHPC_1 - NHPC_2) / C \quad (1)$$

Where B is the bid price for the given unit; C is the offered electric capacity of the given unit; $NHPC_1$ is the NHPC with the given unit activated in the given period, but without the potential electricity income or cost of the unit in the period; and $NHPC_2$ is the NHPC without the given unit in the given time period. Hence, the electricity market bids are not only based on the production costs of the individual units, but also on the change in the expected operation of the other heat producing units.

The simulated period is from 1st of June to 31st of August, corresponding to 2,208 simulation steps. With the exception of the solar collector production, all data comes from this period in 2013. For the purpose of simulating both solar collector fields, production from the one solar collector that existed during those three months in 2013 is doubled. Simply doubling this production is done because the two solar collector fields are identically set-up and placed next to each other; it is also assumed that the older collector field has not suffered any efficiency loss, and is therefore equivalent to the newly built collector field. The heat demand used in the simulations is the hourly data measured by the plant in the three months of 2013, excluding plant and solar collector heat production [100]. In the simulated period, a total of 13,306 MWh_{th} was delivered from the plant. Due to the lack of forecast data, a simple approach has been used to produce forecasts for the heat demand and solar collector production. Each hour of the last full day's heat demand and doubled solar collector production is used in each simulation step as a forecast for the rest of the operation day, and the five following days. To forecast the Ngas prices and Elspot prices, the actual forecasts utilized by RDH in the period are applied.

The heat production costs for each production unit at RDH in the simulated period are shown in Table 5.3. Ngas boilers 1 and 3 are not included in the table, as these are not needed in the summer months. The solar collector fields are assumed to have a heat production cost of zero, and as it is not seen as feasible to close down operation of the solar collector fields, since this would mean covering the panels, production from the solar collector fields is always prioritised.

Production unit	**Fuel transport**	**Taxes incl. CO_2 quota**	**O&M**	**Start**
	EUR/MWh$_{th}$	*EUR/MWh$_{th}$*	*EUR/MWh$_{th}$*	*EUR/start*
Ngas Engine	5.1	30.1	6.3	129.9
Ngas Boilers 2+4	2.6	36.5	0.3	0
Electric boiler	30.1	34.6	0	0

Table 5.3 - Heat production costs for each unit in 2013. The market prices for Ngas and electricity are not included in the table. Conversion rate: 1 EUR = 7.45 DKK

The daily average Elspot price in DK1 and RDH's daily prices for Ngas in the period, excluding transport costs, can be found in Figure 5.8.

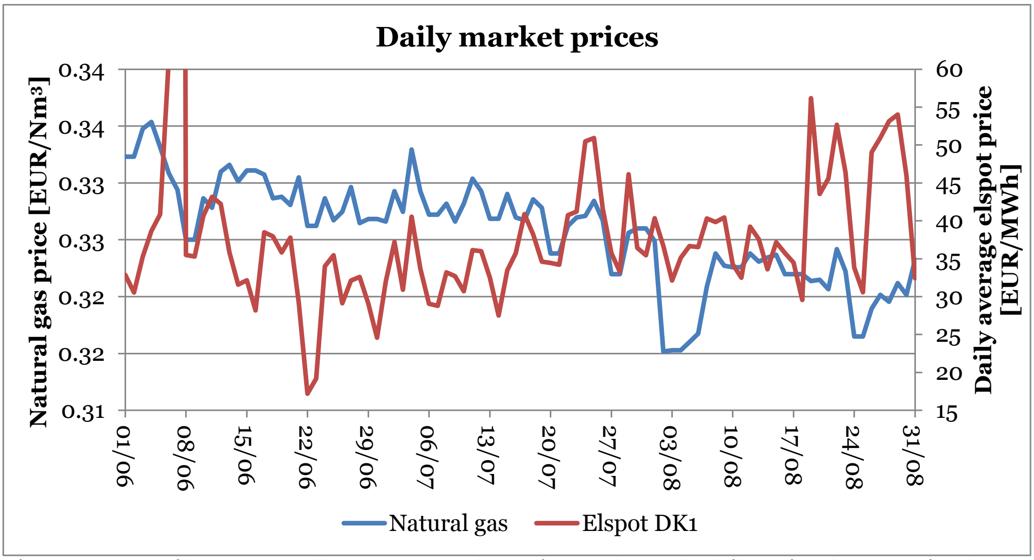

Figure 5.8 – Daily average Elspot DK1 market price and RDH's daily price for Ngas in the period from 1st of June to 31st of August. Conversion rate: 1 EUR = 7.45 DKK. The daily average Elspot DK1 price the 7th of June is 437 EUR/MWh.

Simulation of RDH has been done using three different scenarios:

1. RDH only purchases and sells electricity on Elspot with the described forecasts of market prices, heat demand and solar heating.
2. Like scenario 1, but RDH also participates on the TCR.
3. Like scenario 2, but the forecasts are equal to the actual values (perfect forecast).

Whereas scenarios 1 and 2 provide a fairly realistic simulation of a DH plant, scenario 3 is not seen as realistic, as it requires perfect knowledge of the future. However, it is included in order to highlight the cost of uncertainty that the chosen forecasts introduce, while also illustrating how not including the forecasts affects the results. In all three scenarios, the thermal storage units will be empty at the beginning of the simulation period; however, the storage content at the end of the simulation period can vary. For the purpose of comparing the scenarios, any energy in the thermal storage units at the end of the simulation period will be valued as equal to the average NHPC of August.

The level of detail of the data available for the Danish TCR is full hours [87]. Thus, in the simulations, all activations on the TCR are assumed to be full hours. As such, the simulated activation bids, calculated in each simulation step, are based on the assumption of one full hour of activation. Activations are assumed won if the bid is lower than the market price. Activations are assumed to only occur in the dominant activation direction in the price area DK1, as defined by the market price. Hence, special regulation is not included in the simulation, though as shown in section 5.2.2, the amount of special regulation can make up a considerable portion of TCR activations in some months. Only market prices for Elspot are forecasted. It is assumed that RDH's participation does not affect market prices. All simulated bids on Elspot for the CHP unit are set as price independent bids in blocks of at least 3 hours. For the electric boiler, single hour price independent bids are used for participation on Elspot. In the simulations, the CHP unit and the electric boiler will never operate in part-load. The Ngas boilers are assumed to be capable of part-load operation without a loss of efficiency. In the simulations, the plant will fulfil any won bids, even if this results in the rejection of heat. Heat rejection can occur if the thermal storage units are full and the already traded combined production of the CHP unit and the electric boiler, together with the expected production of the solar collector fields, exceeds the heat demand. If rejection of heat is forecast, the CHP unit and the electric boiler will not be traded into any electricity market, regardless of the expected market price.

5.3.2. Results and discussion

The simulated heat production for each scenario can be found in Figure 5.9.

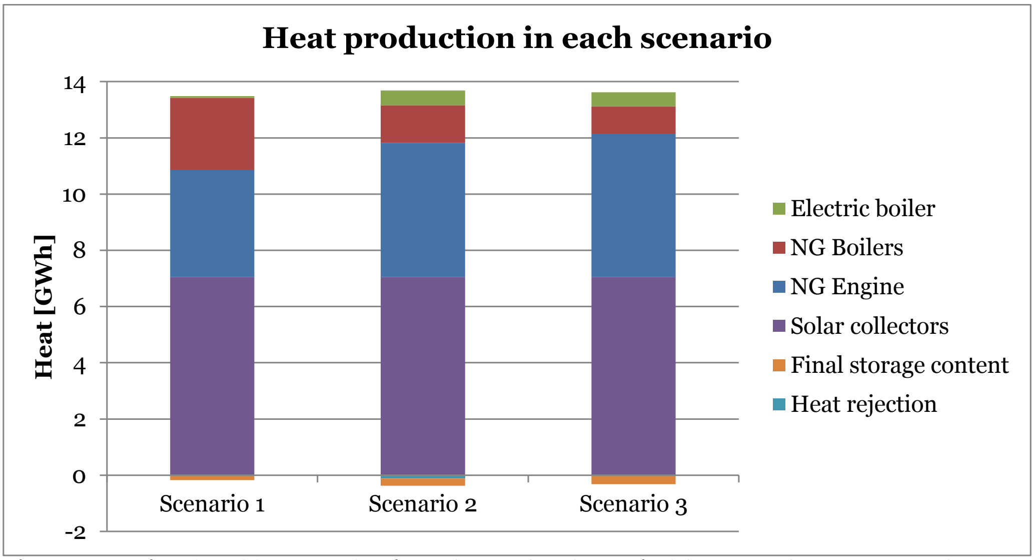

Figure 5.9 - Simulated heat production of RDH for the period from 1st of June to 31st of August 2013.

The costs for each scenario can be found in Figure 5.10.

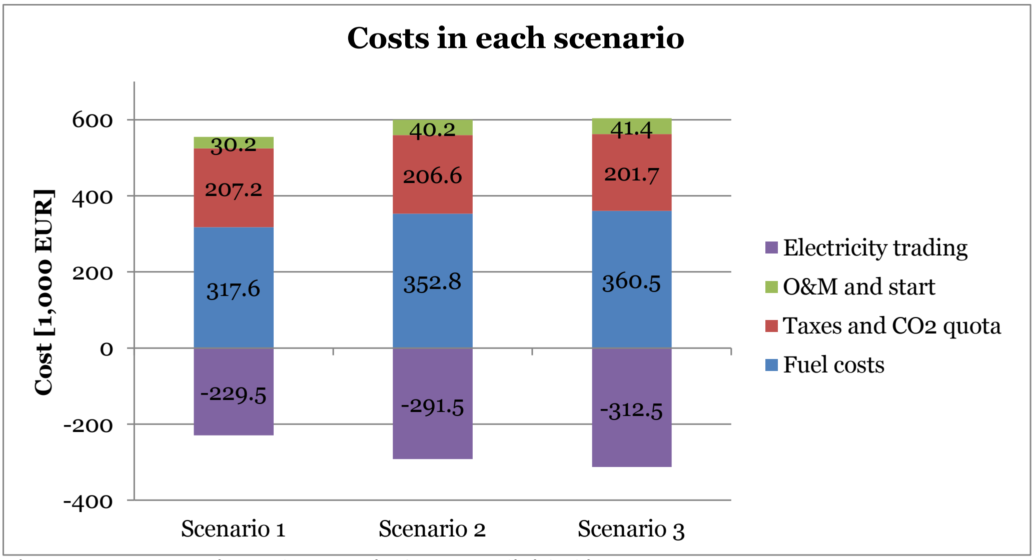

Figure 5.10 – Costs in each scenario for RDH divided into cost types.

The total NHPC for Scenario 1 is 325,500 EUR, for Scenario 2 it is 308,100 EUR and for Scenario 3 it is 291,200 EUR. The results show that participation on both the TCR and the Elspot reduced the NHPC by about 5% when compared to participating only on the Elspot. This is due to an increased operation of the CHP unit. In the simulations, the CHP operation increased by 25% when participating on both the TCR and the Elspot market when compared with participating only on Elspot. Similar tendencies were seen for the electric boiler, however, the electric boiler produces significantly less than the CHP unit. This result should be seen as the best case for RDH, as all activations on the TCR are assumed to be for full hours, while actual activations can be less than an hour. Also, RDH participation was assumed to not affect the market price. However, it can still be concluded that participation on multiple electricity markets can increase both the hours of operation for CHP units and reduce the NHPC for DH plants, even in situations where large amounts of variable RES, in the form of solar panels, delivers heat to the DH system. However, TCR prices are expected to decrease with the addition of more participants, as demand would not be affected by the amount of participants on the supply side.

The simulation results also highlight some of the challenges that DH plants with both CHP units and solar panels can experience. Due to forecast uncertainties, plants run the risk of having to reject heat, e.g., if the solar panel forecast turns out to underestimate the production and the thermal storage units are full. Based on the results, this challenge is especially relevant when trading on multiple electricity markets, as this increases operation of both the CHP unit and the electric boiler significantly. Thus, plants will have to face the possibility of either having to reject heat, or risk losing well-paid hours of operation for the CHP unit or electric boiler, if they do not want to risk rejecting heat.

RDH is a DH plant with relatively many forecasts affecting daily operational planning, and the chosen simulation period is the period that is most affected by forecast uncertainties due to a low heating demand and a high solar heating production. Even so, the simulations show that costs related to forecast uncertainties were only about 5% of the total NHPC in the simulated period. Conducting trade on several electricity markets increases income for the plant, thereby overcoming the negative effect of forecast errors, as shown in Sorknæs et al. [56].

5.4. Summary of learnings from the case of Denmark

It was found that a transition of the Danish energy system started after the oil crisis in 1973. This transition included increased energy efficiency, e.g. by extensive use of CHP, and increased integration of RES. The share of variable RES has increased significantly in Denmark, especially since the early 1990s, and there is a broad political consensus to have an energy system based on RES by 2050. Small DH plants with CHP also saw expanded use during the 1990s; units installed during these years are therefore approaching the end of their technical lifetime. Furthermore, it is uncertain how much of this CHP capacity will remain in the system given decreasing electricity market prices and the removal of a capacity payment. The remaining CHP capacity at small DH plants is expected to experience fewer hours of operation due to political goals that include increased wind power capacity, a trend that can already be seen in the current system. In this way, small Danish DH plants with CHP are already experiencing some of the operational challenges that are shown in the CEESA scenario to be relevant for a future smart energy system based on variable RES.

In order to understand these daily operational challenges, a fitting case plant has been simulated for a three month period that presents high requirements for daily operational planning. From the case it is found that participating both on a wholesale market and a balancing reserve market increases the challenges for daily operation, e.g. by increasing the risk of producing unusable heat. However, participation on both markets increases the hours of operation for the CHP unit and decreases the NHPC of the plant by about 5% in the simulated period, compared with only trading on the wholesale market. Part of the decrease in NHPC comes from the ability to make up for forecast errors by trading on several electricity markets.

6. Lessons from the German system

In this chapter, the German energy system along with its relevant historical development and political goals for the future system are presented. This is followed by a description of the current organisation of the electricity system balancing reserves and wholesale markets. Lastly, the simulation of the examined case with results is presented. It is found that Germany is in the midst of transitioning its energy system away from one based on nuclear power, lignite and coal, heading towards a system based on RES. DH and CHP are not as widely used as in Denmark, though the German government has set goals for increasing both DH and CHP, although the energy transition focuses mostly on the electricity sector. The simulations show that it is difficult for small DH plants with CHP to participate in the most activated balancing reserve market in Germany, due to a relatively inflexible market organisation.

6.1. The German energy system

The description of the German energy system focuses on the electricity system and the DH system.

6.1.1. Historical development

The German energy system has been characterised by a large degree of self-sufficiency due to an extensive use of domestic coal and lignite resources, which together with nuclear power, have made up the vast majority of electricity production in Germany for a number of years. As such, the electricity system has been dominated by large units. [101]

In Germany, a transition of the energy system is currently underway. This transition is commonly known as “Energiewende”. This term was originally coined by the think tank Öko-Institut in 1980 [102], where it was defined as:

> *“growth and prosperity without petroleum and uranium”*
> (Translated version from Strunz [103]*)*

However, for years the vision behind Energiewende was only seen in the policies of the left fringe of German politics. This changed in the early 2000s, when the vision was incorporated into governmental policy, which provided increasing support for RES. Governmental use of the term has carried various meanings compared to the original version in 1980; particularly, changing governments have had different visions for the role of nuclear power in Germany. Where the former center-left coalition government in 2000 made attempts to ban nuclear power in Germany, the conservative government in 2010 saw nuclear power as a transitional technology, and wanted to extend the lifetime of existing nuclear power plants. However, after the Fukushima nuclear disaster in 2011 the conservative government changed its policy, and the nuclear phase-out was sped up with an immediate closure of the eight oldest nuclear power plants. The current goal is a complete nuclear phase-out by 2022. [101,103–105]

With the exception of the nuclear power phase-out, the current German government's political goals for Energiewende are from 2010 [101]. These are further described in section 6.1.2.

The transition of the German energy system can also be seen in Figure 6.1, which shows the yearly gross electricity production by energy source alongside the gross electricity consumption in Germany. As Germany was reunified in 1990, the data goes back to 1991.

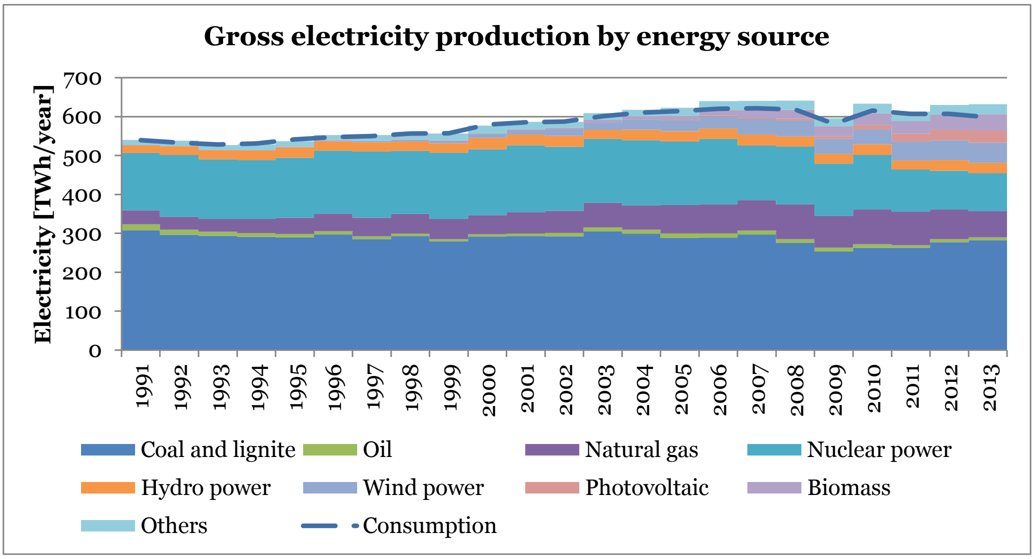

Figure 6.1 - Yearly gross electricity production by energy source and the gross electricity consumption in Germany. Based on data from [106].

As seen in Figure 6.1 electricity production in Germany has mainly been supplied by nuclear, coal and lignite plants, though nuclear power production has experienced a decrease in the last couple of years corresponding to the ongoing phase-out of nuclear power. Another interesting development is the increasing production of electricity from wind and solar, where in 2013 wind and solar accounted for about 13% of total gross electricity production. Germany also has RES electricity production from non-variable sources, for example biomass and hydropower, where especially biomass has seen an increase. The figure also shows that electricity based on Ngas has decreased in the last couple of years, which is due to a combination of high Ngas prices, low CO_2-quota prices and low electricity prices. [101]

Electricity production from CHP has also increased in Germany, from around 14% of total net electricity production in 2005, to 18.1% in 2013. The CHP plants are mostly based on Ngas with 39% of total CHP fuel consumption being

Ngas. RES follows this, providing 28% of CHP fuel consumption, while coal and lignite supply 23%. [106]

This increasing use of RES can also be seen in the installed electricity capacity in Germany, which is shown in Figure 6.2.

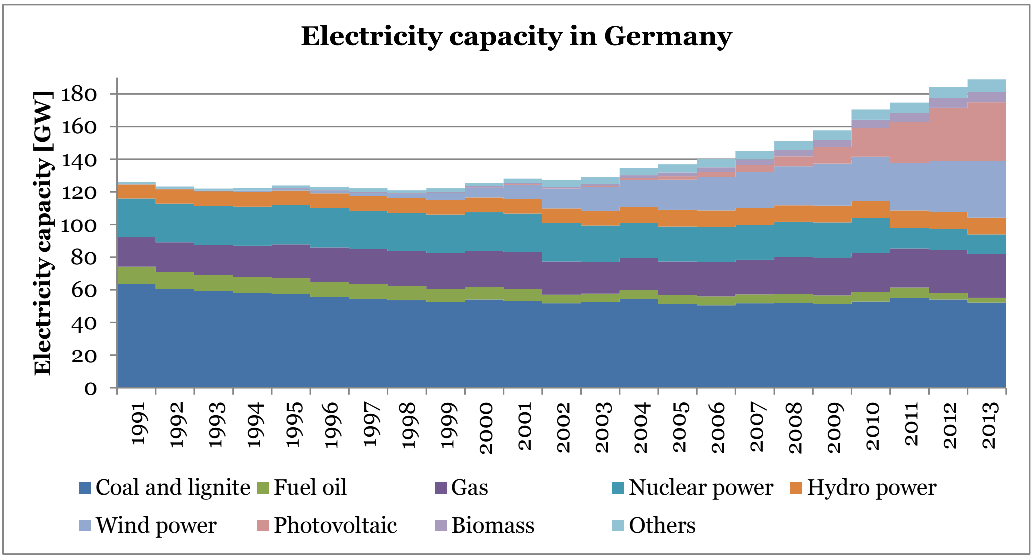

Figure 6.2 - Electricity capacity in Germany in the end of the year. Based on data from [106].

From Figure 6.2 it can clearly be seen that wind power and photovoltaic have seen an increase in installed capacity in the last years, with photovoltaic having increased significantly. The installed capacity of photovoltaic is larger than wind power's capacity, though the yearly production from wind power is greater. It can also be seen that the capacity of nuclear power has reduced, with a large decrease from 2010 to 2011, due to the change in German policy in the wake of the nuclear disaster at Fukushima.

While DH has existed in Germany since 1893, DH has never seen an expansion that compares with the one in Denmark; However, DH has seen a slow expansion in Germany, where especially the oil crisis in the 1970s accelerated development of DH and CHP [107]. DH consumers in Germany are mostly from industry, where in 2013 industry made up about 48% of total DH consumption, corresponding to about 8% of industry's final energy consumption. Households made up about 41% of total DH consumption, corresponding to about 7% of households' final energy consumption, and commercial and public services made up about 11%, corresponding to about 3% of their final energy consumption [106]. Figure 6.3 shows fuel use in the DH system in Germany.

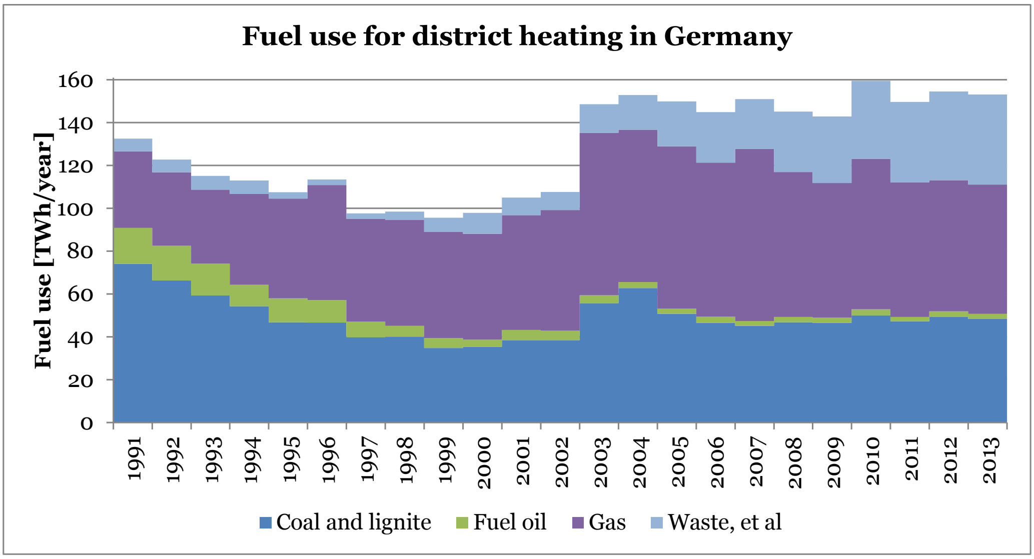

Figure 6.3 - Yearly DH production by type of producer. Based on data from [106]. For CHP plants the fuel use for DH is found using the Finnish Method [108].

As seen in Figure 6.3, the DH production is mainly supplied by gas-fired units, though waste, coal and lignite are also used extensively. The use of gas is mostly Ngas, though biogas has also experienced increased usage in the DH system. [106]

6.1.2. Future of the German energy system

In 2010 the German government adopted an energy strategy called "The Energy Concept", which established the principles behind the long-term political goals for the German energy system [109], with the exception of the nuclear power phase-out by 2022, which was introduced in 2011 [101]. As such, The Energy Concept sets the current political goals for the German Energiewende. The current overall goal is to lower greenhouse gas emissions by at least 40% by 2020 and at least 80% by 2050 compared with 1990 levels. To reach this goal a number of other goals are put forward, such as, reducing primary energy consumption by 20% by 2020 and by 50% by 2050 compared to 2008 levels, and that RES should produce 18% of gross final energy consumption and at least 35% of gross electricity consumption in 2020, and in 2050 it should produce 60% of gross final energy consumption and 80% of gross electricity consumption [110]. As can also be deduced from these goals, the Energiewende mostly focuses on the electricity sector [101,103]. In order to reach these targets, the German government expects that wind power will play a key role; though, as it is expected that most wind power capacity will be installed in northern Germany, due to superior wind resources, a stronger internal electricity grid is needed to transport the electricity from wind power in northern Germany to southern Germany [109]. For CHP, the German government has a goal of increasing the share of CHP in relation to total generated electricity to 25% by 2020. [111]

A number of legislations have been put forward in order to reach these goals, such as, a phase-out of subsidies for domestic coal production by 2018. However, since a number of new coal-fired power plants are currently under construction, it is expected that coal will continue to play a role until 2050, when these new plants reach the end of their technical lifetime. [101]

6.2. Electricity market setup

6.2.1. Wholesale markets

Germany is part of the wholesale electricity market European Power Exchange (EPEX Spot), which currently covers Germany, France, Austria and Switzerland. The EPEX Spot was founded in 2008 with a merger of the previous wholesale markets Powernext, based in France, and European Energy Exchange (EEX), based in Germany. EPEX Spot is divided into three price areas: France, Switzerland and Germany/Austria. In 2014 a total of 382 TWh were traded on EPEX Spot, with 289 TWh traded in Germany/Austria [112]. The total gross electricity consumption in Germany in 2013 was 632 TWh [106]. The specific market rules vary slightly from country to country; here, the rules used in Germany are described.

The main market of EPEX Spot is the day-ahead market, on which 351 TWh was traded in 2014, with 263 TWh traded in Germany/Austria [112]. Trading on EPEX Spot day-ahead market occurs daily. The gate closure for bidding is at 12 noon, and bids have to cover full hours. A single hourly bid can either be price dependent or price independent. It is possible to pool a period of at least three hours into a single price dependent bid, called a block bid, where the average price in the block is used to determine whether the bid is won or not. The market prices for each hour of the following day are revealed before 1 p.m., and the participants are contacted. At this point, the expected electricity production is equal to the expected electricity consumption of each hour of the following day. The day-ahead market on EPEX Spot is a MPP auction.

The monthly average day-ahead wholesale market price for Germany is shown in Figure 6.4.

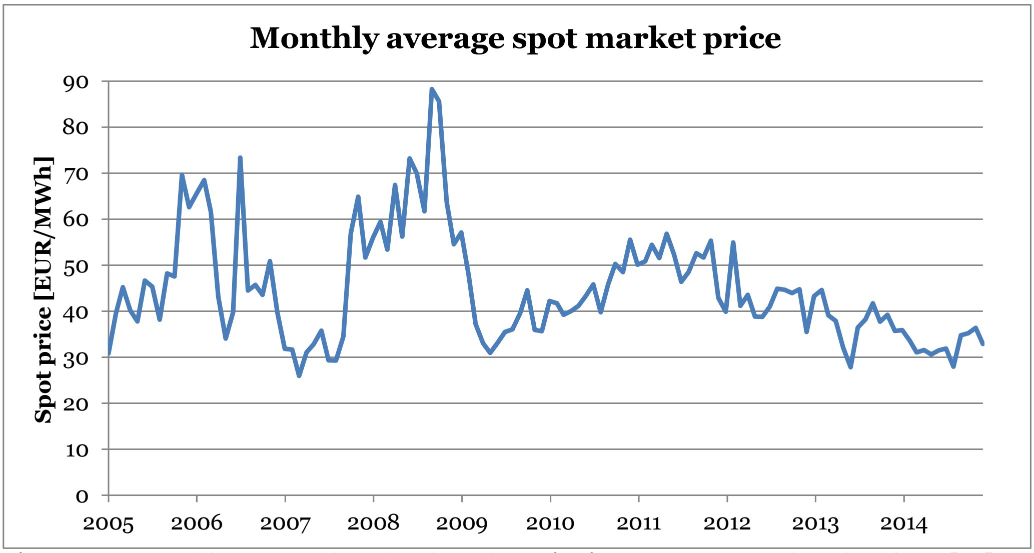

Figure 6.4 - Monthly average day-ahead market price in Germany. Based on data from [87].

From Figure 6.4 it can be seen that the price has decreased since 2011-2012, but also that the price in nominal terms has previously been down at the same level, though for a shorter period of time.

The secondary market of EPEX Spot is the intraday market, on which 30.8 TWh was traded in 2014, with 26.4 TWh traded in Germany/Austria [112]. On the intraday market, bids are settled similar to a bilateral contract, meaning one participant submits a bid to the market and another participant can choose to accept the bid from the market. As such, the intraday market functions differently than the day-ahead market, for example, by not having one specific time where all bids are settled, and it functions according to the PAB principle. Trades on the intraday market can occur until 45 minutes before delivery. Another important aspect of the EPEX Spot intraday market is that, since December 2011, it has been possible to trade on the intraday market down to 15-minute periods. As such, it is possible to make more detailed trading in the intraday market than in the day-ahead market. In Germany, imbalances are settled for each 15-minute period [113], meaning that on EPEX Spot it is only possible to eliminate potential imbalances within an hour block on the wholesale market by using the intraday market.

Participants' imbalances within each 15-minute period are settled according to the so-called reBAP methodology. The reBAP methodology will not be detailed here, though the basis of the reBAP is that it is based on the TSO's costs related to both activation and capacity of the TCR and SCR in the period in which an imbalance exists. With the reBAP, a symmetric imbalance cost is found, meaning that the cost per MWh is the same regardless of whether the participant is short or long. Short being where the participant is producing too little or consuming too much, and long being the participant is producing too much or consuming too little. The reBAP price for each 15-minute period is the same throughout all of Germany. [113]

6.2.2. Balancing reserves

In Germany, the system responsible is the area's TSO. Germany has four different TSOs: 50Hertz, Amprion, TransnetBW and TenneT. Though they are each system responsible for their own area, the four TSOs have, since 2006, procured balancing reserves jointly through a common online platform. [114]

For both the TCR and the SCR, the four German TSOs publish the capacity needed for the coming period before the clearing day. On the clearing day, only the offered capacity payments are used to arrange the bids in a merit order list where the cheapest capacity bids are selected first, until the amounts needed by the German TSOs are reached. An exemption to this rule is if a TSO needs units in a specific area in order to ensure a stable grid, in which case a more expensive unit can be chosen before a less expensive unit. The most expensive winning bid is reduced in size if this unit surpasses the needed amount of capacity. Similar to capacity bids, the activation bids are arranged in a merit order list where the cheapest activation price is activated first, until the needed amount is reached. Again, conditions in the grid can result in a more expensive unit being activated before a less expensive unit. [113]

Organisation of the TCR

The maximum technical response time to participate in the German TCR is 15 minutes, and a minimum of 5 MW has to be offered; however, it is possible to pool units in order to reach this amount. The market is asymmetric, and it is hence possible to offer either downward regulation, activated when there is excess electricity in the system, or upward regulation, activated when there is a lack of electricity in the system. The German TCR is traded daily, with the gate closure for bids for the following day occurring at 10:00 a.m. The TCR operates with blocks of four hours, corresponding to 6 blocks per day, and it is possible to participate in one or more of these blocks, though bids must follow this block structure. Bids include both a price for capacity and for activation of energy, and bids are final after the clearing. All winning bids are settled according to the PAB principle. [113]

Organisation of the SCR

Participants in the German SCR receive payment for both capacity and energy. Bids offered on the SCR cover the entire following week, starting with the following Monday, and are final after the clearing. The SCR is cleared every Wednesday for the next week. The clearing day may, in some weeks, change due to German national holidays. Capacity bids are offered as

EUR/MW$_e$/week. The winning bids are cleared using the PAB principle and the market is asymmetric. The SCR is separated into two periods: hochtarif (HT) being the period from 08:00 to 20:00 on workdays, and niedertarif (NT) being all periods outside of HT. With bids being separate for upward and downward regulation, and for HT and NT, four different products are traded in the SCR. A bid has to be at least 5 MW; however, it is possible to pool units in order to reach this amount. Activations in the SCR must start within 30 seconds and be fully activated within five minutes. [113]

The utilisation of the balancing reserves

After the clearing day, the TSOs publish all winning bids for each balancing reserve in anonymised form, alongside the bids that were not selected due to grid stability needs. For each bid, the capacity offered, the capacity price bid, the activation price bid and whether the bid was accepted are shown. The bids are separated into each of the four products, but not according to control area. The four German TSOs continually publish the amount of SCR and TCR activated in MW for both upward and downward regulation in 15-minute periods. Within each 15-minute period, both upward and downward regulation can occur. [115]

Figure 6.5 shows the monthly average purchased capacity for both SCR and TCR in Germany for upward and downward regulation, respectively.

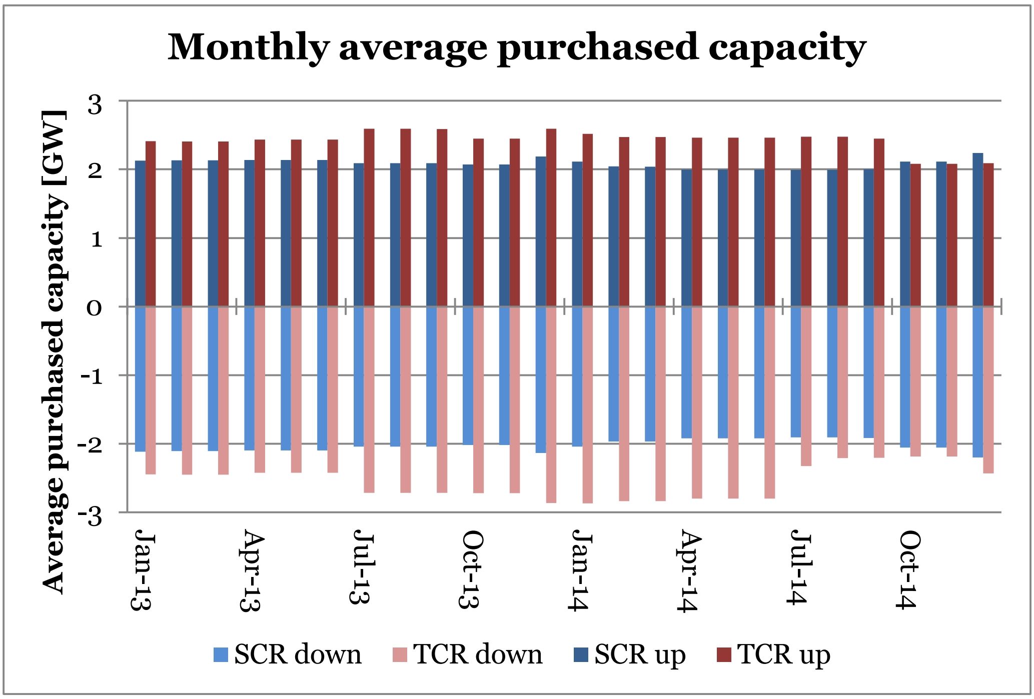

Figure 6.5 - Monthly average purchased SCR and TCR capacity in Germany. Based on data from [116].

As seen in Figure 6.5, the capacity purchased for both SCR and TCR is similar, though more TCR capacity was bought in most months. Looking at the activation, however, gives a different view of the utilisation of these reserves. Figure 6.6 shows the monthly activation of downward and upward regulation in the SCR and the TCR in % of the total activated amounts in the given direction for both of these balancing reserves. The figure is made using data for the deployed activation of SCR and TCR in each 15-minute period for each month.

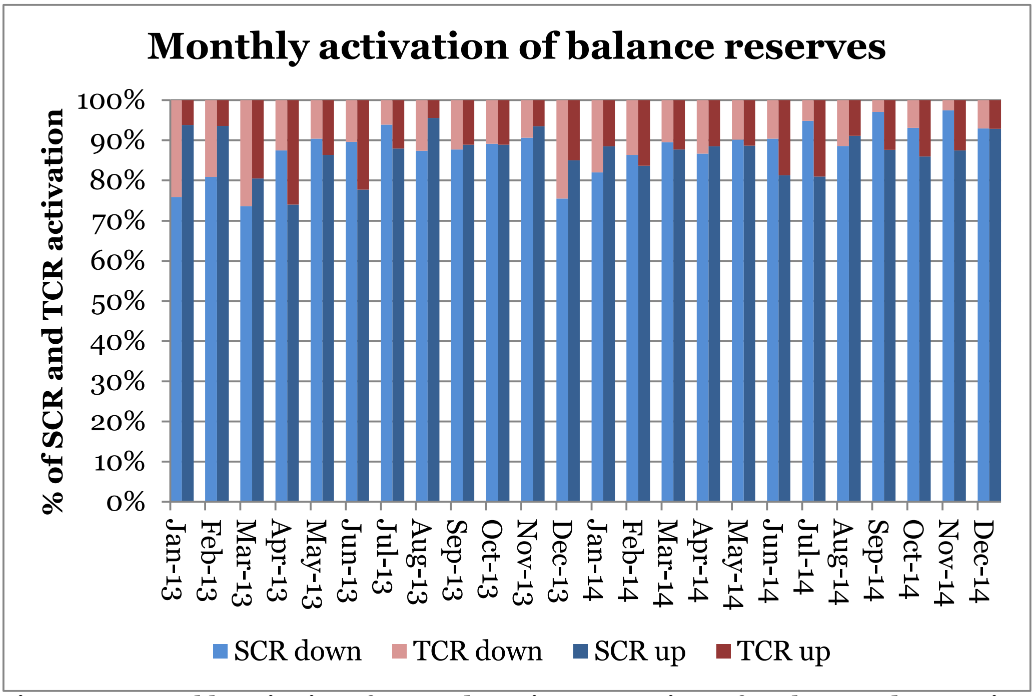

Figure 6.6 - Monthly activation of SCR and TCR in Germany in % of total SCR and TCR activation in each direction. Based on data from [116].

Figure 6.6 shows an important finding about the German utilisation of the balancing reserves: a larger amount of energy is activated on the SCR than on the TCR. As such, the SCR, in this thesis, is seen as the main balancing reserve in Germany.

In 2013, deviations from the activation merit order list for the SCR occurred for periods totalling 2 days, 1 hour and 49 minutes, and for the TCR it occurred for a total of 3 days, 20 hours and 24 minutes [117].

6.2.3. Small CHP plants in the German electricity markets

As mentioned in section 6.1.2, the German government has set a goal of increasing CHP electricity production. In "The Energy Concept", the German government also highlights that in order to integrate variable RES into the electricity system, flexible power plants and CHP plants are needed. As such, the

German government will work towards this goal, though flexible CHP plants will be given precedence. [109]

To increase the share of CHP, the German government currently provides subsidies for CHP electricity production, DH extensions that contribute to increased use of CHP and new thermal storage units for heat from CHP units [118]. The German government also exempts Ngas used in CHP units from taxation if the CHP unit's efficiency is at least 70% on a monthly or annual basis [101].

The subsidy for electricity production is particularly interesting for the focus of this thesis, as it especially benefits small CHP units. This subsidy is known as the "KWK-Zuschlag". The KWK-Zuschlag is an electricity production subsidy given to owners of CHP units for the first 30,000 hours of operation. The size of the subsidy depends on whether the unit went into operation before or after the 19th July 2012 and on the electric capacity of the CHP unit, where a lower capacity provides a higher subsidy per MWh electricity produced. [119]

Besides this subsidy for electricity production, small CHP units can receive a net usage bonus, which is a payment for avoided grid costs, where the size of the payment depends on the connections' voltage level, connection point (substation or cable) and the grid costs of the distribution grid operator. This value varies quite significantly depending on where in Germany the CHP unit is connected; for example, in Schwäbisch Hall in southern Germany it is 4.7 EUR/kWh [120], while in Magdeburg in eastern Germany it is 9.9 EUR/MWh [121].

6.3. Case: Streckienė

A case plant is chosen that is relevant with respect to the described system development. As CHP units will normally be built based on their feasibility in the wholesale market, a plant set-up is chosen based on its feasibility within the German wholesale market. The chosen plant set-up is based on a plant with one 4 MW_e CHP unit, as described by Streckienė et al. [61]. Streckienė et al. analyse the feasibility of several CHP plants with thermal storage systems traded on the day-ahead market of EPEX Spot. The chosen plant set-up was found by Streckienė et al. to be feasible on the day-ahead market of EPEX Spot. As the plant is generic, the results are not affected by local conditions that could affect the results when specific plants are used, making it easier to see general tendencies in the results. The case plant is simulated for the period of 2013.

