AALBORG UNIVERSITY
STUDENT REPORT

Incentivizing flexible power-to-heat utilization in district heating systems by redesigning electricity grid tariff schemes

Master's Thesis

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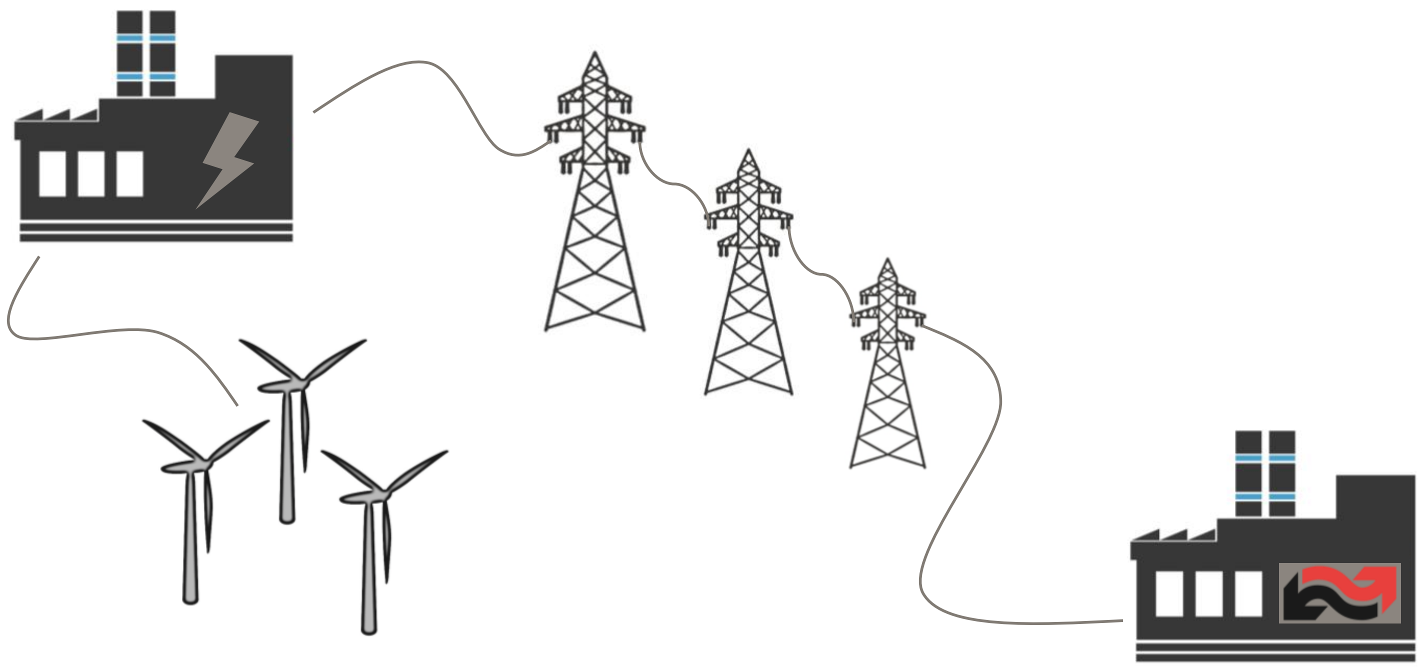
June 2019



AALBORG UNIVERSITY
STUDENT REPORT

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Incentivizing flexible power-to-heat utilization in district heating systems by redesigning electricity grid tariff schemes

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Abstract:

The Danish district heating sector constitutes a large potential for power-to-heat technology utilization and thereby increasing the flexibility potential between the heat- and electricity sectors.
In this master's thesis it is investigated how a redesign of the current flat rate electricity grid tariffs influences the business-economic incentive for flexible power-to-heat operation in a district heating area. The simulation tool energyPRO is used to investigate the influence of three redesigned tariff schemes; a flat rate tariff reduction, a fixed time-of-use tariff scheme and a dynamic tariff scheme. Related barriers to such changes, which are perceived by key-stakeholders, are identified through interviews.
It is concluded that the redesigned tariff schemes show potential for improving business-economic viability of flexible power-to-heat operation. However, measures and careful planning must be undertaken in the design of tariff schemes to ensure that the necessary income for grid operators remains in place.
From the barrier assessment, the most prevalent issue for flexible operation appear to be the current lack of business- and socio-economic incentives. Furthermore, for the implementation of redesigned tariff schemes the increased complexity for both grid operators and consumers hinders immediate implementation.

Resumé

Den igangværende omstilling til vedvarende energi, den stigende andel af fluktuerende elproduktion, og elektrificeringen af samfundet medfører et stigende behov for samspil og integration af energisektorer. Denne udvikling vil sandsynligvis medføre et øget behov for mekanismer som kan skabe denne integration og system fleksibilitet. Danmarks fjernvarme sektor besidder et stort potentiale for at bidrage med fleksibilitet til energisystemet på grund af den store eksisterende varmelagringskapacitet og mulighed for kobling af el- og varmesektoren ved brug af el til varme teknologier som elkedler og elektriske varmepumper.

Særligt elektriske varmepumper har de seneste år vundet frem blandt de danske fjernvarmeværker; et resultat af udfasningen af PSO-tariffen, udfasningen af grundbeløbet som støtte til kraftvarmeværker, og reduktionen af elafgiften. Elektriske varmepumper vil dog typisk fungere som grundlastenheder med mange årlige driftstimer, og vil dermed ikke umiddelbart fungere som en stor kilde til fleksibilitet.

Dette projekt undersøger, hvordan nye fleksible og dynamiske elnet tarif-strukturer kan ændrer på det selskabsøkonomiske incitament for drift af el til varme teknologier for et fjernvarmeselskab. Formålet er, at undersøge om den ændrede incitamentstruktur i form af en tarif omlægning, ændrer driftsmønstret på en måde, som tilgodeser integrationen af vedvarende energi.