The modelled CHP plant has one Ngas-fired 4 MW_e CHP engine with a thermal capacity of 4.7 MW_{th} and an overall efficiency of 87%. Beside the CHP unit, the plant is also equipped with one Ngas-fired boiler with a thermal capacity equal to the peak heat demand incl. grid loss and an efficiency of 91%. The plant is also modelled with a thermal storage system of 650 m^3, corresponding to 30 MWh_{th}. The plant delivers 30,000 MWh_{th} to a local DH system, and must always cover the heat demand in the DH system. The only differences between the plant described by Streckienė et al. [61] and the plant simulated here are that the electricity market prices, temperature data used for distribution of space heat demand throughout the year, subsidies and costs have all been updated to reflect 2013 figures. Table 6.1 shows the economic assumptions for the plant described by Streckienė et al. and the 2013 version used for these simulations.

	Streckienė et al. plant	**2013 version of plant**
Ngas price [EUR/MWh_{fuel}]	25	35
Fuel tax for gas boiler [EUR/MWh_{fuel}]	5.5	5.5
CO_2 certificate [EUR/t CO_2]	20	6
Gas boiler O&M costs [EUR/MWh_{th}]	1	1
CHP unit O&M costs [EUR/MWh_e]	8	8
CHP unit starting cost [EUR/turn on]	32	20
Average spot market price [EUR/MWh_e]	40.00	37.78
Net usage bonus (CHP unit) [EUR/MWh_e]	1.5	6.7

Table 6.1 - Economic assumptions of the CHP plant described by Streckienė et al. [61] and the updated 2013 version of the CHP plant.

The updated Ngas price, CO_2 certificate price, net usage bonus and starting cost are assumed values. As can be seen in Table 6.1, Ngas price and net usage bonus are higher in the 2013 version, whereas CO_2 certificate price and starting cost are lower. The net usage bonus used here is an assumed value.

It is assumed that the CHP plant also receives the KWK-Zuschlag. It is also assumed that the CHP unit went into operation after the 19th July 2012, and it therefore receives 54.1 EUR/MWh_e for the electricity production from the first 50 kW_e of capacity, 40 EUR/MWh_e for capacity between 50 and 250 kW_e, 24 EUR/MWh_e for capacity between 250 and 2,000 kW_e and for the capacity above 2,000 kW_e the subsidy is 18 EUR/MWh_e [119]. Thus, the modelled 4 MW_e CHP unit will receive a KWK-Zuschlag of 22.18 EUR/MWh_e for the first 30,000 hours of operation.

6.3.1. Simulating the daily operation of the German case plant

The CHP unit is simulated for trade on both the day-ahead market of EPEX Spot and the German SCR. As SCR is traded several days before actual delivery, while trade on the spot market is traded day-ahead, the CHP unit will always be traded into the SCR before it is traded on EPEX Spot. In order to estimate the potential gain derived from increased flexibility of the CHP unit, two different capability settings for the technical flexibility of the CHP unit are made: a "reference capability" and an "increased flexible capability"

For the reference capability setup, it is assumed that the CHP unit must be in operation in the periods where SCR is won. In these periods, the CHP unit is traded on the day-ahead market of EPEX Spot with the lowest possible bid, meaning it will always win trade on EPEX Spot in these periods. Trading the CHP unit on EPEX Spot is assumed to never affect the market price. If any non-usable or non-storable heat is produced when the CHP unit is forced to operate to deliver SCR, then this heat is rejected. For SCR trading, it is assumed that the plant is part of a pool with the same bid as the plant, and the plant therefore only needs to offer part of the minimum requirement of 5 MW_e. Under this setup, it is assumed that the plant offers 1 MW_e in the SCR, meaning for periods in which upward SCR is won, the CHP unit will trade 3 MW_e on EPEX Spot, keeping the remaining 1 MW_e ready for activation in the SCR. For periods in which downward SCR is won, all 4 MW_e will be traded on EPEX Spot; thus, for periods in which the CHP unit is activated by the SCR, it will be part-loaded to 3 MW_e. It is assumed that part-loading the CHP unit does not affect its efficiency. It is assumed that the unit must always deliver the amount traded in the SCR, and it cannot rely on the other plants in its pool to deliver this amount. The plant is assumed not to experience any unit breakdowns during the simulated period.

For the increased flexible capability setup of the CHP unit, it is assumed that the CHP unit does not have to be in operation in order to deliver SCR. Currently, the German TSOs require units delivering SCR to be in operation during periods when SCR is won. However, by simulating the CHP unit under increased flexible capability, a maximum potential gain from increased flexibility of the CHP unit can be found. With increased flexible capability of the CHP unit, the full capacity of the CHP unit, 4 MW_e, is traded on the SCR. Hence, the CHP unit is not traded on EPEX Spot in periods when upward SCR is won, and in periods where downward SCR is won, the CHP unit's full capacity is traded on EPEX Spot.

The CHP unit is simulated as only trading in one direction at a time, resulting in a total of four scenarios:

- Scenario 1: Reference capability, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 2: Increased flexible CHP unit, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 3: Reference capability, where the CHP unit is only traded as downward regulation on the SCR.

- Scenario 4: Increased flexible CHP unit, where the CHP unit is only traded as downward regulation on the SCR.

Income from heat sales is not included as it is the same in all scenarios. For periods in which SCR is not won, the CHP unit is traded on EPEX Spot, if the resulting heat production can be either used or stored. Outside of won SCR periods, the CHP unit will be operated in blocks of at least 3 hours. As explained in section 3.3, the operation of the CHP plant is simulated using energyPRO. The assumed goal of the CHP plant is to produce the demanded heat as cheaply as possible.

Bidding strategy for participation on day-ahead market of EPEX Spot

The day-ahead market of EPEX Spot is organised as MPP and as argued in section 2.4.2, the optimal bidding strategy on such markets is to bid using the short-term marginal costs of the unit.

Using the data for the CHP plant shown in Table 6.1, the spot market bid, excluding start costs of the CHP unit, is found to be 15 EUR/MWh_e, rounded up. It is assumed that if the plant's bid is less than EPEX Spot market price, then the plant wins EPEX Spot trade, without affecting the market price.

6.3.2. Participation in the secondary control reserve

As described, the German SCR is organised around the PAB principle. For these simulations, it is assumed that if the plant's bid is lower than the marginal SCR bid, then the plant wins SCR. This applies to both capacity and activation in the SCR. As described in section 2.4.2, participants in recurrent PAB auctions are prone to gamble on the auction, for example by trying to estimate the marginal winning bid for the coming auction in order to increase their income from auction participation. For the purpose of these simulations, it is assumed that the plant will not gamble on the SCR. The bids are instead calculated based on the plant's own expected costs of participating in the SCR.

The SCR capacity payment is, for the purpose of these simulations, seen as the payment required by the plant in order to cover any costs related to standing ready to deliver activation on the SCR. The costs that should be covered by the SCR capacity payment are found to be:

1. The plant has to produce non-useable or non-storable heat by operating the CHP unit in order to be able to deliver SCR. (L_1)
2. The wholesale market price in the won SCR periods is lower than the normal wholesale market bid of the CHP unit. Meaning that it would be cheaper to operate the boiler instead of operating the CHP unit. (L_2)

3. In the case of upward SCR activation, high wholesale market prices in the won SCR periods can provide an opportunity loss, since the CHP unit will only be offered in part-load on the wholesale market in order to be able to deliver upward activation in the SCR. (L_3)
4. SCR participation reduces wholesale market trading in high price periods outside of the won SCR periods. This can occur due to the displacement of heat production using the thermal storage system. (L_4)

For plants where the activation price is not solely based on the plant's own costs, as is the case with the simulated plant, a fifth potential cost could be included in the list. This fifth cost would be the opportunity to earn income from activations, and would normally be a negative cost.

The optimal approach for calculating the sum of these costs is to compare the NHPC if the plant did not participate in the SCR with the NHPC when it does participate in the SCR. In other words, the comparison of NHPC would be between a scenario in which the CHP unit is traded only on EPEX Spot and another scenario in which the CHP unit is traded on EPEX Spot with the lowest possible bid price during the SCR periods, while trading normally on the spot market in the remaining periods. The difference in NHPC between these two scenarios reflects the income needed from the capacity bid. While in principle comparing the NHPC of these two scenarios would be the optimal approach, in practice this approach is problematic. The reason for this is that the clearing day for SCR is more than four days before the first day of potential SCR operation, and forecasts of, for example EPEX Spot prices and heat demand for the period, are very uncertain. To highlight this challenge it is relevant to include forecasts in the simulations. For the purpose of these simulations, a simple approach to forecasting is used. The forecasts are produced based on the knowledge that a plant would have on the SCR clearing day. The SCR clearing day is assumed to only be on Wednesdays. Only heat demand and EPEX Spot price forecasts are included.

The heat demand forecast is created for the SCR trading period using the heat demand from the seven days before the clearing day, being the period from and including the former week's Wednesday up to and including the Tuesday before clearing day. The heat demand from the former week's Wednesday is then used as a forecast for the following Monday, etc. It is assumed that the CHP plant aims to not reject any heat by participating in the SCR. For each clearing day, three different simulations based on the heat demand forecast are carried out for the following SCR trading period, representing an increasing amount of hours traded on the SCR. In the first simulation, the CHP unit operates at full load in all HT periods as for any given week there will always be fewer hours of HT than NT. In the second simulation, the CHP unit will be operated at full load in all NT periods. In the last simulation, the CHP unit will be operated at full load in all periods. If in one of these simulations a rejection of heat is found, then no SCR trading is carried out in that period. For example, if based on the heat demand forecast a rejection of heat is found by operating the CHP unit at full load in the NT periods, then SCR trading is only done in HT periods. No EPEX Spot trading is done in these tests, and the thermal storage system is assumed to be empty at the beginning and the end of the week. With this method, the rejection of heat can still occur, as the expected heat demand is based on an uncertain forecast; however, the rejection of heat is vastly reduced compared with not taking into account the heat demand before trading SCR. In reality, a CHP plant would be able to purchase heat demand forecasts more advanced than the one used in these simulations; however, more advanced forecasts have not been available for these simulations.

To forecast EPEX Spot prices for the upcoming SCR trading period, the seven days before the clearing day's average day-ahead EPEX Spot market price in each of the two periods (HT/NT) are used as a forecast for the corresponding upcoming periods. It is assumed that by using EPEX Spot price averages during these periods, uncertainty regarding the EPEX Spot price forecast would be reduced when compared to forecasting all price variations on the EPEX Spot. However, using this forecast approach removes the possibility of simulating normal EPEX Spot trading, since the forecasts only have two prices, one for NT periods and one for HT periods. It is not possible in the simulations to estimate the potential loss, L_4. However, the EPEX Spot price forecast is seen as a good approximation for how actual forecasting could occur for such a plant.

With the economic loss from L_1 reduced to a very small loss, and the EPEX Spot price forecast removing the potential for using the explained optimal approach to estimate L_4, a simpler approach to calculating the capacity bids is used instead. For upward SCR capacity bids, the simpler approach is based on the one presented for power plants by Müsgens et al. [122]. Müsgens et al. calculate the capacity bid of a power plant delivering upward SCR by using only the power plant's own cost in the capacity bid. Müsgens et al.'s approach to the upward capacity bid of a power plant is shown in Eq. (2).

$$B_{Up-cap} = \begin{cases} \left(B_{spot} - p_{spot}\right) * \frac{CAP_{op}}{CAP_{of}} & , if\ B_{spot} > p_{spot} \\ p_{spot} - B_{spot} & , if\ B_{spot} \leq p_{spot} \end{cases} \quad (2)$$

Where $B_{Up\text{-}cap}$ is the capacity bid for upward regulation in EUR/MW/h, B_{spot} is the EPEX Spot bid of the power plant, p_{spot} is the average EPEX Spot price in the period, CAP_{op} is the load in MW_e at which the power plant operates to deliver upward SCR, and CAP_{of} is the capacity offered as upward SCR.

As seen in formula 2, Müsgens et al. include the losses L_2 and L_3 in the capacity bid of the power plant, which are the only two of the four listed losses that a power plant could experience by providing upward SCR. However, as a CHP plant is simulated here, the loss L_4 should also be included in the capacity bid. Ideally L_4 should be found as shown in Eq. (3).

$L_4 = Inc_{spot} - (B_{spot} * P_e)$ (3)

Where Inc_{spot} is the period's total income from EPEX Spot trading in EUR as gained if SCR is not traded and P_e is the electricity trade won on EPEX Spot in MWh_e if SCR is not traded. B_{spot} is the EPEX Spot bid for the CHP unit.

Based on the earlier discussions, Inc_{spot} and P_e cannot be calculated using the EPEX Spot price forecast utilized here. Therefore, L_4 is instead fixed through the simulated period, and assumed to be 30 EUR/MWh_e. This corresponds to the difference of the average EPEX Spot price for prices above B_{spot} in 2013 and B_{spot}, rounded up. L_4 is added to the EPEX Spot bid of the CHP unit, B_{spot}. Eq. (4) shows the changed Eq. (2), and Eq. (4) is the calculation method used here to calculate capacity bids for upward SCR.

$$B_{Up-cap} = \begin{cases} \left(B_{spot} + L_4 - p_{spot}\right) * \frac{CAP_{op}}{CAP_{of}} & , if\ B_{spot} + L_4 > p_{spot} \\ p_{spot} - (B_{spot} + L_4) & , if\ B_{spot} + L_4 \leq p_{spot} \end{cases} \quad (4)$$

For downward SCR, only the losses L_2 and L_4 need to be included in the capacity bid. The capacity bid for downward SCR is calculated as shown in Eq. (5).

$$B_{Down-cap} = \begin{cases} \left(B_{spot} + L_4 - p_{spot}\right) * \frac{CAP_{op}}{CAP_{of}} & , if\ B_{spot} + L_4 > p_{spot} \\ 0 & , if\ B_{spot} + L_4 \leq p_{spot} \end{cases} \quad (5)$$

Where $B_{Down\text{-}cap}$ is the capacity bid for downward SCR. CAP_{op}, in this thesis, is equal to the full electric capacity of the CHP unit, as the unit will be operated at full load when providing downward SCR.

When excluding start costs, B_{spot} is found to be 15 EUR/MWh_e. Assuming eight hours of operation, B_{spot} incl. start costs is 16 EUR/MWh_e, rounded up. With a L_4 for the CHP unit of 30 EUR/MWh_e, the capacity bid for a 4 MW_e engine offering 1 MW_e would be as shown in Figure 6.7. On each graph, the CHP unit is only offered in one SCR direction.

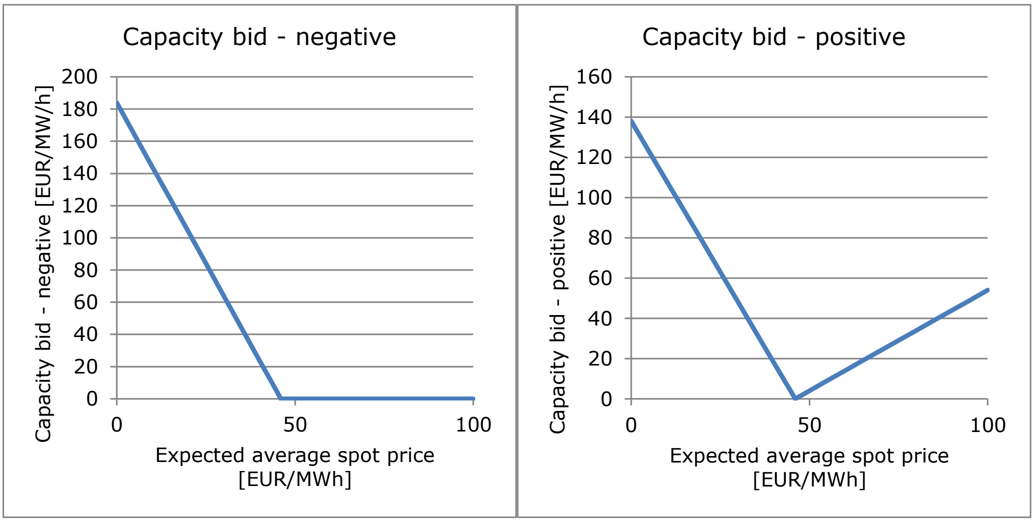

Figure 6.7 - Capacity bids for downward SCR and upward SCR.

The capacity bids presented in Eq. (4), Eq. (5) and Figure 6.7 are in EUR/MW/h; however, SCR capacity bids are given in EUR/MW/week. These capacity bids have to be multiplied with the number of hours of the respective SCR period in the given week.

The bids for SCR activation are fixed through the simulated period. The bid for upward activation is fixed at 46 EUR/MWh_e, being B_{spot} + L_4, and the bid for downward activation is fixed at -16 EUR/MWh_e, being -B_{spot}. L_4 should not be included in the downward activation bid, as L_4 is already covered for the full capacity of the CHP unit through the downward capacity bid.

6.3.3. Results and discussion

Each unit's heat production is shown in Table 6.2 alongside the rejection of heat in each scenario.

[MWh_{th}]	**CHP unit**	**Boiler**	**Heat rejected**
Scenario 1	26,770	3,337	107
Scenario 2	25,358	4,731	89
Scenario 3	26,631	3,629	260
Scenario 4	23,118	6,917	35

Table 6.2 - Heat produced and heat rejected in each scenario.

As seen in Table 6.2, the rejection of heat occurs most often when the CHP unit has the reference flexibility, as in scenarios 1 and 3. The corresponding costs and revenues excluding income from the sale of heat in each scenario are shown in Figure 6.8.

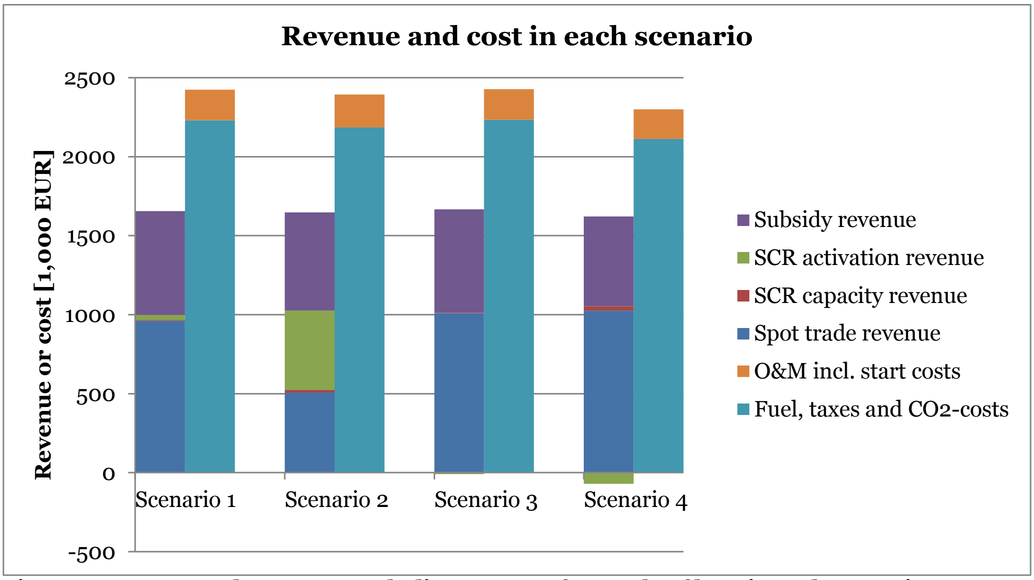

Figure 6.8 - Costs and revenues excluding revenue from sale of heat in each scenario.

The NHPC of scenario 1 is about 768,000 EUR, for scenario 2 it is about 744,000 EUR, for scenario 3 it is about 770,000 EUR and for scenario 4 it is about 749,000 EUR. As seen in Figure 6.8, EPEX Spot revenue is similar in every scenario except for scenario 2. The reason is that, in scenario 2, it is assumed that the CHP unit does not have to be in operation in order to deliver upward regulation, and in periods where SCR is won, the CHP unit is not traded on EPEX Spot. Instead, a high income from SCR activation is found. The resulting total costs in each scenario are similar in size, which is due to the utilized bidding strategy reflecting the plant's own costs, though a decrease in the total costs can be seen in scenarios in which the CHP unit is modelled with increased flexibility. Using a different bidding strategy could increase this difference.

It should be noted that the income from activation is highly uncertain, since the data used for estimating activation for these simulations is created using publicly available data, as described in Sorknæs et al. [123]. Activation of SCR is dependent on where in Germany the participant is located, and as such, the activation income for a specific participant can vary significantly from the activation income presented here.

6.4. Summary of learnings from the case of Germany

It is found that a transition of the German energy system started in the early 2000s. This transition has been characterized by a shift away from nuclear power, lignite and coal, towards RES. Variable RES, particularly in the form of wind power and photovoltaic, has been integrated to a large extent into the German electricity system, and it is expected that wind power especially will play an important role going forward. This transition is broadly supported in German politics. As part of this transition it is the goal of the German government to increase the share of CHP, and as such, new CHP is given subsidies, where small CHP units in particular are given high subsidies per MWh_e. However, existing capacity using Ngas has, in the last couple of years, experienced problems due to low electricity prices, low CO_2-qouta prices and high Ngas prices.

In Germany, the largest amount of balancing reserve energy is provided through the SCR, which is a weekly market using the PAB principle. The operation of a small Ngas-fired DH plant with CHP, Ngas boiler and thermal storage system was simulated, and it was found that four different potential losses could be identified for such a plant participating in the German SCR. From the simulations it was found that the weekly organisation of the SCR introduced costs for small DH plants that are not incurred by power plants. By having increased flexible CHP units, this extra cost could be reduced, though only to some extent.

7. Policy recommendations to facilitate the participation of small CHP plants in electricity system balancing

In this chapter the lessons from Denmark and Germany presented in the previous chapters are first summarised and compared. Lessons from those findings are then used as the basis for a discussion regarding how the organisation of balancing reserves could be changed in order to be more inclusive for small DH plants. Five key points are put forth based on the analyses made. It is also discussed whether participation in balancing reserves is likely to make CHP units, which are unfeasible when operating exclusively on the wholesale markets, feasible. The analyses show that participation in balancing reserves alone is unlikely to make unfeasible CHP units feasible. Lastly, the future organisation of electricity markets is discussed, where the current discussion about Capacity Remuneration Mechanisms is particularly interesting for the future capacity of CHP at small DH plants.

7.1. Lessons from Denmark and Germany

In both Denmark and Germany there is broad political consensus regarding a transition of the energy system towards a system based on RES, where variable RES plays an important role. Hence, the governments in both countries have long-term goals for the development of their energy systems in order to facilitate this transition. The specifics of these goals differ between the countries, where the German goals tend to focus on the electricity system, and the Danish goals tend to focus on both the electricity and heating systems. This variance is likely due to the different development paths each countries' energy systems have taken; where in Denmark, DH with CHP has been widely used for meeting the heat demands of households. This has been done in Denmark in order to increase the efficiency of the energy system, and came about in response to a historical dependency on the use of imported fuels. In Germany, DH with CHP is also utilised in the energy system, though not to the same extent as in Denmark, and mostly for industrial purposes. The German electricity system has instead been dominated by the use of domestic fuel resources and the prevalence of nuclear power plants. As such, there is a different energy system tradition in the two countries.

Small DH plants are quite common in Denmark, where especially domestic Ngas has been used in small DH plants with CHP since the 1990s. However, the future of these Ngas-fired CHP units is quite uncertain, as they are reaching the end of their technical lifetime, and reinvestments are now required to keep this capacity in operation. With an important capacity payment subsidy for these units running out in 2018, alongside a decrease in electricity prices and an increase in Ngas prices, it is expected that many of these units will not undergo reinvestment. Instead, in the last couple of years, Ngas-fired boilers have increasingly been used to provide much of the DH demand at small DH plants.

Many small DH plants have invested in other heat producing units, such as electric boilers and solar thermal panels, in order to substitute the fuel boiler production. It is also expected that compression heat pumps will see an increased integration at small DH plants, though, currently, only a small number of compression heat pumps have actually been installed. As such, many small DH plants in Denmark have already shifted towards the role that the CEESA project predicts they will play in a future smart energy system based on variable RES; specifically, a role in which small DH plants are found to utilise a range of different heat producing units. Several small Danish DH plants have also tried to increase the value of their CHP capacity by providing balancing reserves, which, due to higher flexibility demands, are valued more highly by the system.

From the simulations of the case plant it was found that participating on the main balancing reserve in Denmark, being the TCR, does in fact increase the feasibility of the CHP capacity. For the case plant, in the simulated three summer months, it was found that the NHPC decreased by 5% due to participation on the balancing reserve. However, participation on the balancing reserve was also found to increase the complexity of the plant's daily operation and the potential need to reject heat, as it cannot always be used or stored at the time of production, resulting in a small drop in overall system efficiency of the CHP capacity. That said, the main balancing reserve in Denmark is found to be a suitable market for participation by small DH plants with CHP, as it allows participation up till 45 minutes before the hour of operation, and the CHP unit does not need to be in operation to participate, which reduces the risks associated with forecast errors. However, as a minimum of 10 MW is required to submit a bid, small DH plants will often have to pool together in order to provide a qualifying bid.

The situation for small DH plants is different in Germany, where small DH plants with CHP are not as common as in Denmark. However, as part of the ongoing transition of the German energy system, the German government has set a political goal to increase the share of CHP in electricity production. As such, several subsidies are available for new CHP units, where especially small CHP units are provided higher subsidies than larger units. It is likewise the goal of the German government to increase the amount of flexible electricity producers, in order to be able to balance the growing proportion of variable RES in the electricity system. Small DH plants in Germany based on Ngas are, however, experiencing the same problems with low electricity prices and high Ngas prices as their Danish counterparts.

The main balancing reserve in Germany is found to be the SCR, as the largest amounts of energy are activated on this market. A key distinction in the German system is: because activations on this balancing reserve are partly based on local conditions in the electricity grid, the activation amounts will differ depending on where in Germany a plant is located. From the simulations of the German case plant's participation in the German SCR it was found that the German SCR holds a number of different organisational challenges for small DH plants with CHP. The market is based on weekly tenders, where the gate closure is 5-12 days before delivery. This relatively large timespan before delivery increases potential forecast errors related to DH demand; as the CHP unit must be in operation in order to deliver SCR, the risks of having to reject heat, as well as economic losses from wholesale trading, are increased as a result of this tender method, and these risks are found to be higher for CHP plants than for power plants. Additionally, use of the PAB principle is not optimum for small participants, as was discussed in section 2.4.2 and also shown in the discussion in section 6.3.2 on how to calculate the capacity bid in the German SCR.

7.2. Organisation of balancing reserves with participation of small DH plants

Based on the analyses presented in this thesis, some recommendations to the organisational aspects of the balancing reserves can be stated in order to better facilitate the participation of small DH plants with, for example, CHP and compression heat pumps:

- Set the gate closure for the balancing reserve as close to the actual delivery time as possible, or make it possible to change bids for activation close to the actual delivery time. Additionally, not requiring winning capacity in order to be allowed to deliver activation would help on this point. This will decrease the extra costs that can be experienced by small DH plants due to heat demand forecast errors.
- Keep the period of delivery as short as possible. If a long period of delivery is necessary, then make it possible for participants to deliver balancing reserve electricity without having to already be in operation. This will decrease the extra costs that can be experienced by small DH plants due to heat demand forecast errors.
- Avoid basing balancing reserves on PAB, unless it is likely that an actor will be able to exercise market power. MPP markets are easier for small participants to take part in than PAB markets.
- Keep the minimum capacity or energy requirement for participation as low as possible. Allowing pooling of several units in one bid makes it easier for small plants to participate, but it is still more difficult for these plants compared with larger plants.

- Make the balancing reserve asymmetric. This will allow the small DH plants to be able to offer more on the balancing reserve in each direction, while also being able to participate in a more flexible manner, keeping potential losses low.

It should be noted that this is not a complete list of all relevant aspects, but only the aspects that were determined to be relevant based on the analyses made in this thesis. Likewise, other aspects than the participation of small DH plants with CHP should be considered when discussing the organisational characteristics of balancing reserves. As stated earlier, small DH plants with CHP are experiencing challenges regarding the economic feasibility of their CHP units because they are being increasingly outcompeted by variable RES. As a substantial decrease in hours of operation should also be expected for CHP units in future smart energy systems based on variable RES, it is relevant for these units to provide as much value as possible to the energy system in the few hours that they operate, in order to cover their fixed costs and provide an economic incentive for reinvestment.

While it is found that participation in balancing reserves can improve the feasibility of CHP units for small DH plants, it is uncertain whether this is sufficient to keep existing units in operation and to justify investments in new capacity. In the simulations of the Danish case plant, for the simulated three month period it is found that the NHPC could be reduced by about 17,400 EUR, corresponding to a reduction of 5%, by participating in the main balancing reserve compared with participation only in the wholesale market. Part of this gain comes from an increased use of the electric boiler, but the main part is due to better usage of the CHP unit. With a CHP capacity of 8.8 MW_e, this gain corresponds to 7,920 EUR/MW_e/year, assuming that the gain is representative for a year. However, as a longer period has not been simulated, it cannot be concluded whether or not this gain is representative of the potential gain over a longer time period. However, as the CHP and electric boiler capacities of the plant are highest relative to the DH demand in the summer period, and the gain is achieved due to the reduction of the NHPC, it must be assumed that the gain, percentage-wise, is highest in the summer period. With that said, it does of course depend on market prices in the other periods. It should also be noted that the market price on the balancing reserve would most likely decrease with an increase in the number of participants, resulting in less gain for each individual participant. This point is particularly relevant because the turnover volume in the balancing reserves is only about 2-3% of the total turnover volume in wholesale markets [124]. Additionally, the EU goal of establishing an internal electricity market does seem to suggest that balancing areas will become larger, and as found in section 4.1, this will decrease balancing demands.

An analysis made for the Danish Energy Agency in 2013 found that the fixed cost for keeping small Ngas based CHP units ready for operation is 6,700-20,100 EUR/MW_e/year [125]. This cost is mainly composed of costs for reserving capacity in the Ngas grid, service, insurance and keeping the unit warm; the relatively wide cost range is due to a minimum payment in some service contracts. The calculated gain for participation on the balancing reserves could help cover costs associated with keeping the unit ready for operation, though it can only fully cover these costs for units that are cheap to keep ready for operation. For this reason, as well as the low turnover on the balancing reserves, it is unlikely that the income derived from participating in the balancing reserves will be sufficient to keep otherwise unfeasible CHP units in operation. This is especially relevant for the current Danish situation, where it is expected that a large share of the CHP capacity at small DH plants will be taken out of operation in the coming years. In the Danish context, the investment cost for retrofitting an existing Ngas-fired CHP engine is 0.31-0.51 million EUR/MW_e [126]. New investment in a CHP engine is 1-1.5 million EUR/MW_e [126], and as such, it is significantly cheaper to reinvest in the existing capacity rather than investing in new capacity.

7.3. Future development of electricity markets and small DH plants

Besides the CHP units at small DH plants, many power plants are also experiencing feasibility challenges due to decreasing income from wholesale markets. This can, for example, be seen in the significant decrease in capacity of large coal-fired CHP units in Denmark, as described in section 5.1.1. As shown in chapter 4, dispatchable capacity will still be needed in future smart energy systems based on variable RES, in order to have production capacity during periods with little or no production from variable RES. For this reason, both in Denmark [127] and Germany [128], a discussion is ongoing regarding how to ensure sufficient capacity of flexible dispatchable units.

A number of different solutions are being discussed in each country. One potential solution has received a lot of attention in the form of Capacity Remuneration Mechanisms (CRMs). Basically, this is a payment for capacity in the wholesale market, where traditionally energy-only payments have been the norm. This has been somewhat controversial, as in theory, the energy-only wholesale markets should, in the absence of market failures, be able to provide sufficient economic incentive for investments, and thus CRMs should not be required. Despite this, with a continued decrease in dispatchable capacity, the introduction of CRMs is being discussed extensively in the EU, and some countries have already, or soon will, introduce a CRM [129].

ACER defines a number of different types of CRMs, which are shown in Figure 7.1.

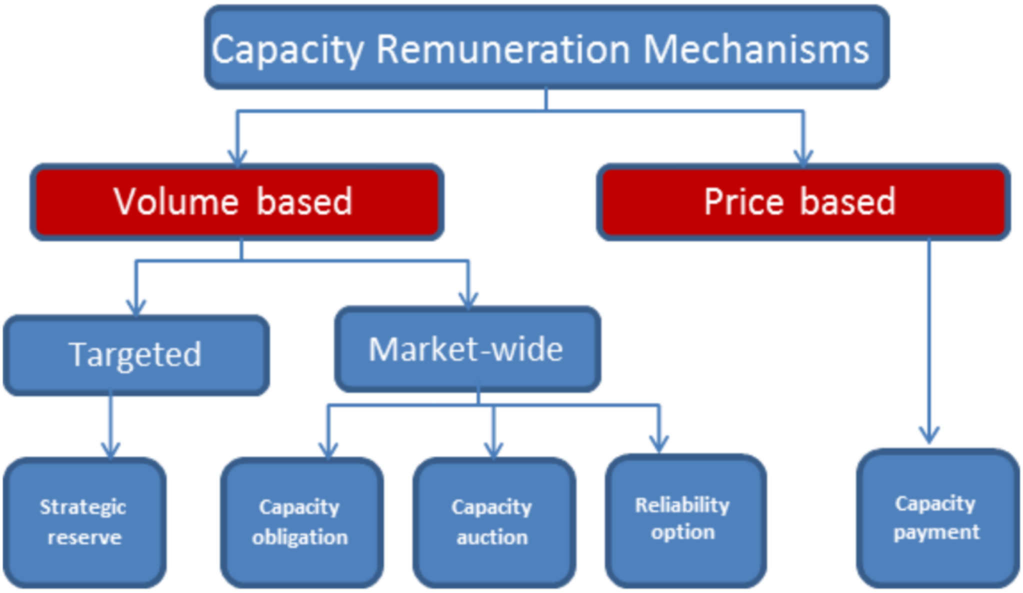

Figure 7.1 – Types of CRMs. Figure from [129].

The CRMs shown in Figure 7.1 are:

- Strategic reserve: An amount of capacity is set aside for activation only in exceptional situations.
- Capacity obligation: A decentralised CRM, where each BRP is obligated to ensure a sufficient level of capacity according to their expected demand for a number of years in the future.
- Capacity auction: A centralised CRM, where the total needed capacity is set centrally for a number of years, and market participants offer their capacity on this central market.
- Reliability options: A fixed payment is given to capacity providers under a reliability option, in which the capacity providers are incentivised to only operate during periods when market prices are high.
- Capacity payments: A fixed price paid to generators for being available for the electricity system.

CRMs are not new in the electricity system, for example, the subsidy given to small DH plants with CHP capacity in Denmark is in the form of a capacity payment, as described in section 5.2.3, and CRMs have also been utilised in e.g. Spain [129], Australia and New Zealand [130]. However, considering a potential shift towards an internal electricity market in the EU, the discussion about CRMs goes from being a national discussion to one that is relevant on the broader EU level [131].

It should also be noted that in the current organisation of the main wholesale markets based on MPP, and given a demand that is fairly price inelastic, variable RES are also experiencing challenges with low electricity prices. As mentioned in section 2.4.2, this is known as the merit order problem. Basically, the merit order problem stems from the fact that variable RES are normally offered in MPP markets at a price close to zero due to very low short-term marginal costs for production, and if variable RES are receiving subsidies, then the bid can even be negative. As variable RES will, in this situation, be among the cheapest participants, they will push the most expensive producers out of the market, resulting in lower market prices. In cases with a high integration of variable RES, it is possible that this variable RES can, in some hours, produce sufficient energy to cover the entire system demand, resulting in very low market prices. As such, with increasing integration of variable RES, the market price per unit of production will, all things being equal, decrease for variable RES. However, as also argued by researchers, this problem can be reduced by making the demand side more price elastic, for example, by introducing new smart electricity demands, such as compression heat pumps in DH, electrolysers and electric vehicles, or by making the existing demand more price elastic. It remains uncertain, though, whether these measures will be sufficient in energy systems based 100% on RES. [46]

There are hence strong arguments for a change in the fundamental organisation of the wholesale markets in order to facilitate the desired transition of the energy system, though the specifics of this new organisation are still being researched and discussed.

8. Conclusion

Due to environmental problems, a transition of the energy system is occurring worldwide. This transition includes efforts to improve energy efficiency and increase the use of variable RES. The speed of this transition differs from country to country, where, for example, Denmark and Germany are two of the frontrunners. CHP in combination with DH could be used to increase the efficiency of an energy system, especially with DH based on low temperatures, the so-called 4GDH. However, in order to be compatible with variable RES, CHP units have to be flexible, and it is found that especially small DH plants with CHP units and thermal storage systems can play an important role in helping to integrate variable RES into the electricity system. As such, the first research question in this thesis is:

1. *What role can be expected for small CHP plants in future smart energy systems based on RES, and to what extent are they expected to take part in electricity system balancing?*

This question is discussed in chapter 4, where it is found that CHP units at small DH plants are expected to play an important role for providing electrical capacity ready for use when variable RES do not produce sufficiently to cover the electricity demand, or when forecast errors for variable RES production result in an imbalance in the electricity system. The CHP units should also expect a substantial decrease in hours of operation per year, partly due to a reduced need for electricity production on these units, but also due to an increase in the number of heat producing units at DH plants. The number of different heat producing units at small DH plants, in tandem with large thermal storage facilities, leads to increased flexibility for these CHP units. As such, the daily operations planning for small DH plants should include the utilisation of a number of different heat producing units alongside the potential to store heat for a number of days. This raises the question of whether the organisation of electricity markets facilitates the participation of small DH plants. It is relevant to investigate this for some of the forerunners of the worldwide energy transition, namely Denmark and Germany. As such, the second and third research questions in this thesis are:

2. *How can small CHP plants participate in the balancing tasks in Denmark, and what are the daily operational challenges within these concrete institutional conditions?*
3. *How can small CHP plants participate in the balancing tasks in Germany, and what are the daily operational challenges within these concrete institutional conditions?*

The second research question is addressed in chapter 5 and the third is handled in chapter 6, where simulations of case plants are also presented.

It is found that in Denmark, the main balancing reserve is the TCR. The TCR is relatively easy for small DH plants to participate on. This is likely a result of the TCR having been intentionally adjusted to facilitate these units' participation on this market, as a large capacity of small CHP plants already exists in Denmark. However, extensive use of special regulations and a minimum requirement of 10 MW to participate do pose some challenges. Danish small DH plants with CHP are already dealing with a number of different heat production units in their daily operations planning, where especially solar thermal panels and electric boilers have seen significant implementation in the last years, and it is expected that compression heat pumps will see increased integration in the coming years. Despite this, overall CHP capacity at small DH plants in Denmark is expected to decrease in the coming years, due primarily to problems associated with keeping them economically feasible in the current electricity markets.

In Germany, the main balancing reserve is the SCR. The German SCR is based on weekly tenders with the trading day being several days before actual delivery. Additionally, it is expected that participating units must be in operation for at least eight consecutive hours in order to deliver SCR. As such, the German SCR poses some challenges for participation by small DH plants. The heat demand forecast becomes especially important, as it is found that the potential production of unusable or non-storable heat introduces extra costs for participating CHP plants, a cost not experienced by traditional power plants. The German government has a goal of increasing CHP capacity in the country, and as such, several subsidies are provided for CHP production, with especially small CHP plants being provided a relatively high subsidy per MWh_e.

Based on the lessons from small DH plants' participation in the balancing reserves in Denmark and Germany it is relevant to bring forth some policy recommendations for facilitating the participation of small DH plants with CHP in the balancing reserves. As such, a fourth research question is put forward:

4. *How can the rules for electricity system balancing be set up in order to facilitate participation of small CHP plants in a way that also facilitates a lower integration cost of RES?*

This question is based on the lessons taken from the previous three research questions, and is discussed in chapter 7. Through the analyses presented in this thesis, the following recommendations are found to be relevant for the organisation of the main balancing reserve in order to facilitate the participation of small DH plants with, for example, CHP and compression heat pumps:

- Set the gate closure for bids as close to the actual delivery time as possible, or make it possible to change bids for activation close to the actual delivery time. Additionally, not requiring winning capacity in order to be allowed to deliver activation would help.
- Keep the period of delivery as short as possible. If a long period of delivery is necessary, then make it possible for participants to deliver balancing reserve electricity without having to already be in operation.
- Avoid basing balancing reserves on PAB, unless it is likely that an actor will be able to exercise market power.
- Keep the minimum capacity or energy requirement for participation as low as possible.
- Make the balancing reserve asymmetric.