Ved brug af teknisk-økonomisk modellering af Ringkøbing Fjernvarmeværk i programmet energyPRO, undersøges effekten af tre tarif-strukturer: 1) flad tarif nedsættelse (FT), 2) tidsvarierende tarif (TOU) og 3) dynamisk tarif (Dyn). Dette kombineres med en kvalitativ vurdering af kritiske barrierer forbundet med overgangen til nye tarif-strukturer og øget fleksibilitet, baseret på interviews med danske nøgle aktører. Identificerede barrierer sammenholdes og vurderes i henhold til markedsøkonomisk- og "innovative democracy" teori, for i højere grad at opnå en forståelse for de forskellige aktørers holdninger og synspunkter.

Resultaterne viser, at nye tarif-strukturer kan ændre det økonomiske incitament og dermed driftsmønstret for el til varme teknologier. Tabel 1 viser en oversigt over hvordan de tre undersøgte tarifstrukturer ændrer på den lokale integration af vindmøllestrøm i form af en eksport balance af vindmøllestrøm for Ringkøbing-Skjern Kommune.

	Ref	**FT**	**TOU**	**Dyn**
	Sum	**Difference**		
Eksport balance [MWh]	513,810	-2,418	-1,140	-3,349
Top 5 % eksport [MWh]	136,761	-330	62	-374

Tabel 1: Lokal integration af vindmøllestrøm.

Resultaterne fra Tabel 1 skal ses i forhold til referencescenariet, hvor tarifstrukturen

fra 2019 ikke er ændret. Det kan observeres, at det dynamiske tarifscenarie resulterer i den største reduktion af eksporteret vindmøllestrøm, efterfulgt af scenariet med flad tarif nedsættelse, og endeligt den tidsvarierende tarif-struktur. Desuden ses effekten i de 5 % af årets timer hvor den største eksport af vindmøllestrøm finder sted, med andre ord de mest kritiske timer for elnettets kapacitet. Også i de mest kritiske timer med hensyn til elnet kapacitet, medfører den dynamiske tarif-struktur den største reduktion af eksporteret vindmøllestrøm, efterfulgt af den flade tarif nedsættelse. Den tidsvarierende tarif har dog en uønsket effekt, hvor eksporten øges lidt i de timer, hvor eksporten i forvejen er høj.

Sammenholdt med den samlede produktion fra vindmøllerne er effekten forholdsvis begrænset, her skal det dog bemærkes at modellen blot inkluderer ét fjernvarmeværk, og en ændret tarif-struktur vil sandsynligvis påvirke andre fjernvarmeværker, industrivirksomheder, og muligvis også private forbrugere, og den kumulative effekt kan derfor alligevel vise sig at være signifikant. Påvisning af dette kræver en anden analytisk tilgang med fokus på systemmodellering fremfor det enkelte værk.

Væsentlige barrierer til fleksibilitet i fjernvarmesektoren og øget anvendelse af el til varme teknologier, inkluderer blandt andet den nuværende markedsstruktur med mangel på selskabsøkonomiske incitamenter som belønner fleksibilitet. Derudover indgår værdien af fleksibilitet ikke tilstrækkeligt i samfundsøkonomiske vurderinger, og det nuværende meget lukrative marked for special regulering begrænser særligt anvendelsen af elkedler.

På baggrund af dette projekt vurderes omstillingen til mere fleksible eller potentielt dynamiske elnet tariffer at være en relevant fremtidig fleksibilitets mekanisme, såfremt det implementeres i stor skala. Potentialet skal dog ikke overvurderes, og kan ikke stå alene som kilden til fleksibilitet. Den konkrete udformning og design af fremtidige tarif-strukturer på en omkostningsægte måde, hvor det nødvendige provenu til net- og transmissionselskab sikres, er en væsentlig udfordring. Desuden vil sådanne tarifstrukturer, og i særdeleshed dynamiske tarif-strukturer, øge kompleksiteten i kontrol- og styringsmekanismer. Derfor kan erfaringer fra mindre komplicerede tarif-strukturer, såsom en tidsvarierende struktur, være et vigtigt springbræt mod fuldt ud dynamiske elnet tariffer i fremtiden.

Preface

This is the resulting master's thesis from the 4th semester in the Master's programme of Sustainable Energy Planning and Management at Aalborg University. The master thesis has been carried out in the spring semester of 2019.

We would like to extend our sincerest gratitude and appreciation to Peter Sorknæs from Aalborg University for valuable supervision and guidance throughout our master's thesis.

During this master's thesis we have been fortunate enough to encounter many kind and incredibly helpful people, and for that we are very grateful. In particular we would like to thank:

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Finally, we would also like to thank the following people, listed below in alphabetical order, for providing us with valuable insights and/or data for this master's thesis.

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- Martin Halkjær Kristensen from Hvide Sande district heating company.
- Nathaniel Bo Jensen from the Danish Energy Agency.
- Søren Dyck Madsen from CONCITO.

Reading Guide

Figures, equations and tables in this master's thesis are numbered according to the chapter of their appearance. For example, the third figure in Chapter 1, is numbered 1.3. The same applies for equations and tables. Every figure and table is provided with a caption explaining its content.

The abbreviations used throughout the report can be found in a list at the beginning of the report. When an abbreviation is first introduced in the text it is written in full, followed by the abbreviation presented in parenthesis.

Throughout the report references appear in brackets. The references have been noted using the Harvard method, meaning that the references in the text are stating the author's surname or the website if no author appeared, and year of publication. An example of this is [Author, Year]. For instance, books are listed with author, title, year, publisher and ISBN and web pages are listed with author, title, URL and date. By clicking on the reference link the reader will be led directly to the reference list. The complete reference list can be found starting on page 95. Appendices are placed at the end of the report and are denoted A, B and so forth.

Report structure

In Figure 1, the report structure of this master's thesis can be seen. In the figure it is also illustrated how the theoretical framework and the methodology is used throughout the report.

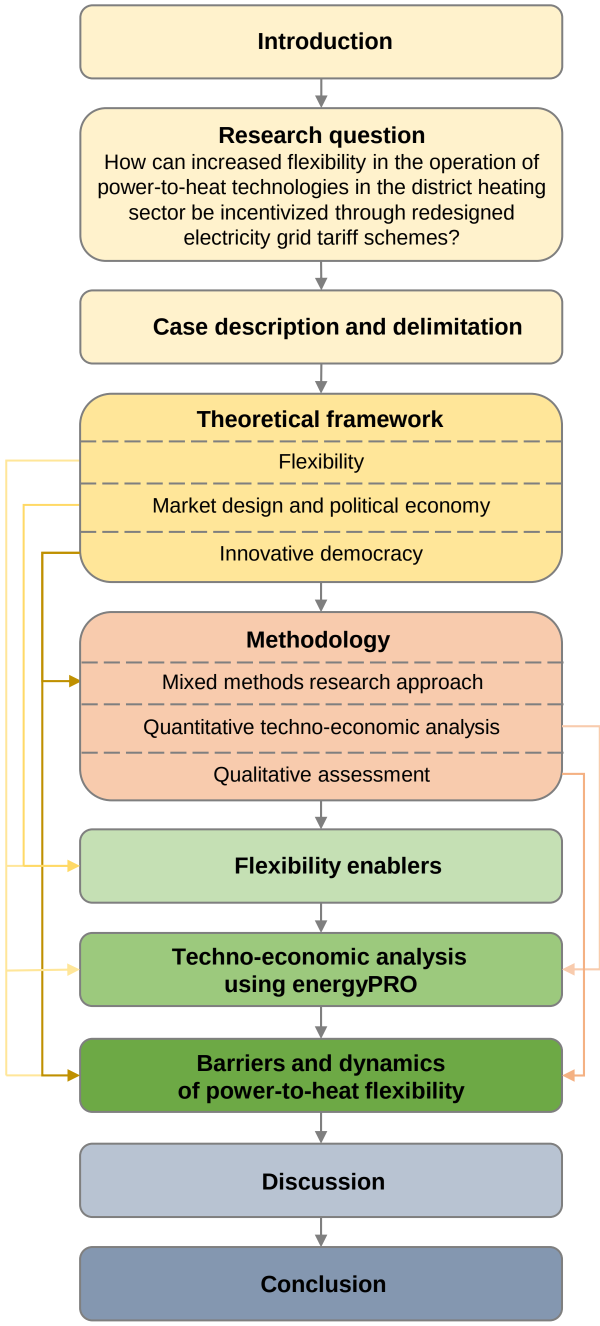


Figure 1: Report structure.

List of abbreviations

Abbreviations

CHP	Combined heat and power
COP	Coefficient of performance
DH	District heating
DMI	Danish Meteorological Institute
DRY	Design reference year
DSO	Distribution system operator
Dyn	Dynamic
EB	Electric boiler
FT	Flat rate
HP	Heat pump
NHPC	Net heat production cost
P2H	Power-to-heat
RAH	Ringkøbing Amts Højspændingsforsyning
RE	Renewable energy
TOU	Time-of-use
TSO	Transmission system operator
VRE	Variable renewable electricity

Table of contents

Chapter 1 Introduction **1**

1.1 Power-to-heat technologies in district heating 1
1.2 Flexibility and integration of renewables 3
1.3 Research question 6

Chapter 2 Case description and delimitation **7**

2.1 Focus on Ringkøbing-Skjern Municipality 7
2.2 Focus on a specific district heating plant 8

Chapter 3 Theoretical framework **13**

3.1 Flexibility 13
3.2 Market design and political economy 16
3.3 Innovative democracy 20
3.4 Focus areas going forward 23

Chapter 4 Methodology **25**

4.1 Mixed methods research approach 25
4.2 Energy system analysis tool selection 26
4.3 Quantitative techno-economic analysis 27
4.4 Qualitative assessment and data collection 34

Chapter 5 Flexibility enablers **37**

5.1 Flexibility enabling technologies 37
5.2 Flexibility enabling tariff schemes 44

Chapter 6 Techno-economic analysis using energyPRO **53**

6.1 EnergyPRO model description 53
6.2 Results from flat rate tariffs 59
6.3 Results from fixed time-of-use tariffs 62
6.4 Results from dynamic tariffs 66
6.5 Cross comparison 69
6.6 Sensitivity analysis 75
6.7 Key findings 77

Chapter 7 Barriers and dynamics of power-to-heat flexibility **79**

7.1 Lacking incentives for flexibility in district heating 81
7.2 Market development 83

Chapter 8 Discussion **87**

8.1 Methodological discussion 87
8.2 Designing future flexible tariff schemes 88
8.3 Ensuring tariff income in a changed tariff structure 90

Chapter 9 Conclusion **93**

Bibliography **95**

Appendix A Time series and external conditions **105**
A.1 Ambient temperature . . . 105
A.2 Solar radiation . . . 106
A.3 Heat demand . . . 106
A.4 Electricity demand . . . 108
A.5 Wind production . . . 108

Appendix B Production units and storage **109**
B.1 Heat pump modelling . . . 109
B.2 Solar heating . . . 110
B.3 Thermal storage . . . 111

Appendix C EnergyPRO: technical and economic assumptions **113**

Appendix D EnergyPRO: energy conversion and operational income **125**

Introduction 1

Denmark is committed to transition to a 100 % renewable energy (RE) system by 2050 [Danish Energy Agency, 2018a]. An ambitious goal which requires both technical and institutional changes and development. The on-going expansion of wind power and solar photovoltaic capacity in Denmark results in a continuous increase in variable renewable electricity (VRE) production. Utilizing and integrating this fluctuating electricity production is a tremendous challenge which needs to be overcome if the goal of a 100 % RE supply is to be fulfilled.