While it is relevant for the system to facilitate the participation of small DH plants with, for example, CHP and compression heat pumps in the balancing reserve, it is uncertain whether this participation will provide sufficient economic incentives to bring about the needed investments in this small DH capacity. This is important because sufficient capacity is needed in the electricity system to meet overall demand, and dispatchable CHP electric capacity is particularly desirable in order to achieve high overall energy system efficiency; it is therefore relevant to see these two in combination. As balancing reserves are unlikely to provide sufficient incentives to ensure this desirable system development, it is relevant to investigate other possibilities.

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10. Appendices

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Appendix I

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Market Integration of Wind Power in Electricity System Balancing

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CASE STUDY

Market integration of wind power in electricity system balancing

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ARTICLE INFO

Article history:
Received 23 October 2012
Received in revised form
11 January 2013
Accepted 20 January 2013
Available online 12 February 2013

Keywords:
Electricity market
Balancing service
Wind power integration

ABSTRACT

In most countries markets for electricity are divided into wholesale markets on which electricity is traded before the operation hour, and real-time balancing markets to handle the deviations from the wholesale trading. So far, wind power has been sold only on the wholesale market and has been known to increase the need for balancing. This article analyses whether wind turbines in the future should participate in the balancing markets and thereby play a proactive role. The analysis is based on a real-life test of proactive participation of a wind farm in West Denmark. It is found that the wind farm is able to play a proactive role regarding downward regulation and thereby increase profits.

1. Introduction

With increasing penetration of wind power in many countries, questions about the impacts and costs associated with maintaining a stable grid are receiving growing attention. Several studies have analysed these impacts and costs when operating power systems with high penetration of wind power [1–4]. The studies found that high penetration of wind power increases the demand for and the cost of balancing the electricity system.

Traditionally, wind turbines are seen as passive producers of electricity that are producing when the wind is blowing, regardless of the demand for electricity in the system. For this reason, studies of increasing wind power penetration tend to focus on how to adjust the technical set-up of the electricity system to facilitate higher penetration of these passive producers. This can be seen in studies for different regions. In Ref. [5] a maximum feasible wind power penetration in the Chinese energy system is analysed. Wind power's effect on thermal plants' operation costs in China are analysed in Ref. [6]. The potential for a 20% wind power penetration in the US electricity system is analysed in Ref. [7]. The synergy effect of wind power and photovoltaics is analysed for New York state in Ref. [8], and for the overall European energy system in Ref. [9]. Integrating fluctuating renewable energy in the energy system using pumped hydroelectric energy storage is investigated for the Irish energy system in Ref. [10], and for the Greek energy system in Ref. [11]. The optimal wind generation for the UK energy system in 2020 is investigated in Ref. [12]. The maximum feasible wind power penetration in the Italian energy system is investigated in Ref. [13]. Technologies to balance wind power in the West Danish energy system are investigated in Ref. [14]. The connection between power plant cycling and wind power penetration in the West Danish energy system is analysed in Ref. [15]. All these studies have in common that wind power acts as a passive producer in the energy system, and other units in the energy system will provide the balancing imposed by this passive producer.

This article argues that wind power should not only function as a passive producer, but instead be a proactive producer that helps reduce imbalances in the electricity system, and reduces production in situations with excess electricity in the electricity system. In that way wind power will both be active in the electricity system balancing tasks, and be proactive by reducing the balancing impact of the forecast errors. This point has also been argued in Ref. [16] in which it is stated that as energy systems are becoming more sustainable, increasing penetration of wind power and other distributed energy sources will occur, and at some point these distributed sources will have to take part in the electricity system balancing tasks which earlier had been left to large production units. The need for flexible distributed generation has also been argued in Ref. [17].

Other studies have investigated how a wide range of other distributed and energy storage technologies can actively participate in the electricity system balancing tasks.

Abbreviations: BRP, balance responsible party; TSO, transmission system operator; NWP, numerical weather prediction.

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http://dx.doi.org/10.1016/j.esr.2013.01.006

Lund and Andersen showed in Ref. [18] that small combined heat and power (CHP) plants with thermal storage can participate in balancing the electricity system. In Refs. [19] and [20] it was shown that Danish CHP plants can participate in several electricity system balancing tasks. Operation strategies of pumped hydroelectric energy storages participating in the balancing tasks were investigated in Ref. [21]. The possibility of using compressed air energy storage (CAES) for electricity system balancing in a future Danish energy system based heavily on wind power is analysed in Ref. [22], and operation strategies for such CAES are analysed in Ref. [23]. The possibility of using vehicle-to-grid systems for electricity system balancing in a future Danish energy system with a high penetration of wind power is analysed in Refs. [24] and [25].

To show that wind turbines also can provide balancing for the electricity system, a test of Sund & Bælt's 21 MW wind farm in West Denmark offering balancing has been conducted. Denmark has high penetration of wind power in the system, and in 2011 the wind power production accounted for 28.1% of the domestic electricity supply [26].

As part of the European Union (EU), Denmark is subject to the EU Directives regarding electricity trading. According to EU Directive 2003/54/EC [27], the trading of electricity and procurement of electricity system balancing has to be non-discriminatory and market based. Generally, there are two overall market types for electricity: wholesale markets where electricity is traded before the operation hour, and real-time balancing markets to handle the deviations. In the UK, wind farms can participate on the balancing market [28]. In Denmark, wind power is generally integrated in the electricity system through the day-ahead and intraday wholesale markets but is not participating on the balancing markets. However, Danish wind power plants with a capacity above 11 kW are required to support the frequency through technical regulations [29].

With the quality of day-ahead wind production prognoses available today, the day-ahead wholesale markets are able to integrate the majority of the wind production, while the deviations from the prognoses are integrated and balanced in the intraday wholesale markets and the balancing markets [1].

Proactive participation of wind turbines in a market based setting means that the wind turbines should participate both in the wholesale markets and the balancing markets. As the balancing markets are generally used to impose penalties on those that create imbalances in the system, it is expected that the proactive participation will reduce the wind power's imbalance costs as set by the balancing markets, provided that the market rules facilitate this proactive market participation of wind turbines. This is also discussed in Ref. [30], where different support schemes and market designs for wind power in Europe are examined. In Ref. [30] it is found that it is important to provide market signals to wind power, so that the cost of integrating wind power will be as low as possible. This is also discussed in Ref. [31], which provides recommendations on how to organise balancing power markets in order to integrate wind power. Several on-going research projects also investigate this, such as the TWENTIES project whose purpose is to investigate technologies required to integrate an increasing share of renewable energy in the EU based on the EU's goals for 2020 [32], and the German project "Regelenergie durch windkraftanlagen" whose purpose is to develop a proposal for how wind turbines can provide electricity system balancing in Germany [33].

In a well-structured energy system, proactive participation of wind turbines should only be necessary in very exceptional situations, as reducing wind power production results in lost energy, which is unlike e.g. gas fired units where reducing production also reduces gas consumption. It is therefore expected that proactive participation of wind turbines should generally only occur as a last resort when e.g. all other units have provided balancing except potential must-run units, all potential energy storages are full, and export of excess electricity production is not possible e.g. due to transmission constraints. In this paper the proactive participation of wind turbines is only analysed and discussed on the basis of the wind turbine owners' financial incentive to actively provide balancing to the energy system in such situations.

The Danish Transmission System Operator (TSO), Energinet.dk, has with [34] changed its regulation in order to make it manageable for wind turbines to offer balancing by offering activation in one of the balancing markets, more specifically the Scandinavian regulating power market. In this article, the 21 MW wind farm has been tested with these new rules from Energinet.dk by offering downward regulation on the Scandinavian regulating power market. Earlier, wind turbines in Denmark were not able to participate on the regulating power market on the same terms as the other participants. Wind farms were contacted directly on an ad hoc basis by Energinet.dk when activation was needed, and the test described in this paper is therefore an early test of having wind farms participate on the regulating power market on the same terms as other units.

The structure of the paper is as follows: Section 2 provides an overview of the electricity markets in West Denmark. Section 3 describes short-term forecasting of wind power production. Section 4 describes grouping of wind turbines to offer balancing. Section 5 describes the live test of Sund & Bælt's 21 MW wind farm. Section 6 provides a rough estimation of potential income over a 9 month period. Section 7 provides recommendations for electricity market organization to facilitate proactive wind power participation. Section 8 concludes the analysis.

2. Overview of the wholesale and balancing markets in Denmark

The organisation of the West Danish electricity markets is shown in Fig. 1. The time indicated above each market shows the maximum technical response time allowed in order to participate on the market.

The primary reserve market's task is to stabilise the frequency. The automatic reserves (also known as secondary reserves) will bring the frequency back to 50 Hz. The TSO also uses the automatic reserves to bring the flows across the interconnectors to other TSO areas back to schedule. Imbalances between scheduled wind production (as traded on the wholesale markets) and the actual wind production may be balanced on the manual regulating power market (also known as tertiary reserve market or Scandinavian regulating power market). The Elbas market and the spot market are the intraday wholesale market and the day-ahead wholesale market, respectively [36].

On the Scandinavian regulating power market, a market participant can offer both to be available for regulation the day before, and activation for specific hours. Winning availability is not a requirement for offering activation. The market is asymmetric, and it is thereby possible to offer either downward regulation, activated when there is excess electricity in the system, or upward regulation, activated when there is a lack of electricity in the system. The gate closure for activation bids in the Scandinavian regulating power market is 45 min before the operating hour and the minimum bid size is 10 MW. To offer at least 10 MW downward regulation in the regulating power market, it is necessary to group turbines [36].

It will normally be cheaper for the TSO to activate regulating power market than to activate the secondary reserve. The reason is that more plants are able to participate on the regulating power market, e.g. a plant with a stopped engine may offer upward regulation on the regulating power market, because it has 15 min to deliver a won activation — enough time to make a cold start on the engine, but a cold engine is not able to start fast enough to deliver secondary reserve. In Denmark, this is also true per definition —

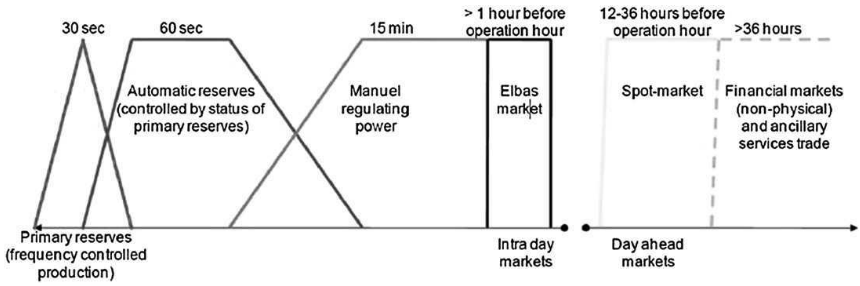

Fig. 1. Organisation of the West Danish electricity markets [35].

simply because activation of the secondary reserve means being paid 100 DKK/MWh on top of the best prices on the regulating power market and the spot market [36].

This price hierarchy is also used by Energinet.dk to emphasise to the balance responsible party (BRP) the hierarchy in the information that they send to the TSO. The BRP sends the following information to Energinet.dk:

- Hourly energy notification (hourly energy amounts traded on the wholesale market)
- Power schedule at 5-min intervals (updated as often as necessary)

For Energinet.dk, being responsible for the right frequency and the correct flows across the interconnectors to other TSO areas, it is important that the power schedules are more precise than the hourly energy notifications in order to use these power schedules to plan the purchase of the regulating power market in the operational hour. This is reflected in how imbalances are penalised:

- Imbalances in the hourly energy notification are settled with the activation prices on the regulating power market.
- Imbalances in the power schedule are settled with the activation prices in the Secondary reserve market.

Since activation on the secondary reserve and regulating power markets is organised as marginal price markets, and the penalties are cost reflective, these activation prices paid to the plants that remove the imbalances are equal to the penalties paid by the energy plants that have caused the imbalances, with only very few exceptions.

2.1. New regulation to facilitate proactive participation of wind turbines in the regulating power market

Energinet.dk has changed its regulation with the intent to make it manageable for wind turbines themselves to participate in the regulating power market [34].

For wind turbines used actively in the markets, the BRP now has to send the TSO the following information:

- Hourly energy notification (hourly energy amounts traded)
- Special 5-min time series showing the number of MWs (installed capacity) of the total portfolio of operational wind power plants that have been closed down.

Settlement of imbalances for wind turbines is simplified to the following:

- Imbalances in the hourly energy notification are settled with the activation prices on the regulating power market.
- Imbalances in the power schedule are NOT settled.

The BRP must be able to reduce the offered amount of MW-wind production in the full operating hour.

3. Short-term forecasting of wind production

As electricity is traded in advance of the actual delivery, the trading of wind power is directly dependent on the wind forecasts. Forecast models operate on different distinct time horizons, from the ultra-short scale (a number of seconds) to the long-term range (a week or more). These very different time scales inherently deal with features such as instantaneous turbine control, power trading, maintenance planning and load balancing. Not all models work equally well on all time scales. Ref. [37] states that a persistence model for turbine yield will typically outmatch a meteorological model in ranges below 4 h. In Denmark, the bulk of electricity is traded on the Nord Pool Spot market where the trading deadline is at 12 noon the day before delivery, meaning that wind power traded on the spot market uses forecasts for 12–36 h later. Errors in these wind forecasts introduce imbalances in the electricity system. In Denmark, these imbalances can be handled on the manual regulating power market, where the bidding deadline is 45 min before the hour of operation.

In order to provide a bid on the regulating power market, the expected production in the given hour has to be estimated, as the TSO will need to know the regulated amount. However, with Energinet.dk's new rules for wind power participation on the regulating power market, there is no requirement for how certain a wind power forecast has to be in order to offer regulation of wind turbines. In their current form, Energinet.dk's new rules therefore do not take into account that even though wind turbines now are able to offer regulating power on the same terms as other production units, their production forecast is much more uncertain. It is unclear whether Energinet.dk will include these considerations in the rules at a later stage. In this paper, the focus is on the forecasts on the short-term range (1–2 h) and the medium-term range (from one day to one week).

3.1. Dealing with uncertainties and forecast errors

Much of the uncertainty related to wind power forecasting still comes from the numerical weather prediction (NWP) systems used as input to the wind power forecasts. This area has received much attention during the last decades [38]; states that 80% of the uncertainty related to wind power forecasts still derives from the weather forecast model.

When invoking a complex real-time modelling framework for short-term forecasting, uncertainties and errors within the analysis need to be considered and potentially also mitigated. One major source of error is the NWP models. Some uncertainty associated to the NWP modelling can be removed by running or analysing output from models generally driven by different global models as well as using a model with ensemble forecasts. Such an analysis improves the insight into the variation of different NWPs, but such a scatter requires in-house meteorological knowledge to handle.

Errors in the NWP are grouped in either scale errors (models do not predict the right level) or phase errors (models predict erroneous times for ramp events). Typically such events are dealt with by also trading on the intraday wholesale market.

To some degree, errors in the NWP are mitigated by including more spatially distributed wind farms into the portfolio. According to Ref. [39], the mean absolute error was 5% lower for a portfolio of 3 UK wind farms when comparing with the individual ones (wind farms have a separation of some hundreds of kilometres). Such an effect is due to synoptic weather conditions affecting the sites at different times, reducing local effects of the terrain as well as reducing local errors.

3.2. Including direct online measurements

To be able to trade on the regulating power market in order to reduce imbalance payments, it is crucial to be able to determine the quantities of imbalance in each trading hour. An essential tool is to be able to monitor the production of the affected turbines online. By doing this, it is possible to merge information from online production with information from NWP and thus get a more exact estimate of the imbalance in the short time frame, which eventually enables trading on the short-term market.

The examples shown in this paper do not consider the forecasting uncertainty's effect on the bidding strategy on the regulating power market. It is therefore not considered whether e.g. a potential overproduction of energy, compared with the energy traded on the spot market, should have a different bidding price on the regulating power market than the one traded on the spot market. This could be the case as the overproduction is more expensive to produce as it is associated with imbalance costs.

4. Establishing groups of turbines

In Denmark, a BRP is able to make an activation bid for downward regulation of 10 MW in the regulating power market, when the production prognosis shows that all the BRP's turbines will produce at least 10 MW in each quarter of the coming operating hour. If downward regulation activation has been won in a given hour, the BRP should reduce a certain number of turbines with a production equal to the won regulation. Since activation in the regulating power market is organised as a marginal price market, an activation bid can be set at the marginal cost.

In the testing period, Sund & Bælt's wind turbines received the spot market price and a feed-in premium of 250 DKK/MWh electricity produced. This is set by Danish law [40]. This feed-in premium is given to wind turbines established after 21 February 2008 in the wind turbines' first 22,000 full load hours. If the wind turbines win a downward regulation, the turbines will not be paid this feed-in premium for the reduced amount in that hour, since the wind turbines will reduce the electricity production. As the feed-in premium is for a certain amount of full load hours, the feed-in premium for the hour will however not be lost but instead be delayed to the end of the premium period. Therefore in this case, depending on how close a turbine is to the end of its feed-in premium period, the owner of the turbine has to estimate, the cost of delaying the feed-in premium. This cost becomes the highest bidding price for this turbine – if e.g. the cost of delaying the premium is estimated to 100 DKK/MWh, the highest bidding price for this turbine for a downward regulation is −100 DKK/MWh. It should be noted that the bidding price for a downward regulation is the highest price that the operator is willing to pay the TSO for a downward regulation – when the bidding price is negative the operator wants money for it. When the turbines are at the end of the premium period, this activation bid could be raised to e.g. 0 DKK/MWh. The turbines will only generate an income when winning downward regulation if a more expensive unit is also activated, as the regulating power market is set-up as marginal price market, where the market price is equal to the bidding price of the most expensive auction winning unit.

When it comes to a recommendable distribution of the turbines in a certain group, it may be an advantage that the turbines in the group are distributed geographically. That will expectedly improve the quality of the hour ahead wind production prognosis of the group. This improvement is well documented when day-ahead wind production prognoses are considered [41]. This consideration has, however, not been included in the test described in this paper as only one wind farm has been included here.

5. Live test of wind turbines offering downward regulation on the regulating power market

Throughout the test period, the wind turbines were activated as downward regulation several times. Here, an example of 1 h won activation of downward regulation is described. The activation was won in hour 24, 14 February 2012. In that hour, the activation price in the West Danish market area of the

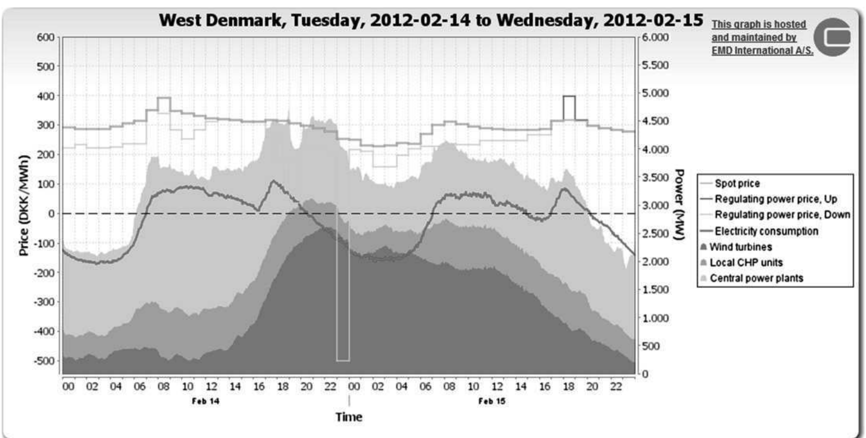

Fig. 2. The electricity production, electricity consumption and electricity prices in West Denmark on 14–15 February 2012 [42].

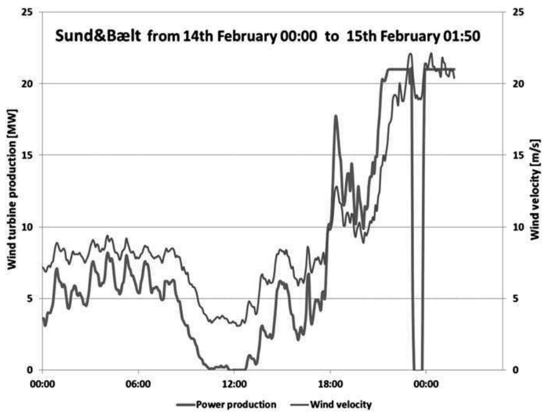

Fig. 3. The electricity production of Sund & Bælt's 21 MW wind farm alongside the wind velocity at the site.

regulating power market was −498 DKK/MWh, see Fig. 2.

Sund & Bælt's turbines went into operation in December 2009 and had thus been operating for about two years, when the hour of activation was won. It is expected that the wind turbines on average will produce around 66 GWh/year, corresponding to 3143 full load hours/year. It is therefore expected that a production of 22,000 full load hours will be reached 7 years after the wind farm went into operation. At the time of downward regulation, the premium would be delayed about 5 years. Using a conservatively high discount rate of 20%, the net present value of delaying the premium is 100 DKK/MWh. The wind turbine activation bid was thereby cheaper than the most expensive activated bid and the wind turbines were hereby activated as downward regulation in the regulating power market. The activation can be seen in Fig. 3, where the wind farm's production is shown alongside the wind velocity.

In the hour of activation, a production of 17.8 MWh had been sold on the spot market the day before. If the wind turbine production had not been reduced in that hour, the turbines would have produced 21 MWh, and would have created an imbalance in the electricity system with the 3.2 MWh excess production. This excess production would have been settled according to the price in the regulating power market, and as the price here was negative, the wind farm would have had to pay for producing the extra 3.2 MWh.

By instead trading into the regulating power market, the wind production in that hour was reduced to 6.7 MWh, as the activation was not for the entire hour. During the hour, the wind farm both removed its own imbalance, and through the market also helped remove some other producers' or consumers' imbalance. The wind farm was compensated for this balancing service, and the activation thereby improved the wind farm's profit. The increase in earning in hour 24 on 14 February 2012 is calculated in Table 1. For that hour it is found that by participating in the balancing market by providing downward regulation, the wind turbines' profit was increased by 196%.

Table 1
Calculation of Sund & Bælt's increase in profit due to winning downward regulation in hour 24 on 14 February 2012.

Profit calculation of won downward regulation in hour 24 on 14 February 2012						
Production in hour 24 if not being downward regulated			21.0	MWh		
Production in hour 24 when being downward regulated			6.7	MWh		
Sold at spot market in hour 24			17.8	MWh		
Spot market price in hour 24			252.7	DKK/MWh		
Downward regulation price in hour 24			−498.0	DKK/MWh		
Cash flow in hour 24 in case of not offering downward regulation						
Sold at spot market	17.8	MWh à	253	DKK/MWh	4498	DKK
Surplus (imbalance), (21.0−17.8 MWh)	3.2	MWh à	−498	DKK/MWh	−1594	DKK
Total payment for hour 24					2905	DKK
Cash flow in hour 24 in case of offering downward regulation						
Sold at spot market	17.8	MWh à	253	DKK/MWh	4498	DKK
Settlement (Regulating power), (17.8−6.7 MWh)	−11.1	MWh à	−498	DKK/MWh	5527	DKK
Net present value of delayed premium (21.0−6.7 MWh)	14.3	MWh à	−100	DKK/MWh	−1430	DKK
Total payment for hour 24					8595	DKK
Increase in profit in hour 24 in case of offering downward regulation					5690	DKK
					196	%

6. Simulated profit for wind turbines offering downward regulation

Based on the historical spot prices, the historical activation prices on the regulating power market and historical production and sale data, a simulation has been done on what Sund & Bælt's 21 MW wind farm could have earned by offering activation on the regulating power market for the first 9 months of 2010. The result is shown in Table 2, where it is found that the earnings would have increased by around 8%, but that the production in these 9 months would have been reduced by around 5%, if offering activation of downward regulation on the regulating power market.

The simulation in Table 2 is a rough estimation, which assumes that activation is always occurring in full hours and that the wind farm's participation would not change the activation price. The estimation is thereby the theoretical maximum and cannot be used to estimate future earnings.

If enough turbines offer activation, they will soon become the plants determining the activation prices on the regulating power market in the hours with negative activation prices. In that situation, the wind turbines will not increase profit when winning activation and only a few of them will be activated. However, all the turbines will still benefit from these proactive turbines offering activation, because they will all avoid high imbalance costs. This will also reduce the imbalances high penetration of wind power inflicts on an energy system.

7. Recommendations for market organisation

It is not the goal of this article to provide a thorough walkthrough on how to organise electricity markets to facilitate proactive participation of wind power in the balancing tasks. However, some relevant aspects are described in this section.

Wind power production can participate in the regulating power market. However, to make the regulating power market feasible for balancing wind production, the TSOs need to do as much of the balancing as possible using the regulating power market instead of the more expensive secondary reserve market. The rationale is that the balancing should never be done on a higher level than needed — in the sense that the secondary reserve market is on a higher level than the regulating power market.

Table 2
Rough estimation of the increase in profit for Sund & Bælt's 21 MW wind farm, if it had offered downward regulation in the regulating power market the first 9 months of 2010.

(All amounts in €)	Proactive	Reference
Sold electricity in the spot market	1,270,825	1,270,825
Surplus (imbalance)	188,052	147,224
Shortfall (imbalance)	−158,963	−158,999
Activation income in the Regulating power market	88,745	
Value of delayed 250 DKK/MWh (33.6 €/MWh) premium	−23,057	
Income total	1,365,602	1,259,050
Profit of proactive participation	106,552	
Increase in profit by proactive participation	8.5%	
Produced in the first 9 month of 2010	32,788 MWh	
Sold in spot the first 9 month of 2010	30,100 MWh	
Downward regulated when being proactive	1718 MWh	
Average error in prognosis (relative to full load)	6.2%	

It is also important to split the balancing market into an availability market and an activation market, and the gate closure for the activation bids should be close to the operating hour, as the wind turbine production forecasts improve as the operation hour gets closer. It is also important that offering activation is not conditional to winning availability.

As wind turbines for the most part will only be interested in offering activation in one direction, it is relevant to make the market asymmetric, allowing only upward or downward power offering.

These recommendations are much in line with the EU agency, Agency for the Cooperation of Energy Regulators' (ACER) framework for balancing markets from September 2012 [43]. ACER was created to assist the regulatory authorities in performing regulatory tasks at community level and to coordinate their actions in order to facilitate the creation of an internal European market for both electricity and natural gas. In the framework, ACER suggests that balancing markets are separated into an activation market and an availability market, and that the balancing markets are made asymmetric.

8. Conclusion and recommendations

Currently, wind turbines in the EU are mainly integrated in the electricity system through the wholesale markets, both intraday and day-ahead markets, but are not participating on the balancing markets.

Energinet.dk, the Danish TSO, has recently changed its regulation in order to make it manageable for wind turbines themselves to offer activation on the Scandinavian regulating power market.

Energinet.dk's new regulation has been tested on a 21 MW wind farm. During the test period, the wind farm has been activated for downward regulation on the regulating power market several times. It has been shown that this proactive participation of wind turbines on a balancing market increases the profit of the turbines, and lets the wind turbines help reduce imbalances in the electricity system.

Proactive participation of wind turbines on the wholesale markets is in fact also a possibility. E.g. in the Scandinavian day-ahead spot market, Nord Pool Spot, sale offers at negative prices are allowed, and wind turbines can thereby close down due to sufficiently negative prices on the day-ahead spot market. During these hours, the closed down wind turbines could in principle offer activation of upward regulation if the regulation facilitates this proactive participation. The implications of offering upward regulation are, however, not analysed in this article.

In order for wind turbines to participate proactively on the balancing markets, it is important that the organisation balancing markets facilitates this proactive participation. It is recommended that the market organisation includes the following:

- Splitting the market into an availability market and an activation market. The deadline for activation bids should be as close to the operating hour as possible. Activation bids should not be conditional to winning availability.
- Making the market asymmetric, allowing only upward or downward power offerings.

The conclusion is that allowing wind turbines themselves to offer activation on the regulating power market will result in all wind turbines benefitting from this, because they will all avoid high imbalance costs. It will also result in a better balance between the needed investments in the turbines and the needed investments in the electricity system.

Acknowledgements

The work presented is partly a result of the research project "Proactive participation of wind turbines in the electricity markets" financed by the Danish Transmission System Operator, Energinet.dk, as well as the Strategic Research Centre for 4th Generation District Heating Technologies and Systems (4DH) partly financed by the Danish Council for Strategic Research.

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Appendix II

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Small-Scale Combined Heat and Power as a Balancing Reserve for Wind

International Journal of Sustainable Energy Planning and Management Vol. 04 2014 31–42

International Journal of Sustainable Energy Planning and Management

Small-scale combined heat and power as a balancing reserve for wind – The case of participation in the German secondary control reserve

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ABSTRACT

Increasing amounts of intermittent renewable energy sources (RES) are being integrated into energy systems worldwide. Due to the nature of these sources, they are found to increase the importance of mechanisms for balancing the electricity system. Small-scale combined heat and power (CHP) plants based on gas have proven their ability to participate in the electricity system balancing, and can hence be used to facilitate an integration of intermittent RES into electricity systems. Within the EU electricity system, balancing reserves have to be procured on a market basis. This paper investigates the ability and challenges of a small-scale CHP plant based on natural gas to participate in the German balancing reserve for secondary control. It is found that CHP plants have to account for more potential losses than traditional power plants. However, it is also found that the effect of these losses can be reduced by increasing the flexibility of the CHP unit.

Keywords:

Combined heat and power,
balancing reserve,
electricity market

URL:
dx.doi.org/10.5278/ijsepm.2014.4.4

Abbreviations

CHP	=	Combined heat and power
DH	=	District heating
TSO	=	Transmission system operator
HT	=	Hochtarif
NT	=	Niedertarif
MOL	=	Merit order list
NHPC	=	Net heat production cost
PCR	=	Primary control reserve
SCR	=	Secondary control reserve
TCR	=	Tertiary control reserve
RES	=	Renewable energy sources
EU	=	European Union
ENTSO-E	=	European Network of Transmission System Operators for Electricity

1. Introduction

Increasing amounts of intermittent renewable energy sources (RES) such as wind power and solar power are being integrated into energy systems worldwide [1]. An example of this is the European Union (EU), where the political goal is to increase RES in the energy sector to

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20% of the gross final consumption by 2020 [2]. In 2012 RES accounted for 14.1% of the consumption in the EU, increased from 8.3% in 2004 [3]. Within the electricity sector especially intermittent RES have experienced a large increase in the EU [4].

While intermittent RES have shown promising results with respect to reaching the EU political goal, RES also introduce different challenges to the electricity system. Due to the more unpredictable nature of these sources, they are found to increase the importance of mechanisms for balancing the electricity system [5–7]. Balancing of the electricity systems is paramount, as electricity production must always equal electricity consumption to ensure a stable electricity system. Thus, those responsible for the electricity system balancing have kept reserves ready for balancing. Within the EU, the task of balancing the electricity system falls to the transmission system operators (TSOs). In accordance with the EU Directive 2003/54/EC, the TSOs have to obtain balancing reserves through market-based procurements that are transparent and non-discriminatory [8]. The specific organisation and utilization of the balancing reserves vary between countries; however, the European Network of Transmission System Operators for Electricity (ENTSO-E) defines three types of balancing reserves [9]:

- Primary control reserve (PCR), used to gain a constant containment of frequency deviations. The activation time of units will generally be up to 30 seconds. This reserve is also known as frequency containment reserves.
- Secondary control reserve (SCR), used to restore frequency after sudden system imbalances. The activation time of units will typically be up to 15 minutes. This reserve is also known as frequency restoration reserves.
- Tertiary control reserve (TCR), used for restoring any further system imbalances. The activation time of units will typically be from 15 minutes to one hour. This reserve is also known as replacement reserves.

The PCR is set by ENTSO-E at 3,000 MW for the synchronously interconnected system of continental Europe [9], where each country contributes with an agreed amount of capacity. The practical utilization of the SCR and the TCR, however, differs significantly between countries. The TCR is the primary balancing reserve in, e.g., Denmark, whereas the SCR is the primary balancing reserve in, e.g., Germany [10]. The difference in balancing procurement occurs partly due to differences in planning procedures by the TSOs in the two countries. Both these countries have a relatively high integration of intermittent RES in their electricity system. In Denmark, wind power and solar power accounted for 33.8% of the total electricity production in 2012 [11], and in Germany they accounted for 12.2% in 2012 [12]. As Germany is the largest electricity consumer [1] and producer [13] within the EU and also an important transmission country for electricity, the development of the German electricity system is of particular importance to reaching the EU's goals.

Besides the goals for RES, the EU also has a goal of reducing the primary energy consumption by 20% by 2020 [2]. As a part of reaching this goal, the EU promotes combined heat and power (CHP) production. In Germany, the generation of electricity from CHP plants has increased from 9.3% of the gross electricity generation in 2004 to 12.6% in 2012 [14]. A significant part of this increase is due to an increasing capacity of small-scale CHP plants [15].

As argued by Lund [16], the capacity of large inflexible production units, which traditionally have delivered balancing to the electricity system, is expected to be reduced alongside the increase in intermittent RES. This in turn will make it increasingly more important for flexible units to help maintain the electricity system stability. Small-scale CHP plants based on gas have proven to be flexible, and have, in other countries, demonstrated their ability to participate in the electricity system balancing [17]. In Germany, the SCR is currently mostly provided by large-scale power plants [18]. It is therefore relevant to investigate how flexible small-scale CHP plants can participate in the balancing of the German electricity system by participating in the market for SCR.

Other papers deal with participation in the German SCR. Thorin et al. [19] describe a tool based on mixed integer linear-programming and Lagrangian relaxation to simulate a district heating (DH) plant with steam turbines, gas turbines and fuel boilers participating in the German spot market and providing SCR. Thorin et al. do not include heat storage systems, and do only include a simple participation in the SCR. Koliou et al. [20] investigate the possibilities of having demand response participate in the German balancing markets. Müsgens et al. [21] analyse the market design and behaviour of participants in the German TCR and SCR, and in doing this develop a simple approach using the spot market prices for estimating the costs that a power plant could experience by offering capacity on either of these markets. However, Müsgens et al. do not include CHP plants in the discussion and do not use the method in simulations of the operation of a plant. No research has been found that directly deals with small-scale CHP plants participating in the German SCR. The goal of this paper is hence to fill this gap in the research by investigating and discussing the possibilities for small-scale CHP plants to participate in the German market for SCR using the current rules for this market. It is the goal to provide an understanding of the different challenges in the daily operation of traditional power plants and small-scale CHP plants, respectively, highlighting how the rules for balancing reserves can limit or encourage the participation of small-scale CHP plants.

In this paper, a method for simulating a small-scale CHP plants operation in the German SCR is presented. The method is used to simulate a case plant. The potential gain for the plant from having an increase in the flexibility of the CHP unit is also examined.

2. The German secondary control reserve

The German SCR receives payment for both capacity and activation, and the bids offered in one week cover all of the following week and are final after the clearing. Capacity bids are EUR/MW_e/week and activation bids are EUR/MWh_e. The winning bids are cleared using the pay-as-bid principle, where each winning participant is settled according to that participant's bid. The market is asymmetric, meaning that bids are separated into upward regulation, used when the system is short, and downward regulation, used when the system is long. Two periods are used in the SCR; hochtarif (HT) being the period from 08:00 to 20:00 on workdays, and niedertarif (NT) being all periods outside of HT. Bids are separate for upward and downward regulation, and for HT and NT; as such four different products are traded in the SCR. A bid has to be at least 5 MW; however, it is possible to pool units in order to reach this amount [18].

The SCR is cleared every Wednesday for the next week starting next Monday. Before the clearing day, the four German TSOs publish the capacity needed for the coming week. The four German TSOs are 50 Hertz, Amprion, Transnet BW and TenneT. The clearing day may in some weeks change due to German national holidays. On the clearing day, only the offered capacity payments are used to arrange the bids in a merit order list (MOL) where the cheapest capacity bids are selected first, until the amounts needed by the German TSOs are reached. An exemption to this rule is if a TSO needs units in a specific area in order to ensure a stable grid; then a more expensive unit can be chosen before a less expensive unit. The most expensive winning bid is reduced in size, if the needed amount of capacity is surpassed by this unit. Activations in the SCR must start within 30 seconds and be fully activated within five minutes. Similar to capacity bids, the activation bids are arranged in a MOL where the cheapest activation price is activated first, until the needed amount is reached. Again, conditions in the grid can result in a more expensive unit being activated before a less expensive unit [18]. In 2013, deviations from the activation MOL occurred for periods totalling 2 days, 1 hour and 49 minutes [22].

2.1. Public data for the German secondary control reserve

After the clearing day, the TSOs publish all winning bids in anonymised form, alongside the bids that were not selected due to grid stability needs. For each bid, the capacity offered, the capacity price bid, the activation price bid and whether the bid was accepted are shown. The bids are separated into each of the four products, but not according to control area. The four German TSOs continually publish the amount of SCR activated in MW for both upward and downward regulation in 15-minute periods. Within each 15-minute period, both upward and downward regulation can occur [23].

As the capacity payments for each week are publicly available, it is possible to use the data for capacity payments directly in the simulations. As described in section 1, other studies have investigated the potential income of distributed units in the SCR, but these have only estimated the income from capacity payments. In this study, activations are included in the simulation in order to estimate the potential effect of activations. However, the German TSOs do not publish the figures of payment for activation of the SCR for each 15-minute period. Thus, a method for estimating this is devised.

2.1.1. Estimating activation prices

In order to estimate activation prices in the SCR, several assumptions must be made. Firstly, it is assumed that all activations are chosen solely based on the price of activation, and activations of a more expensive unit due to grid restrictions are not included. Secondly, it is assumed that activations cover the full length of each 15-minute period; however, activations do not necessarily follow these 15-minute periods. Thirdly, if the activation amount in one direction in a 15-minute period is less than 5 MW, then this direction in that period is assumed to have no activations. This assumption is made to reduce the number of activations in periods in which there are clearly no new activations. The marginal activation price in each 15-minute period is then estimated by choosing the cheapest activations until the activated amount for the whole of Germany is reached. The last activated bid is reduced in size, if by activating this bid the registered activated amount is surpassed. Through this approach, the average and marginal activation prices for each 15-minute period are found.

Due to the uncertainties described for this method, the method cannot be used to estimate the potential income from an actual SCR participation, but can be used to highlight how different technologies would operate differently in the SCR.

3. Simulation approach

As a case, a natural gas fired small-scale CHP plant has been simulated. The simulated period is 2013. As CHP units will normally be built based on their feasibility in the wholesale market, a plant set-up is chosen based on its feasibility on the German wholesale market. The chosen plant set-up is based on the plant with one 4 MW_e CHP unit described by Streckienė. et al. [24]. Streckienė et al. analyse the feasibility of several CHP plants with thermal storage systems traded on the German day-ahead wholesale market, EPEX Spot, from here referred to as spot market. The chosen plant set-up was by Streckienė et al. found to be feasible on the spot market. As the plant is generic, the results are not affected by local conditions that could affect the results when specific plants are used, making it easier to see general tendencies in the results.

The modelled CHP plant has one natural gas fired 4 MW_e CHP engine with a thermal capacity of 4.7 MW_{th} and an overall efficiency of 87%. Besides the CHP unit, the plant is also equipped with one natural gas fired boiler with a thermal capacity equal to the peak heat demand and an efficiency of 91%. Besides the production units, the plant is also modelled with a thermal storage system of 650 m^3 corresponding to 30 MWh_{th}. The plant delivers ex plant 30,000 MWh_{th} to a local district heating system, and must always cover the heat demand in the district heating system. The only differences between the plant described by Streckienė et al. [24] and the plant simulated for this paper is that the electricity market prices, the temperature data used for distribution of the space heat demand through the year, the subsidies and the costs have all been updated to 2013 figures. See Table 1 for the economic assumptions for the plant described by Streckienė et al. and the 2013 version used in this paper.

The updated natural gas price, CO_2 certificate price, net using bonus and starting cost are assumed values based on the experience of the authors. As can be seen in Table 1, natural gas price and net using bonus are higher in the 2013 version, whereas CO_2 certificate price and starting cost are lower. The net using bonus is a payment for avoided grid costs where the size of the payment depends on the connections' voltage level, connection point (substation or cable) and the grid costs of the distribution grid operator. This value varies quite significantly depending on where in Germany the CHP unit is connected; e.g., in Schwäbisch Hall in southern Germany it is 4.7 EUR/kWh [25], and in Magdeburg in eastern Germany it is 9.9 EUR/MWh [26]. The value used here is an assumed value.

It is assumed that the CHP plant also receives the so-called *KWK-Zuschlag*. The KWK-Zuschlag is an electricity production subsidy given to owners of CHP units for the first 30,000 hours of operation. The size of the subsidy depends on whether the unit went into operation before or after the 19^{th} July 2012 and on the electric capacity of the CHP unit. It is here assumed that the CHP unit went into operation after this date, and it receives 54.1 EUR/MWh_e for the electricity production of the first 50 kW_e of capacity, 4 EUR/MWh_e for the capacity between 50 and 250 kW_e, 24 EUR/MWh_e for the capacity between 250 and 2,000 kW_e and for the capacity above 2,000 kW_e the subsidy is 18 EUR/MWh_e [27]. Thus, the modelled 4 MW_e CHP unit will receive a KWK-Zuschlag of 22.18 EUR/MWh_e for the first 30,000 hours of operation.

The CHP unit is simulated as traded both on the spot market and the German SCR. As SCR is traded several days before the actual delivery and the trade on the spot market is traded day-ahead, the CHP unit will always be traded into the SCR before it is traded

Table 1: Economic assumptions of the CHP plant described by Streckien et al. [24] and the updated 2013 version of the CHP plant used in this paper.

	Streckien et al. plant	2013 version of plant
Natural gas price [EUR/MWh-fuel]	25	35
Fuel tax for gas boiler [EUR/MWh-fuel]	5.5	5.5
CO_2 certificate [EUR/t CO_2]	20	6
Gas boiler O&M costs [EUR/MWh_{th}]	1	1
CHP unit O&M costs [EUR/MWh_e]	8	8
CHP unit starting cost [EUR/turn on]	32	20
Average spot market price [EUR/MWh_e]	40.00	37.78
Net using bonus (CHP unit) [EUR/MWh_e]	1.5	6.7

on the spot market. In order to estimate the gain of increased flexibility of the CHP unit, two different capabilities for the technical flexibility of the CHP unit is made.

For the reference capability, it is assumed that the CHP unit must be in operation in the periods where SCR is won. In these periods, the CHP unit is traded on the spot market with the lowest possible bid, meaning it will always win trade on the spot market in these periods. EPEX-Spot is organised as a marginal price auction, where the market is cleared based on the most expensive winning bid [28]. Trading the CHP unit on the spot market is assumed to never affect the market price. If any non-usable or non-storable heat is produced when the CHP unit is forced to operate to deliver SCR, this heat is rejected. For the SCR trading, it is assumed that the plant is part of a pool with the same bid as the plant, and the plant therefore only needs to offer part of the minimum requirement of 5 MW_e. For the reference capabilities of the CHP unit, it is assumed that the plant offers 1 MW_e in the SCR, meaning in periods where upward SCR is won, the CHP unit will trade 3 MW_e on the spot market, keeping the remaining 1 MW_e ready for activations in the SCR. In periods where downward SCR is won, all 4 MW_e will be traded on the spot market; thus, in periods where the CHP unit is activated, it will be part-loaded to 3 MW_e. It is assumed that part-loading the CHP unit does not affect its efficiency. It is assumed that the unit must always deliver the amount traded in the SCR and it cannot rely on the other plants in its pool to deliver this amount. The plant is assumed not to have breakdowns of its units in the simulated period.

For the increased flexible capability of the CHP unit, it is assumed that the CHP unit does not have to be in operation in order to deliver SCR. Currently, the German TSOs require units delivering SCR to be in operation in periods where SCR is won. However, a simulation of the increased flexible capability of the CHP unit shows the maximal potential gain from increasing the flexibility of the CHP unit. With increased flexible capability of the CHP unit, the full capacity of the CHP unit, 4 MW_e, will be traded on the SCR. Hence, the CHP unit will not be traded on the spot market in periods where upward SCR is won, and in periods where downward SCR is won, the CHP unit's full capacity is traded on the spot market.

The CHP unit will be simulated as only trading in one direction at a time, resulting in a total of four scenarios:

- Scenario 1: Reference capability, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 2: Increased flexible CHP unit, where the CHP unit is only traded as upward regulation on the SCR.
- Scenario 3: Reference capability, where the CHP unit is only traded as downward regulation on the SCR.
- Scenario 4: Increased flexible CHP unit, where the CHP unit is only traded as downward regulation on the SCR.

Income from heat sales is not included as it is the same in all scenarios. In periods where SCR is not won, the CHP unit is traded on the spot market, if the resulting heat production can be either used or stored. Outside won SCR periods, the CHP unit will be operated in blocks of at least 3 hours. The operation of the CHP plant is simulated using energyPRO version 4.1. energyPRO is a simulation tool developed primarily for simulating district heating plants. The simulation objective of energyPRO is to minimize the net heat production cost (NHPC). energyPRO was also used for simulating the plant in Streckienė et al. [24], and is hence usable for the simulations presented in this paper.

3.1. Bidding strategy for the spot market

The assumed goal of the CHP plant is to produce the demanded heat as cheap as possible. The EPEX-Spot is organised as a marginal price auction and the optimal bidding strategy on such markets is bidding with the short-term marginal costs of the unit [28]. Thus, the spot market bid should be based both on the short-term marginal costs of operating the CHP unit and the reduced costs related to reduced boiler operation. Hence, the spot market bid of the CHP unit (B_{spot}) is calculated as shown in Eq. (1).

$$B_{spot} = \left(VHC_{CHP} - VHC_{boiler}\right) * CAP_{CHP-th} \,/\, CAP_{CHP-e} \tag{1}$$

Where VHC_{CHP} is the short-term marginal costs in EUR per MWh_{heat} produced on the CHP unit, VHC_{boiler} is the short-term marginal costs in EUR per MWh_{heat} produced on the boiler, $CAP_{CHP\text{-}th}$ is the thermal capacity of the CHP unit in MW, and $CAP_{CHP\text{-}e}$ is the electric capacity of the CHP unit in MW.

Using the data for the CHP plant shown in Table 1, the spot market bid excluding start costs of the CHP unit is found to be 15 EUR/MWh_e, rounded up. It is assumed that if the plant's bid is less than the spot market price, then the plant wins spot market trade without affecting the spot market price.

3.2. Participation in the secondary control reserve

For trade simulation in the SCR, it is assumed that if the plant's bid is lower than the marginal SCR bid, then the plant wins SCR. This applies both to capacity and activation in the SCR. Due to the pay-as-bid principle, the winning participants in the SCR are paid their asking price. Nielsen et al. [28] indicate that the participants in recurrent pay-as-bid auctions are prone to gamble on the auction, e.g., by trying to estimate the highest possible winning bid of the coming auction in order to increase their income from auction participation. For the purpose of these simulations, it is assumed that the plant will not gamble on the SCR. The bid will instead be calculated based on the plant's own expected costs of participating in the SCR.

The SCR capacity payment is for the purpose of these simulations, seen as the payment that the plant needs in order to cover any costs related to the activation of SCR. For the simulated CHP plant, the following potential costs from SCR participation are identified:

1. The plant has to produce non-useable or non-storable heat by operating the CHP unit in order to be able to deliver SCR. (L_1)
2. The spot market price in the won SCR periods is lower than the normal spot market bid of the CHP unit. Meaning that it would be cheaper to operate the boiler instead of operating the CHP unit. (L_2)
3. In the case of upward SCR, high spot market prices in the won SCR periods can provide an opportunity loss, since the CHP unit will only be offered in part-load on the spot market in order to be able to deliver upward activation in SCR. (L_3)
4. The SCR participation reduces the spot market trading in high price periods outside of the won SCR periods. This can occur due to the displacement of heat production using the thermal storage system. (L_4)

For plants where the activation price is not solely based on the plant's own costs, as is the case of the simulated plant, a fifth potential cost could be included in the list. This fifth cost would be the opportunity to earn income from activations, and would normally be a negative cost.

The optimal approach to calculating the sum of these costs is to compare the NHPC if the plant did not participate in the SCR with the NHPC when participating in the SCR. In other words, the comparison of NHPC would be between a scenario in which the CHP unit is traded only on the spot market and another scenario in which the CHP unit in the SCR periods is traded on the spot market with the lowest possible bid price, as well as traded normally on the spot market in the remaining periods. The difference in NHPC between these two scenarios reflects the income needed from the capacity bid. Though in principle comparing the NHPC of these two scenarios would be the optimal approach, in practice this approach is problematic. The reason for this is that the clearing day for SCR is more than four days before the first day of potential SCR operation, and forecasts of, e.g., spot market prices and heat demand for the period are very uncertain. To highlight this challenge it is relevant to include forecasts in the simulations. For the purpose of the simulations presented in this paper, a simple approach to forecasting is used. The forecasts are produced based on the knowledge that a plant would have on the SCR clearing day. The clearing day is assumed to be only on Wednesdays. Only heat demand and spot market price forecasts are included.

The heat demand forecast is created for the SCR trading period using the heat demand from the seven days before the clearing day, being the period from and including the former week's Wednesday up to and including the Tuesday before clearing day. The heat demand from the former week's Wednesday is then used as a forecast for the following Monday, etc. It is assumed that the CHP plant aims to not reject any heat by participating in the SCR. For each clearing day, three different simulations based on the heat demand forecast are carried out for the following SCR trading period, representing an increasing amount of hours traded on the SCR. In the first simulation, the CHP unit operates at full load in all HT periods, as there in any given week will always be fewer hours of HT than NT. In the second simulation, the CHP unit will be operated at full load in all NT periods. In the last simulation, the CHP unit will be operated at full load in all periods. If in one of these simulations a rejection of heat is found, then no SCR trading is carried out in that period. E.g., if based on the heat demand forecast a rejection of heat is found by operating the CHP unit at full load in the NT periods, then SCR trading is only done in HT periods. No spot market trading is done in these tests, and the heat storage system is assumed to be empty at the beginning and the end of the week. With this method, the rejection of heat can still occur, as the heat demand is based on a forecast; however, the heat demand is vastly reduced compared with not taking into account the heat demand before trading SCR. In reality, a CHP plant would be able to purchase heat forecasts more advanced than the one used in these simulations; however, more advanced forecasts have not been available for these simulations.

To forecast spot market prices for the upcoming SCR trading period, the seven days before the clearing day's average spot market price in each of the two periods (HT/NT) are used as a forecast for the corresponding upcoming periods. It is assumed that spot market price averages covering these periods will provide a less uncertain spot market price forecast than when forecasting all price variations on the spot market. However, using this forecast approach removes the possibility of simulating a normal spot market trading, since the forecasted spot market will only have two prices, one for NT periods and one for HT periods. It is not possible in the simulations to estimate the potential loss, L_4. However, the spot market price forecast is seen as a good approximation to how actual forecasting could occur for such a plant.

With the economic loss from L_1 reduced to a very small loss and the spot price forecast removing the potential for using the explained optimal approach to estimate L_4, a simpler approach to calculating the capacity bids is used instead. For upward SCR capacity bids, the simpler approach will be based on the one presented for power plants by Müsgens et al. [21]. Müsgens et al. calculate the capacity bid of a power plant delivering upward SCR by using only the power plant's own cost in the capacity bid. Müsgens et al.'s approach to the upward capacity bid of a power plant is shown in Eq. (2).

$$B_{Up-cap} = \begin{cases} \left(B_{spot} - p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, & \text{if } B_{spot} > p_{spot} \\ p_{spot} - B_{spot}, & \text{if } B_{spot} > p_{spot} \end{cases} \quad (2)$$

Where $B_{Up\text{-}cap}$ is the capacity bid for upward regulation in EUR/MW/h, B_{spot} is the spot market bid of the power plant, p_{spot} is the average spot market price in the period, CAP_{op} is the load in MW_e at which the power plant operates to deliver upward SCR, and CAP_{of} is the capacity offered as upward SCR.

As seen in formula 2, Müsgens et al. include the losses L_2 and L_3 in the capacity bid of the power plant, which is the only two of the listed four losses that a power plant could experience by providing upward SCR. However, as a CHP plant is simulated in this paper, the loss L_4 should also be included in the capacity bid. Ideally L_4 should be found as shown in Eq. (3).

$$L_4 = Inc_{spot} - \left(B_{spot} * P_e\right) \quad (3)$$

Where Inc_{spot} is the period's total spot market income in EUR as gained if SCR is not traded and P_e is the electricity trade won on the spot market in MWh_e if SCR is not traded. B_{spot} is the spot market bid for the CHP unit as calculated in Eq. (1).

Based on the earlier discussions, Inc_{spot} and P_e cannot be calculated using the spot market forecast utilized in this paper. Therefore, L_4 is instead fixed through the simulated period, and assumed to be 30 EUR/MWh_e.

This corresponds to the difference of the average spot market price for prices above B_{spot} in 2013 and B_{spot}, rounded up. L_4 is added to the spot market bid of the CHP unit, B_{spot}. Eq. (4) shows the changed Eq. (2), and Eq. (4) is the calculation method used in this paper for capacity bids for upward SCR.

$$B_{Up-cap} = \begin{cases} \left(B_{spot}+L_4-p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, \text{ if } B_{spot}+L_4>p_{spot} \\ p_{spot}-\left(B_{spot}+L_4\right) \quad , \text{ if } B_{spot}+L_4 \le p_{spot} \end{cases} \tag{4}$$

For downward SCR, only the losses L_2 and L_4 need to be included in the capacity bid. The capacity bid for downward SCR is calculated as shown in Eq. (5).

$$B_{Down-cap} = \begin{cases} \left(B_{spot}+L_4-p_{spot}\right) * \dfrac{CAP_{OP}}{CAP_{Of}}, \text{ if } B_{spot}+L_4>p_{spot} \\ 0 \quad , \text{ if } B_{spot}+L_4 \le p_{spot} \end{cases} \tag{5}$$

Where $B_{Down\text{-}cap}$ is the capacity bid for downward SCR. CAP_{op} is here equal to the full electric capacity of the CHP unit, as the unit will be operated at full load when providing downward SCR.

Bspot excluding start costs is found to be 15 EUR/MWh$_e$, assuming 8 hours of operation. B_{spot} incl. start costs is 16 EUR/MWh$_e$, rounded up. With a L_4 for the CHP unit of 30 EUR/MWh$_e$, the capacity bid for a 4 MW$_e$ engine offering 1 MW$_e$ would be as shown in Figure 1. On each graph, the CHP unit is only offered in one SCR direction.

The capacity bids presented in Eq. (4), Eq. (5) and Figure 1 are in EUR/MW/h; however, SCR capacity bids are given in EUR/MW/week. These capacity bids have to be multiplied with the number of hours of the respective SCR period in the given week.

For the purpose of the simulations in this paper, the activation bids are fixed through the simulated period. The bid for upward activation is fixed at 46 EUR/MWh$_e$, being B_{spot} + L_4, and the bid for downward activation is fixed at -16 EUR/MWh$_e$, being -B_{spot}. L_4 should not be included in the downward activation bid, as L_4 is already covered for the full capacity of the CHP unit through the downward capacity bid.

3.3. Example of simulation approach

Figure 2 shows the simulated heat production of scenario 1 in the period from 21st to the 28th of October 2013. The clearing day for the period is the 16th of October. The forecasted heat demand for the period was 499.9 MWh$_{th}$, and it was found that SCR delivery in the NT periods would result in rejection of heat, and as such SCR was only traded in the HT periods. The actual heat demand in the period is 364.7 MWh$_{th}$ as such the heat demand is significantly lower than expected. The forecasted average spot market price in the HT periods was 58.14 EUR/MWh$_e$. Hence, the capacity bid was 728.4 EUR/MW/week, corresponding to 12.14 EUR/MW/h. The marginal capacity bid in the market is 1.054 EUR/MW/week and hence the plant won upward SCR in the HT periods. The actual average spot market price in the HT periods is 46.41 EUR/MWh$_e$.

Figure 2 shows three different graphs: the top graph being the spot market price, the middle graph shows the heat production of each production unit, heat demand and rejection of heat and the bottom graph shows the energy content of the thermal storage system.

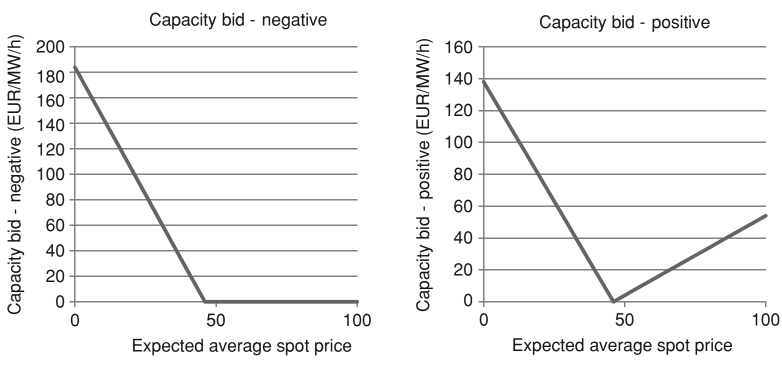

Figure 1: Capacity bids for downward SCR and upward SCR.

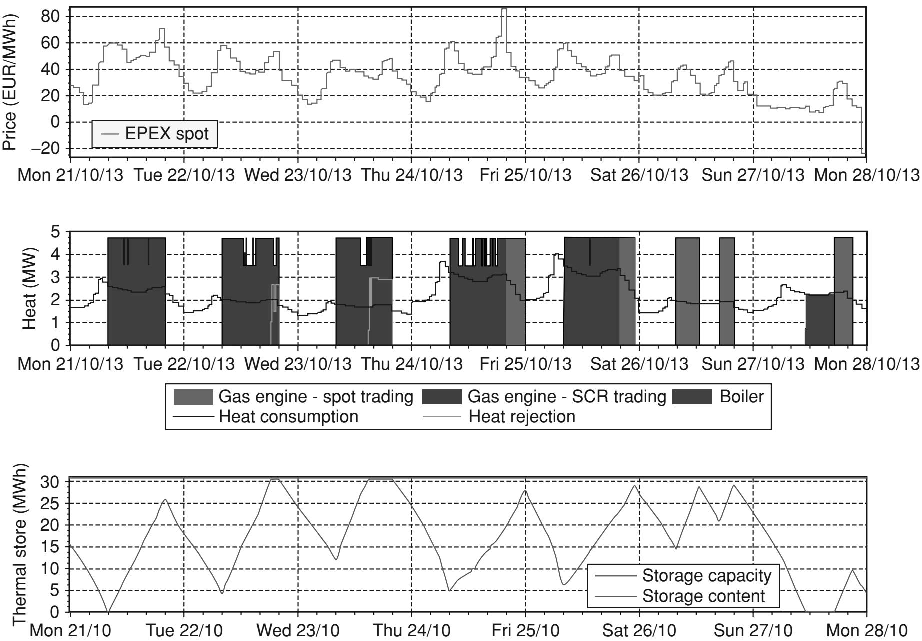

Figure 2: Example of one week's simulated heat production in scenario 1.

As can be seen in Figure 2, in the shown period the plant wins upward SCR in HT periods. In the rest of the week the engine can be used for trading in the spot market, and spot market trading is won in several periods in the end of the week. The heat demand forecast did, however, underestimate the heat demand and in periods the 22nd and the 23rd non-useable and non-storable heat is produced resulting in rejection of heat.

Figure 3 shows the simulated heat production of scenario 2. The shown period is the same as in Figure 2. As in Figure 2, in the shown period the plant wins upward SCR in HT periods, however, as the engine here is assumed to be able to deliver upward SCR activation without being in operation beforehand, the engine is only in operation when being activated as upward SCR, and when traded into the spot market outside of the HT periods.

4. Results of the simulations

Each unit's heat production is shown in Table 2 alongside the rejection of heat in each scenario.

As seen in Table 2, the rejection of heat especially occurs when the CHP unit has the reference flexibility, as in scenarios 1 and 3. The corresponding costs and revenues excluding income from the sale of heat in each scenario are shown in Table 3.

As seen in Table 3, spot revenue is similar in every scenario except for scenario 2. The reason is that, in scenario 2, it is assumed that the CHP unit does not have to be in operation in order to deliver upward regulation, and in periods where SCR is won, the CHP unit is not traded on the spot market. Instead a high income from SCR activation is found. The resulting total costs in each scenario are similar in size, which is due to the utilized bidding strategy reflecting the plant's own costs. Though a decrease in the total costs can be seen in scenarios in which the CHP unit is modelled with increased flexibility. Using a different bidding strategy could increase this difference.

It should be noted that the income from activation is highly uncertain, since the data used for activation is created for this paper using public available data, as described in section 2.1.1. Activation of SCR is depended on where in Germany the participant is located, and as such, the activation income for a specific participant can vary significantly from the activation income presented here.

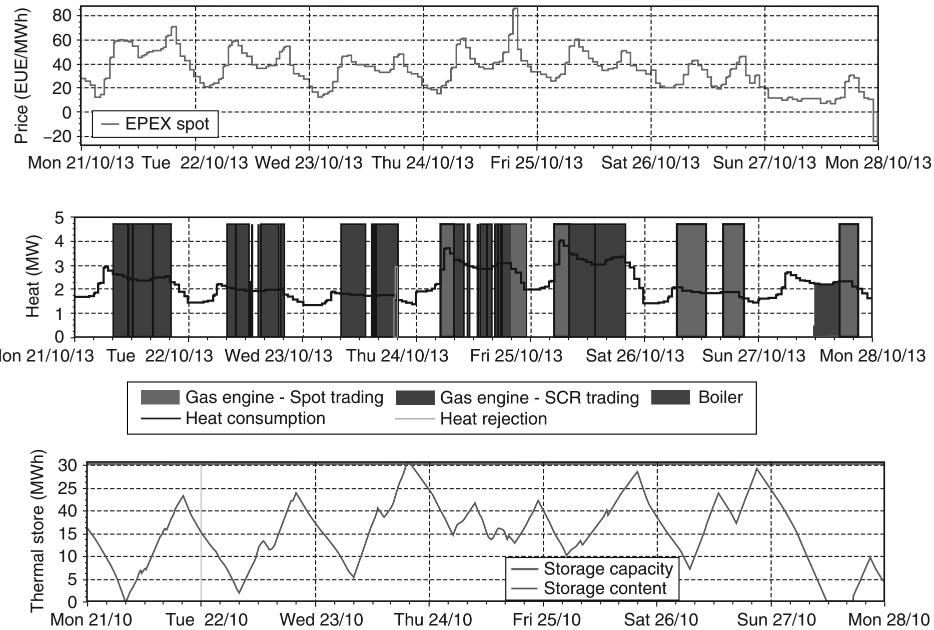

Figure 3: Example of one week's simulated heat production in scenario 2. The week is the same as in Figure 2.

Table 2: Heat produced and heat rejected in each scenario.

[MWh_{th}]	CHP unit	Boiler	Heat rejected
Scenario 1	26,770	3,337	107
Scenario 2	25,358	4,731	89
Scenario 3	26,631	3,629	260
Scenario 4	23,118	6,917	35

Table 3: Costs and revenues excluding income from sale of heat in each scenario.

[1,000 EUR]	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Fuel, taxes and CO2-costs	2,230	2,185	2,233	2,112
O&M incl. start costs	194	208	195	188
Spot trade revenue	961	507	1,009	1,026
SCR capacity revenue	5	17	4	27
SCR activation revenue	32	501	–10	–70
Subsidy revenue	658	623	654	568
Total costs	**768**	**744**	**770**	**749**

4.1. Sensitivity analyses on L_4

In order to estimate the effect of the chosen L_4, a sensitivity analysis has been made for L_4. L_4 is in the reference set at 30 EUR/MWh$_e$. Here L_4 is tested for each 5 EUR/MWh$_e$ increment from 15 EUR/MWh$_e$ to 75 EUR/MWh$_e$. The resulting total costs for each scenario are shown in Figure 4.

As seen in Figure 4, scenario 2 is mostly affected by a change in L_4. The reason is the change in capacity bids, where in scenario 2 the bid for spot prices estimated at below $B_{spot} + L_4$ is zero, as the CHP unit does not have to be in operation in order to deliver activation. In scenario 2, at a low L_4, the CHP unit wins upward SCR in only a few hours and, at a high L_4, the CHP unit wins upward SCR in many hours with a capacity bid of zero. Scenario 2 provides lower total costs than scenario 1 with a L_4 from around 30 EUR/MWh$_e$ to 60 EUR/MWh$_e$. In the shown range of L_4, Scenario 4 provides lower total costs than scenario 3.

5. Conclusion

In this paper, an approach to simulating the participation of a small-scale CHP plant in the German SCR is discussed. Part of the simulation approach is the bidding strategy of the CHP plant, where the discussed strategy aims at making the bid reflect the plant's own costs. The discussion of the bidding strategy takes its departure in the current research of bidding strategies for power plants as discussed by Müsgens et al. [21], adjusting it to the special circumstances for small-scale CHP plants. It is found that the CHP plant's participation in the German SCR is affected by four potential losses that do not affect the participation of a traditional power plant.

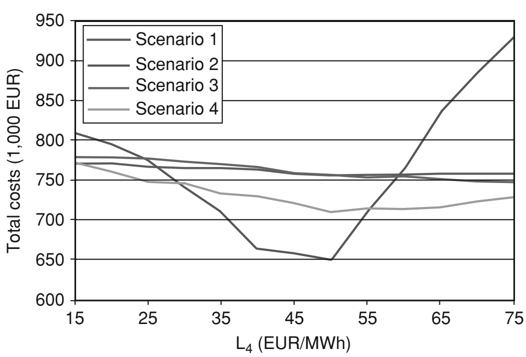

Figure 4: Total costs at different L_4 in each scenario.

Each of these losses should be included in a CHP plant's bid in order for the bid to be cost-reflective; however, the effect of these losses will, due to the time span between market clearing and actual operation, have to be estimated based on relatively uncertain forecasts. In order to make it more attractive for the small-scale CHP plants to participate in the German SCR, the rules for the SCR should help minimize these losses and reduce the corresponding uncertainties. Specific suggestions for changing the rules of the SCR have not been presented in this paper; however, e.g. having the clearing day closer to the first delivery day and granting market participants the possibility to change activation bids after the clearing day, would result in reduced uncertainty for the small-scale CPH plants.

In this paper, it is also investigated how different capabilities for the technical flexibility of the CHP unit affect the potential gain from participating in the German SCR. An increased flexibility of the CHP unit is found to increase the potential gain that the CHP plant can attain in the German SCR, especially when offering upward regulation in the SCR. The results are especially sensitive to the bidding strategy utilized by the plant.

Acknowledgements

The work presented is a result of the Strategic Research Centre for 4th Generation District Heating Technologies and Systems (4DH) partly financed by the Danish Council for Strategic Research. Thanks to Arne Jan Hinz at Stadtwerke Schwäbisch Hall for his comments on the method.

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Appendix III

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Future Power Market and Sustainable Energy Solutions – The Treatment of Uncertainties in the Daily Operation of Combined Heat and Power Plants

Applied Energy 144 (2015) 129–138

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Future power market and sustainable energy solutions – The treatment of uncertainties in the daily operation of combined heat and power plants

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HIGHLIGHTS

- Increasing renewables make electricity system balancing increasingly important.
- Small-scale combined heat and power plants can provide electricity system balancing.
- Plants are experiencing decreasing feasibility of combined heat and power units.
- We simulate a small-scale district heating plant with solar collector fields.
- Providing electricity system balance can increase feasibility of small-scale plants.

ARTICLE INFO

Article history:
Received 21 June 2014
Received in revised form 3 February 2015
Accepted 9 February 2015
Available online 27 February 2015

Keywords:
Electricity market
Balancing service
District heating
CHP
Solar heating

ABSTRACT

Intermittent renewable energy sources (RES) are increasingly used in many energy systems. The higher capacity of intermittent RES increases the importance of introducing flexible generation units into the electricity system balancing. Distributed district heating plants with combined heat and power (CHP) can provide this flexibility. However, in electricity systems with a high penetration of intermittent RES, CHP units are currently experiencing decreasing hours of operation, making it likely that existing CHP capacity will be phased out from the energy system. Furthermore, when the plants provide balancing for the electricity system, the complexity of their daily operation planning is increased. This article analyses and discusses how these units can improve their economic feasibility by providing balancing services to the electricity system, benefitting both each individual plant and the system as a whole. This is done by using the case of the Danish district heating plant, Ringkøbing District Heating, which has a relatively high capacity of solar heating installed and is located in an area with a high penetration of wind power. It is found that the plant can increase the economic feasibility of the CHP unit by participating in the electricity balancing tasks; however, it is uncertain whether the benefits are substantial enough to keep the distributed CHP capacity in operation.

1. Introduction

The transformation of the existing energy system into a future sustainable energy system imposes new challenges to the energy system. The increased capacity of intermittent renewable energy sources (RES) increases the need for flexibility in the energy system [1,2]. Lund et al. [3] found that district heating (DH) should have an increased interaction with the electricity system in future sustainable energy systems, as DH can help integrate flexible solutions and improve the energy efficiency of the system. This is supported by studies of different countries energy system. Connolly and Mathiesen [4] present a pathway to a 100% renewable energy system, using Ireland as a case. In the pathway DH is utilized with a high degree of interaction with the electricity system. The Danish governmental appointed Commission on Climate Change [5], The Danish Society of Engineers [6], Lund et al. [7] and Münster et al. [8] all investigate the role of DH in future sustainable energy system in Denmark. They all find that DH should play an active role and have an increased interaction with the electricity system. Liu et al. [9] investigate the ability of the Chinese energy system to

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http://dx.doi.org/10.1016/j.apenergy.2015.02.041
0306-2619/

integrate wind power, and finds that an increased interaction between DH and the electricity system can greatly increase the ability to integrate wind power. DH is a system which allows the distribution of heat produced centrally through a network to end consumers in larger areas. DH enables the use of a wider variety of heat sources and an increased flexibility in heat production. Production units such as combined heat and power (CHP) units and heat pumps enable DH interaction with the electricity system, thus providing flexibility in the electricity system. These production units are found to be of increasing importance to the energy system and can also be useful in other connections than DH, such as desalination [10].

An increasing capacity of intermittent RES will increase the need for balancing the electricity system [11,12], and it becomes increasingly important to have flexible generation units participate in this balancing [13,14]. Sorknæs et al. [15] show that wind power can provide some balancing through a balancing market; however, this is expected only to be relevant in relatively few cases. Balancing has traditionally been provided by large production units, such as hydro power and steam turbines based on fossil fuels and nuclear power. As many of the large production units are inflexible by design, it is expected that these will become unfeasible with a high penetration of intermittent RES in the energy system [16]. As these large units leave the system, flexible distributed generation units will be needed to provide a larger share of the balancing. Here, the distributed DH plants can play an important role. However, it is also expected that buildings will become increasingly energy efficient [17,18], resulting in lower heat demands. This in turn will reduce the hours of operation of the DH production units [19]. It will still be possible to have a stable or increasing DH demand in areas, where the DH demand can feasibly be increased by connecting new buildings to the DH system, to an extend where it makes up for the heat demand reduction from improved energy efficiency of buildings. However, this will not be possible in all areas [20]. As the hours of operation are reduced, it will become even more important for DH plants to increase the value of each hour of operation to cover the long-term marginal costs. This can be done by, for example, increasing the value of traded electricity by selling or purchasing electricity at times when the electricity system needs it the most. A practice already utilized by many DH plants. Likewise, the DH plants can participate in the balancing of the electricity system to increase their income. Thus, providing electricity system balancing does not only benefit the electricity system as a whole, but can also benefit the individual DH plants.

As argued by Lund and Andersen [21], in the EU, distributed DH plants with CHP have undergone a change in the interaction with the electricity system. Lund and Andersen [21] define this change as a four-stage development; going from the first stage with electricity being settled by a fixed price and subsidy, to the last stage with electricity being settled on international electricity markets where fluctuating renewable energy has a major influence on the market price. This development also highlights the development of an increasing amount of uncertainties in the daily operation of a DH plant. This is especially the case of distributed DH plants with several production units or a thermal storage system, as these plants are flexible in terms of how and when the required heat is produced. In the earlier stages with a fixed price and subsidy, the electricity price was known weeks or months in advance. In the later stages, the electricity price is only known after the electricity trading has occurred, and then often for only the following 12–36 h on day-ahead wholesale markets. On intraday wholesale markets and balancing markets, the period can be even shorter. The participation on balancing markets introduces further uncertainty, as the dispatch on balancing markets is often not guaranteed and only known once the dispatch of the units has taken place. Further, the price on a balancing market is for some price structures settled after dispatch. Besides these uncertainties, the participation on different markets will often result in different gate closures for bidding, and an offer on one market could partly be based on the forecasts of prices on markets with later gate closure, which further complicates the daily operation. For distributed DH plants, these challenges are especially prominent, as these rarely have the manpower to analyse this on a daily basis.

These challenges are already visible in Denmark. Denmark has an extensive use of DH. In 2012, about 62% of all households were connected to DH. Likewise, the implementation of distributed CHP units in DH plants is relatively high. In 2012, 541 distributed CHP units accounted for about 13% of the total installed electric capacity in Denmark [22]. Danish CHP plants with a capacity larger than 5 MW_e have since 2007 been required to trade on market terms, and most of the distributed CHP plants in Denmark trade under market conditions [23]. Prior to being forced to assign to market conditions, the distributed CHP plants were managed according to the so-called triple tariff, where three different tariff rates are set according to Danish regulations [24]. Units smaller than 5 MW_e can choose to stay on the triple tariff until 2015 [23]. The triple tariff operates with low payments for electricity in the weekend, and this originally incentivised the plants to acquire thermal storage systems that could store heat from the CHP through the weekend. Therefore, the distributed CHP plants in Denmark have for the most part installed thermal storage systems. More detailed overviews of the Danish incentive policies for CHP in DH and RES can be found in Sovacool [25], Hvelplund [26] and Chittum and Østergaard [27].

Besides the development of the distributed CHP plants, a large share of RES in the form of wind turbines is installed in the Danish electricity system. In 2013, wind power production accounted for 33.8% of the total electricity production in Denmark [28]. Like the distributed CHP plants, a large share of the Danish wind turbines trade under market conditions and their production directly affects the market price. Thus, increased wind power penetration has proven to decrease the market price [29]. Denmark is an integral part of the power exchange Nord Pool Spot. The Nord Pool Spot area covers Denmark, Estonia, Finland, Latvia, Lithuania, Norway and Sweden. The Nord Pool Spot area is geographically divided into smaller bidding zones, where prices are settled separately when bottlenecks occur between the bidding zones. The Danish electricity system is divided into two bidding zones, Western Denmark (DK1) and Eastern Denmark (DK2). These are interconnected to Continental Europe and the Scandinavian Peninsula, respectively [30]. Most of the Danish wind power is produced in DK1. In the last couple of years, the average wholesale electricity price in DK1 has decreased from a peak of about 48 EUR/MW h in 2011 to about 39 EUR/MW h in 2013. Likewise, the number of hours with high electricity prices has also decreased. In 2011, the price was above 45 EUR/MW h in 5309 h, while in 2013, this had decreased to 1826 h [31]. Danish distributed CHP plants will for the most part sell electricity during hours with high electricity prices. Due to the decreasing number of these hours, the electricity production from distributed CHP plants in Denmark went from 6.18 TWh in 2011 to 4.48 TWh in 2013 [28]. The DH not produced by CHP units is to a large extent instead produced on fuel boilers producing only heat, which for many Danish distributed CHP plants is natural gas fired boilers. As the advantage of a DH network is among other the ability to utilize otherwise discarded heat [3], e.g. using CHP units, this development is problematic as it reduces the advantages of DH, as heat production using natural gas boilers can occur more fuel efficiently at each individual building, when taking into account heat loss in DH grids. The Danish distributed CHP plants are already now experiencing the challenge of covering their long-term marginal cost with decreasing hours of operation. As the CHP units' hours of operation are decreasing, many distributed

CHP plants in Denmark are looking into the possibilities of installing other production units to keep their production costs low. As many of these plants are required by law to use natural gas as a fuel, many distributed CHP plants are installing large solar collector fields in order to reduce the use of natural gas, which is increasingly used in boilers. In Denmark natural gas is particular expensive when used for heat-only production due to energy duties. In 2007, the total installed solar collector field area in district heating systems was less than 50,000 m^2. In 2013, this had increased to nearly 400,000 m^2, and more collector fields are expected in the future [32]. This increase reduces the need for CHP units for heat production, especially in the summer period. Due to the production nature of solar collector fields, it also increases the uncertainties in the daily operation planning. Understanding the influence of these aspects on the daily planning of distributed CHP plants is becoming increasingly relevant. The aim is to make sure that the flexibility that can be provided by these units is utilized in the energy system, thus benefitting both the individual plants and the system as a whole.

Investing in the correct technologies is essential for these plants, and as such investment analysis has received some attention, both on energy system level and on individual plant level. Examples of investment analysis on energy system level include Lund and Münster [33] that investigate how CHP plants with heat pumps could help balance the fluctuating wind power in the Danish energy system, and found that this could make it possible to increase the share of wind power to 40% without balance problems, and Lund and Clark [34] that investigate the social economic benefits of balancing wind power production with Danish CHP plants by investing in increased heat storages and heat pumps instead of reliance on import and export. On individual plant level, Fragaki and Andersen [35] explore the most economic-size gas-fired CHP plant with a thermal storage in the UK market setting, Streckienė et al. [36] investigate the feasibility of CHP plants with thermal storage systems in the German spot market, Lund and Andersen [21] investigate optimal investment in CHP plants under different pricing schemes in Denmark and Fleten and Näsäkkälä [37] analyse investment threshold levels for gas-fired power plants.

These feasibility studies have shown that these types of plants can achieve economic feasibility, though the feasibility is dependent on the setup of the energy system in which they are integrated and under what conditions they have to operate. As the energy systems and conditions are changing with the increasing integration of intermittent RES, it is relevant to investigate the potential challenges in the daily operation of these plants in an energy system with a high integration of intermittent RES. As the integration of intermittent RES is already high in Denmark, an existing Danish DH plant is used as a case. The scope of this paper is to further investigate these challenges in relation to the daily operation of DH plants. The paper will not include any investment analysis, as such only technologies already utilized at the case plant will be included. The methodology is discussed and described in Section 2; the analysis is described in Section 3, and the results of the analysis are shown and discussed in Section 4.

Table 1
Natural gas-fired units currently in operation at RDH. The total efficiency is found using the lower heating value for natural gas, and the efficiency can therefore for some units increase above 100%.

Production unit	Electric capacity MW	Heat capacity MW	Total efficiency %
Engine	8.8	10.3	96
Boiler 1	–	7.0	103
Boiler 2	–	11.5	105
Boiler 3	–	10.0	91
Boiler 4	–	11.5	105

2. Methodology

The specific challenges can vary between countries and between plants, and it is relevant to analyse the described challenges through the simulation of a specific case. As the market conditions in Denmark have proven their ability to integrate large shares of intermittent RES [1], these market conditions are perceived as representative for market systems with a high integration of intermittent RES. Likewise, Denmark has a relatively high amount of DH plants with flexible distributed CHP units. On this basis, a distributed DH plant in Denmark is chosen as a case, the Ringkøbing District Heating plant (RDH). RDH is a consumer-owned DH plant situated in the western part of Denmark, where it delivers heat to the town of Ringkøbing. Currently, RDH has a CHP unit, an electric boiler, thermal storage units, natural gas fired boilers, and large solar collector fields. RDH participates both on the wholesale electricity market and offers balancing services to the electricity system. Thus, RDH is a useful case for analysing the challenges described above.

2.1. Electricity markets in Denmark

Denmark is part of Nord Pool Spot. The main market of Nord Pool Spot is Elspot, which is a day-ahead wholesale market. Trading on Elspot occurs daily and starts with each transmission system operator (TSO) in the Nord Pool Spot area informing the market about the available capacity on the interconnectors for trade on Elspot on the following day. This occurs at 10 a.m. The gate closure for bidding on Elspot is at 12 noon, and bids have to cover full hours. A single hourly bid can either be price dependent or price independent. It is possible to pool a period of at least three hours into a single price dependent bid, called a block bid, where the average price in the block is used to determine whether the bid is won or not. The market prices for each hour of the following day are revealed before 1 p.m., and the participants are contacted. At this point, the expected electricity production is equal to the expected electricity consumption of each hour of the following day. Elspot is a marginal price auction, where the market is cleared based on the most expensive winning bid [30]. Trades on Elspot are binding, but it is still possible to trade expected imbalances on the wholesale intra-day market Elbas until one hour before the operating hour. After the gate closure of Elbas trading, any imbalances between scheduled production and consumption are penalised using the activation prices on the balancing market, the Nordic regulating power market [38].

The Nordic regulating power market is the balancing market for tertiary control reserve, which the TSO uses to replace activated secondary control reserve [39]. On the Nordic regulating power market, a market participant can for each hour offer both to be available for regulation the day before, and to be activated as regulation. The maximum technical response time to participate in the market is 15 min. The gate closure for availability bids for the following day is at 9:30 a.m. Winning availability is not a requirement for offering activation. However, if availability is won, the participant has to offer the corresponding type of activation in those hours. Like Elspot, the market is asymmetric, and it is hence possible to offer either downward regulation, activated when there is excess electricity in the system, or upward regulation, activated when there is a lack of electricity in the system. Bids on the regulating power market cover full hours; however, the period of activation can be shorter than one hour. Only activation periods longer than ten minutes are settled according to the market price at that hour. In case of activations periods below ten minutes, the activation payment is settled according to the pay-as-bid principle, meaning that the participant must pay for activation according to the participant's bid and not the market price. The market price is equal to the bid of the marginal unit in the dominant activation direction in that hour. If activation occurs in the direction that is not dominant, the unit is settled according to the pay-as-bid principle. When a participant is activated as upward regulation, the participant is paid by the TSO, and if downward regulated, the participant has to pay the TSO. Activation can also occur due to special balancing needs, such as local congestion in the transmission grid. This type of activation is settled using the pay-as-bid principle. The length of activations and the chance of even being activated are not known to the participants at gate closure. The gate closure for activation bids on the regulating power market is 45 min before the operating hour, and the minimum bid size is 10 MW. It is possible to pool several participants into one bid in order to reach this minimum requirement [38].