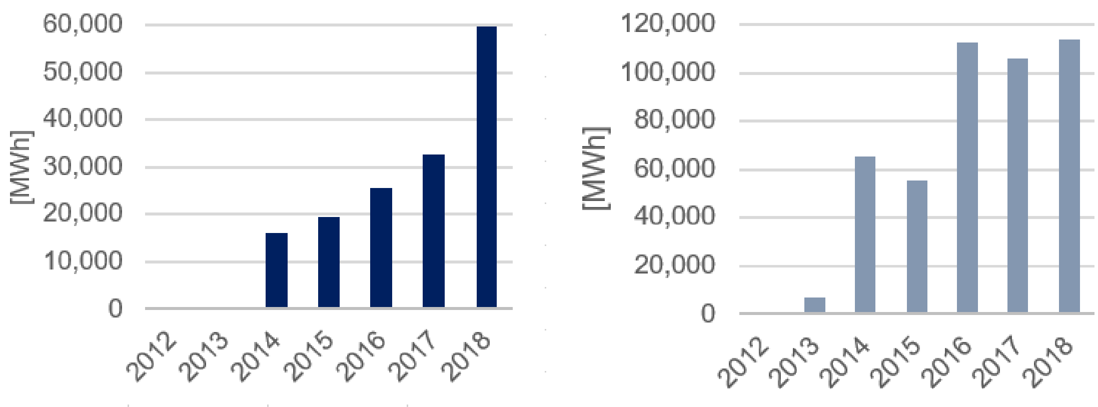
By nature, the electricity production from wind and solar fluctuates, and thus flexibility of the energy system will be key to accommodate and integrate an increasing production of VRE. Combined heat and power (CHP) has traditionally been an important source of flexibility in Denmark, however several circumstances could lead to a changing role for CHP plants in the future. In future RE systems with increasing VRE market penetration, the electricity spot market prices are expected to decrease [Sorknæs et al., 2019], likely leading to a decrease in full-load hours for decentral CHP plants. Such a trend was observed from 2010 - 2015, where the full-load hours of Danish decentral CHP plants steadily decreased [Grøn Energi, 2018]. This changed in 2016 and 2017, where a slight increase in full-load hours was observed due to a combination of low wind power production and increasing electricity prices. Combined with the phase-out of the capacity payment, which started in the beginning of 2019 for decentral CHP plants, the installed CHP capacity is expected to decline, reducing this former flexibility source.

The energy systems of the future will need to explore alternative flexibility measures to accommodate VRE production in the most effective way, to maintain a high level of security of supply and to limit the expansion of costly electricity transmission lines. Integration of sectors, e.g. the heat and transportation sector, is expected to be an integral part of this transition. In particular the Danish district heating (DH) sector has an important role to play in the future integration and balancing of RE, due to a combination of existing storage capacity and technological diversity [Lund et al., 2018]. Furthermore, despite decreasing costs, battery storage remains too expensive for long term electricity storage compared to heat storage alternatives found in the DH sector [Lund et al., 2016a]. As such, DH is an integral part of both the current and future Danish energy system in the transition towards 100 % RE systems.

1.1 Power-to-heat technologies in district heating

Power-to-heat (P2H) technologies are technologies which enable the conversion of electricity to heating; typically based on conventional heating resistors, electrode boilers, or electrical heat pumps (HPs). While the denotation P2H can be applied both for small-scale HPs and electric boilers (EBs) for individual households, this study applies P2H specifically in the context of large-scale (>0.5 MW_{th}) HPs and EBs installed in DH systems. A more detailed description on the working principle and typical application of EBs and HPs can be seen in Chapter 5.

A transition towards P2H technologies, such as EBs and electric HPs, coupled with heat storage could very well provide the critically needed flexibility and be an integral part of the future integration of VRE. The socio-economic benefits of electric HPs in DH systems have been mentioned in research for years already [Mathiesen et al., 2015; Lund et al., 2016b], however until 2018 actual deployment has been slow. It appears many DH companies have been hesitant to invest due to the uncertain future of the capacity payment and high electricity taxes and tariffs which have severely diminished the business-economic attractiveness of P2H solutions. With the reduction of the electricity tax as of 2019, out-phasing of the public service obligation tariff, and out-phasing of the capacity payment, the interest among DH companies in especially HPs is high, a tendency that seems apparent from Figure 1.1a.



(a) Heat production from HPs.

(b) Heat production from EBs.

Figure 1.1: Aggregated heat production from HPs and EBs in Danish DH systems from 2012 - 2018, based on data from the Danish District Heating Association [2018].

From 2013 - 2017, HP production has slowly but steadily increased, and from 2017 - 2018 production has almost doubled[1], a development likely related to the announcement of the electricity tax reductions. Looking at Figure 1.1b the same trend is not apparent for EBs, where no significant changes in production can be observed from 2016 - 2018.

At the end of 2017 an estimated total of 49 EBs and 21 HPs were operational in the approximately 384 Danish DH systems [Danish Energy Agency, 2017]. Looking at the total installed capacity of P2H technologies relative to other technologies, as seen in Figure 1.2, it is apparent that the share of P2H technologies remains low in the Danish DH sector.

[1]The data is self-reported by the DH companies to the Danish District Heating Association and the reliability and completeness is thus limited; it is however the most comprehensive production overview available.

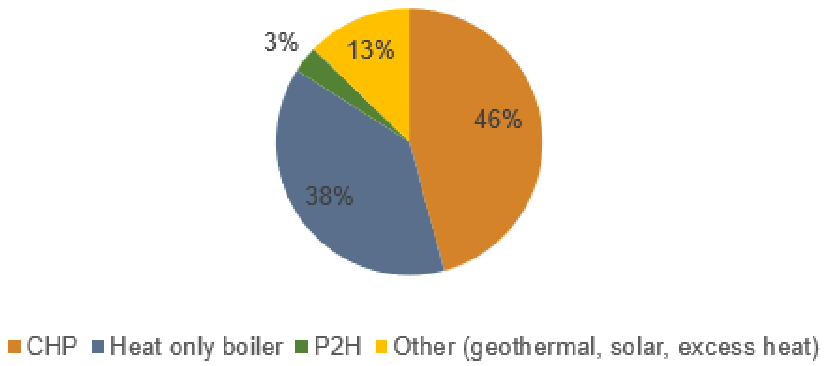


Figure 1.2: Share of installed heat production capacity in the Danish DH sector, based on data from the Danish Energy Agency [2017].

The reduction of the electricity tax does not influence the business-economy of an EB in most cases, since EBs typically operates on a different taxation scheme than e.g. HPs. While both EBs and HPs work to couple the heat and electricity sector and are useful technologies in integrating and utilizing VRE production, EBs and HPs are very different technologies and provide vastly different benefits to the energy system. HPs typically function as base-load units with many production hours due to a high investment cost, low operation costs, and high efficiencies [David et al., 2017]. Therefore, HPs could prove to be an unreliable source of flexibility in the future, given the current operation mechanisms, since HPs only to a limited extent react to price signals from the day-ahead spot market and fluctuations in VRE production.

EBs are almost the exact opposite technology of HPs, providing a lower investment cost, but also a lower efficiency. Given the current regulatory framework an EB in the Danish DH system will have very few operating hours based on operation according to spot market prices, where the vast majority of electricity is traded. Enabling greater system flexibility through flexible operation of both EBs and HPs could prove to be a pivotal challenge for future RE systems.

1.2 Flexibility and integration of renewables

While the importance of flexibility in RE integration has already been stressed, the underlying reasoning and argumentation as to why this is the case has so far only been cursory. The aim of this section is to connect the concept of flexibility to the on-going challenges of RE integration, while outlining how P2H technologies can partake in this transition.

The electricity grid is constantly being balanced by the Danish transmission system operator (TSO) Energinet in accordance with the Danish distribution system operators (DSOs). In this context, balancing means matching the electricity demand to the production, a task that is being complicated by VRE production from primarily wind power. Figure 1.3 illustrates an example of this relationship between production, consumption, and the electricity spot price for Ringkøbing-Skjern Municipality.

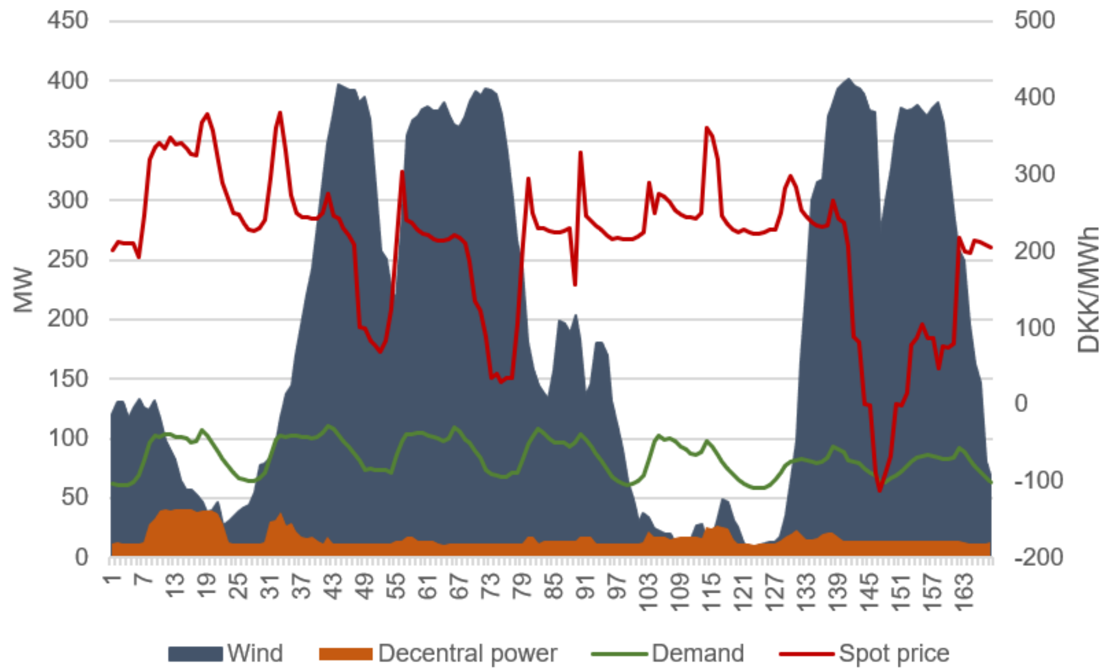


Figure 1.3: Overview of electricity production, consumption and spot prices for the 4th week of January 2018 in Ringkøbing-Skjern Municipality. Data regarding the electricity production from wind power and decentral power plants, and the electricity spot prices originates from Energinet. The electricity demand is modelled as described in Appendix A.