As the used electricity markets cover several countries, it is expected that the methodology presented in this paper can directly be applied to any of these. Likewise, it is expected that the methodology can be used for countries with similar organisation of the wholesale trading of electricity and the tertiary control reserve.

2.2. Ringkøbing District Heating

RDH delivers heat for space heating and hot water consumption to approximately 4000 consumers in the town of Ringkøbing. In 2013, the total sale of heat was 97,356 MW h and the heat loss in the grid was 19.1%. The primary fuel of the plant is natural gas, which is used in the production units shown in Table 1. The efficiencies shown for the engine are when operated at full load. For the natural gas boilers the average efficiencies are presented.

The natural gas fired engine is a Wärtsilä 20V34SG. Besides the natural gas-fired units, the plant also has a 12 MW_{th} electric boiler and two similar solar collector fields, each with 15,000 m^2 of solar panels with a peak capacity of 11 MW_{th}. The first of these fields was established in 2010 and the second was established in early 2014. The solar thermal collector fields comprise of a total of 2400 individual collectors, where 1440 collectors are of the type ARCON HT-HEAT store 35/10 with foil and the remaining 960 collectors are of the type ARCON HT-HEAT boost 35/10 without foil. They are in each field set in 24 rows with a distance between the rows of 4 m. All collectors are oriented towards south and placed on flat terrain. The solar collectors have an inclination of 30 degrees to the surface. The measured efficiency of the electric boiler is close to 100%, and for the purposes of this paper it is assumed to be 100%. Furthermore, the plant also has three thermal storage units. The first storage unit has a net storage capacity of 250 MW h_{th}, and is utilized by the engine and electric boiler. The second and third unit each has a net storage capacity of 60 MW h_{th}, and they are both primarily used for storing heat from the solar panels. The net storage capacities of the thermal storage systems are based on the net volume of water in the tank that can actually be used for thermal storage and the temperature levels in the top and bottom of the thermal storage units in the simulated period.

In the simulated period, RDH participated on Elspot and the Nordic regulating power market. Every day at 10 a.m., RDH's electricity market trader and aggregator provides them with a forecast of the hourly prices on Elspot for the following five days. The daily trading on the Elspot market at RDH is carried out around 11 a.m. At this time, a rough estimation of the following day's heat demand and solar heating production is also made based on the weather forecast for the area and the current heat demand and production. RDH's trader and aggregator only offers the plant the ability to submit block bids and price independent single hourly bids on Elspot. RDH does not offer availability on the regulating power market. Instead upward regulation is offered if the engine has not won trade on Elspot. Downward regulation is offered if the engine has won trade on Elspot or the electric boiler has not won trade on Elspot.

In the simulated period, RDH's price of natural gas was settled based on the price on the gas exchange NetConnect Germany. The natural gas price for RDH is settled on a daily basis on the day after operation, and RDH does not have a gate closure for trading on this market. However, the price of the natural gas is not known by the plant until the day after it has been used. For the natural gas price forecast, RDH uses the price from the day before as a forecast for the following days.

3. Simulating the daily operation

To analyse the case, the daily operation of RDH has been simulated. Even though the simulation of CHP plants is well described in literature [40], the challenges in the daily operation described above have not received much attention. However, some studies have investigated strategies for the daily electricity trading of DH plants. Pirouti et al. [41] describe a method for the optimal daily operation of a biomass CHP plant with a thermal storage unit trading electricity on a day-ahead wholesale market. The study does not include balancing markets or forecasts. Rolfsman [42] describes an optimization model for the daily operation strategy of CHP plants utilizing thermal storage units on a day-ahead wholesale market and an intra-day wholesale market. The model uses a simplified approach to the prices on the intra-day wholesale market. For the wholesale market, a price forecast is used for the coming 24 h. The model does not include forecasts for the heat demand, nor does it include balancing markets. Thorin et al. [43] introduce a model for the optimization of CHP plants operating on both a day-ahead wholesale electricity market and a frequency restoration reserve market. The model does not consider market gate closures, but uses a simplified approach to model the operation on the balancing market. Andersen and Lund [44] calculate the activation bids on a balancing market by using forecasts of heat demand and wholesale market prices. These forecasts are used alongside the short-term operation costs to calculate how the possible activation of a unit on a balancing market will change the expected net heat production cost (NHPC) the following days. The method is developed for systems with CHP units and fuel boilers. Though these studies investigate the daily operation, none of them include sufficient details of how to deal with the described challenges in the daily operation of distributed DH plants. Another approach is used in this paper.

The objective of the simulations is to approximate the daily operation of a DH plant. The simulation approach should account for the chronological decision time aspect and the use of forecasts in the decision process. The chronological simulation approach is gained by dividing each day into 24 separate simulations, one for

Table 2
Heat production costs for each unit in 2013. The market prices for natural gas and electricity are not included in the table. Conversion rate: 1 EUR = 7.45 DKK.

Production unit	Fuel transport costs EUR/MW h_{th}	Taxes incl. CO_2 quota cost EUR/MW h_{th}	O&M costs EUR/ MW h_{th}	Start costs EUR/ start
NG engine	5.1	30.1	6.3	129.9
NG boilers 2 + 4	2.6	36.5	0.3	0
Electric boiler	30.1	34.6	0	0

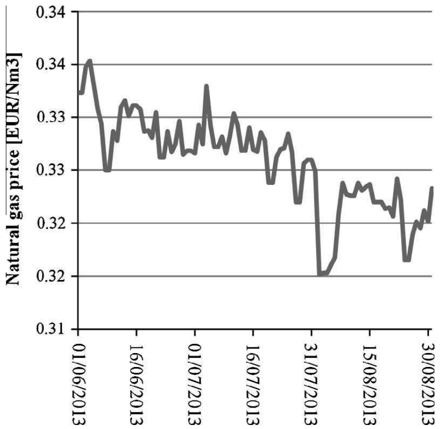

Fig. 1. RDH's daily prices for natural gas in the period from 1st of June to 31st of August. Conversion rate: 1 EUR = 7.45 DKK.

each hour. All at the starting point of each hour. These are, in this paper, referred to as simulation steps. Each of these simulation steps represents a time of decision in the daily planning process, corresponding to the gate closures on the regulating power market. The simulation steps are then run chronologically, so that decisions in earlier simulation steps affect the later steps. All simulation steps cover a simulation period of 6 days; one being the day of operation and five being the days following this day. The 24 simulation steps of each day can be divided into four different periods:

- At 12 midnight, the forecasts for natural gas price, heat demand and solar collector production are updated. The Elspot price forecast from the day before is used. At this point, trading only occurs on the regulating power market.
- In the period from 1 to 11 a.m. the Elspot price forecast from the day before is used. In this period, trading only occurs on the regulating power market.
- At 11 a.m., the forecast for the Elspot prices is updated. Trading occurs both on the regulating power market for the following hour and on Elspot for the following day.
- In the period from 12 noon to 12 midnight, the actual Elspot prices for the following day are used instead of the forecasted prices. The productions won on Elspot for the following day are locked. In this period, trading only occurs on the regulating power market.

For each simulation step, the thermal storage units in the end of the six-day period will be set at a level equal to the content in the beginning of the period. The only exception is if the forecasted solar collector production and any heat production from units already traded on any electricity market are greater than the forecasted heat demand. In that case, any surplus heat increases the thermal storage units' content in the end of the period by that amount.

Each electricity market bid is calculated using the method developed by Andersen and Lund [44] to calculate bids. Using this method, the electricity market bids are calculated as the change in total forecasted NHPC for the following days taking into account the content in the thermal storage units. More specifically, the bid price is found as shown in Eq. (1).

$$B = (\mathrm{NHPC}_1 - \mathrm{NHPC}_2)/C \quad (1)$$

where B is the bid price for the given unit; C is the offered electric capacity of the given unit; NHPC_1 is the NHPC with the given unit activated in the given period, but without the potential electricity income or cost of the unit in the period; and NHPC_2 is the NHPC without the given unit in the given time period. Hence, the electricity market bids are not only based on the production costs of the individual units, but also on the change in the expected operation of the other heat producing units.

To simulate the expected NHPC for the following days at RDH, the simulation tool energyPRO has been utilized. energyPRO has been used for a number of simulations of DH plants in research. Streckienė et al. [36] use energyPRO to investigate the feasibility of CHP plants with thermal storage systems in the German spot market. A similar analysis was made for the UK by Fragaki et al. [45], also using energyPRO. Fragaki and Andersen [35] use energyPRO to find the most economic size of a gas engine and a thermal storage system, for CHP plants that are traded aggregated in the UK electricity system. Nielsen and Möller [46] use energyPRO as part of an investigation in how excess solar heat production from buildings would affect the local DH systems. Lund et al. [47] investigate how boiler production in DH in Lithuania can be replaced by CHP units using energyPRO. Østergaard [48] uses energyPRO to analyse the effect of different energy storage options for a local energy system with 100% renewable energy. EnergyPRO has been used for the design of most of the distributed CHP plants in Denmark [21]. energyPRO can simulate the energy consumption and production of a DH plant trading on several electricity markets and fuel markets, while utilizing CHP units, electric boilers, fuel boilers, solar collector fields and thermal storage units. The simulation objective of energyPRO is to reduce NHPC of the modelled DH plant. energyPRO does this by splitting a simulation period into blocks, down to five minutes each, and for each of these blocks, the NHPC of each production unit is calculated. Afterwards, the production units are utilized until the heat demand is reached, starting with the unit and block with the lowest NHPC, taking into account the minimum operation time of units, thermal storage units, and the heat demand of the blocks [49]. However, this also means that energyPRO does not simulate a period chronologically. The chronological approach is instead attained by the authors through the previously mentioned simulation steps, where each simulation step corresponds to one simulation in energyPRO.

RDH is simulated for the summer period. The simulated period is from 1st of June to 31st of August, corresponding to 2208 simulation steps. This period was chosen as the heat demand ex plant is relatively low and the solar collector production is high. The CHP unit, NG boilers and the electric boiler will therefore in this period have to produce smaller amounts of heat, compared with other periods of the year, making it important to find the best hours of production for these. As finding these hours will be based on forecasts, the uncertainties are especially predominant in the daily operation planning in the summer period. As such, the summer period is seen as the best period to highlight the challenges of

Table 3
Simulated heat production for the period from 1st of June to 31st of August 2013. The difference in total heat demand in scenario 3 is due to rounding.

Production unit	Scenario 1 $\mathrm{MW\,h_{th}}$	Scenario 2 $\mathrm{MW\,h_{th}}$	Scenario 3 $\mathrm{MW\,h_{th}}$
NG engine	3811	4779	5109
NG boilers	2571	1336	969
Electric boiler	60	528	504
Solar collectors	7042	7042	7042
Heat rejection	0	116	0
Final storage content	178	263	320
Heat demand	13,306	13,306	13,304

Table 4
NHPC of scenario 1.

Production unit	Fuel costs 1000 EUR	Taxes incl. CO_2 quota cost 1000 EUR	O&M and start costs 1000 EUR	Electricity trading 1000 EUR	NHPC 1000 EUR
NG engine	241.5	114.4	30.1	−232.8	153.2
NG boilers	79.1	93.1	0.7	–	172.9
Electric boiler	1.8	2.1	–	0.2	4.1
Final storage	−4.9	−2.4	−0.6	3.2	−4.7
Total	317.6	207.2	30.2	−229.5	325.5

the increased uncertainties in the daily operation planning. With the exception of the solar collector production, all data used is from this period in 2013. For the purpose of simulating the two solar collector fields, the solar collector production from the three months of 2013 is doubled. The double production is assumed as the two solar collector fields are of identical set-ups and placed next to each other, and it is assumed that the older collector field has not suffered any efficiency loss. The heat demand ex. plant and solar collector heat production used in the simulations are the hourly data measured by the plant in the three months of 2013 [50]. In the simulated period of 2013, a total of 13,306 MW h_{th} was delivered ex plant. Due to the lack of forecast data, a simple approach has been used to produce forecasts of the heat demand and solar collector production. Each hour of the last full day's heat demand and doubled solar collector production is used in each simulation step as a forecast for the rest of the operation day and the five following days. To forecast the natural gas prices and Elspot prices, the forecasts utilized by RDH in the period are applied.

The heat production costs of each production unit at RDH in the simulated period are shown in Table 2. Natural gas (NG) boilers 1 and 3 are not included in the table, as these are not needed in the summer months. The solar collector fields are assumed to have a heat production cost of zero, and as it is not seen as feasible to close down operation of the solar collector fields, as this would mean covering the panels, the production from the solar collector fields is always prioritised.

RDH's daily prices for natural gas excl. transport costs in the period can be found in Fig. 1.

Based on these data for RDH, three different scenarios have been defined using the simulation approach described:

1. RDH only purchases and sells electricity on Elspot with the described forecasts of market prices, heat demand and solar heating.
2. As scenario 1, but RDH also participates on the regulating power market.
3. As scenario 2, but the forecasts are equal to the actual values (perfect forecast).

Whereas scenarios 1 and 2 provide a fairly realistic simulation of a DH plant, scenario 3 is not seen as realistic as it requires perfect knowledge of the future. However, it is included in order to highlight the cost of the uncertainty that the chosen forecasts introduce, while also illustrating how not including the forecasts affect the results. In all three scenarios, the thermal storage units will be empty at the beginning of the simulation period; however, the storage content at the end of the simulation period can vary. For the purpose of comparing the scenarios, any energy in the thermal storage units at the end of the simulation period will be valued as equal to the average NHPC of August.

The level of detail of the data available for the regulating power market is full hours [31]. Thus, in the simulations, all activations on the regulating power market are assumed to be full hours. As such, the simulated activation bids, calculated in each simulation step, are based on the assumption of one full hour of activation. Activations are assumed won, if the bid is lower than the market price. Activations are assumed to only occur in the dominant activation direction in the price area DK1, as defined by the market price. Hence, special regulation is not included in the simulation. Only market prices for Elspot are forecasted. It is assumed that RDH's participation does not affect the market prices. All simulated bids on Elspot for the CHP unit is set as price independent bids in blocks of at least 3 h. For the electric boiler, single hour price independent bids are used for the participation on Elspot. In the simulations the CHP unit and the electric boiler will never be operated in part-load. The NG boilers are assumed to be able to part-load without a loss of efficiency. For the technical modelling, each production unit is modelled using only its input and output capacities, as described in Section 2.2. The thermal storage units are modelled using only their capacity for storing energy. Aspects such as stratification in the thermal storage units and capacity in and out of the thermal storage units are not included. In the simulations, the plant will fulfil any won bids, even if this results in the rejection of heat. Heat rejection can occur if the thermal storage units are full and the already traded combined production of the CHP unit and the electric boiler, and the expected production of the solar collector fields, exceeds the heat demand. If rejection of heat is forecasted, the CHP unit and the electric boiler will not be traded into any electricity market.

As mentioned earlier, energyPRO is utilized by both industry and in other scientific studies. As such, the energyPRO part of the simulation approach is seen as validated by its existing use. The remaining simulation approach was validated by extracting the production data found by energyPRO for each simulation step. The production data was then checked manually, and simulation steps featuring certain situations, e.g. periods with rejection of heat and downward or upward regulation of units, was recalculated

Table 5
NHPC of scenario 2.

Production unit	Fuel costs 1000 EUR	Taxes incl. CO_2 quota cost 1000 EUR	O&M and start costs 1000 EUR	Electricity trading 1000 EUR	NHPC 1000 EUR
NG engine	303.1	143.4	40.8	−292.6	194.7
NG boilers	41.1	48.4	0.4	–	89.9
Electric boiler	15.8	18.3	–	−4.2	29.9
Final storage	−7.2	−3.6	−1.0	5.4	−6.6
Total	352.8	206.6	40.2	−291.5	308.1

Table 6
NHPC of scenario 3.

Production unit	Fuel costs 1000 EUR	Taxes incl. CO_2 quota cost 1000 EUR	O&M and start costs 1000 EUR	Electricity trading 1000 EUR	NHPC 1000 EUR
NG engine	324.1	153.3	42.4	−315.7	204.1
NG boilers	29.9	35.1	0.3	–	65.2
Electric boiler	15.1	17.5	–	−3.4	29.2
Final storage	−8.6	−4.2	−1.2	6.7	−7.3
Total	360.5	201.7	41.4	−312.5	291.2

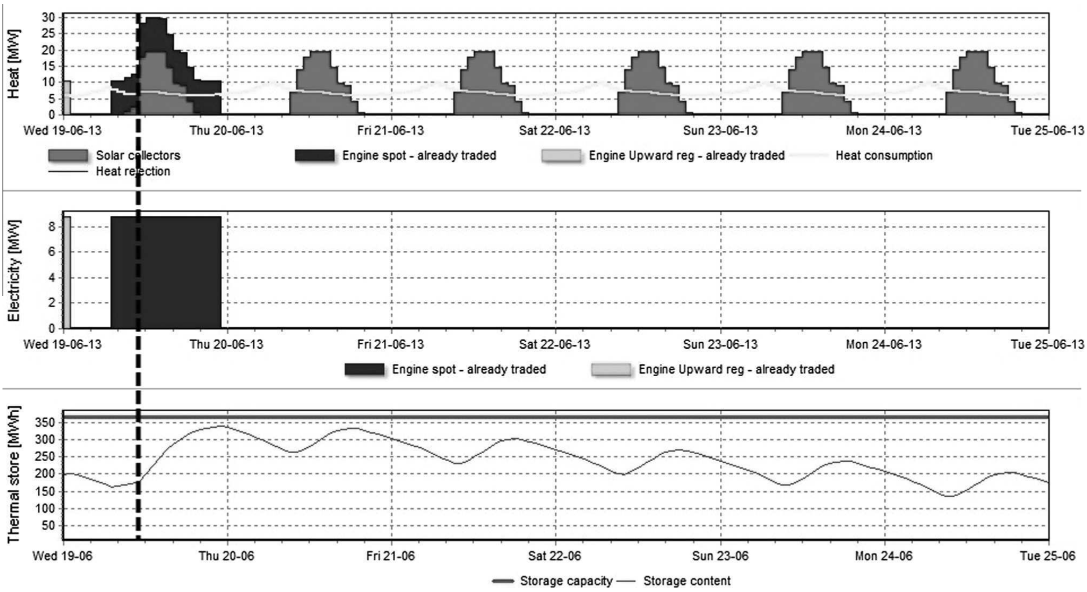

Fig. 2. Scenario 2 at 11 a.m. on the 19th of June. The dotted black line indicates the time.

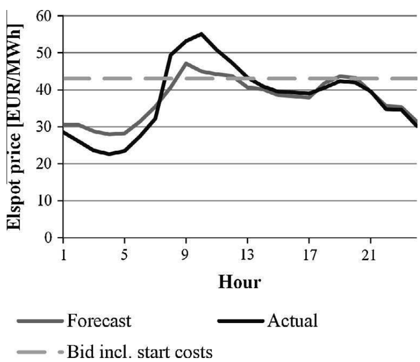

Fig. 3. Actual and forecasted Elspot prices for DK1 on the 20th of June 2013. Actual prices from [31].

manually in order to check that the simulation approach produced the lowest NHPC for each simulation step, according to the method described. The RDH specific economic data and data for production units were validated though contact with RDH.

4. Results

The simulated heat production of each scenario can be found in Table 3. The economic results of each scenario can be found in Tables 4–6, respectively.

The results show that the participation on both the regulating power market and the wholesale market can reduce the NHPC by about 5%, compared to only participating on the wholesale market. This is due to an increased operation of the CHP unit. In the simulations, the CHP operation increased by 25% when participating on both the regulating power market and the Elspot market, compared with participating only on Elspot. Similar tendencies were seen for the electric boiler; however, the electric boiler produces significantly less than the CHP unit. This result should be seen as the best case for RDH, as all activations on the regulating power market were assumed to be for full hours and activations can be shorter than an hour. Also, the RDH participation was assumed not to affect the market price. However, it can still be concluded that the multi-electricity market participation can increase both the hours of operation of CHP units and reduce the NHPC of DH plants. However, the regulating power market prices are expected to decrease with more participants, as the demand would not be affected by the amount of participants.

4.1. Challenges in the daily operation

The simulation results also highlight some of the challenges that DH plants with both CHP units and solar panels can experience. Due to the uncertainties of the forecasts, plants run the risk of having to reject heat, e.g., if the solar panel forecast turns out to underestimate the production and the thermal storage units are full. Based on the results, this challenge is especially relevant when trading on multiple electricity markets, as this increases the operation of the CHP unit and the electric boiler significantly. Thus, plants will have to face the possibility of either having to reject heat or to lose well-paid hours of operation on the CHP unit or electric boiler, if they do not want to risk rejecting heat.

RDH is a DH plant with relatively many forecasts affecting the daily operation planning, and the chosen simulation period is the period which is most affected by the forecast uncertainties, due to a low heating demand and a high solar heating production. Though, the simulations show that the costs related to the forecasts uncertainties were only about 5% of the total NHPC in the simulated period.

4.2. Making up for errors in the forecasts

From the simulations, it is found that trading on more electricity markets to some extent makes it possible for a plant to make

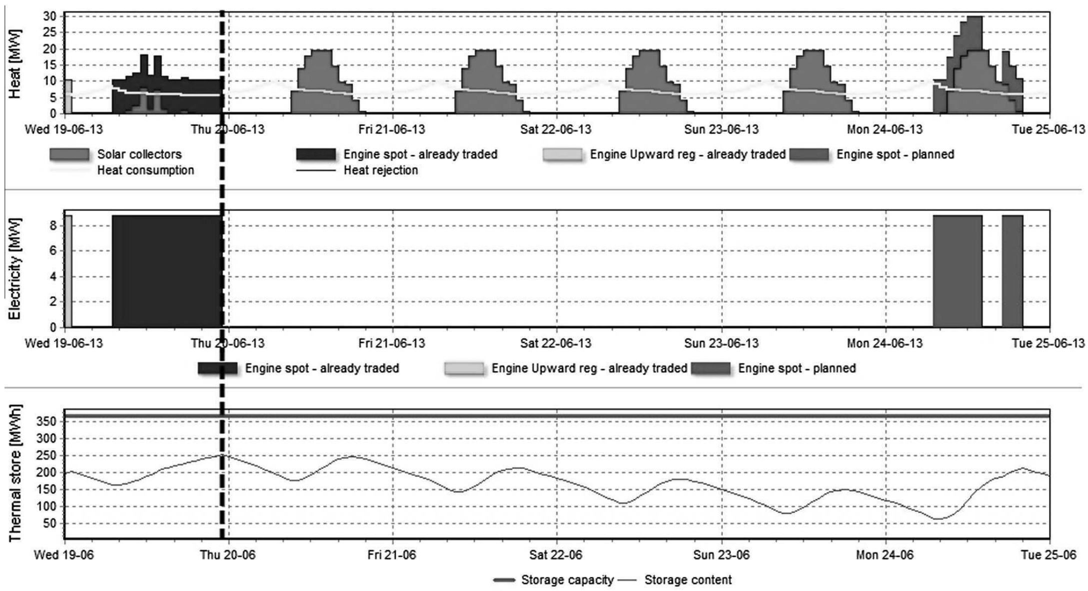

Fig. 4. Scenario 2 at 11 p.m. on the 19th of June. The dotted black line indicates the time.

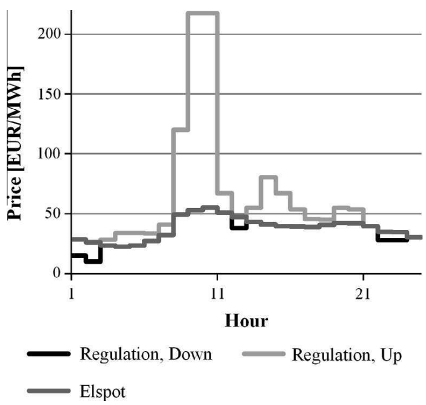

Fig. 5. Elspot and regulating power market prices in DK1 on the 20th of June 2013 [31].

up for uncertainties in the forecasts. On the regulating power market, the gate closure is close to the hour of operation, where the forecasts are much more certain, than on Elspot. This can be seen by the example illustrated in Fig. 2. Fig. 2 shows scenario 2 on the 19th of June at 11 a.m. At this point, RDH carries out its bidding on Elspot for the 20th of June.

The Elspot forecast and the actual market prices for the 20th of June can be seen in Fig. 3, alongside the bidding price of the CHP unit, when compared with the cheapest natural gas boiler. From Fig. 3 it can be seen that both the forecasted and actual Elspot prices in the period from hour 9 to hour 12 are higher than the bidding price of the CHP unit. However, as can be seen in Fig. 2, nothing is traded on Elspot for the 20th of June. This is due to the fact that a relatively high production of solar heating is forecasted for the following days.

However, as can be seen in Fig. 4, the solar collector production on the 19th of June turns out to be significantly smaller than forecasted, leaving more room in the thermal storage units.

This extra room in the thermal storage units makes it possible to trade the CHP unit as upward regulation on the regulating power market on the 20th of June. As can be seen in Fig. 5, an upward activation was needed in the system on the 20th of June, with a relatively high activation price for upward regulation.

As shown in Fig. 6, the CHP unit is utilized on the regulating power market, and upward activation is won for several hours that day.

Similar results could most likely be gained by trading on intraday wholesale markets, such as Elbas. However, this is not analysed further in this paper.

4.3. Sensitivity analyses

Two sensitivity analyses have been made for each of the three scenarios. One where the market price of natural gas price is reduced by 10%, and one where the solar collector fields are increased to 45,000 m^3 and an extra 60 MW h_{th} thermal storage unit is installed. Only the heat production data is shown for the sensitivities.

As shown in Table 7, the decreased natural gas price significantly increases the use of the engine, replacing especially the NG boilers. However, this increased usage of the engine results in increased heat rejection in scenario 1. In scenario 2 the heat rejection is instead decreased, which is due to an increase in hours where both spot market and downward regulation is won alongside a decrease in the electric boiler production, around the period where most of the heat is rejected in the reference.

As seen in Table 8, the increased solar collector fields reduce the heat production of the other units, while also increasing the heat rejection to a point where heat rejection occur even with perfect forecast.

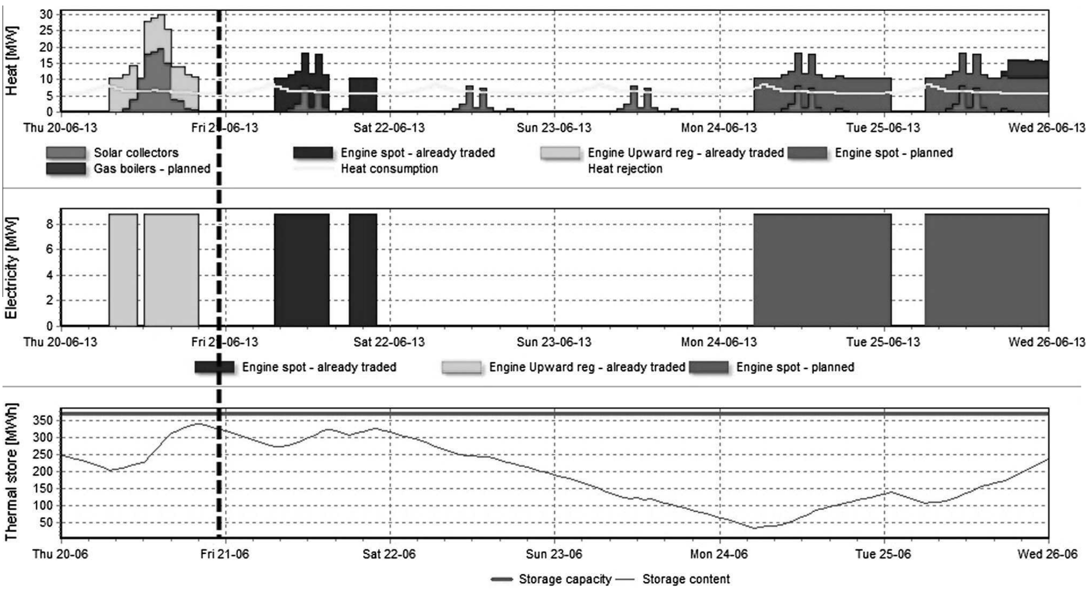

Fig. 6. Scenario 2 at 11 p.m. on the 20th of June. The dotted black line indicates the time.

Table 7
Simulated heat production for the period from 1st of June to 31st of August 2013. The natural gas price has been reduced by 10%. The difference in total heat demand in scenarios 2 and 3 is due to rounding.

Production unit	Scenario 1 MW h_{th}	Scenario 2 MW h_{th}	Scenario 3 MW h_{th}
NG engine	4965	5428	5366
NG boilers	1407	908	926
Electric boiler	60	264	288
Solar collectors	7042	7042	7042
Heat rejection	8	35	0
Final storage content	160	301	316
Heat demand	13,306	13,305	13,305

Table 8
Simulated heat production for the period from 1st of June to 31st of August 2013. Solar collector fields have been increased to 45,000 m^3. The difference in total heat demand in scenario 3 is due to rounding.

Production unit	Scenario 1 MW h_{th}	Scenario 2 MW h_{th}	Scenario 3 MW h_{th}
NG engine	2565	3255	2668
NG boilers	1274	466	253
Electric boiler	72	396	468
Solar collectors	10,563	10,563	10,562
Heat rejection	962	1059	267
Final storage content	206	314	378
Heat demand	13,306	13,306	13,305

5. Conclusion

The participation of DH plants on both the wholesale market and the balancing market can increase the operation of CHP units, while reducing the NHPC of the plants. The simulation results for RDH indicate that CHP operation can be increased by up to 25% and that NHPC can be decreased by up to 5%. This mostly occurs, as the participation on more markets increases the hours in which the operation costs of the CHP unit are lower than the operation costs of the fuel boiler. Furthermore, the income is also increased as the plant is able to reduce the negative effects of forecast uncertainty, when participating on more than one electricity market. However, it is expected that the simulation results for RDH overestimate what can be gained in the actual operation of a DH plant, as, e.g., the hours of operation on the regulating power market are overestimated and it is assumed that RDH will not affect the market prices by participating.

The potential increase in the operation of CHP units and plant income will vary depending on the specific conditions of the country, the available electricity markets, and the plant in question. It is uncertain whether the improvements found are substantial enough for each plant to keep its CHP capacity in operation. Thus, other measures, such as a capacity market, might still be needed to keep the capacity required in the system to provide the needed balancing.

Acknowledgments

The work presented is a result of the Strategic Research Centre for 4th Generation District Heating Technologies and Systems (4DH) partly financed by the Danish Council for Strategic Research.

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Glossary

RES: renewable energy sources
DH: district heating
CHP: combined heat and power
RDH: Ringkøbing District Heating
TSO: transmission system operator
NHPC: net heat production cost

Appendix IV

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Notat om Hvide Sande Fjernvarmes fordel ved overskudsvarmen - v1 (Memo on Hvide Sande District Heating’s benefit by utilising excess heat – v1)

Af Peter Sorknæs, PhD-forsker, AAU
14-10-2014

Notat om Hvide Sande Fjernvarmes fordel ved overskudsvarmen - v1 (Memo on Hvide Sande District Heating's benefit by utilising excess heat – v1)

English summary

It is estimated that about 1,500 MWh of excess heat can be collected from cold stores and a local ice factory for use in the DH system in the town of Hvide Sande. In this memo an early estimate of the value of this excess heat for the DH system is shown. It is assumed that the excess heat can be used directly in the DH grid without boosting the temperature. The value of the excess heat is based on the change in NHPC.

Two scenarios are simulated:

- The reference: Where Hvide Sande DH does not receive excess heat.
- The alternative: As the reference, but Hvide Sande DH receives yearly 1.500 MWh excess heat.

The difference between the NHPC in the two scenarios provides the value that the excess heat have for Hvide Sande DH. It corresponds to the maximum payment that Hvide Sande DH can give for the excess heat. The simulation is done for three different natural gas prices: 2 DKK/Nm^3, 2.5 DKK/Nm^3 and 3 DKK/Nm^3.

With a natural gas price of 2 DKK/Nm^3 a reduction in the NHPC by using excess heat of 663,000 DKK/year is found, corresponding to 442 DKK/MWh-excess heat.

With a natural gas price of 2.5 DKK/Nm^3 a reduction in the NHPC by using excess heat of 732,000 DKK/year is found, corresponding to 488 DKK/MWh-excess heat.

With a natural gas price of 3 DKK/Nm^3 a reduction in the NHPC by using excess heat of 797,000 DKK/year is found, corresponding to 531 DKK/MWh-excess heat.

Af Peter Sorknæs, PhD-forsker, AAU
14-10-2014

1 Indledning og resume

Det er skønnet, at der kan være samlet omkring 1.500 MWh overskudsvarme pr. år fra frysehuse og et isværk liggende i Hvide Sande. I dette notat vises et tidligt estimat for værdien af denne overskudsvarme for Hvide Sande Fjernvarme. Det antages, at overskudsvarmen kan benyttes direkte uden at booste temperaturen. Dette estimeres baseret på hvilken ændring i netto varmeproduktionsomkostningen (NVPO). NVPO'en er de variable omkostninger minus de variable indtægter.

Der simuleres overordnet to scenarier:

- Referencen: Hvor Hvide Sande Fjernvarme ikke modtager overskudsvarme.
- Alternativet: Som Referencen, men Hvide Sande Fjernvarme modtager årligt 1.500 MWh overskudsvarme.

Forskellen på NVPO imellem disse to scenarier giver den værdi overskudsvarmen har for Hvide Sande Fjernvame. Dette svarer til, hvad Hvide Sande Fjernvarme maksimalt kan betale for overskudsvarmen. Der regnes med tre forskellige naturgaspriser: 2 kr/Nm^3, 2,5 kr/Nm^3 og 3 kr/Nm^3.

Ved en gaspris på 2 kr/Nm^3 findes der en reduktion i NVPO ved brug af overskudsvarmen på 663.000 kr., svarende til 442 kr/MWh-overskudsvarme.

Ved en gaspris på 2,5 kr/Nm^3 findes der en reduktion i NVPO ved brug af overskudsvarmen på 732.000 kr., svarende til 488 kr/MWh-overskudsvarme.

Ved en gaspris på 3 kr/Nm^3 findes der en reduktion i NVPO ved brug af overskudsvarmen på 797.000 kr., svarende til 531 kr/MWh-overskudsvarme.

<u>Det skal bemærkes, at dette notat er et tidligt estimat, som ikke kan danne grundlag for en endelig beslutning omkring brug af overskudsvarme.</u>

2 Simuleringsmetode

Der simuleres overordnet to scenarier:

- Referencen: Hvor Hvide Sande Fjernvarme ikke modtager overskudsvarme. Motorerne handles kun i spotmarkedet, og elkedlen handles i både spotmarkedet og regulerkraftmarkedet.
- Alternativet: Som Referencen, men Hvide Sande Fjernvarme modtager overskudsvarme fra hhv. lokale frysehuse og det lokale isværk. Overskudsvarmen sættes til at koste 0 kr/MWh, og det er derved forskellen mellem Referencen og Alternativet som giver værdien af overskudsvarmen.

Værket simuleres i energyPRO v4.2, hvor værkets drift simuleres på timebasis. Alle simuleringer laves for et år, 1. januar til 1. januar.

Der laves for hvert scenarie følsomhedsanalyse på naturgasprisen.

2.1 Tekniske forudsætninger

Hvide Sande Fjernvarme har to ens naturgasmotorer. Ved fuld last har de to motorer hver en indfyret effekt på 9,61 MW, hvor der produceres 3,7 MW_{el} og 4,9 MW_{varme}. Varmevirkningsgraden på motorerne er således 51 % og elvirkningsgraden er 38,5 %.

Den primære naturgaskedel har en varmekapacitet på 10 MW og en virkningsgrad på 108 %. Den sekundære naturagaskedel har en varmekapacitet på 4 MW virkningsgrad på 100%.

Elkedlen er på 6 MW_{el}, og antages at have en virkningsgrad på 100 %.

Fjernvarmelageret modelleres med en kapacitet på 125 MWh.

Solvarmen simuleres med en årlig varmeproduktion på 4.287 MWh, og en spidskapacitet på ca. 6 MW.

Det årlige varmebehov sættes til 41.100 MWh, som fordeles henover året vha. temperaturerne i et dansk normaltår. Sommerlasten sættes til ca. 1,88 MW.

2.1.1 Overskudsvarme

Det antages simpelt, at det kun er overskudsvarmen uden for sommerperioden, som er interessant for Hvide Sande Fjernvarme, grundet solvarmen. Alle mængder præsenteret her, er baseret på Ebbe Münster's skøn[1]. Baseret på disse skøn antages det, at varmen kan leveres direkte til fjernvarmenettet uden, at temperaturen først skal hæves.

Frysehusene skønnes årligt at kunne levere omkring 1.000 MWh_{varme} overskudsvarmen uden for sommermånederne. I denne analyse antages det simpelt, at denne varme er konstant igennem året, dog uden leverance i juni, juli og august. Derved findes der en konstant leverance af overskudsvarme fra frysehusene udenfor sommermånederne på 152,7 kW.

Isværket skønnes årligt at kunne levere 500 MWh_{varme} uden for sommermånederne. Leverencen af denne varme er dog ikke konstant, men forventes at kunne leveres i kortere perioder med en kapacitet på 2 MW, svarende til ca. 250 timer/år. Disse timer ligger især om natten. For at estimere denne varierende leverence

[1] Jf. mail fra Ebbe Münster, PlanEnergi, d. 11. oktober 2014

antages det i simuleringerne, at produktionen foregår ved de billigste 250 timer nattetimer uden for sommermånederne. Nattetimer defineres her timerne fra kl 22 til kl 6.

2.2 Økonomiske forudsætninger

Der medtages kun de omkostninger og indtægter, som kan forventes, at ændres for Hvide Sande Fjernvarme ved, at der aftages overskudsvarme. Således er f.eks. de faste omkostninger og indtægter ikke medtaget i scenarierne.

Der benyttes en CO_2-kvote pris på 65 kr/ton CO_2 med en CO_2-udledning på 56,9 kg/GJ naturgas.

Scenarierne simuleres med tre forskellige marginale naturgaspriser ekskl. afgifter men inkl. transmission, lager og distribution. De tre naturgaspriser er hhv. 2 kr/Nm^3, 2,5 kr/Nm^3 og 3 kr/Nm^3.

De variable drift- og vedligeholdelsesomkostninger (D&V) for motorerne er sat til 50 kr/MWhel. Naturgaskedlernes variable D&V er sat til 0 kr/MWh. Elkedlens D&V er sat til 1 kr/MWh.

Indfødningstariffen sættes til 3,33 kr/MWh_{el}. Der regnes med en samlet variabel handelshåndtering og balanceomkostning på 4 kr/MWh_{el} for el handlet på spotmarkedet. Den samlede transportbetaling for brug af el til elkedlen sættes til 251 kr/MWh_{el}.

2.2.1 Afgifter til brug for simuleringerne

Der benyttes de afgifter, som er gældende for perioden 1. januar 2014 til 31. december 2014, jf. SKAT's "Den juridiske vejledning 2014-2".

Ved brug af motorerne er energiafgiften 2,845 kr/Nm^3, CO_2-afgiften er 0,377 kr/Nm^3, NOx-afgiften er 0,144 kr/Nm^3 og metan-afgiften er 0,065 kr/Nm^3. Den andel af naturgassen, som kan tilskrives elproduktionen er fritaget for både energiafgiften og CO_2-afgiften. Størrelsen af afgiftsgrundlaget kan beregnes på to måder, vha. e-formlen eller v-formlen. Hvide Sande Fjernvarme har valgt at afregne med e-formlen. Med e-formlen findes afgiftsgrundlaget ved at trække elproduktionen divideret med 0,67 fra brændselsforbruget.

De anvendte energi- og CO_2-afgifter for naturgasforbruget ved kedelproduktion sættes til at være tilbagebetalingsgrænsen, for når naturgassen benyttes til fjernvarmeproduktion uden samproduktion af el. Grænsen er for energiafgiften 215,28 kr/MWh_{varme}, og for CO_2-afgiften er den 47,52 kr/ MWh_{varme}. NOx-afgiften på forbrug af naturgas til kedelproduktion sættes til 0,041 kr/Nm^3.

Der skal for varmen produceret på elkedlen betales afgifter svarende til naturgaskedlens grænse på energi- og CO_2-afgift.

2.2.2 Elmarkedspriser

For elmarkedspriserne benyttes priserne fra 2013. Spotmarkedsprisen i 2013 var i gennemsnit ca. 290 kr/MWh, med en maksimal pris på 14.910 kr/MWh og en mindste pris på -463 kr/MWh.

Elmarkedspriserne er hentet fra http://energinet.dk/DA/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

3 Resultater

3.1 Gaspris på 2 kr/Nm3

Varmeproduktionen ved hhv. Referencen og Alternativet ses i Tabel 1.

[MWh-varme]	**Reference**	**Alternativ**	***Ændring***
Solfanger	4.287	4.287	*0*
Motorer	11.001	10.795	*-206*
Elkedel	300	300	*0*
Naturgaskedler	25.499	24.205	*-1.295*
Overskudsvarme	0	1.501	*1.501*
Samlet	**41.087**	**41.087**	***0***

Tabel 1 - Årlige varmeproduktion ved en gaspris på 2 kr/Nm^3.

De variable indtægter og omkostninger ved hhv. Referencen og Alternativet ses i Tabel 2. NVPO står for netto varmeproduktionsomkostning, og er de de variable omkostninger minus de variable indtægter. En lavere NVPO er således et udtryk for reducerede omkostninger ved varmeproduktionen.

[1.000 kr]	**Reference**	**Alternativ**
Indtægter		
Spotsalg	3.652	3.591
Udgifter		
Gaskøb	8.216	7.925
CO2-kvoter	602	580
Motorer - afgifter	3.098	3.040
Naturgaskedler - afgifter	6.789	6.445
Elkedel -afgifter	79	79
El-tariffer, mm.	136	135
Køb af el - spot og reg.	-70	-70
D&V	416	408
Samlede udgifter	**19.265**	**18.541**
NVPO	**15.613**	**14.950**

Tabel 2 – Varaible indtægter og omkostninger ved en gaspris på 2 kr/Nm^3.

Ved en gaspris på 2 kr/Nm^3 findes der derved en reduktion i omkostningerne ved brug af overskudsvarmen på 663.000 kr., svarende til 442 kr/MWh-overskudsvarme.

3.2 Gaspris på 2,5 kr/Nm³

Varmeproduktionen ved hhv. Referencen og Alternativet ses i Tabel 3.

[MWh-varme]	**Reference**	**Alternativ**	***Ændring***
Solfanger	4.287	4.287	*0*
Motorer	5.121	5.037	*-83*
Elkedel	498	498	*0*
Naturgaskedler	31.181	29.764	*-1.417*
Overskudsvarme	0	1.501	*1.501*
Samlet	**41.087**	**41.087**	***0***

Tabel 3 – Årlige varmeproduktion ved en gaspris på 2,5 kr/Nm³.

De variable indtægter og omkostninger ved hhv. Referencen og Alternativet ses i Tabel 4. NVPO står for netto varmeproduktionsomkostning, og er de de variable omkostninger minus de variable indtægter. En lavere NVPO er således et udtryk for reducerede omkostninger ved varmeproduktionen.

[1.000 kr]	**Reference**	**Alternativ**
Indtægter		
Spotsalg	1.809	1.781
Udgifter		
Gaskøb	8.845	8.510
CO2-kvoter	518	499
Motorer - afgifter	1.442	1.419
Naturgaskedler - afgifter	8.302	7.925
Elkedel -afgifter	131	131
El-tariffer, mm.	153	153
Køb af el - spot og reg.	-92	-92
D&V	194	191
Samlede udgifter	**19.493**	**18.734**
NVPO	**17.685**	**16.952**

Tabel 4 – Varaible indtægter og omkostninger ved en gaspris på 2,5 kr/Nm³.

Ved en gaspris på 2,5 kr/Nm³ findes der derved en reduktion i omkostningerne ved brug af overskudsvarmen på 732.000 kr., svarende til 488 kr/MWh-overskudsvarme.

3.3 Gaspris på 3 kr/Nm^3

Varmeproduktionen ved hhv. Referencen og Alternativet ses i Tabel 5.

[MWh-varme]	**Reference**	**Alternativ**	***Ændring***
Solfanger	4.287	4.287	*0*
Motorer	1.196	1.186	*-10*
Elkedel	882	882	*0*
Naturgaskedler	34.722	33.232	*-1.491*
Overskudsvarme	0	1.501	*1.501*
Samlet	**41.087**	**41.087**	**0**

Tabel 5 – Årlige varmeproduktion ved en gaspris på 3 kr/Nm^3.

De variable indtægter og omkostninger ved hhv. Referencen og Alternativet ses i Tabel 6. NVPO står for netto varmeproduktionsomkostning, og er de de variable omkostninger minus de variable indtægter. En lavere NVPO er således et udtryk for reducerede omkostninger ved varmeproduktionen.

[1.000 kr]	**Reference**	**Alternativ**
Indtægter		
Spotsalg	469	465
Udgifter		
Gaskøb	9.409	9.027
CO2-kvoter	459	441
Motorer - afgifter	337	334
Naturgaskedler - afgifter	9.245	8.848
Elkedel -afgifter	232	232
El-tariffer, mm.	228	228
Køb af el - spot og reg.	-89	-89
D&V	46	46
Samlede udgifter	**19.867**	**19.067**
NVPO	**19.399**	**18.601**

Tabel 6 – Varaible indtægter og omkostninger ved en gaspris på 3 kr/Nm^3.

Ved en gaspris på 3 kr/Nm^3 findes der derved en reduktion i omkostningerne ved brug af overskudsvarmen på 797.000 kr., svarende til 531 kr/MWh-overskudsvarme.

Appendix V

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Notat om tilkobling af Højmark til Lem Varmeværk - v1 (Memo on connecting Højmark to Lem District Heating – v1)

Notat om tilkobling af Højmark til Lem Varmeværk - v1 (Memo on connecting Højmark to Lem District Heating – v1)

English summary

In this memo it is investigated how the NHPC will change for Lem DH plant by expanding the DH grid in the town of Lem to the town of Højmark. As such, this memo only estimates the business economy for Lem DH plant excl. investments.

To estimate the change in the NHPC for Lem DH plant, three scenarios are simulated:

- The reference: Where Lem DH plant only delivers heat to existing DH consumers.
- Højmark 80%: As the reference, but it is assumed that 80% of the total heat demand in Højmark is connected to the DH grid in Lem.
- Højmark 50%: As Højmark 80%, but only 50% of the total heat demand in Højmark connects to the DH grid.

Each scenario simulates for the year 2012/2013 and 2013/2014, respectively. It is assumed that 2012/2013 represents a cold year and 2013/2014 represents a warm year. Only the existing units at Lem DH plant are included.

The consequences for Lem DH plant of connecting Højmark to Lem DH can be seen in Table 1.

	2012/2013		2013/2014	
	Højmark 80%	**Højmark 50%**	**Højmark 80%**	**Højmark 50%**
Heat sale in Højmark [MWh]	4,205	2,628	3,593	2,246
Increased production on the wood chip boiler [MWh]	1,636	1,025	1,743	1,150
Increased production on the gas boiler [MWh]	3,348	2,091	2,630	1,584
Increased NHPC [1,000 DKK]	1,935	1,217	1,606	975

Table 1 – Consequences for Lem DH plant of connecting Højmark to Lem DH.

Af Peter Sorknæs, PhD-forsker, AAU
16-10-2014

1 Indledning og resume

I dette notat undersøges, hvilke varmeproduktions relaterede driftsomkostninger Lem Varmeværk ville have, ved at Højmark blev tilsluttet Lem Varmeværk via en transmissionsledning. Der vurderes således ikke på samfundsøkonomien eller brugerøkonomien i dette notat. Ligeledes medtages investeringen i transmissionsledningen heller ikke, men denne må forventes, at skulle dækkes af de potentielle fjernvarmeforbrugere i Højmark.

For at vurdere ekstra omkostningerne for Lem Varmeværk simuleres der tre scenarier:

- Referencen: Hvor Lem Varmeværk kun leverer varme til eksisterende forbrugere.
- Højmark 80%: Som Referencen, men det antages, at 80% af det samlede varmebehov i Højmark tilslutter sig Lem Varmeværk.
- Højmark 50%: Som Højmark 80%, men kun 50% af varmebehovet i Højmark tilslutter sig.

Hver af disse scenarier simuleres for hhv. 2012/2013 og 2013/2014. Det antages, at 2012/2013 er et koldt år, og 2013/2014 er et varmt år. Der medtages kun de anlæg, som allerede er i drift ved Lem Varmeværk.

Effekterne ved tilslutning af Højmark til Lem Varmeværk kan ses i Tabel 1.

	2012-2013		**2013-2014**	
	Højmark 80%	**Højmark 50%**	**Højmark 80%**	**Højmark 50%**
Varmesalg i Højmark [MWh]	4.205	2.628	3.593	2.246
Forøgelse af produktion på fliskedel [MWh]	1.636	1.025	1.743	1.150
Forøgelse af produktion på gaskedel [MWh]	3.348	2.091	2.630	1.584
Øgede variable driftsudgifter [1.000 kr.]	1.935	1.217	1.606	975

Tabel 1 – Effekt af tilslutning af Højmark til Lem Varmeværk.

<u>Det skal bemærkes, at dette notat ikke kan danne grundlag for en endelig beslutning. En videre analyse bør især fokusere på at kvantificere varmebehovet ved Højmark, samt omkostningerne ved bl.a. at ligge transmissionsledningen.</u>

2 Simuleringsmetode

Der simuleres overordnet tre scenarier:

- Referencen: Hvor Lem Varmeværk kun leverer varme til eksisterende forbrugere. Gasmotoren medtages ikke.
- Højmark 80%: Som Referencen, men der ligges en transmissionsledning til Højmark, og det antages, at 80% af det samlede varmebehov i Højmark tilslutter sig Lem Varmeværk.
- Højmark 50%: Som Højmark 80%, men kun 50% af varmebehovet i Højmark tilslutter sig Lem Varmeværk.

Scenarierne sammenlignes på den ændrede drift af de eksisterende enheder på Lem Varmeværk, samt den dertilhørende ændring i driftsudgifter. Værket simuleres i energyPRO v4.2, hvor værkets drift simuleres på timebasis. Hver simulering løber over et år fra d. 1. juni til d. 1. juni det følgende år. De tre scenarier simuleres for hhv. 2012/2013 og 2013/2014.

2.1 Tekniske forudsætninger

Lem Varmeværks fliskedel har en indfyret kapacitet på ca. 5,1 MW og en varmekapacitet på 5,4 MW. Det antages i simuleringerne, at fliskedlen ikke dellastes, men at det er muligt at oplagre varme fra fliskedlen i varmelagrene. Således er fliskedlens virkningsgrad altid den samme i simuleringerne. Det antages, at fliskedlen er ude til service i de tre første uger af august. Derudover medtages muligheden for at benytte den nye absorptionsvarmepumpe sammen med fliskedlen, som når den benyttes, hæver varmekapaciteten på fliskedlen med 0,5 MW. Absorptionsvarmepumpen holdes ude af drift i sommermånederne.

Den primære naturgaskedel har en varmekapacitet på 12 MW og en virkningsgrad på 105%. Den sekundære naturagaskedel har en varmekapacitet på 5 MW virkningsgrad på 100%.

Det samlede fjernvarmelager modelleres med en kapacitet på 120 MWh.

Ved leverance af varme til Højmark antages det, at der skal ligges transmissionsledning med en samlet kapacitet på 1,65 MW. Det antages yderligere, at der skal ligges ca. 1.565 m. transmissionsledning.

2.1.1 Eksisterende varmebehov

Det eksisterende varmebehov ab værk ved Lem Varmeværk er modelleret baseret på målte månedsværdier, samt udendørstemperaturer på timebasis nær Lem. Således varierer en del af varmebehovet efter udendørstemperaturen. Det er søgt at tilpasse varmebehovet ab værk mest muligt de målte månedsværdier. Varmebehovet ab værk vil således ikke nødvendigvis passe på timeniveau, men vil passe på månedsniveau, og vil variere med udendørstemperaturen. De benyttede månedsværdier ses i Tabel 2. Enkelte værdier varierer en smule fra de målte værdier.

[MWh-varme]	**2012/2013**	**2013/2014**
Juni	1.678	1.405
Juli	1.042	1.007
August	1.106	1.025
September	1.743	1.609
Oktober	3.149	2.560
November	4.219	4.427
December	6.484	4.988
Januar	7.001	6.954
Februar	6.254	5.214
Marts	6.732	4.438
April	4.040	3.160
Maj	1.998	2.046
Årligt ab værk	**45.445**	**38.833**

Tabel 2 – Benyttet varmebehov ab værk for eksisterende forbrugere ved Lem Varmeværk.

Året 2012/2013 antages her for at være et koldt år, og 2013/2014 antages at være et varmt år.

2.1.2 Varmebehov i Højmark

Varmebehovet i Højmark er i disse analyser baseret på et tidligt estimat. Det er således usikkert, om det benyttede varmebehov er repræsentativt for det faktuelle varmebehov i Højmark. Derved bør en videre analyse arbejde med at kvantificere varmebehovet i Højmark yderligere.

Det samlede varmebehov i Højmark estimeres at være 4.874 MWh/år for et normalt år. Dette omfatter rumvarmebehov og forbrug af varmt vand. Estimatet er baseret på Varmeatlas fra Aalborg Universitet. Varmeatlas er baseret på en varmeforbrugsmodel fra Statens Byggeforskningsinstitut (SBi), som sammenholdt med BBR information kan estimere det forventede varmebehov i danske bygninger på nuværende tidspunkt. Dette varmebehov er angivet på bygningsniveau, og er her opsummeret for Højmark.

Det antages, at i et koldt år vil det samlede varmebehov i Højmark være ca. 5.256 MWh/år, og i et varmt år vil det være ca. 4.492 MWh/år, svarende til en ændring på ca. 8%. Det antages, at nettabet vil være på 20% af det tilsluttede varmbehov i et normalt år, og at 80% af varmesalget er rumopvarmning. Der simuleres med hhv. 80% og 50% tilslutning. Der findes således følgende behov i hhv. et varmt år og koldt år, som findes i Tabel 3.

	80% tilslutning	**50% tilslutning**	
Varmesalg (normalt år)	3.899	2.437	MWh/år
Antaget nettab	20%	20%	
Nettab	780	487	MWh/år
Varmt år ekskl. Nettab	**3.593**	**2.246**	**MWh/år**
Koldt år ekskl. Nettab	**4.205**	**2.628**	**MWh/år**

Tabel 3 – Estimeret fjernvarmebehov i Højmark ved hhv. 80%- og 50%-tilslutning

2.2 Økonomiske forudsætninger

Der medtages kun de omkostninger og indtægter, som kan forventes, at ændres for Lem Varmeværk, ved at en del af forbrugerne i Højmark tilsluttes værket. Således er f.eks. de faste omkostninger og indtægter ikke medtaget i scenarierne. Medmindre andet er noteret benyttes disse forudsætninger i alle simuleringer. Der er ligeledes heller ikke medtaget indtægten fra varmesalg.

Den samlede betaling for køb af flis er sat til 50 kr/GJ.

Den marginale naturgaspris ekskl. afgifter men inkl. transmission, lager og distribution er sat til 2,421 kr/Nm^3.

Der benyttes en CO_2-kvote pris på 65 kr/ton CO_2 med en CO_2-udledning på 56,9 kg/GJ naturgas.

De variable drift- og vedligeholdelsesomkostninger (D&V) for både fliskedlen og absorptionsvarmepumpen er sat til 18 kr/MWh$_{varme}$. Naturgaskedlernes variable D&V er sat til 3 kr/MWh.

2.2.1 Afgifter til brug for simuleringerne

Der benyttes de afgifter, som er gældende for perioden 1. januar 2014 til 31. december 2014, jf. SKAT's "Den juridiske vejledning 2014-2".

Det antages, at der betales en NOx-afgift for brug af flis i fliskedlen på 2,3 kr/GJ-flis.

De anvendte energi- og CO_2-afgifter for naturgasforbruget ved kedelproduktion sættes til at være tilbagebetalingsgrænsen, for når naturgassen benyttes til fjernvarmeproduktion uden samproduktion af el. Grænsen er for energiafgiften 215,28 kr/MWh$_{varme}$, og for CO_2-afgiften er den 47,52 kr/ MWh$_{varme}$. NOx-afgiften på forbrug af naturgas til kedelproduktion sættes til 0,041 kr/Nm^3.

3 Resultater

3.1 2012/2013

Varmeproduktionen ved Lem Varmeværk i 2012/2013 for de tre scenarier ses i Tabel 4.

[MWh-varme]	Reference	M. Højmark 80%	M. Højmark 50%
Fliskedel	32.935	34.398	33.896
Absorptionsvarmepumpe	2.214	2.387	2.278
Gaskedler	10.297	13.645	12.387
Samlet	**45.445**	**50.430**	**48.561**

Tabel 4 – Varmeproduktion for hver enhed i de tre scenarier i 2012/2013.

Som det ses af Tabel 4, vil der ved 80%-tilslutning i Højmark blive produceret ekstra 1.636 MWh_{varme} på fliskedlen og absorptionsvarmepumpen samt ekstra 3.348 MWh_{varme} på naturgaskedlerne. Ved 50%-tilslutning i Højmark bliver der produceret ekstra 1.025 MWh_{varme} på fliskedel og absorptionsvarmepumpen samt 2.091 MWh_{varme} ekstra på naturgaskedlerne.

Driftsudgifterne i hvert scenarie kan findes i Tabel 5.

[1.000 kr.]	Reference	M. Højmark 80%	M. Højmark 50%
Fliskøb	5.592	5.841	5.756
Flis - NOx-afgift	257	269	265
D&V - Fliskedel + abs. vp.	633	662	651
Gaskøb	2.158	2.860	2.597
Gaskedler - afgifter	2.743	3.634	3.299
CO_2-kvoter	130	172	157
D&V - Gaskedler	31	41	37
Samlede driftsudgifter	**11.544**	**13.479**	**12.761**
Meromkostning ift. reference	-	*1.935*	*1.217*

Tabel 5 – Driftsudgifter i hver af de tre scenarier i 2012/2013.

Som det ses af Tabel 5, findes der en ekstra udgift ved 80% tilslutning i Højmark på ca. 1,9 mio. kr. pr. år, ift. kun at levere varme til eksisterende fjernvarmeforbrugere i Lem. Ved et varmesalg på 4.205 MWh/år svarer det til 460 kr/MWh solgt varme. Ved 50% tilslutning i Højmark findes en ekstra udgift på ca. 1,2 mio. kr. pr. år. Ved et varmesalg på 2.628 MWh/år svarer det til 463 kr/MWh solgt varme.

3.2 2013/2014

Varmeproduktionen ved Lem Varmeværk i 2013/2014 for de tre scenarier ses i Tabel 6.

[MWh-varme]	**Reference**	**M. Højmark 80%**	**M. Højmark 50%**
Fliskedel	31.552	33.140	32.540
Absorptionsvarmepumpe	1.872	2.028	2.034
Gaskedler	5.408	8.038	6.992
Samlet	**38.833**	**43.205**	**41.566**

Tabel 6 - Varmeproduktion for hver enhed i de tre scenarier i 2013/2014.

Som det ses i Tabel 6 vil der ved 80%-tilslutning i Højmark blive produceret ekstra 1.743 MWh_{varme} på fliskedel og absorptionsvarmepumpen samt ekstra 2.630 MWh_{varme} på naturgaskedlerne. Ved 50%-tilslutning i Højmark bliver der produceret ekstra 1.150 MWh_{varme} på fliskedel og absorptionsvarmepumpen samt 1.584 MWh_{varme} ekstra på naturgaskedlerne. Den ekstra varmeproduktion på fliskedlen til Højmark ift. 2012/2013 beregningerne skyldes et lavere varmebehov i 2013/2014 i Lem, resulterende i mere ledig kapacitet på fliskedlen.

Driftsudgifterne i hvert scenarie kan findes i Tabel 7.

[1.000 kr.]	**Reference**	**M. Højmark 80%**	**M. Højmark 50%**
Fliskøb	5.358	5.627	5.525
Flis - NOx-afgift	246	259	254
D&V - Fliskedel + abs. vp.	602	633	622
Gaskøb	1.134	1.685	1.466
Gaskedler - afgifter	1.440	2.141	1.862
CO_2-kvoter	68	102	88
D&V - Gaskedler	16	24	21
Samlede driftsudgifter	**8.864**	**10.470**	**9.839**
Meromkostning ift. reference	-	*1.606*	*975*

Tabel 7 - Driftsudgifter i hver af de tre scenarier i 2013/2014.

Som det ses af Tabel 7, findes der en ekstra udgift ved 80% tilslutning i Højmark på ca. 1,6 mio. kr. pr. år, ift. kun at levere varme til eksisterende fjernvarmeforbrugere i Lem. Ved et varmesalg på 3.593 MWh/år svarer det til 447 kr/MWh solgt varme. Ved 50% tilslutning i Højmark findes en ekstra udgift på ca. 1 mio. kr. pr. år. Ved et varmesalg på 2.246 MWh/år svarer det til 434 kr/MWh solgt varme.

Appendix VI

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Notat om varmepumpe ved Troldhede Fjernvarme - v2 (Memo on heat pump at Troldhede District Heating – v2)

Af Peter Sorknæs, PhD-forsker, AAU
18-12-2014

Notat om varmepumpe ved Troldhede Fjernvarme - v2 (Memo on heat pump at Troldhede District Heating – v2)

English summary

This memo contains an analysis of the business economic perspective for Troldhede DH plant alongside the owners of a local wind turbine of 3 MW by directly connecting a compression heat pump to the wind turbine outside of the public electricity grid. In this memo the economic perspective is found as a total for both these independent legal entities. As such, the total earnings that can be shared by these two entities are found.

Three different scenarios are made:

- The reference: Troldhede DH plant's and the wind turbine's current operation are simulated.
- Scenario 1: Like the reference, but a heat pump is installed at Troldhede DH plant that is directly connected to the wind turbine outside of the public grid.
- Scenario 2: Like scenario 1, but electricity for the heat pump can here also be purchased from the public grid.

The earnings for scenario 1 and 2 are found in their difference to the reference. Two different heat sources for the heat pump are analysed. A range of different sizes of heat pump and extra thermal storage unit is analysed. It is for both heat sources and for both scenarios found that a heat pump with a heat capacity of 1 MW has the highest net present value. The earnings from the heat pump comes from saved costs for purchase of natural gas and payment of taxes on natural gas, which surpasses the losses from the reduced sale of electricity from the wind turbine and the lost subsidy for the wind turbine. The net present value varies considerably depending on the heat source, which is due to a difference in the investment.

Using excess heat from a local dairy's waste water (COP 5):

- Scenario 1: For a 1 MW_{heat} heat pump with a new DH thermal storage of 10 MWh a net present value of about 13.7 million DKK was found.
- Scenario 2: For a 1 MW_{heat} heat pump with a new DH thermal storage of 5 MWh a net present value of about 14.9 million DKK was found. The earnings by importing electricity from the grid were found to be 60,000 DKK/year.

Using ground water as the heat source (COP 4):

- Scenario 1: For a 1 MW_{heat} heat pump with a new DH thermal storage of 10 MWh a net present value of about 7.2 million DKK was found.
- Scenario 2: For a 1 MW_{heat} heat pump with a new DH thermal storage of 5 MWh a net present value of about 8.1 million DKK was found. The earnings by importing electricity from the grid were found to be 60,000 DKK/year.

Indholdsfortegnelse

1 Indledning og resume

Dette notat omhandler de virksomhedsøkonomiske konsekvenser for Troldhede Fjernvarmeværk samt ejerne af en lokal vindmølle på 3 MW, ved en direkte sammenkobling af en varmepumpe til levering af fjernvarme med vindmøllen uden om det offentlige elnet. I forbindelse med dette notat regnes ændringen af økonomien samlet for begge juridiske enheder. Der regnes således den samlede gevinst, som ved en aftale forventes at kunne fordeles mellem de to separate juridiske enheder.

Der regnes tre forskellige scenarier:

- Referencen: Troldhede Fjernvarmes og vindmøllens nuværende drift simuleres.
- Scenarie 1: Som Referencen, men der installeres en varmepumpe ved Troldhede Fjernvarme, som direkte tilkobles vindmøllen uden om det offentlige elnet.
- Scenarie 2: Som scenarie 1, dog kan varmepumpen her også modtage el fra elnettet.

Indtjeningen ved scenarie 1 og 2 findes i deres forskel til Referencen. Der regnes på to forskellige varmekilder for varmepumpen. Det er for begge scenarier og ved begge varmekilder fundet, at en varmepumpe med en varmekapacitet på 1 MW har den højeste nutidsværdi. Gevinsten ved varmepumpen fremkommer især ved sparede omkostninger til køb af naturgas og betaling af afgifter for naturgas, som overgår tabet ved vindmøllens elsag og eltilskud. Nutidsværdien varierer dog betragteligt afhængig af varmekilden, hvilket især skyldes en forskel i investeringen.

<u>Brug af mejeris spildevand (COP 5):</u>

- <u>Scenarie 1:</u> Der blev fundet en nutidsværdi af en 1 MW_{varme} varmepumpe med et nyt fjernvarmelager på 10 MWh på ca. 13,7 mio. kr.
- <u>Scenarie 2:</u> Der blev fundet en nutidsværdi af en 1 MW_{varme} varmepumpe med et nyt fjernvarmelager på 5 MWh på ca. 14,9 mio. kr. Gevinsten ved import af el ved samme varmepumpe størrelser blev fundet til at være ca. 60.000 kr/år.

<u>Brug af grundvand (COP 4):</u>

- <u>Scenarie 1:</u> Der blev fundet en nutidsværdi af en 1 MW_{varme} varmepumpe med et nyt fjernvarmelager på 10 MWh på ca. 7,2 mio. kr.
- <u>Scenarie 2:</u> Der blev fundet en nutidsværdi af en 1 MW_{varme} varmepumpe med et nyt fjernvarmelager på 5 MWh på ca. 8,1 mio. kr. Gevinsten ved import af el ved samme varmepumpe størrelser blev fundet til at være ca. 60.000 kr/år.

<u>Det skal bemærkes, at dette notat er et tidligt estimat, som ikke kan danne grundlag for en endelig beslutning. I notatet medtages ikke en eventuel kapacitetsbetaling til det lokale distributionsnet.</u>

2 Simuleringsmetode

Der simuleres overordnet tre scenarier:

- Referencen: Troldhede Fjernvarmes og vindmøllens nuværende drift simuleres.
- Scenarie 1: Som Referencen, men der installeres en varmepumpe ved Troldhede Fjernvarme, som direkte tilkobles vindmøllen uden om det offentlige elnet. Varmepumpen benytter ikke strøm fra elnettet.
- Scenarie 2: Som scenarie 1, dog kan varmepumpen her også modtage el fra elnettet. Der medtages i dette scenarie ikke den kapacitetsbetaling, som det lokale distributionsnet vil skulle have.

Værket og vindmøllen simuleres i energyPRO v4.3, hvor driften simuleres på timebasis. Alle simuleringer laves for et år. Indtjeningen ved scenarie 1 og 2 findes i deres forskel til Referencen. Der beregnes således en samlet årlig netto indtjening for Troldhede Fjernvarme og ejerne af vindmøllen.

Der beregnes for både scenarie 1 og 2 indtjeningen ved forskellige størrelser af varmepumpe og nyt fjernvarmelager.

2.1 Tekniske forudsætninger

2.1.1 Troldhede Fjernvarme

Troldhede Fjernvarme har en naturgasmotor. Ved fuld last har motoren en indfyret effekt på 2.111 kW, hvor der produceres 760 kW_{el} og 1.140 kW_{varme}. Varmevirkningsgraden på motoren er således 54 %, og elvirkningsgraden er 36 %.

Den primære naturgaskedel har en varmekapacitet på 1.860 kW og en virkningsgrad på 105 %. Den sekundære naturagaskedel har en varmekapacitet på 2.610 kW virkningsgrad på 90 %.

Det eksisterende fjernvarmelager modelleres med en kapacitet på 12 MWh.

Det årlige varmebehov ab værk sættes til 5.700 MWh, som fordeles henover året vha. temperaturerne for hver time i perioden fra d. 1. oktober 2013 til 1. oktober 2014. Sommerlasten sættes til ca. 290 kW og spidslasten sættes til ca. 1,5 MW.

2.1.2 Vindmøllen

Vindmøllen er en 3 MW V112, og den antages at have en årlig produktion på 10.000 MWh. Produktionen på 10.000 MWh fordeles over den simulerede periode med timedata for vindhastigheden i perioden fra d. 1. oktober 2013 til 1. oktober 2014.

2.1.3 Varmepumpen

Der laves simuleringer på to forskellige varmekilder til varmepumpen:

- Spildevand fra det lokale mejeri:
  Spildevandet fra mejeriet forventes at være 25 °C med et jævnt flow igennem året, og det forventes, at der kan hentes op imod 4 MW-varme herfra.[1] Det antages, at varmepumpen igennem hele året kan operere ved en COP på 5.

[1] Baseret på data fra Ebbe Münster, PlanEnergi

- <u>Brug af grundvand:</u>
  I en tidligere analyse fra PlanEnergi blev det fundet, at der er et potentiale for udnyttelse af grundvand som varmekilde for en varmepumpe i Troldhede. I dette notat antages det, at brugen af varme fra grundvandet alene begrænses af antallet af boringer som foretages. Baseret på andre analyser af brug af grundvand som varmekilde til varmepumper, antages en COP på 4[2] igennem hele perioden.

I begge tilfælde antages det simpelt, at varmepumpen kan dellaste ned til 50 % af fuldlast, uden at det påvirker varmepumpens effektivitet. Ligeledes antages det, at varmepumpen altid kan hente den nødvendige varme fra varmekilden. Det antages, at varmen fra varmepumpen kan lagres i det eksisterende varmelager.

Størrelsen af varmepumpen analyseres senere i notatet baseret på den økonomiske gevinst ved forskellige størrelser af varmepumpen baseret på beregning af nutidsværdien igennem 20 års drift med faste priser og en realrente på 3 %.

2.2 Økonomiske forudsætninger

Der medtages kun de omkostninger og indtægter, som kan forventes, at ændres for Troldhede Fjernvarme og ejerne af vindmøllen. Således er f.eks. de eksisterende faste omkostninger og indtægter ikke medtaget i scenarierne.

2.2.1 Troldhede Fjernvarme

Scenarierne simuleres med en marginal naturgaspris ekskl. afgifter men inkl. transmission, lager og distribution på 2,31 kr/Nm^3.

De variable drift- og vedligeholdelsesomkostninger (D&V) for motorerne er sat til 50 kr/MWh$_{el}$. Naturgaskedlernes variable D&V er sat til 5 kr/MWh$_{varme}$.

Indfødningstariffen sættes til 3,87 kr/MWh$_{el}$.

Afgifter

Der benyttes de afgifter, som er gældende for perioden 1. januar 2015 til 31. december 2015, jf. SKAT's "Den juridiske vejledning 2014-2". Der medtages dog ændringerne i LOV nr 1174 af 05/11/2014, hvor forsyningssikkerhedsafgiften tilbagerulles.

Ved brug af motorerne er energiafgiften 2,158 kr/Nm^3, CO_2-afgiften er 0,384 kr/Nm^3, NOx-afgiften er 0,146 kr/Nm^3 og metan-afgiften er 0,066 kr/Nm^3. Den andel af naturgassen, som kan tilskrives elproduktionen er fritaget for energiafgiften. Størrelsen af afgiftsgrundlaget kan beregnes på to måder, vha. e-formlen eller v-formlen. Troldhede Fjernvarme har valgt at afregne med v-formlen. Med v-formlen findes afgiftsgrundlaget ved at dividere varmeproduktionen med 1,2.

De anvendte energi- og CO_2-afgifter for naturgasforbruget ved kedelproduktion sættes til at være tilbagebetalingsgrænsen, for når naturgassen benyttes til fjernvarmeproduktion uden samproduktion af el.

[2] Baseret på data fra Ebbe Münster, PlanEnergi

Grænsen er for energiafgiften 163,44 kr/MWh_{varme}, og for CO_2-afgiften er den 48,6 kr/ MWh_{varme}. NOx-afgiften på forbrug af naturgas til kedelproduktion sættes til 0,042 kr/Nm^3.

2.2.2 Vindmøllen

Det antages, at vindmøllen er opsat imellem 21. februar 2008 og 31. december 2013, og således modtager støtte iht. reglerne herfor. Iht. disse regler modtager vindmøller et pristillæg på 250 kr/MWh i de første 22.000 fuldlasttimer, samt et balanceringstilskud på 23 kr/MWh i hele møllens levetid. I simuleringerne antages det, at vindmøllen stadigt modtager begge disse tilskud.

Det antages, at ved brug af strøm fra vindmøllen til varmepumpen, mistes begge tilskud for den mængde el, som benyttes af varmepumpen. [3]

2.2.3 Varmepumpen og sammenkobling

Ved import af el fra nettet sættes den samlede variable nettariff til 251 kr/MWh_{el}. Der medtages ikke eventuelle faste årlige betalinger.

Ved import af el fra nettet sættes elafgiften til 349 kr/MWh_{el} jf. LOV nr 1174 af 05/11/2014, og PSO-tariffen sættes til 217 kr/MWh_{el}. Udover disse afgifter forventes det, at der også skal betales overskudsvarmeafgift i det tilfælde, hvor der bruges overskudsvarme fra mejeriet som varmekilde til varmepumpen. Overskudsvarmeafgiften er som udgangspunkt 38 % af vederlaget til sælgeren af overskudsvarmen. Ved brug af en varmepumpe gælder det dog, at der kun skal betales overskudsvarmeafgift for den del af den producerede varme, som skyldes en COP på mere end 3. Dette svarer altså til, at overskudsvarmeafgiften i dette tilfælde er 15,2 % af vederlaget til ejeren af varmepumpen (38%*(5-3)/5 = 15,2%). Reelt vil vederlaget skulle fastsættes i aftalen mellem ejeren af varmepumpen og fjernvarmeselskabet, men da en sådan aftale ikke er indgået ved dagsdato, benyttes her i stedet en simpel antagelse for vederlagets størrelse. Det antages, at vederlaget er lig med de omkostninger, der er forbundet med investering og drift af varmepumpen. Det antages yderligere, at vederlaget består af hhv. en variabel del, som omfatter de variable produktionsomkostninger for varmepumpen, og en årlig fast del, som omfatter faste omkostninger til lån. Således i de beregninger hvor der bruges overskudsvarme fra mejeriet til varmepumpen, er overskudsvarmeafgiften også fastsat som hhv. en variabel del og en fast årlig del. Den variable del findes som 15,2 % af:

- Tabt elsalg for vindmøllerne
- Tabt tilskud til vindmøllerne
- D&V på varmepumpen
- Køb af el fra nettet til varmepumpen
- Nettarif, afgifter og PSO ved køb af el fra nettet

Den faste del af overskudsvarmeafgiften svarer til 15,2% af de årlige renter og afdrag på lån. Det antages, at realrenten er 3%. Der er således ikke medtaget nogen form for risikodækning for ejeren af varmepumpen.

For de specifikke omkostninger for varmepumpen benyttes ”Drejebog til store varmepumpeprojekter i fjernvarmesystemet” fra december 2014 [4]. Jf. drejebogen vil investeringen i en elektrisk varmepumpe ligge

[3] Jf. mail-korrespondance med John Tang ved Dansk Fjernvarme.
[4] http://www.danskfjernvarme.dk/groen-energi/projekter/drejebog-om-store-varmepumper

på 4-6 mio. kr. pr MW_{varme}. I dette notat antages det simpelt, at investeringsomkostningen for en varmepumpe er 6 mio. kr. pr MW_{varme} med en minimumsinvestering på 3 mio. kr.

Ved en eventuel sammenkobling mellem mejeri og varmepumpe forventes det, at det bl.a. involverer en underboring af en vej, samt at der skal investeres i teknik til håndtering af spildevand med fedtindhold. Disse ekstra investeringer antages at være 1 mio. kr. i alt.

Det er muligt ved brug af overskudsvarme i en varmepumpe at opnå en engangsindtægt via energibesparelsestilskud, og det antages her, at dette svarer til 460 kr. pr MWh overskudsvarme som udnyttes i varmepumpen i løbet af et år.

Investeringen i en eventuel grundvandsboring antages at være 6 mio. kr. uanset størrelsen på varmepumpen.

Det antages, at investeringen i elkablet fra vindmøllen til varmepumpen vil være 340.000 kr., og investeringen i koblingsstationen vil være 400.000 kr. Investeringen i sammenkobling af varmepumpen og fjernvarmenettet antages at være 300.000 kr., og investeringen i styresystemet antages at være 300.000 kr. Således antages det, at investeringen i de tekniske installationer, som er nødvendige for at sammenkoble vindmølle og varmepumpe samt varmepumpe og fjernvarmenet, at være 1,34 mio. kr. Udover disse investeringer ligger der en usikkerhed i, at vindmøllen og dens tilkobling er delvis PSO finansieret, og det vil således evt. være nødvendig at frikøbe denne del. Det antages her, at dette løber op i en yderligere investering på 1 mio. kr. Således antages det, at investeringen i sammenkoblingen mellem vindmøllen og varmepumpen er 2,34 mio. kr.

D&V for varmepumpen sættes til 15 kr/MWh_{varme}.

Investeringen i et nyt fjernvarmelager tilhørende varmepumpen antages at være 40.000 kr/MWh_{varme}.[5]

2.2.4 Elmarkedspriser

For elmarkedspriserne benyttes Nord Pool Spot priserne for DK1 for perioden fra d. 1. oktober 2013 til d. 1. oktober 2014. Elmarkedspriserne i denne periode var i gennemsnit ca. 234 kr/MWh, med en maksimal pris på 1.193 kr/MWh og en mindste pris på -463 kr/MWh.

Elmarkedspriserne er hentet fra http://energinet.dk/DA/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

[5] Baseret på http://www.ens.dk/sites/ens.dk/files/info/tal-kort/fremskrivninger-analyser-modeller/teknologikataloger/teknologikatalog_jan_2014v4a.pdf

3 Resultater

3.1 Referencen

Driftsindtægter og driftsudgifter for referencen ses i Tabel 1. Der medtages både indtægterne for vindmøllen og Troldhede Fjernvarmeværk. Udgifterne er kun for Troldhede Fjernvarmeværk, da det antages, at udgifterne til selve vindmøllen vil være uændrede.

Driftsindtægter	*[1.000 kr.]*
Spot salg - Fjernvarmeværk	64
Spot salg - Vindmølle	2.074
Vindmølle tilskud	2.730
Samlede driftsindtægter	**4.868**
Driftsudgifter	
Indfødningstarif el	39
Gaskøb	1.179
Afgifter - Motor	54
Afgifter - Kedler	1.185
D&V - Motor	7
D&V - Kedler	27
Samlede driftsudgifter	**2.492**
Samlede netto indtægter	**2.376**

Tabel 1 – Driftsindtægter og driftsudgifter for hhv. Troldhede Fjernvarme og vindmøllen uden varmepumpe. Der medtages kun indtægter og udgifter, som forventes påvirket af installationen af en varmepumpe.

Der findes således, at der samlet set er et årligt overskud på ca. 2,38 mio. kr. Det skal bemærkes, at ikke alle indtægter og udgifter er medtaget, men kun de indtægter og udgifter, som efterfølgende kan variere ved installationen af en varmepumpe.

I Referencen leveres fjernvarmen hovedsageligt af naturgaskedlerne, som bliver brugt til at producere ca. 5.495 MWh_{varme}, mod motoren som producerer ca. 205 MWh_{varme}. Installationen af en varmepumpe vil herved hovedsageligt blive benyttet til at erstatte naturgaskedlerne.

Det er fundet ved simuleringer, at tilføjelse af et nyt fjernvarmelager ikke ændrer på de samlede netto indtægter for Referencen.

3.2 Mejeri som varmekilde

Ved brug af overskudsvarmen fra mejeriet antages en COP på 5.