Looking at Figure 1.3, several challenges can be observed. Perhaps the first thing to notice is how the wind power production is highly fluctuating in a seemingly unpredictable pattern. The spot prices mostly follow the wind power production, where increased wind power production results in lower spot prices, an effect known as the merit-order-effect [Hvelplund et al., 2013]. The electricity demand fluctuates as well, however not quite as unpredictably, and with no obvious correlation to the wind power production. This leads to some immediate questions and concerns regarding the operation of future energy systems, such as; who will produce power or limit consumption during times where the demand exceeds the VRE production? And who will curtail VRE production or increase electricity consumption during hours of excess VRE production?

Curtailing VRE production is at times an undesired necessity given the current market structure due to negative spot prices, a situation observed in Figure 1.3 around hour 151. It is however an undesirable effect in a system aiming for 100 % RE, where adequate storage capacities could instead assist in shifting this excess production to other hours with a deficit of RE. The challenges described are likely to be exacerbated in the future, as a result of increasing VRE production, underlining the need for improved flexibility strategies and measures [Auer and Haas, 2016; Hirth and Ziegenhagen, 2015].

The most important sources of flexibility and strategies for increasing flexibility according to Nolting and Praktiknjo [2019] are 1) grid expansion, 2) storage capacity, 3) local smart grids and 4) sector coupling through synergies. P2H solutions and DH are very capable solutions especially for supplying flexibility through 2) storage capacity and 4) sector coupling, making it a seemingly strong option for increasing system flexibility. Furthermore, increased integration of heat and electricity markets would essentially increase the value of wind power and could thus potentially negate the effect of VRE being curtailed due to negative spot prices [Hvelplund et al., 2013].

P2H solutions and their potential for contribution in DH systems are well-established and have been investigated in various existing studies, with results indicating that P2H solutions in DH system can provide flexibility to the energy system [Sandberg et al., 2019; Kirkerud et al., 2017], however estimating how much and secondly, actually realizing this potential could prove to be difficult. Schweiger et al. [2017] has made an effort to determine a technical potential of P2H in the Swedish DH sector and found there is a significant potential in high wind and solar scenarios.

While the technical potential for increasing flexibility through P2H solutions might exist, realizing the potential could prove to be difficult, due to a lack of economic incentives and due to the current market structures. Both taxes and tariffs influence operation and prioritization of technologies, however only tariffs have the specific purpose of being cost reflective [Danish Energy, 2015]. The electricity tax is part of the state budget, and as such does not have a stated requirement of balancing production and consumption; it is primarily a source of income for the state. Meanwhile, tariffs are supposed to be cost reflective, and it is thus more feasible to discuss a restructuring of the tariffs as opposed to the taxes.

An area of growing interest among both academics and grid operators is the utilization of redesigned electricity tariff schemes as a tool for encouraging flexible operation, with examples including Sandberg et al. [2019] and Bergaentzlé et al. [2019]. In an investigation of policy incentives for flexible DH in the Baltic countries, Sneum et al. [2016] argues how flexibility today in mainly provided by market incentives and very little by energy policy. This raises the question of whether the existing market incentives are sufficient mechanisms for ensuring that the increased demand for flexibility is met, a challenge which is further exacerbated due to the conflict of ecological and financial efficiency of P2H control strategies, and the current lack of financial incentives for flexible P2H operation [Nolting and Praktiknjo, 2019].

Danish grid operators are however also investigating in the application of redesigned tariff schemes. Most notably, the DSOs Radius and Konstant have already implemented time varying tariffs in their respective areas, consisting of the north-eastern part of Zealand, where Copenhagen is included for Radius and the central-eastern part of Jutland, where Aarhus is included for Konstant [Danish Energy, 2018b]. The purpose is evidently to negate undesired consumption peaks during peak load hours, primarily during the evening in the hours of 17 - 20 during the winter months.

In an interview conducted with Hansen [2019a] from Energinet, he mentiones how Energinet, the Danish TSO, is also currently very interested in the potential for applying a lower tariff rate to some consumers in exchange for being interruptible, also with the purpose of increasing flexibility. This underlines the interest from both the DSOs and the TSO in optimizing grid tariff schemes in the future.

1.3 Research question

Ensuring energy system and power system flexibility is a tremendous challenge necessary to the integration of increased VRE production and to reach the RE targets of the future.

Going forward, reviewing and altering the regulatory framework and market conditions could prove to be a critical step towards unlocking the flexibility of P2H solutions, and the existing rigid tariff scheme might need to be comparably flexible to adjust for VRE production and incentivize flexible operation of P2H technologies.

This report sheds light on the utilization of P2H technologies in the DH sector through answering the following research question:

How can increased flexibility in the operation of power-to-heat technologies in the district heating sector be incentivized through redesigned electricity grid tariff schemes?

The research question is answered through a combination of quantitative and qualitative methods, an approach which is further described in Chapter 4. Firstly, a quantitative case dependent analysis is conducted for a Danish DH plant where techno-economic modelling is utilized to determine the influence of redesigned tariff schemes on the production patterns and business-economic feasibility of P2H solutions. A detailed case introduction and description can be seen in Chapter 2. Secondly, a qualitative case independent assessment of barriers and dynamics of P2H flexibility is carried out, delving into the complex challenge of reforming the current institutional market design. This is explored through the lenses of the innovative democracy approach and economic market theory, correlating the opinions and perceptions of key stakeholders with the purpose of obtaining a holistic understanding of the research topic.

Case description and delimitation 2

The following chapter describes how and why it is chosen to work with a case in the form of a specific municipality and DH plant within the municipality. Furthermore, a short description of the chosen DH plant can be found, along with the tariffs and fixed payments associated to the DH plant's electricity consumption.