3.2.1 Scenarie 1: Ingen import af el fra nettet

Tabel 2 viser den årlige gevinst ved installation af en varmepumpe, som kun aftager el fra vindmøllen. Den årlige gevinst er merindtægten ift. de samlede netto indtægter i Referencen på 2,38 mio. kr. Der medtages ikke investeringsomkostninger i Tabel 2.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	**Varmekapacitet**	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
0,05	**0,25**	0,46	0,45	0,45	0,45	0,45	0,45	0,44	0,44	0,44	0,44	0,43	0,43	0,43
0,1	**0,5**	0,89	0,89	0,89	0,89	0,89	0,89	0,89	0,88	0,88	0,88	0,88	0,88	0,87
0,15	**0,75**	1,22	1,22	1,23	1,23	1,23	1,23	1,22	1,22	1,22	1,22	1,22	1,21	1,21
0,2	**1**	1,41	1,43	1,45	1,46	1,46	1,47	1,47	1,46	1,46	1,46	1,46	1,46	1,45
0,25	**1,25**	1,43	1,47	1,49	1,51	1,52	1,53	1,53	1,54	1,54	1,54	1,54	1,54	1,53
0,3	**1,5**	1,41	1,45	1,48	1,50	1,52	1,53	1,53	1,54	1,54	1,54	1,54	1,54	1,54
0,35	**1,75**	1,38	1,44	1,47	1,50	1,51	1,52	1,53	1,53	1,53	1,53	1,53	1,53	1,53
0,4	**2**	1,33	1,41	1,45	1,48	1,50	1,51	1,52	1,52	1,52	1,52	1,52	1,52	1,52
0,45	**2,25**	1,28	1,38	1,43	1,46	1,48	1,50	1,51	1,51	1,51	1,51	1,51	1,51	1,51
0,5	**2,5**	1,24	1,34	1,41	1,44	1,47	1,48	1,49	1,50	1,50	1,50	1,50	1,50	1,50
0,55	**2,75**	1,19	1,34	1,39	1,42	1,45	1,47	1,48	1,49	1,49	1,49	1,49	1,49	1,49
0,6	**3**	1,14	1,30	1,36	1,40	1,43	1,45	1,46	1,47	1,47	1,47	1,47	1,48	1,48
0,65	**3,25**	1,10	1,27	1,34	1,38	1,41	1,43	1,45	1,45	1,46	1,47	1,46	1,47	1,47
0,7	**3,5**	1,06	1,24	1,34	1,36	1,40	1,42	1,44	1,44	1,45	1,45	1,45	1,45	1,45
0,75	**3,75**	1,00	1,18	1,31	1,35	1,38	1,40	1,42	1,43	1,43	1,44	1,44	1,44	1,44
0,8	**4**	0,98	1,16	1,28	1,32	1,35	1,37	1,39	1,41	1,42	1,42	1,42	1,43	1,43
0,85	**4,25**	0,90	1,11	1,25	1,30	1,33	1,36	1,37	1,39	1,40	1,41	1,41	1,41	1,41
0,9	**4,5**	0,82	1,05	1,22	1,28	1,31	1,33	1,36	1,38	1,39	1,39	1,40	1,40	1,40
0,95	**4,75**	0,74	1,03	1,18	1,25	1,28	1,32	1,33	1,36	1,37	1,37	1,38	1,39	1,39
1	**5**	0,58	0,99	1,15	1,22	1,26	1,28	1,31	1,34	1,35	1,36	1,37	1,37	1,38

Tabel 2 – Samlet årlig gevinst i mio. kr. for Troldhede Fjernvarme og ejerne af vindmøllen ved en sammenkobling af vindmølle og varmepumpe uden import af el fra elnettet ved forskellige størrelser af varmepumpe og nyt varmelager. Varmepumpe COP på 5.

Forøgelserne af de samlede årlige gevinster i Tabel 2 sammenholdes i Tabel 3 med de forventede investeringsomkostninger til varmepumpe og nyt fjernvarmelager. I Tabel 3 findes nutidsværdien i mio. kr. for hver størrelse af varmepumpe og tilhørende nyt fjernvarmelager. Nutidsværdien findes med en realrente på 3 % og levetiden antages at være 20 år.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	**Varmekapacitet**	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
0,05	**0,25**	1,1	0,9	0,6	0,4	0,2	-0,1	-0,3	-0,5	-0,8	-1,0	-1,2	-1,4	-1,7
0,1	**0,5**	8,0	7,9	7,7	7,5	7,3	7,1	6,8	6,6	6,4	6,2	5,9	5,7	5,5
0,15	**0,75**	11,9	11,8	11,7	11,5	11,3	11,0	10,8	10,6	10,4	10,1	9,9	9,7	9,4
0,2	**1**	13,5	13,7	13,7	13,7	13,6	13,4	13,2	13,0	12,8	12,5	12,3	12,1	11,9
0,25	**1,25**	12,3	12,8	12,9	13,0	13,0	12,9	12,8	12,7	12,5	12,3	12,1	11,9	11,7
0,3	**1,5**	10,5	11,0	11,3	11,4	11,4	11,5	11,4	11,2	11,0	10,8	10,6	10,4	10,2
0,35	**1,75**	8,6	9,3	9,6	9,8	9,9	9,9	9,8	9,6	9,4	9,2	9,0	8,8	8,6
0,4	**2**	6,2	7,4	7,9	8,0	8,2	8,2	8,1	7,9	7,8	7,5	7,4	7,2	6,9
0,45	**2,25**	4,0	5,4	6,1	6,3	6,4	6,4	6,4	6,3	6,1	5,9	5,7	5,6	5,3
0,5	**2,5**	1,8	3,3	4,2	4,5	4,7	4,8	4,7	4,6	4,4	4,3	4,1	3,9	3,7
0,55	**2,75**	-0,4	1,8	2,3	2,6	2,9	3,0	3,0	2,9	2,7	2,5	2,4	2,2	2,0
0,6	**3**	-2,8	-0,3	0,5	0,9	1,1	1,2	1,2	1,1	1,0	0,9	0,6	0,5	0,3
0,65	**3,25**	-4,8	-2,4	-1,4	-0,9	-0,6	-0,5	-0,5	-0,6	-0,7	-0,8	-1,0	-1,1	-1,4
0,7	**3,5**	-6,9	-4,3	-3,0	-2,7	-2,3	-2,2	-2,1	-2,3	-2,4	-2,5	-2,7	-2,9	-3,1
0,75	**3,75**	-9,4	-6,7	-4,8	-4,4	-4,1	-3,9	-3,9	-4,0	-4,1	-4,2	-4,4	-4,6	-4,8
0,8	**4**	-11,3	-8,6	-6,7	-6,3	-6,0	-5,9	-5,8	-5,7	-5,8	-6,0	-6,1	-6,2	-6,5
0,85	**4,25**	-14,0	-10,8	-8,8	-8,2	-7,9	-7,7	-7,7	-7,5	-7,5	-7,7	-7,8	-8,0	-8,2
0,9	**4,5**	-16,7	-13,2	-10,8	-9,9	-9,7	-9,6	-9,3	-9,2	-9,2	-9,4	-9,4	-9,6	-9,9
0,95	**4,75**	-19,5	-15,1	-12,9	-11,9	-11,7	-11,3	-11,2	-11,0	-11,0	-11,2	-11,2	-11,4	-11,6
1	**5**	-23,5	-17,2	-14,9	-14,0	-13,5	-13,3	-13,0	-12,8	-12,8	-12,9	-13,0	-13,1	-13,2

Tabel 3 – Nutidsværdi i mio. kr. af investering i hhv. varmepumpe og nyt lager baseret på årlig indtjening vist i Tabel 2.

I Tabel 3 ses, at en varmepumpe med en kapacitet på 0,2 $MW_{el\text{-}ind}$ og 1 MW_{varme} med et nyt 10 MWh fjernvarmelager har den højeste nutidsværdi. I Tabel 4 ses driftsindtægter og driftsudgifter for hhv. Reference og Scenarie 1 med en varmepumpekapacitet på 1 MW_{varme} og nyt 10 MWh fjernvarmelager.

[1.000 kr.] **Referencen**		**Scenarie 1 – COP 5 – 1 MW_{varme}**
Driftsindtægter		
Spot salg - Fjernvarmeværk	64	16
Spot salg - Vindmølle	2.074	1.847
Vindmølle tilskud	2.730	2.443
Samlede driftsindtægter	**4.868**	**4.306**
Driftsudgifter		
Indfødningstarif el	39	35
Gaskøb	1.179	98
Afgifter - Motor	54	13
Afgifter - Kedler	1.185	85
D&V - Motor	7	2
D&V - Kedler	27	2
D&V - Varmepumpe	-	79
Overskudsvarmeafgift	-	189
Samlede driftsudgifter	**2.492**	**503**
Samlede netto indtægter	**2.376**	**3.803**

Tabel 4 – Driftsindtægter og driftsudgifter for hhv. Referencen og Scenarie 1 med en varmepumpe på 1 MW_{varme} og COP på 5.

Det ses af Tabel 4, at indtjeningen ved varmepumpen især fremkommer ved sparede omkostninger til køb af naturgas og betaling af afgifter for naturgas, som overgår tabet ved vindmøllens elsag og eltilskud.

3.2.2 Scenarie 2: Med import af el fra nettet

Tabel 5 viser den årlige gevinst ved installation af en varmepumpe, som både aftager el fra vindmøllen og importerer el fra elnettet, når elprisen er tilstrækkelig lav. Den årlige gevinst er merindtægten ift. de samlede netto indtægter i Referencen på 2,38 mio. kr. Der medtages ikke investeringsomkostninger i Tabel 5.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	**Varmekapacitet**	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
0,05	**0,25**	0,52	0,51	0,51	0,51	0,51	0,51	0,50	0,50	0,50	0,50	0,50	0,49	0,49
0,1	**0,5**	0,98	0,98	0,98	0,98	0,98	0,97	0,97	0,97	0,97	0,97	0,96	0,96	0,96
0,15	**0,75**	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,30	1,30	1,30	1,30	1,30
0,2	**1**	1,49	1,50	1,51	1,51	1,51	1,51	1,51	1,51	1,51	1,51	1,51	1,50	1,50
0,25	**1,25**	1,51	1,53	1,54	1,54	1,55	1,55	1,55	1,55	1,55	1,55	1,55	1,55	1,55
0,3	**1,5**	1,49	1,52	1,53	1,54	1,54	1,55	1,55	1,55	1,55	1,55	1,55	1,55	1,55
0,35	**1,75**	1,47	1,50	1,52	1,53	1,54	1,54	1,54	1,55	1,54	1,54	1,54	1,54	1,54
0,4	**2**	1,41	1,48	1,51	1,52	1,53	1,53	1,54	1,54	1,53	1,53	1,53	1,53	1,53
0,45	**2,25**	1,37	1,46	1,49	1,50	1,51	1,52	1,52	1,53	1,53	1,53	1,53	1,52	1,52
0,5	**2,5**	1,33	1,42	1,47	1,49	1,50	1,51	1,51	1,51	1,52	1,52	1,52	1,52	1,51
0,55	**2,75**	1,29	1,41	1,45	1,47	1,48	1,49	1,50	1,50	1,50	1,50	1,50	1,50	1,50
0,6	**3**	1,23	1,38	1,43	1,46	1,47	1,48	1,49	1,49	1,49	1,49	1,49	1,49	1,49
0,65	**3,25**	1,20	1,34	1,41	1,44	1,45	1,46	1,47	1,48	1,48	1,48	1,48	1,48	1,48
0,7	**3,5**	1,16	1,31	1,40	1,42	1,44	1,45	1,46	1,46	1,47	1,47	1,47	1,47	1,47
0,75	**3,75**	1,11	1,27	1,37	1,40	1,42	1,44	1,44	1,45	1,45	1,46	1,45	1,46	1,46
0,8	**4**	1,09	1,24	1,35	1,38	1,40	1,41	1,43	1,44	1,44	1,44	1,44	1,44	1,44
0,85	**4,25**	1,03	1,20	1,32	1,36	1,38	1,40	1,41	1,42	1,43	1,43	1,43	1,43	1,43
0,9	**4,5**	0,96	1,15	1,30	1,34	1,36	1,38	1,39	1,41	1,41	1,41	1,42	1,42	1,42
0,95	**4,75**	0,86	1,13	1,27	1,32	1,34	1,36	1,37	1,39	1,40	1,40	1,40	1,40	1,40
1	**5**	0,69	1,10	1,24	1,29	1,32	1,34	1,35	1,37	1,38	1,38	1,38	1,39	1,39

Tabel 5 - Samlet årlig gevinst i mio. kr. for Troldhede Fjernvarme og ejerne af vindmøllen ved en sammenkobling af vindmølle og varmepumpe med import af el fra elnettet ved forskellige størrelser af varmepumpe og nyt varmelager. Varmepumpe COP på 5.

Der findes således en gevinst ved at importere el ift. Scenarie 1, hvor der ikke importeres el til varmepumpen. Ved en varmepumpe med en kapacitet på 0,2 $MW_{el\text{-}ind}$ og 1 MW_{varme} er gevinsten ca. 0,06 mio. kr.

De samlede årlige gevinster i Tabel 5 sammenholdes i Tabel 6 med de forventede investeringsomkostninger til varmepumpe og nyt varmelager. I Tabel 6 findes nutidsværdien i mio. kr. for hver størrelse af varmepumpe og tilhørende nyt fjernvarmelager. Nutidsværdien findes med en realrente på 3 % og levetiden antages at være 20 år.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	Varmekapacitet	0	5	10	15	20	25	30	35	40	45	50	55	60
0,05	0,25	2,1	1,9	1,7	1,4	1,2	1,0	0,8	0,5	0,3	0,1	-0,2	-0,4	-0,6
0,1	0,5	9,6	9,4	9,2	9,0	8,8	8,6	8,3	8,1	7,9	7,6	7,4	7,2	6,9
0,15	0,75	13,5	13,3	13,1	12,9	12,7	12,5	12,3	12,0	11,8	11,6	11,3	11,1	10,9
0,2	1	14,8	14,9	14,8	14,6	14,5	14,3	14,1	13,8	13,6	13,4	13,1	12,9	12,7
0,25	1,25	13,7	13,8	13,7	13,6	13,5	13,3	13,2	13,0	12,8	12,5	12,3	12,1	11,9
0,3	1,5	12,0	12,1	12,1	12,1	11,9	11,8	11,6	11,4	11,2	11,0	10,8	10,6	10,4
0,35	1,75	10,1	10,4	10,5	10,4	10,3	10,2	10,0	9,8	9,6	9,4	9,2	9,0	8,8
0,4	2	7,6	8,6	8,7	8,7	8,7	8,5	8,4	8,2	8,0	7,8	7,6	7,4	7,1
0,45	2,25	5,5	6,7	7,0	7,0	7,0	6,8	6,7	6,6	6,4	6,2	6,0	5,7	5,5
0,5	2,5	3,3	4,6	5,2	5,3	5,2	5,2	5,0	4,9	4,7	4,5	4,3	4,1	3,9
0,55	2,75	1,2	3,0	3,4	3,5	3,5	3,5	3,4	3,2	3,0	2,8	2,6	2,4	2,2
0,6	3	-1,1	1,0	1,6	1,8	1,8	1,8	1,7	1,5	1,3	1,1	1,0	0,8	0,5
0,65	3,25	-3,1	-1,1	-0,2	0,0	0,0	0,0	0,0	-0,2	-0,4	-0,5	-0,7	-0,9	-1,1
0,7	3,5	-5,2	-3,1	-1,9	-1,8	-1,6	-1,7	-1,7	-1,9	-2,0	-2,2	-2,4	-2,6	-2,8
0,75	3,75	-7,6	-5,2	-3,8	-3,5	-3,4	-3,4	-3,5	-3,6	-3,7	-3,9	-4,1	-4,3	-4,5
0,8	4	-9,3	-7,2	-5,7	-5,3	-5,2	-5,3	-5,2	-5,3	-5,4	-5,6	-5,8	-6,0	-6,2
0,85	4,25	-11,7	-9,3	-7,6	-7,1	-7,0	-7,0	-7,0	-7,0	-7,1	-7,3	-7,5	-7,7	-7,9
0,9	4,5	-14,5	-11,6	-9,4	-9,0	-8,8	-8,8	-8,8	-8,7	-8,8	-9,0	-9,2	-9,3	-9,5
0,95	4,75	-17,5	-13,3	-11,3	-10,8	-10,6	-10,5	-10,6	-10,5	-10,6	-10,8	-10,9	-11,1	-11,3
1	5	-21,7	-15,3	-13,2	-12,7	-12,5	-12,4	-12,3	-12,3	-12,3	-12,5	-12,7	-12,8	-12,9

Tabel 6 - Nutidsværdi i mio. kr. af investering i hhv. varmepumpe og nyt lager baseret på årlig indtjening vist i Tabel 5.

I Tabel 6 ses, at en varmepumpe med en kapacitet på 0,2 $MW_{el\text{-}ind}$ og 1 MW_{varme} med et nyt 5 MWh fjernvarmelager har den højeste nutidsværdi. I Tabel 7 ses driftsindtægter og driftsudgifter for hhv. Reference og Scenarie 2 med en varmepumpekapacitet på 1 MW_{varme} og nyt 5 MWh varmelager.

[1.000 kr.]	Referencen	Scenarie 2 – COP 5 – 1 MW_{varme}
Driftsindtægter		
Spot salg - Fjernvarmeværk	64	4
Spot salg - Vindmølle	2.074	1.850
Vindmølle tilskud	2.730	2.447
Samlede driftsindtægter	**4.868**	**4.300**
Driftsudgifter		
Indfødningstarif el	39	35
Gaskøb	1.179	19
Afgifter - Motor	54	2
Afgifter - Kedler	1.185	18
D&V - Motor	7	0
D&V - Kedler	27	0
D&V - Varmepumpe	-	84
Nettarif og afgifter - Varmepumpe	-	68
Køb af spot el - Varmepumpe	-	19
Overskudsvarmeafgift	-	179

Samlede driftsudgifter	**2.492**	**425**
Samlede netto indtægter	**2.376**	**3.875**

Tabel 7 - Driftsindtægter og driftsudgifter for hhv. Referencen og Scenarie 2 med en varmepumpe på 1 MW_{varme} og COP på 5.

Det ses af Tabel 7, at indtjeningen ved varmepumpen især fremkommer ved sparede omkostninger til køb af naturgas og betaling af afgifter for naturgas, som overgår tabet ved vindmøllens elsag og eltilskud.

3.3 Grundvand som varmekilde

Ved brug af grundvand som varmekilde antages en COP på 4.

3.3.1 Scenarie 1: Ingen import af el fra nettet

Tabel 8 viser den årlige gevinst ved installation af en varmepumpe, som kun aftager el fra vindmøllen. Den årlige gevinst er merindtægten ift. de samlede netto indtægter i Referencen på 2,38 mio. kr. Der medtages ikke investeringsomkostninger i Tabel 8.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	Varmekapacitet	0	5	10	15	20	25	30	35	40	45	50	55	60
0,05	0,2	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40	0,40
0,1	0,4	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75	0,75
0,15	0,6	1,05	1,06	1,06	1,06	1,06	1,06	1,06	1,06	1,06	1,06	1,06	1,06	1,06
0,2	0,8	1,28	1,30	1,30	1,30	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,31	1,31
0,25	1	1,43	1,46	1,47	1,48	1,49	1,50	1,50	1,50	1,50	1,50	1,50	1,50	1,50
0,3	1,2	1,47	1,50	1,53	1,54	1,56	1,57	1,57	1,58	1,58	1,59	1,59	1,59	1,59
0,35	1,4	1,46	1,51	1,54	1,56	1,58	1,59	1,60	1,60	1,61	1,61	1,62	1,62	1,62
0,4	1,6	1,46	1,51	1,54	1,57	1,59	1,60	1,61	1,61	1,62	1,62	1,62	1,63	1,63
0,45	1,8	1,45	1,51	1,55	1,57	1,59	1,60	1,62	1,62	1,63	1,63	1,63	1,63	1,64
0,5	2	1,41	1,50	1,54	1,57	1,59	1,61	1,62	1,63	1,63	1,64	1,64	1,64	1,64
0,55	2,2	1,39	1,50	1,54	1,57	1,59	1,61	1,62	1,63	1,64	1,64	1,64	1,65	1,65
0,6	2,4	1,37	1,47	1,54	1,56	1,59	1,62	1,63	1,63	1,64	1,64	1,65	1,65	1,65
0,65	2,6	1,35	1,49	1,53	1,56	1,59	1,61	1,63	1,64	1,64	1,65	1,65	1,65	1,65
0,7	2,8	1,33	1,48	1,52	1,56	1,59	1,62	1,63	1,64	1,65	1,65	1,65	1,66	1,66
0,75	3	1,31	1,45	1,52	1,56	1,59	1,61	1,63	1,64	1,65	1,65	1,66	1,66	1,66
0,8	3,2	1,27	1,43	1,50	1,56	1,59	1,61	1,63	1,64	1,65	1,66	1,66	1,66	1,66
0,85	3,4	1,27	1,42	1,52	1,55	1,58	1,61	1,63	1,64	1,65	1,66	1,66	1,67	1,67
0,9	3,6	1,24	1,41	1,52	1,54	1,57	1,61	1,63	1,65	1,65	1,66	1,66	1,67	1,67
0,95	3,8	1,19	1,38	1,50	1,54	1,58	1,61	1,62	1,64	1,65	1,66	1,67	1,67	1,67
1	4	1,20	1,36	1,49	1,53	1,57	1,60	1,62	1,64	1,65	1,66	1,67	1,67	1,68

Tabel 8 - Samlet årlig gevinst i mio. kr. for Troldhede Fjernvarme og ejerne af vindmøllen ved en sammenkobling af vindmølle og varmepumpe uden import af el fra elnettet ved forskellige størrelser af varmepumpe og nyt varmelager. Varmepumpe COP på 4.

Forøgelserne af de samlede årlige gevinster i Tabel 8 sammenholdes i Tabel 9 med de forventede investeringsomkostninger til varmepumpe og nyt fjernvarmelager. I Tabel 9 findes nutidsværdien i mio. kr. for hver størrelse af varmepumpe og tilhørende nyt fjernvarmelager. Nutidsværdien findes med en realrente på 3 % og levetiden antages at være 20 år.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	**Varmekapacitet**	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
0,05	**0,2**	-5,4	-5,6	-5,8	-6,0	-6,2	-6,4	-6,6	-6,8	-7,0	-7,2	-7,4	-7,6	-7,8
0,1	**0,4**	-0,2	-0,4	-0,5	-0,7	-0,9	-1,1	-1,3	-1,5	-1,7	-1,9	-2,1	-2,3	-2,5
0,15	**0,6**	3,7	3,6	3,4	3,3	3,1	2,9	2,7	2,5	2,3	2,1	1,9	1,7	1,5
0,2	**0,8**	6,0	5,9	5,8	5,7	5,5	5,3	5,1	4,9	4,7	4,5	4,3	4,1	3,9
0,25	**1**	6,9	7,1	7,2	7,1	7,1	6,9	6,7	6,5	6,3	6,1	5,9	5,7	5,5
0,3	**1,2**	6,3	6,6	6,8	6,8	6,8	6,8	6,7	6,6	6,4	6,3	6,1	5,9	5,7
0,35	**1,4**	5,0	5,5	5,8	5,9	6,0	6,0	5,8	5,7	5,6	5,4	5,3	5,1	4,9
0,4	**1,6**	3,7	4,4	4,6	4,8	4,9	4,8	4,8	4,7	4,5	4,4	4,2	4,1	3,9
0,45	**1,8**	2,4	3,1	3,5	3,6	3,7	3,7	3,7	3,6	3,4	3,3	3,2	3,0	2,8
0,5	**2**	0,7	1,8	2,2	2,4	2,5	2,6	2,5	2,5	2,3	2,2	2,0	1,9	1,7
0,55	**2,2**	-0,8	0,5	1,0	1,2	1,4	1,4	1,4	1,3	1,2	1,1	0,9	0,7	0,6
0,6	**2,4**	-2,4	-1,0	-0,2	-0,1	0,2	0,3	0,3	0,1	0,1	-0,1	-0,3	-0,4	-0,6
0,65	**2,6**	-3,9	-2,0	-1,5	-1,3	-1,0	-1,0	-0,9	-1,0	-1,1	-1,3	-1,4	-1,5	-1,7
0,7	**2,8**	-5,4	-3,3	-2,9	-2,5	-2,2	-2,1	-2,1	-2,1	-2,3	-2,4	-2,5	-2,7	-2,9
0,75	**3**	-6,9	-5,0	-4,2	-3,7	-3,5	-3,3	-3,3	-3,3	-3,5	-3,6	-3,7	-3,8	-4,0
0,8	**3,2**	-8,7	-6,4	-5,6	-4,9	-4,7	-4,5	-4,5	-4,5	-4,6	-4,7	-4,9	-5,0	-5,2
0,85	**3,4**	-9,8	-7,9	-6,6	-6,2	-6,0	-5,8	-5,7	-5,7	-5,8	-5,9	-6,0	-6,1	-6,3
0,9	**3,6**	-11,5	-9,2	-7,8	-7,6	-7,3	-7,0	-6,9	-6,9	-7,0	-7,1	-7,2	-7,3	-7,5
0,95	**3,8**	-13,5	-10,8	-9,2	-8,8	-8,4	-8,3	-8,2	-8,1	-8,2	-8,2	-8,4	-8,4	-8,7
1	**4**	-14,5	-12,3	-10,6	-10,2	-9,8	-9,5	-9,4	-9,4	-9,4	-9,5	-9,6	-9,7	-9,8

Tabel 9 – Nutidsværdi i mio. kr. af investering i hhv. varmepumpe og nyt lager baseret på årlig indtjening vist i Tabel 8.

I Tabel 9 ses, at en varmepumpe med en kapacitet på 0,25 $MW_{el\text{-}ind}$ og 1 MW_{varme} med et nyt fjernvarmelager på 10 MWh har den højeste nutidsværdi. I Tabel 10 ses driftsindtægter og driftsudgifter for hhv. Reference og Scenarie 1 med en varmepumpekapacitet på 1 MW_{varme} og nyt 10 MWh varmelager.

[1.000 kr.]	**Referencen**	**Scenarie 1 – COP 4 – 1 MW_{varme}**
Driftsindtægter		
Spot salg - Fjernvarmeværk	64	18
Spot salg - Vindmølle	2.074	1.795
Vindmølle tilskud	2.730	2.376
Samlede driftsindtægter	**4.868**	**4.188**
Driftsudgifter		
Indfødningstarif el	39	34
Gaskøb	1.179	112
Afgifter - Motor	54	14
Afgifter - Kedler	1.185	99
D&V - Motor	7	2
D&V - Kedler	27	2
D&V - Varmepumpe	-	78
Samlede driftsudgifter	**2.492**	**341**
Samlede netto indtægter	**2.376**	**3.848**

Tabel 10 - Driftsindtægter og driftsudgifter for hhv. Referencen og Scenarie 1 med en varmepumpe på 1 MW_{varme} og COP på 4.

3.3.2 Scenarie 2: Med import af el fra nettet

Tabel 11 viser den årlige gevinst ved installation af en varmepumpe, som både aftager el fra vindmøllen og importerer el fra elnettet, når elprisen er tilstrækkelig lav. Den årlige gevinst er merindtægten ift. de samlede netto indtægter i Referencen på 2,38 mio. kr. Der medtages ikke investeringsomkostninger i Tabel 11.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	Varmekapacitet	0	5	10	15	20	25	30	35	40	45	50	55	60
0,05	0,2	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44	0,44
0,1	0,4	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83	0,83
0,15	0,6	1,14	1,14	1,14	1,14	1,15	1,15	1,15	1,15	1,15	1,15	1,15	1,15	1,15
0,2	0,8	1,37	1,38	1,38	1,38	1,39	1,39	1,39	1,39	1,39	1,39	1,39	1,39	1,39
0,25	1	1,51	1,53	1,53	1,54	1,55	1,55	1,55	1,55	1,55	1,55	1,55	1,55	1,55
0,3	1,2	1,55	1,57	1,58	1,59	1,59	1,60	1,60	1,60	1,61	1,61	1,61	1,61	1,61
0,35	1,4	1,54	1,57	1,59	1,60	1,61	1,61	1,62	1,62	1,62	1,63	1,63	1,63	1,63
0,4	1,6	1,54	1,58	1,59	1,61	1,62	1,62	1,63	1,63	1,63	1,63	1,64	1,64	1,64
0,45	1,8	1,53	1,58	1,60	1,61	1,62	1,63	1,63	1,64	1,64	1,64	1,64	1,65	1,65
0,5	2	1,50	1,57	1,60	1,61	1,62	1,63	1,64	1,64	1,65	1,65	1,65	1,65	1,65
0,55	2,2	1,48	1,56	1,60	1,61	1,63	1,64	1,64	1,65	1,65	1,65	1,66	1,66	1,66
0,6	2,4	1,45	1,55	1,60	1,61	1,63	1,64	1,65	1,65	1,66	1,66	1,66	1,66	1,66
0,65	2,6	1,44	1,56	1,60	1,61	1,63	1,64	1,65	1,66	1,66	1,66	1,67	1,67	1,67
0,7	2,8	1,43	1,55	1,59	1,61	1,63	1,64	1,65	1,66	1,66	1,66	1,67	1,67	1,67
0,75	3	1,40	1,53	1,59	1,61	1,63	1,65	1,65	1,66	1,67	1,67	1,67	1,68	1,68
0,8	3,2	1,37	1,51	1,57	1,61	1,63	1,65	1,65	1,66	1,67	1,67	1,67	1,68	1,68
0,85	3,4	1,37	1,50	1,58	1,61	1,63	1,65	1,66	1,67	1,67	1,67	1,68	1,68	1,68
0,9	3,6	1,35	1,49	1,58	1,60	1,62	1,64	1,66	1,67	1,67	1,68	1,68	1,68	1,69
0,95	3,8	1,30	1,46	1,57	1,60	1,63	1,64	1,66	1,67	1,67	1,68	1,68	1,69	1,69
1	4	1,31	1,45	1,56	1,59	1,62	1,64	1,65	1,67	1,67	1,68	1,68	1,69	1,69

Tabel 11 - Samlet årlig gevinst i mio. kr. for Troldhede Fjernvarme og ejerne af vindmøllen ved en sammenkobling af vindmølle og varmepumpe med import af el fra elnettet ved forskellige størrelser af varmepumpe og nyt varmelager. Varmepumpe COP på 4.

Der findes således en gevinst ved at importere el ift. Scenarie 1, hvor der ikke importeres el til varmepumpen. Ved en varmepumpe med en kapacitet på 0,25 $MW_{el\text{-}ind}$ og 1 MW_{varme} er gevinsten ca. 0,06 mio. kr.

De samlede årlige gevinster i Tabel 11 sammenholdes i Tabel 12 med de forventede investeringsomkostninger til varmepumpe og nyt fjernvarmelager. I Tabel 12 findes nutidsværdien i mio. kr. for hver størrelse af varmepumpe og tilhørende nyt fjernvarmelager. Nutidsværdien findes med en realrente på 3 % og levetiden antages at være 20 år.

Varmepumpe [MW]		Lagerstørrelse [MWh]												
El ind	**Varmekapacitet**	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**55**	**60**
0,05	**0,2**	-4,8	-5,0	-5,2	-5,4	-5,6	-5,8	-6,0	-6,2	-6,4	-6,6	-6,8	-7,0	-7,2
0,1	**0,4**	1,0	0,8	0,6	0,4	0,2	0,0	-0,2	-0,4	-0,6	-0,8	-1,0	-1,2	-1,4
0,15	**0,6**	5,0	4,8	4,7	4,5	4,3	4,1	3,9	3,7	3,5	3,3	3,1	2,9	2,7
0,2	**0,8**	7,3	7,2	7,0	6,9	6,7	6,5	6,3	6,1	5,9	5,7	5,5	5,3	5,1
0,25	**1**	8,1	8,1	8,1	8,0	7,8	7,7	7,5	7,3	7,1	6,9	6,7	6,5	6,3
0,3	**1,2**	7,5	7,6	7,5	7,5	7,4	7,2	7,1	6,9	6,8	6,6	6,4	6,2	6,0
0,35	**1,4**	6,2	6,5	6,5	6,4	6,4	6,3	6,1	6,0	5,8	5,6	5,5	5,3	5,1
0,4	**1,6**	5,0	5,3	5,4	5,3	5,3	5,2	5,1	4,9	4,7	4,6	4,4	4,2	4,0
0,45	**1,8**	3,7	4,1	4,2	4,2	4,1	4,1	4,0	3,8	3,7	3,5	3,3	3,1	2,9
0,5	**2**	1,9	2,8	3,0	3,0	3,0	2,9	2,8	2,7	2,5	2,4	2,2	2,0	1,8
0,55	**2,2**	0,5	1,5	1,8	1,8	1,8	1,8	1,7	1,6	1,4	1,3	1,1	0,9	0,7
0,6	**2,4**	-1,1	0,1	0,7	0,7	0,7	0,7	0,6	0,4	0,3	0,1	0,0	-0,2	-0,4
0,65	**2,6**	-2,6	-1,0	-0,6	-0,5	-0,5	-0,5	-0,6	-0,7	-0,8	-1,0	-1,2	-1,3	-1,5
0,7	**2,8**	-3,9	-2,3	-1,9	-1,7	-1,7	-1,7	-1,8	-1,8	-2,0	-2,2	-2,3	-2,5	-2,7
0,75	**3**	-5,5	-3,8	-3,1	-3,0	-2,9	-2,9	-3,0	-3,0	-3,2	-3,3	-3,5	-3,6	-3,8
0,8	**3,2**	-7,2	-5,2	-4,5	-4,1	-4,1	-4,1	-4,1	-4,2	-4,3	-4,5	-4,6	-4,8	-5,0
0,85	**3,4**	-8,4	-6,6	-5,6	-5,4	-5,3	-5,2	-5,3	-5,4	-5,5	-5,6	-5,7	-5,9	-6,1
0,9	**3,6**	-9,9	-8,0	-6,8	-6,7	-6,6	-6,5	-6,5	-6,5	-6,7	-6,8	-6,9	-7,1	-7,2
0,95	**3,8**	-11,8	-9,6	-8,2	-7,9	-7,7	-7,7	-7,7	-7,7	-7,9	-8,0	-8,1	-8,2	-8,4
1	**4**	-12,8	-10,9	-9,6	-9,3	-9,0	-9,0	-9,0	-8,9	-9,1	-9,1	-9,3	-9,4	-9,6

Tabel 12 - Nutidsværdi i mio. kr. af investering i hhv. varmepumpe og nyt lager baseret på årlig indtjening vist i Tabel 11.

I Tabel 12 ses, at en varmepumpe med en kapacitet på 0,25 $MW_{el\text{-}ind}$ og 1 MW_{varme} med et nyt 5 MWh fjernvarmelager har den højeste nutidsværdi. I Tabel 13 ses driftsindtægter og driftsudgifter for hhv. Reference og Scenarie 2 med en varmepumpekapacitet på 1 MW_{varme} og nyt 5 MWh varmelager.

[1.000 kr.]	**Referencen**	**Scenarie 2 – COP 4 – 1 MW_{varme}**
Driftsindtægter		
Spot salg - Fjernvarmeværk	64	4
Spot salg - Vindmølle	2.074	1.798
Vindmølle tilskud	2.730	2.380
Samlede driftsindtægter	**4.868**	**4.182**
Driftsudgifter		
Indfødningstarif el	39	34
Gaskøb	1.179	19
Afgifter - Motor	54	2
Afgifter - Kedler	1.185	18
D&V - Motor	7	0
D&V - Kedler	27	0
D&V - Varmepumpe	-	84
Nettarif og afgifter - Varmepumpe	-	98
Køb af spot el - Varmepumpe	-	27
Samlede driftsudgifter	**2.492**	**283**
Samlede netto indtægter	**2.376**	**3.899**

Tabel 13 - Driftsindtægter og driftsudgifter for hhv. Referencen og Scenarie 2 med en varmepumpe på 1 MW_{varme} og COP på 4.

Appendix VII

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Electricity Market Auction Settings in a Future Danish Electricity System with a High Penetration of Renewable Energy Sources – A Comparison of Marginal Pricing and Pay-as-Bid

Energy 36 (2011) 4434–4444

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Electricity market auction settings in a future Danish electricity system with a high penetration of renewable energy sources – A comparison of marginal pricing and pay-as-bid

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ARTICLE INFO

Article history:
Received 3 December 2010
Received in revised form
29 March 2011
Accepted 31 March 2011
Available online 30 April 2011

Keywords:
Electricity market
Auction systems
Renewable energy scenarios

ABSTRACT

The long-term goal for Danish energy policy is to be free of fossil fuels through the increasing use of renewable energy sources (RES) including fluctuating renewable electricity (FRE).

The Danish electricity market is part of the Nordic power exchange, which uses a Marginal Price auction system (MPS) for the day-ahead auctions. The market price is thus equal to the bidding price of the most expensive auction winning unit. In the MPS, the FRE bid at prices of or close to zero resulting in reduced market prices during hours of FRE production. In turn, this reduces the FRE sources' income from market sales. As more FRE is implemented, this effect will only become greater, thereby reducing the income for FRE producers.

Other auction settings could potentially help to reduce this problem. One candidate is the pay-as-bid auction setting (PAB), where winning units are paid their own bidding price.

This article investigates the two auction settings, to find whether a change of auction setting would provide a more suitable frame for large shares of FRE. This has been done with two energy system scenarios with different shares of FRE.

From the analysis, it is found that MPS is generally better for the FRE sources. The result is, however, very sensitive to the base assumptions used for the calculations.

1. Introduction

In 2007, the wind power share in Denmark amounted to 21.2% of the electricity production [1]. Danish wind production was however, unevenly split up into two separate electricity systems until July 2010; i.e., Western Denmark and Eastern Denmark, which are interconnected to Continental Europe and the Scandinavian Peninsula, respectively. In 2009, Western Denmark had a RES share of the electricity production of 29.5% [2], making this a very interesting case for studying market-based wind power integration.

Western Denmark joined the Nordic electricity exchange market in 1999 with the aim of improving efficiency and competition within the system [3], as part of a general European electricity market that opened in 1996 [4]. The Nord Pool Spot market now covers Denmark, Finland, Sweden, Norway and Estonia. The market is divided into the Elspot and Elbas markets, where Elspot is the day-ahead market for commercial players and Elbas is an intraday balancing market. Trading on Nord Pool Spot corresponded to approximately 70% of the total trading in the Nordic countries in 2008. Most of the trading takes place on the Elspot market, where in 2008, 297.6 TWh of electricity was traded compared to only 1.8 TWh on Elbas [5]. Wind power is almost exclusively traded on the Elspot market [6]and, as a result, this market is the focus of this article.

Nord Pool was renamed on November 1st 2010 to NASDAQ OMX Commodities Europe; however, in this article, the well-established name Nord Pool is used.

Buyers and sellers on the Elspot market place bids before noon the day before the physical transaction takes place, thus, 12–36 h ahead in time. On Nord Pool Spot, the purchase bids are aggregated into a demand curve and the offers are aggregated into a supply curve for each hour of the day [7]. The resulting price for each hour is the price level at which the supply and demand curves intersect, and this is calculated after noon. Subsequently, all players are

Abbreviations: CHP, combined heat and power; CSHP, cogeneration of steam heat and power; DEA, Danish Energy Authority; FRE, fluctuating renewable electricity; IDA, The Danish Society of Engineers; LTMC, long-term marginal cost; MPS, marginal price auction system; PAB, pay-as-bid auction system; RES, renewable energy source; STMC, short-term marginal cost.

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doi:10.1016/j.energy.2011.03.079

notified of their sales and purchases of the given hour [7]. This type of price formation is designated as uniform price setting or Marginal Price auction system (MPS), meaning that all the sellers and buyers settle at the same marginal kWh cost of electricity. This is illustrated in Fig. 1.

The figure shows how the different types of production units typically offer electricity at different costs corresponding to their short-term marginal cost (STMC), which is the variable costs of producing one extra unit of electricity, typically including the cost of fuel, CO_2 quotas and variable operation and maintenance costs. The production units with the lowest STMC are wind turbines, hydro plants and nuclear plants. These sources are followed by combined heat and power (CHP) units, condensing power plants, and peak load facilities, shown as coal, biomass, gas and oil in Fig. 1. The demand is shown as a vertical line, as it is fairly inelastic in the short run [8]. In a market with MPS, all of the producers get the same price, even though they offer to sell at different prices. In theory, this means that the economically most efficient production units will earn the most, and the units with the highest STMC will earn just enough to cover their STMC. This also means that if the production units with the lowest marginal costs can meet the whole demand, the price will drop dramatically [9]. In Western Denmark, wind power has already forced the spot market price down to zero during some hours (based on data from [10]).

The long-term goal of the current Danish Government is a society independent of fossil fuels achieved by means of energy efficiency and RES [11]. A key source of renewable energy in Denmark is wind power, which, however, may have a reducing effect on the average price of electricity. The correlation between wind power and electricity spot prices is not always evident, but in average, the price decreases with more wind in the system. In Western Denmark in 2009, the average price was 37.19 €/MWh with a wind production below 750 MW, which occurred during 6040 h that year, and 34.46 €/MWh with a wind production above 1750 MW, which occurred for 297 h (based on data from [12]). In 2009, an installed wind power capacity of 213 MW offshore and 2207 MW onshore in Western Denmark (based on register data from [13]) played a part at a price of zero during 28 h in 2008 and 46 h in 2009 [10]. Additional reasons for the reductions in price are heat bound electricity production from CHPs during these hours as well as bottlenecks in the transmission out of Western Denmark. The bids of the CHPs depend on their start-up costs and the alternative heat production available in the local area. Large CHPs offer a large share of electricity at low prices and sometimes it can be feasible to even sell at negative prices to avoid a start-up.

Since November 30th 2009, even negative Nord Pool Spot prices have been seen [14]. This was the result in Western Denmark during 18 h up until October 5th 2010, of which 14 h were during the winter season (based on data from [12]). The night between December 25th and 26th 2009 was significant, as Western Denmark had negative prices during 8 consecutive hours with prices reaching −119 €/MWh.

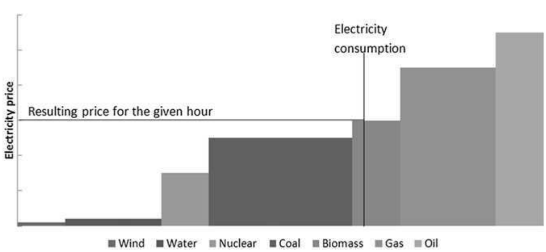

Fig. 1. Resulting market price in a marginal pricing setting for 1 h in the Nordic area. Inspired by [6].

In the present electricity system, these reductions in price are not a large issue, because they seldom happen. However, in a future electricity system with larger shares of wind production, it could occur with higher frequency. The hours with negative prices are also the hours during which wind power would have the greatest potential for earning its long-term marginal costs (LTMC), when only considering the amounts of electricity produced during these hours. The LTMC are the STMC plus the fixed costs of building and running the facility, i.e., the total cost of the facility divided by each unit sold throughout the lifetime of the facility. LTMC include payback on investments, fixed operation and maintenance costs, taxes on facilities, and insurance costs. An increased number of hours with reduced prices could result in less income from the electricity market for wind power, making the investments less feasible and less likely to take place.

An important factor in the willingness to invest in new electricity capacity is a high electricity price, which 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 experienced player and owner of existing production facilities. The ownership of other production facilities may form an obstacle to investing in new facilities, since the new facility will compete against the old units. New market players do not run this same risk of competing against their own facilities, but they will compete against the STMC of older units. The competitive situation in the market and the degree of certainty in the future political framework for the market will also affect the willingness to invest. CO_2 quota cost has an influence, as does the amount of wind power production. A large share of wind power will generally give lower electricity prices, as shown before, reducing the profitability of investing in new electricity capacity. As Morthorst [15] points out, the worst case of investing in new electricity capacity is when the share of wind power in the system is large and the CO_2 quota cost is low.

Investments in conventional power plants (PP) in Denmark seem to have stopped in 2001 [16]. Normally, PPs have a lifetime of around 30 years, meaning that many of the Danish PPs older than 25 years will be decommissioned in the near future [17]. The wind power capacity has been quite stable at around 3200 MW from 2001 to 2008, but unlike the large PPs, old wind power capacity has been replaced on an on-going basis [18]. It must be assumed that, unless the electricity demand drops, investments in new capacity will be required. It is therefore relevant to investigate in which technologies investment is most likely within the current MPS; and especially, whether the current MPS benefits technologies that would help realize an energy system free of fossil fuels in line with Danish political goals.

Some of the problems could be due to market design, where the ability to earn money on investments in new production facilities depends on whether the more expensive units win 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 asking price rather than the price of the most expensive winning unit. PAB makes each unit less dependent on other more expensive units, since they are only paid their offering price and not what a more expensive unit is paid. They are therefore, in principle, more likely to bid a price that will cover their LTMC plus a desired profit. This would also mean that units would generally not bid a price of zero, since that would not result in any payment. The PAB is, e.g., used in the British electricity system [19].

In [20], Oren discusses PAB vs MPS arguing for a tendency for revenue equalisation between the two pricing regimes based on qualitative deliberations and without support from quantitative energy systems analyses. Oren further states that products are not homogeneous and that *"winner determination is often based on attributes such as location, ramp rate, reactive power capability etc. that are not explicitly priced in the auction"*. However, this is not so much an issue in the Nordic system where the market is fragmented with particular markets for, e.g., different reserves. Even the market systems are differentiated with secondary reserves being PAB in Denmark. Ren and Galiana [21,22]have conducted quantitative probabilistic analyses of current systems showing similar revenues in the two systems. They arrive at the primary conclusion *"that although MP and PAB yield identical expected generator profits and consumer payments, the risk of not meeting the expected values is greater under MP than under PAB"* and thereby, in effect, argue for a higher level of investor certainty with PAB. It should be stressed, though, that they find similar levels despite variances in the two auction settings. Son et al. [23] have applied game theory to demonstrate a tendency for lower revenues in PAB. Yet other analyses have investigated appropriate auction systems for the reactive power markets [24]or reserve markets [25]. The mentioned references do not, however, factor in what market structures are beneficial in terms of creating a dynamic energy sector, which facilitates changes towards a carbon neutral energy supply.

2. Scope and structure of the article

Summarising the previous section, the Danish electricity system is part of the Nord Pool market, which uses MPS. With more wind energy in the system, this could create a problem regarding the price setting, since more hours with prices below the LTMC may be expected in the future. As income dwindles, so does the willingness to invest, as Morthorst correctly points out [15]. This applies to RES technologies and fossil-based technologies alike; however, the situation is worse for the new market entrants – in this case the RES-based technologies – that cannot compete at STMC as opposed to old market players.

On the basis of this, the article investigates how different auction settings would affect the income from electricity sales for the different production units in the Danish energy system in a future Nord Pool Elspot market relying heavily on fluctuating renewable energy.

The analyses focus on the technologies in which the market players would wish to invest seen in relation to the market's allocation of income and the behaviour of the market players. This is done within the context of MPS and PAB, using two different energy scenarios with different amounts of fluctuating RES. This approach makes it possible to identify the most appropriate auction setting in terms of reaching the goal of a fossil-free energy system.

The report starts with a more detailed introduction to the auction settings, followed by a description of the EnergyPLAN model, which is used in a modified form for the energy systems analyses. In section 5, two different scenarios are presented, followed by modelling in section 6, and, finally, the main findings of the article in chapter 7.

3. Auction settings in electricity markets

Since this article wishes to clarify which technologies will benefit from a change of auction setting in different energy system scenarios, it is relevant to introduce institutional economy. Institutional economy focuses on institutional settings and how these affect technological changes. Here, the auction setting is an institutional setting for the electricity system, and the transition towards a RES-based energy system is the technological change. In this context, an institutional economic perspective is of relevance. Institutional economy treats the market as an institutional construct which may be changed to achieve a more socially desirable outcome. In institutional economy, it is hence also of importance to identify the expected winners and losers of a specific institutional setting [27].

In order to better understand these institutional structures, a market is defined as: *"a decentralized collection of buyers and sellers whose interactions determine the allocation of a good or set of goods through exchange"* ([28] page 56). Markets are thus decentralized as opposed to auctions, which are centralized around an auctioneer [28].

In the context of Nord Pool Spot, this distinction is particularly interesting, since it implies that, in order to understand the workings of the Nord Pool electricity market, the workings of the auctions are in focus rather than market theory. However, it must be assumed that auction theory does not supersede market theory, but builds upon market theory by providing a more detailed look into a specific market situation. Auction theory is an applied branch of Game Theory, which focuses on a player's behaviour in situations where the player's success is affected by the choice of other players [29]. Basically, four types of auction settings can be defined:

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*: Starting from a high price, the level is decreased until a buyer accepts the given price.
4. *First-price sealed-bid auction*: Buyers submit sealed bids, and the winner pays the bidden price [29].

MPS falls under the category "Second-price sealed-bid auction", since all winners are paid the same and the bid is sealed; whereas PAB is a "First-price sealed-bid auction", since the winners of the auction are paid the amount that they bid and the bids are sealed [9].

3.1. Marginal Price auction system

In MPS auctions, all the winners of the auction are paid the same price for the product in question, which is the price of the most expensive winning bid. This auction is also known as Uniform price auction [19]. The MPS is the most commonly utilised type of auction setting in electricity markets [30], and it is also the model used by Nord Pool Spot. In MPS, there is a link between the STMC and the bids of the suppliers. This is due to the fact that the market players will prefer to bid close to their own STMC and have the highest possible chance of winning the auction, while also hoping to win more expensive bids. Bidding too high would entail a risk of not winning the bid at all, and thereby not selling the product. Therefore, this auction setting provides a framework similar to an efficient market in which the suppliers with the lowest costs are chosen first.

The MPS is only efficient when there is no collusion in the market, meaning that players do not explicitly or tactically work together to increase their own gains. Since MPS auctions on electricity markets are repeated on a daily basis, they are particularly vulnerable to collusion, as all winning bids affect the resulting price. The risk of collusion in an auction is, however, reduced when a competitive market exists; since this will make the players compete rather than collude [29]. Collusion is not investigated in this article, though. It is assumed that the bidding prices in the MPS are fairly close to the STMC of the bidding players. The auction setting is widespread, particularly because it is seen as fair, since all winners are paid the same amount no matter their bid [30]. It is also fairly easy to enter the auction, since new market players will only need to know the market price and their own STMC; whereas in a PAB, players will need more market information regarding the bids of other players in order to perform well [29].

3.2. Pay-as-bid auctions

In PAB, the winners of the auction are paid their asking price, without taking other winning bids into account. This auction setting is also known as a "discriminatory auction", since the winners are paid different prices depending on their bids [19]. PABs find the resulting market price by calculating the average price of the winning bids. The general difference between MPS and PAB is illustrated in Fig. 2.

There are only few examples of PAB being used in electricity markets. PAB was 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 [31]. In most electricity markets, PAB is only used in submarkets, if used at all. However, the British electricity market (covering England, Scotland and Wales) changed from an MPS electricity market to a PAB electricity market. The institutional setting was an important part of the reason for the change of market system, since the MPS, which was set up in 1990, was perceived as operating in favour of the generators of electricity. This meant that the wholesale prices did not decrease during the period in which the MPS was in place; despite the fact that the electricity producers' cost of generation was halved and the general efficiency of the PPs increased during that period. Therefore, the government decided to change the system to reduce the potential for exercising market power by changing to an allegedly more competitive market system for electricity [32].

The specific institutional conditions of the British electricity system make it difficult to base a Nord Pool system using PAB upon this system. However, an important difference could be that Nord Pool is successful at capturing a large share of the available market. In 2008, 71% of the consumption of electricity in the Nord Pool area was traded via Nord Pool Spot [7]. Unfortunately, the corresponding data from the British market is not readily available for comparison.

It is assumed that a potential Nord Pool PAB would be able to function using the current exchange system, with the difference being that the market price would be calculated as the average price of the winning bids and that each winning bid would be paid their bid.

In the USA, PAB is also brought up for discussion during times with high electricity prices. This is due to an argument stating that PAB will ensure that consumers do not over-compensate producers with low costs [34]. 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 estimating the final marginal auction price and therefore bid just below this price instead of bidding on the basis of their actual costs [19]. In addition, this would only be the potential behaviour of the major players, since only these players 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, have control over less production capacity, and have less information about the market to do so. Therefore, the small players will get less profit than the major players in a PAB, leaving these an advantage. The market players in MPS only need information regarding their own costs in order to make a bid [29,35].

Another important argument against PAB's potential for reducing consumer prices is that the low bids in MPS must account for their fixed costs in the bidding price, which will result in a bid corresponding to their LTMC plus profits instead of their STMC. 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 will normally also have high fixed costs, will try to 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 [9,19].

PAB is, however, very useful to avoid potential collusion in a market. This is due to the nature of PAB, where one's bid mainly affects one's own resulting price. This is in contrast to MPS, where the ultimate bid sets the price for all other winning bids and all lower bids also affect the price [29]. These arguments regarding PAB provide two different types of potential bidding behaviours for PAB auctions. First and foremost, all players are assumed to bid a price that will cover their LTMC and also provide a profit when selling electricity. Therefore, a potential bidding behaviour would be one in which all players will bid into the market with bids that are able to cover their LTMC plus a profit. Another bidding behaviour would be one in which the major players will try to gamble on the market with some of their units, in order to improve their gain.

4. Modelling energy systems with the EnergyPLAN model

To make the analyses for this article, the energy systems analysis model *EnergyPLAN* is used. EnergyPLAN, which is developed by Lund [36–46], has been used in several published analyses [47–62] and is capable of analysing the whole energy system in hourly steps. The calculation time of the model is less than a half minute for simulating a whole year and enabling more simulations and an iterative working process.

4.1. The overall structure of EnergyPLAN

EnergyPLAN is a model designed for energy systems analyses at a regional or national level. The energy sectors included are district heating, electricity, transport, industry and individual heating.

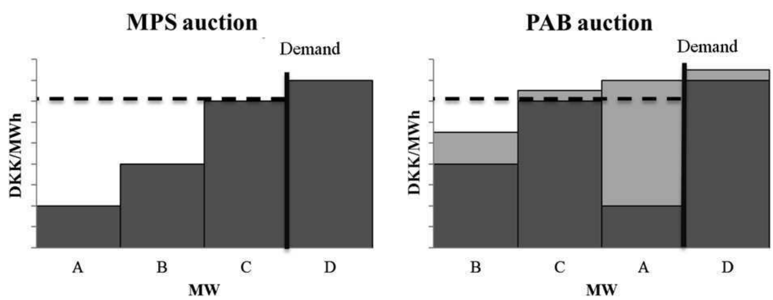

Fig. 2. Approach to finding the resulting auction prices in the MPS and PAB auctions. Dark grey is the STMC of the units and light grey is the difference between the PAB bids and the STMCs, and dashed line represents the price resulting from auction. Inspired by figure from [19].

EnergyPLAN 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 annual basis with an hourly resolution.

EnergyPLAN is a deterministic input/output model. The model inputs are divided into three overall categories. The first defines the technical system; the second identifies the economic parameters related to the system; and the third comprises the regulation of the system. The ability to switch between different regulation strategies makes it possible to apply both technical and economic strategies. These different strategies are described in detail later. To understand how the model operates, the technical input part is described in the following.

EnergyPLAN operates with aggregated data inputs for the different types of energy production and consumption. This means that, for instance, individual power plant units are not added separately in the model, but are aggregated into one unit. The same applies to all types of production and consumption units.

It is possible to include demand time series for electricity, district heating, transport, industry and individual heating. Production units are described by different inputs depending on the type of 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 with an hourly resolution for its production. Other types of production units are dispatchable, producing according to prices or regulating strategies.

District heating systems are aggregated into three different groups; the first is based on boilers; the second is based on small CHPs, and the third on central CHPs [39].

When the technical system is designed, the next step is choosing the appropriate regulation strategy for the analysis. EnergyPLAN has four technical regulation strategies as well as an economic strategy. The main ones are listed here:

1. CHPs produce only 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. CHPs produce according to both heat and electricity demands. In this strategy, electricity export is minimized by switching heat production from CHPs to boilers and heat pumps. This way the heat production is maintained while the electricity production is decreased. Import and electricity production on condensing power plants are minimised by using CHP units and heat storages actively.
3. In the economic strategy, electricity is exported when the market price is higher than the marginal production price, and imported when the market price is lower than the marginal production price. All production units except for fluctuating RES run according to their STMC in this strategy [39,46].

The third strategy is used in these analyses as the functioning of the electricity market is in focus. Some changes to the model's algorithms have been made to make it possible to calculate the PAB; these changes are described in section 4.3.

4.2. The market economic optimisation in EnergyPLAN

The focus of this description is how the market economy is being optimised in the model and, furthermore, how the specific STMC calculations are used in the article.

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 performed continuously when running the market optimisation strategy. The first calculation, in the market economic strategy, is to find the difference between the demand and supply; this is called *Net import demand* and is found using Eq (1):

$$\text{Net import demand}_{\text{hourly}} = \text{Total demand}_{\text{hourly}} - \text{total production}_{\text{hourly}} \tag{1}$$

The Net import demand is found by summarizing the demand and production for each hour. The next step is to determine the external market price for each hour. This is done using Eq (2):

$$p_x = p_i + (p_i/p_0) \times F_{\text{ACdepend}} \times \text{Net import demand}_{\text{hourly}} \tag{2}$$

- 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
- Net import $\text{demand}_{\text{hourly}}$ is the trade on the market [46]

The price elasticity is used to find the influence of import/export on the external market price. 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 Eq (2).

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

A general note to make, 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. The input determines the percentage share of each MWh produced. The marginal price for each fuel is calculated as follows in Eq (3):

$$\text{Marginal fuel price} = \text{Fuel price} + CO_2 \text{ price} + \text{handling cost} + \text{tax cost} \tag{3}$$

The marginal fuel price is not always the same as the STMC excluding variable O&M costs, because some technologies, like CHPs, compare their production costs with those of the boilers or heat pumps, as the heat will have to be produced regardless of whether the CHPs are running or not.

4.3. Changes to EnergyPLAN

To make the simulations and thereby the analyses of the PAB possible, some changes to the EnergyPLAN model have been made by the authors. 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 modelling 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 decentralised 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 to these.

In the PAB version, the only new STMC calculations are made for the fluctuating RES, and since these do not have any of the aforementioned costs, the resulting STMC is the same as the variable O&M input for RES. 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 during an hour, it is not possible to produce more than this amount of wind power, even if wind power is the cheapest solution.

5. Two long-term renewable energy scenarios

To make an analysis of the effects of changing the auction setting, two technical scenarios are used. The first scenario represents a system similar to the present situation in Denmark, and the second shows a possible future situation with a larger share of wind power. The two technical scenarios are both from "The IDA Climate Plan 2050" made by The Danish Society of Engineers (IDA) and are detailed further in [44,47,63].

The IDA Climate Plan focuses on three different scenarios for the years 2015, 2030 and 2050, respectively. The difference between the scenarios is the amount of RES in the system, where 2015 is similar to the present situation and 2050 is a 100% RE system. Each of the IDA scenarios is a changed version of the reference systems forecasted by the Danish Energy Authority (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 scenario with 45.7% RE of all energy produced [63].

The DEA2030 scenario is a basic forecast for 2030 made by the DEA on the 30th of April 2009. This means that it is based on 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 scenario uses the same prices, taxes, etc., but looks into different technological set-ups than the DEA2030. The technologies used in the IDA2030 scenario arise from several different steps looking into how a flexible energy system can be made and how resource use can be minimized with more efficient technologies. These steps include CHP regulation, large heat pumps, flexible electricity demands, electric vehicles, and fuel cells. Hereby, the IDA2030 scenario incorporates demand flexibility, which is relevant when implementing fluctuating RES. In Fig. 3, the capacities of different technologies used for electricity generation in both DEA2030 and IDA2030 are shown.

It does not appear from the bar chart that the transmission capacity for import/export in both cases is 2500 MW and no bottlenecks exist between Western Denmark and Eastern Denmark, since the plan covers both areas [63].

In the IDA Climate Plan's EnergyPLAN modelling of DEA2030 and IDA2030, different fuel consumptions have been used for the two scenarios. For DEA2030, the goal has been to approximate the modelled fuel consumption to the DEA forecasted fuel consumptions.

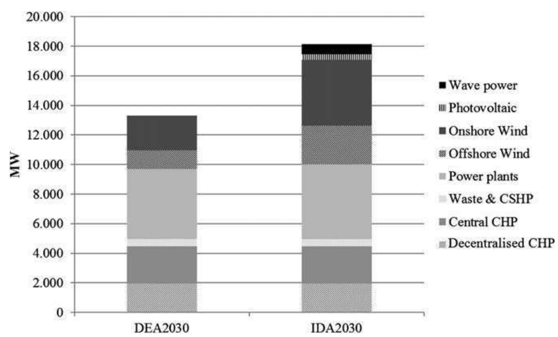

Fig. 3. Electric capacities in the two scenarios from the IDA Climate Plan. CSHP = Industrial CHP [63].

In order to achieve this, the biomass fuel has been kept as a fixed fuel amount in the EnergyPLAN modelling. This approach is useful for approximating a forecasted future, but it is not a desirable modelling strategy for this analysis, as it leaves out an important part of the foundation for the hourly choice of technologies. For this reason, the fuel modelling for DEA2030 has been altered in order to change the biomass fuel from being a yearly cost to forming part of the STMC. The fuel consumption for modelling IDA2030 in EnergyPLAN has therefore been applied to DEA2030, as IDA2030 is modelled with variable fuel consumption. Hereby, the DEA2030 presented throughout this article differs from the one presented in "The IDA Climate Plan 2050" in terms of different fuel consumptions for the technologies.

This change of the fuel, the capacities and the efficiencies has been used in the EnergyPLAN modelling in combination with hourly distribution files for demands and non-thermal production. The hourly distribution used for wind power in the modelling is shown in Fig. 5.

As seen in Fig. 5, there are many fluctuations in wind power during a year and, when looking at the duration curve, it can be seen that the production from wind is only above 20% of the maximum value for approximately 3500 h during the year.

Both scenarios are calculated with the market economic strategy selected in EnergyPLAN (See section 4) in order to include trade on the external electricity market. It has to be noticed that the costs used for this initial analysis are also different from the ones used in the original IDA Climate Plan, since the DEA has updated their forecasts in April 2010 [64]. The updated costs are used, with the exception of taxes and variable O&Ms, which still are those used in the IDA Climate Plan scenario modelling. One of the overall outputs is the annual electricity production and consumptions for the two scenarios, which are shown in Fig. 4.

Looking at the amounts in Fig. 4 for DEA2030, which represents the present energy system, it can be seen that the production is based mainly upon CHP, PP, Waste and CSHP (Cogeneration of Steam heat and power - industrial CHP), which produce 32 TWh/year. In contrast, the key element in IDA2030 is wind power producing approximately 23 TWh/year. IDA2030 also introduces a more flexible demand with, e.g., electric vehicles and larger amounts of heat pumps, but also reduces the overall consumption by implementing energy savings.

6. Modelling and analysis of two auction settings

In order to discuss the modelling of PAB, the modelling of the MPS is first explained as it forms the basis for the PAB. In the modelling of MPS, the technologies are assumed to bid an amount close to their STMC of producing electricity. In the analyses, it is assumed that the technologies in the scenarios are able to earn enough to at least cover their LTMC on a yearly basis by bidding their STMC in the MPS, since the players should otherwise make higher bids.

6.1. Scenarios and bidding prices

Whereas technologies in MPS can be assumed to bid their STMC, this is not the case in a PAB, where the technologies are expected to bid higher than their STMC to cover fixed costs. However, the analyses in this article only include the spot market and no other income potentials from, e.g., the regulating market. Hence, the LTMC cannot be used as the basis for the PAB bids, as the other income sources will also be used to cover fixed costs. If the LTMC were used as basis for the bids, then the bids would be too high for the CHP units. Bidding prices are instead based on the assumption that the technologies are able to cover all costs with the income received in the MPS. The bidding price in PAB is, therefore, based on the annual income from the electricity market in MPS divided by

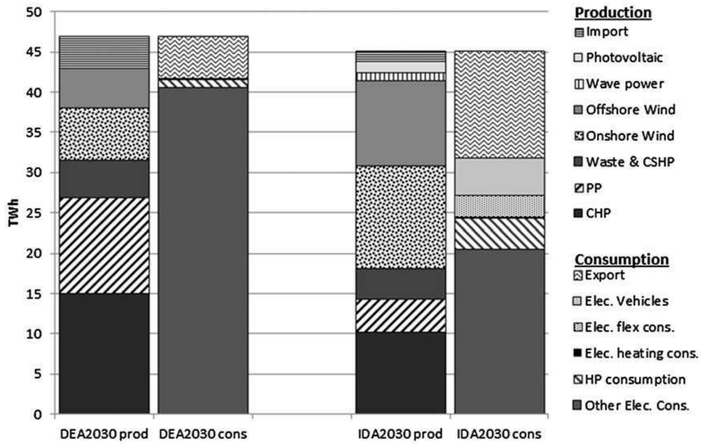

Fig. 4. Electric production and demand in the DEA2030 and IDA2030 scenarios. HP = Heat Pump.

the annual production in MPS. As this income is a yearly sum, it has to be divided into a price per MWh based on an expected electricity sale per year. This is done on the basis of the production hours found in the MPS scenarios.

This provides a PAB in which none of the producers will try to gamble on the market; however; in PAB, gambling may occur. 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 for gambling successfully. 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. For this reason, the offshore wind power and the central plants' potential for maximizing their profits by being willing to take risks is analysed. On the basis of these analyses, a new PAB situation in which the major players gamble is defined.

To distinguish between the different scenarios, the following naming scheme 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. These are MPS, PAB, and for the pay-as-bid with gambling, PAB2. The second part represents the technical scenario, being either DEA or IDA. The scenarios are hence:

1. MPS-DEA
2. MPS-IDA
3. PAB-DEA
4. PAB-IDA
5. PAB2-DEA
6. PAB2-IDA

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

The first two scenarios are the MPS scenarios. Bids consist of different parts, where the first is the STMC for fuels, including 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 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 linked to the district heating production; this is the saved variable costs and taxes connected with the use of one technology instead of another. In the MPS-IDA scenario, the bids are calculated in exactly the same manner as in the MPS-DEA scenario. The reason that the bids differ in the two scenarios is that different efficiencies are used.

In the PAB2 scenarios, 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 find more optimal bid strategies for these technologies, a range of different bids have been modelled 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

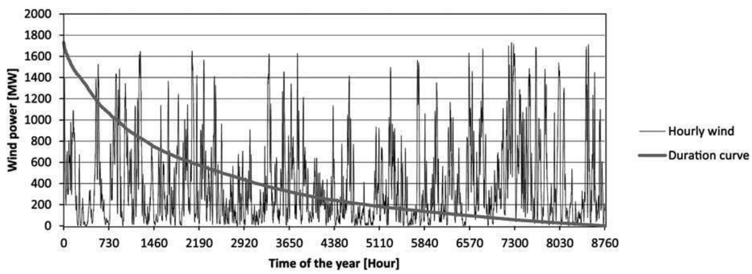

Fig. 5. Hourly distributions of wind power for one year used in the analyses combined with a duration curve showing how many hours wind production is above a certain value. Data are for Western Denmark 2001. Constructed on the basis of data from [12].

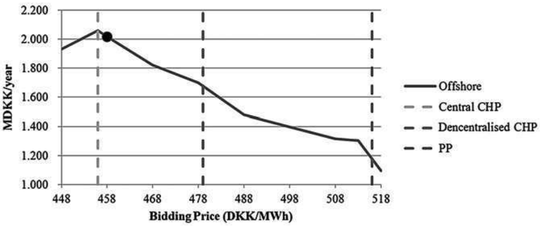

Fig. 6. Yearly income from electricity sales for offshore wind power for a range of bidding prices. The black dot represents the starting point, being the PAB-DEA bid.

into a graph for each technology, showing the bids' effect on the technology's yearly income or yearly profit.

To give an example of how the bidding price in PAB2 is found, Fig. 6 shows the effect of changing the bidding price for offshore wind power in PAB2-DEA. This approach is used for all scenarios.

In Fig. 6, it can be seen that an increase in the bidding price for offshore wind power results in a loss of yearly income. A small decrease in the bidding price introduced to equal the central CHPs' bidding price could result in a small increase in income. However, as the bid of central CHPs may also change, and the offshore wind may not win the auction, this small increase is not seen as a relevant option for offshore wind power. The bidding price for offshore wind power in the PAB2-DEA scenario will be equal to the PAB-DEA bid. By making similar studies of the rest of the technologies, the gambling bidding prices in PAB2 are found. The bidding prices for PAB2-IDA are found using the same approach as in PAB2-DEA, where the difference is the technical set-up utilized. The final bidding prices for all six scenarios are shown in Table 1.

From the left in Table 1, the initial MPS-DEA scenario is shown in which onshore and offshore offer their electricity at zero. The CHPs and PPs offer prices around 300-500 DKK/MWh.

In the PAB, there are some major changes in the bidding prices. The CHPs and fluctuating RES increase their bids, so they are much nearer to those of the PPs. The order from lowest to highest bid is still the same, where RES bid lowest, followed by central CHPs, decentralized CHPs and then PPs, which remain the highest bidder.

In PAB2, the major players try to find the bid which will bring 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 by 22 DKK/MWh, so it is close to the price offered by the decentralised CHPs.

Looking at the overall tendency of the three scenarios, the next move of the CHPs and RES could be to approximate their bids 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.

Table 1
Final bidding prices (DKK/MWh) in the scenarios (data based on simulations).

DKK/MWh	MPS-DEA	PAB-DEA	PAB2-DEA	MPS-IDA	PAB-IDA	PAB2-IDA
Decentralised CHP	403	479	479	379	394	394
Central CHP	315	456	478	330	369	359
Condensing CHP & PP	514	516	616	436	437	587
Onshore	0	455	455	0	313	313
Offshore	0	458	458	0	326	351
Wave	n.a.	n.a.	n.a.	0	339	339
PV	n.a.	n.a.	n.a.	0	346	346

In the IDA scenarios, the tendencies are the same as in the DEA scenarios, where in the MPS, the fluctuating RES are bidding a price of 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 bids of the condensing CHPs and PPs without losing income. This leads to RES biddings close to each other with onshore wind power lowest, then offshore wind power and wave, and photovoltaic, which is the highest of the RES biddings. Both the central and decentralised CHPs also increase their bids to get close to the PPs, but the central CHPs keep their bids below the decentralised CHPs.

The last scenario is the PAB2-IDA scenario, in which 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 by 150 DKK/MWh, giving a bidding price close to 600 DKK/MWh.

In order to make it possible to conduct the analyses, it has been necessary to model the external market as a fixed market, regardless of modelled changes in the Danish system and market. The external market is thus MPS. This is naturally a simplification.

6.2. Results of the analyses

The results of the modelling are presented in this section in terms of yearly values for each technology's production of electricity and heat, income from electricity sales, and profit from electricity production. Furthermore, the import and export are shown alongside the technologies, as they vary with the bidding strategies. It should be noted that the DEA and IDA set-ups cannot directly be compared, due to the difference in the mix of technologies, and will therefore be described separately, even though they are presented in the same tables.

As it can be seen in Table 2, all of the technologies in the DEA technical scenario, with the exception of condensing CHP, experience a decrease in electricity production when going from MPS-DEA to PAB-DEA. Also the import increases significantly. This increase in import occurs due to the increase in prices for the cheaper technologies, which results in a smaller increase in prices than in the case of MPS-DEA. For this reason, the import of electricity increases when changing from MPS-DEA to PAB-DEA and PAB2-DEA. This increase in imports results in reductions in wind power production, as the bidding price in MPS-DEA was zero, and after being changed to PAB, it is outbid by the external market during many hours. Also the CHPs experience a decrease in production due to the external market being cheaper during many hours. When making the transition from PAB-DEA to PAB2-DEA, there is a further increase in the import of electricity. Offshore wind power experiences a small increase in

Table 2
Yearly electricity produced, imported, and exported in the different auction settings (data based on simulations).

TWh/year	MPS-DEA	PAB-DEA	PAB2-DEA	MPS-IDA	PAB-IDA	PAB2-IDA
PP	3.86	3.73	1.58	0.77	0.86	0.59
Onshore	6.58	5.69	5.69	12.63	12.50	12.53
Offshore	4.93	4.40	4.46	10.67	10.39	10.01
Wave	–	–	–	1.41	1.23	1.25
Photovoltaic	–	–	–	0.90	0.85	0.86
CHP condensing	7.94	8.01	5.55	3.30	3.34	1.39
Central CHP	9.86	9.05	8.78	7.29	6.10	6.50
Decentralised CHP	5.18	4.29	4.21	2.93	2.59	2.61
Import	3.91	6.38	8.73	1.39	2.03	2.20
Export	5.22	4.51	1.97	13.33	11.86	9.92

production, which occurs due to the increase in the bidding price of the central CHPs. Onshore wind power has an unchanged production, whereas the rest of the technologies experience a drop in yearly production. Again, this is mainly due to the import being cheaper during many hours. During these hours, condensing CHPs and PPs experience the greatest reduction in production due to a large increase in their bidding price.

Going from MPS-IDA to PAB-IDA increases the PPs' and condensing CHPs' productions. These increases occur because of different conditions in the two scenarios. During some hours, prices are lower on the external market, which results in the full utilization of the import capacity to the external market, thus activating the PPs and condensing CHPs in order to meet the internal demand. Others conditions are due to heat storage constraints at times with high prices on the external market, where the PPs in some situations produce because the heat storages are full, resulting in neither need nor room for heat production from CHPs during those hours. The import increases again due to the many hours during which the price is low on the external market, caused by the use of an external market price distribution based on an MPS. This also results in a small reduction of electricity production for all of the RES and CHPs as well as 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 only takes place when comparing PAB-IDA and PAB2-IDA; going from MPS-IDA to PAB2-IDA, a decrease is seen for all production, except the imported.

As heat cannot be imported or exported and the demand is completely inelastic in the model, the heat demand is unchanged for each electricity auction setting, though it is different for the two technical set-ups. This can be seen in Table 3, which shows the heat production. When changing MPS-DEA to either PAB-DEA or PAB2-DEA, the result is an increase of the boiler production in 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 energy efficiency point of view, it is best to have the CHPs producing as much as possible, as the simultaneous production of heat and power gives optimal fuel efficiency. So for the DEA technical scenarios, any change from the current system results in a less optimal situation for the production of heat when using the explained modelling approach.

Looking at the results for the IDA technical scenario; when going from MPS-IDA to PAB-IDA, there is an increase in the heat pump and boiler production. This is due to a decrease in the heat production from CHPs, caused by the decrease in the electricity production from CHPs, which is outbid by the external market. Looking at the step from PAB-IDA to PAB2-IDA, this is slightly improved, because the Central CHPs bid a lower price and are thereby able to compete better with the external market.

Returning to the electricity production, the income from selling the produced electricity is of great relevance to this analysis, as the income from electricity production is one way of illustrating which technologies benefit and which lose from changing the auction setting.

Table 3
Yearly production of heat for the different auction settings (data based on simulations).

TWh/year	MPS -DEA	PAB -DEA	PAB2 -DEA	MPS -IDA	PAB -IDA	PAB2 -IDA
Central CHP	15.24	13.98	13.57	7.12	5.95	6.34
Central heat pumps	–	–	–	5.55	5.77	5.68
Central boilers	0.08	1.33	1.74	1.40	2.36	2.05
Decentralised CHP	6.67	5.53	5.43	2.57	2.28	2.29
Decentralised heat pumps	–	–	–	3.03	3.11	3.12
Decentralised boilers	0.54	1.68	1.78	3.03	3.25	3.23

Table 4 shows the yearly income from electricity production for the electricity producing technologies, together with the import and export of electricity. The change from MPS-DEA to PAB-DEA shows the same overall tendencies as for the electricity production, i.e., condensing CHPs seem to benefit from the change and the other technologies are increasingly outbid by the external market. The change from PAB-DEA to PAB2-DEA shows the same tendencies as with the production, the only major difference being that central CHPs seem to increase the yearly income in PAB2-DEA. This is due to the fact that central CHPs change their bid to maximize profit in the PAB2. 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 modelling shows that wind power production will lose income if the auction setting of the DEA technical scenario is switched to PAB, when using the explained modelling approach.

Focusing on the first step for the IDA technical scenario, going from MPS-IDA to PAB-IDA, the income is linked to the production shown in Table 2, where the PPs and condensing CHPs increase their production and thus increase their income. The RES all lose income when switching to PAB-IDA. This is due to a combination of producing less and only getting their bidding price, and not the higher price set by the last produced unit of electricity as in the case of MPS-IDA. A different change is seen when going from PAB-IDA to PAB2-IDA. The PPs' and condensing CHPs' incomes are reduced; however, 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-IDA to PAB2-IDA. The central 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, offshore wind power is the only technology apart from PPs which increases its income by switching from MPS-IDA to PAB2-IDA. This is again due to the increase of import caused by the lower prices on the external market.

The resulting changes in income do not change the economy for the technologies, since many of them also have costs associated with each MWh of electricity produced, and these costs should be recovered each year. For this reason, Table 5 presents the yearly profit per MW of installed electric capacity as the yearly income minus the yearly variable costs of producing. 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 modelled as not having an STMC.

It can be seen in Table 5 that by changing the auction setting from MPS-DEA to PAB-DEA, all the technologies, besides the PPs, increase their yearly profit. However, for condensing CHPs, going from MPS-DEA to PAB-DEA only results in a fairly small increase. For decentralised CHPs, going from PAB-DEA to PAB2-DEA also provides only a fairly small increase. An important observation is the negative profits for the CHPs, which is due to the income of the

Table 4
Yearly electricity sales income, value of imports, and value of exports in the different auction settings (data based on simulations).

MDKK/year	MPS-DEA	PAB-DEA	PAB2-DEA	MPS-IDA	PAB-IDA	PAB2-IDA
PP	1991	1923	974	323	377	344
Onshore	2991	2587	2587	3946	3914	3921
Offshore	2256	2017	2043	3478	3389	3515
Wave	–	–	–	479	417	425
Photovoltaic	–	–	–	311	295	297
CHP condensing	4091	4134	3420	1429	1459	817
Central CHP	4498	4128	4200	2692	2249	2329
Decentralised CHP	2478	2053	2017	1153	1020	1026
Import	1738	3052	4726	530	788	1022
Export	2572	2315	1142	4581	4270	3585

Table 5
Yearly profit for electricity sales for the thermal facilities per MW in the different auction settings (data based on simulations).

MDKK/MW/year	MPS-DEA	PAB-DEA	PAB2-DEA	MPS-IDA	PAB-IDA	PAB2-IDA
PP	0.012	0.012	0.041	0.004	0.006	0.026
CHP condensing	0.045	0.048	0.275	0.046	0.051	0.128
Central CHP	−1.589	−1.455	−1.333	−0.868	−0.723	−0.797
Decentralised CHP	−0.997	−0.824	−0.809	−0.435	−0.385	−0.386

heat produced simultaneously with the electricity not being accounted for in these results. But overall for the DEA scenario, changing the auction setting from MPS to PAB and PAB2 does increase the yearly profit for the thermal facilities.

When looking at the yearly profit from electricity sale of the thermal facilities in the IDA technical scenario, all of the technologies experience an increase in profits when going from MPS-IDA to PAB-IDA. When going from MPS-IDA to PAB2-IDA, all of the technologies increase their profit. However, when going to PAB2-IDA from PAB-IDA, the CHPs decrease their profits.

7. Error analysis and validation of results

The analyses in this article have been conducted using the EnergyPLAN model, which has been used for a large number of analyses published in peer-reviewed journal articles - see section 4. The results of the energy analyses are coherent with expectations based on previous analyses of PAB and MPS as found in the work by Oren [20]and the work by Ren and Galiana [21,22]as detailed in section 1 of this article. The tendency for revenue equalisation discussed by Oren and found by Ren and Galliana was incorporated into the strategy for establishing bidding prices, so there is a natural coherence here. However, the probabilistic analyses by Ren and Galliana showing a higher certainty in PAB cannot be reproduced in these deterministic analyses.

8. Conclusion

In this article, two different scenarios have been analysed with respect to how the MPS and PAB would affect the income of different technologies. The results of the analysis show that, when introducing PAB, wind power risks being outbid by other technologies or the import from the external market and hereby risks a shutdown during hours when they would normally produce in MPS.

When observing the results for the DEA2030 scenario, all of the modelled technologies have their highest yearly electricity production and income from electricity sales in the MPS. However, when instead considering their profit, all the thermal units have their highest yearly profit in PAB2. These results are, however, sensitive to the fuel cost, as low costs will likely make the power plants prefer PAB, while offshore wind power and central CHPs are more likely to prefer the PAB2. A high fuel cost, however, makes decentralised CHPs prefer both PAB and PAB2 instead of MPS.

The results for the IDA2030 scenarios are also sensitive to input parameters. All the fluctuating renewable energy sources and all the CHPs have the highest production in the MPS, and all of these technologies, with the exception of the offshore wind power, also have the largest income in this setting. The offshore wind power has its highest income in the PAB2. 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 auction. However, this is again dependent on, e.g., fuel costs, where lower fuel costs make PAB better for offshore wind power and PAB2 better for onshore wind power and central CHPs. Using the base assumptions on costs, etc., the MPS is generally the best system for fluctuating renewable energy, when considering gained income. However, the result is sensitive to the input parameters.

The identification of the preferable auction setting, when targeting an energy system free of fossil fuels, is sensitive to the assumption of fuel prices, etc. However, these analyses indicate that the MPS is generally preferable to the fluctuating renewable energy sources in all of the technical set-ups. There is, however, a tendency for revenue equalization, as also found by other researchers and quantitative analyses as the ones presented in this article. Therefore, the analysis may need to be combined with analyses of the institutional capability of different actors to accurately predict prices and optimise bids.

Acknowledgements

This article was originally written as a master's thesis by Sorknæs and Nielsen [65] at the Sustainable Energy Planning and Management programme at Aalborg University, Denmark. Special thanks go to Georges Salgi, Vattenfall, Copenhagen, for many valuable comments and questions to the manuscript. In addition, 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, and Chief Consultant at Energinet.dk Steen Kramer Jensen for making themselves available for interviews.

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