2.1 Focus on Ringkøbing-Skjern Municipality

Throughout this study, it is chosen to work with a specific municipality and a specific DH system. It is chosen to focus on Ringkøbing-Skjern Municipality due to their ambitious RE goals for the near future and due to their existing RE resources in the municipality, mainly in the form of wind power.

Ringkøbing-Skjern Municipality is currently in the final phase of implementing their 2020 energy vision, focusing on the Municipality becoming self-supplied with RE by the year 2020. According to Ringkøbing-Skjern Municipality [2016], this means that the municipality must produce RE equivalent to the energy consumption of the households, industries and transport sector within the municipality, calculated on an annual basis.

From the most recent overview of the energy production and consumption in Ringkøbing-Skjern Municipality by PlanEnergi [2017], it is known that the RE share of the municipality in 2017 was around 66 % of the total energy consumption. It is evident that from 2017 - 2020 the municipality must increase their RE share by 34 percentage points in order to reach their goal of becoming 100 % self-sustainable with RE.

From the energy 2020 vision it can be seen that the focus areas are split into four broad main topics, where the second focus area, according to Ringkøbing-Skjern Municipality [2016], consists of having an efficient energy and heat supply based on RE in Ringkøbing-Skjern Municipality in 2020. Furthermore, these four broad topics are represented in nine more specific work areas, which all have an estimated effect on increasing the municipality's RE share. One of these nine specific work areas focus on increasing the share of RE in the DH sector, which according to Ringkøbing-Skjern Municipality [2016] will increase the total RE share of the municipality by 4.7 percentage points in 2020. The three specific municipal focus areas on the DH sector are:

1. 60 % of the DH supply is based on RE (increases from 40 % - 60 % by 2020).
2. Full household connection to DH in existing DH areas.
3. Gradually increased focus on the integration of wind power in the heat supply.

This study will in part explore ways of supporting the 1st and 3rd focus areas. There is however not a focus on expanding the existing DH areas in this study.

In addition to the ambitious RE goals of Ringkøbing-Skjern for the near future, they are also a municipality with a high share of wind power generation in their current energy supply system. This is due to various factors, the main ones according to Donslund [2019], special consultant at the Energy Secretariat in Ringkøbing-Skjern Municipality, being that Ringkøbing-Skjern Municipality is the original home to the wind turbine producer Vestas and the ideal location of the municipality in terms of wind conditions.

From the electricity balance for 2017 made by PlanEnergi [2017], it is apparent that wind power within the municipality is responsible for the majority of the electricity production, as seen in Table 2.1.

Electricity balance 2017	**Production [TJ/year]**
CHP plants	446
Wind power, onshore	4,086
Wind power, offshore	0
Solar power, hydropower etc.	109
Electricity import	-1,742
Total	2,900

Table 2.1: Electricity production based on production unit, as part of Ringkøbing-Skjern Municipality's electricity balance 2017 [PlanEnergi, 2017].

According to Donslund [2019], the current wind power capacity installed in the municipality is a great RE source, which should be utilized by the municipality to the greatest extent. As seen from the specific municipal focus areas on the DH sector mentioned above, the focus on integrating wind power in the heat supply should gradually be increased. The DH plants in the municipality can help to achieve this focus area by installing more P2H technologies and utilizing them to a greater extent when the wind is blowing. By doing this, the municipality is also able to increase the amount of DH supply based on RE, if more of the electricity produced by wind power can be utilized by P2H technologies in the DH plants.

2.2 Focus on a specific district heating plant

In addition to focusing on a specific municipality in this study, a specific DH plant within the municipality will also be chosen, to have a specific case to use in the techno-economic analysis in Chapter 6.

There are currently 13 DH plants in Ringkøbing-Skjern Municipality, which according to local heat planner Schmidt [2019], supplies around 50 % of the municipality with heat. An overview of the different DH plants, their annual heat production in 2018, their RE percentage according to the municipality and the fuels/technologies used in 2018, can be seen in Table 2.2.

DH plant	Heat production	% of total	RE %	Fuels/technologies used
Ringkøbing	113,013 MWh	26 %	25 %	EB, solar, natural gas (w. HP)
Skjern	76,636 MWh	18 %	95 %	Biomass, excess heat, natural gas
Tarm	57,842 MWh	13 %	100 %	Biomass (w. abs HP), solar
Lem	47,673 MWh	11 %	77 %	Biomass, solar, natural gas
Videbæk	44,813 MWh	10 %	70 %	Excess heat, EB, natural gas
Hvide Sande	40,586 MWh	9 %	27 %	EB, solar, natural gas
Spjald	15,517 MWh	4 %	87 %	Biogas, HP, natural gas
Ørnhøj-Grønbjerg	11,818 MWh	3 %	92 %	Biomass, solar, natural gas
Tim	9,580 MWh	2 %	22 %	Solar, natural gas
Kloster	5,923 MWh	1 %	0 %	Natural gas
Troldhede	5,455 MWh	1 %	0 %	Natural gas
Aadum	3,851 MWh	1 %	99 %	Heat from Tarm, EB, natural gas
Hemmet	3,710 MWh	1 %	100 %	Biomass

Table 2.2: Overview of the 13 DH plants in Ringkøbing-Skjern Municipality. Data and information regarding the DH plants is provided by local heat planner Schmidt [2019].

The DH areas seen in Table 2.2 are listed according to the amount of annual heat production in 2018, starting with the largest amount of heat production. For each of the 13 DH areas, the annual heat production for 2018 can be seen, both in MWh and as a percentage of the total heat production. A percentage representing how large an amount of the annual heat production is produced using RE can also be seen. Finally, an overview of the fuels/technologies used in each DH area can be seen. EBs and HPs are mentioned as technologies instead of mentioning electricity as the energy source, since for this study it is relevant to have an overview of the P2H technologies currently present in the areas.

From the information regarding the various DH plants in Ringkøbing-Skjern Municipality seen in Table 2.2, it can be seen that the DH plants differ both in size and in which type of fuels/technologies they use. Due to the focus of this study on P2H technologies in the DH sector, as mentioned in the research question in Chapter 1.3, it is relevant to choose a DH plant which actually has P2H technologies or plan to implement P2H technologies in the near future. Based on information from Schmidt [2019], it is known that Kloster DH plant is currently in the process of implementing an air-to-water HP, Hvide Sande DH plant are in the process of investigating the conditions for implementing a groundwater heat source HP and Troldhede DH plant have recently been granted approval for a solar power and HP project. According to Andersen [2019b], director of Ringkøbing DH plant, they expect to connect their natural gas HP to the electricity grid in the near future to enable heat production on the HP based on either natural gas or electricity in the future. Furthermore, Ringkøbing DH expects to add additional HP capacity to Ringkøbing DH plant in the future to increase their RE share.

Based on the gathered information regarding the current situations for the various DH plants in the municipality and their future plans regarding P2H technologies, it is chosen to include Ringkøbing DH plant as the DH case in the techno-economic analysis in Chapter 6. Ringkøbing DH plant is chosen based on the fact that they currently have a P2H technology in the form of their EB, they have plans of connecting their natural gas powered HP to the electricity grid in the near future and they have several hot water storage tanks. They therefore have a solid foundation of flexibility enabling technologies within their DH system. Furthermore, their current RE share of 25 % is fairly low compared to other DH plants in the municipality, changes are therefore expected to be necessary in the future for them to be in accordance with the municipal RE goals.

Ringkøbing DH plant has various heating technologies installed which provides a large potential for the DH plant for flexible operation. These heating technologies consists of; natural gas boilers, a natural gas CHP plant, a natural gas air-to-water HP, an EB, solar heating, and hot water storage tanks. A more detailed description of the DH system can be seen in Chapter 6.1.

2.2.1 Associated tariffs and fixed payments

Due to the focus of this study on incentivizing flexible operation of P2H technologies through redesigned tariff schemes, as described in Chapter 1.3, it is relevant to have an overview of the current tariff scheme applicable to Ringkøbing DH plant.

Ringkøbing DH Plant is located in the area where the local DSO "Ringkøbing Amts Højspændingsforsyning" (RAH) is in charge of operation and maintenance of the local electricity distribution grid. RAH is the DSO for most of Ringkøbing-Skjern Municipality.

The tariffs and subscription costs, which Ringkøbing DH plant must pay for the electricity they use, are set by RAH. The income from the tariffs collected by the local DSO, must reflect the cost which the DSO uses on operation and maintenance of the local distribution grid [Danish Energy, 2015]. If various tariff and subscription costs are compared for various DSOs in Denmark, is it observed that they vary considerably. Danish Energy, which is a business and interest organization for energy companies in Denmark, collects information regarding the various tariff and subscription costs managed by the various DSOs in Denmark and compares them in an annual report. According to this report from 2018, it can be observed that prices for both tariff and subscription costs are rather high for RAH's customers compared to prices from other DSOs in Denmark [Danish Energy, 2018b]. In Table 2.3, a total cost per MWh representing the total cost for transmission-, system- and distribution tariffs and fixed payments which electricity consumers must pay, can be seen for the DSO RAH specifically and for all Danish DSOs in general. The transmission- and system tariff is collected by the TSO and the distribution tariff is collected by the DSO.

	Annual consumption (kWh) and customer category (A, B and C)							
	2,000	4,000	15,000	100,000	250,000	1 M	1 M	25 M
DKK/MWh	C	C	C	C	B low	B high	A low	A high
RAH	**548.6**	**428.6**	**340.6**	**319.5**	**217.5**	**197.4**	**136.0**	**120.4**
All of Denmark								
Highest prices	768.0	524.0	426.9	398.3	256.0	229.0	163.0	120.4
Lowest prices	227.4	205.0	113.3	85.0	82.0	101.2	96.5	92.5
Weighted average	500.7	399.3	325.0	309.2	195.8	173.2	119.4	105.5

Table 2.3: Total price, including transmission-, system- and distribution tariffs and fixed payments, illustrated for RAH and for all of Denmark. These are 2018 costs which originates from Danish Energy [2018b].

In Table 2.3, "All of Denmark" consists of all the DSOs in Denmark. The highest and lowest prices for each customer category are based on the highest and lowest prices observed by Danish Energy [2018b] from the various DSOs. The weighted average are prices calculated based on all of the prices from all the Danish DSOs.

The tariffs and fixed payment costs vary according to the customer type. The different customer types are generally grouped into C, B or A customers for the various DSOs. Usually there are also low and high subcategories for each of the groups. In general, C customers are smaller customers such as households, B customers are usually medium/large customers such as small/medium sized DH plants or small industries and A customers are usually large DH plants or large industries. Depending on the DSO, these groups are generally sorted by annual consumption, as seen in Table 2.3, or by which voltage level or transformer station the consumer is connected to.

In Table 2.3 it can be observed that in general the total prices for tariffs and fixed payments are high for the DSO RAH compared to the weighted average prices for all DSOs in Denmark. The prices in all of the customer categories are higher for RAH than the weighted average prices. It can also be seen that RAH has the highest total price, out of all the DSOs in Denmark, for the customer category A high of 120.4 DKK/MWh. The prices illustrated in Table 2.3 proves that RAH is among the DSOs with the highest total prices, regarding both tariffs and fixed payments.

Danish Energy [2018b] also provides an overview similar to the information represented in Table 2.3, which shows, in more detail, what the different DSOs have priced the distribution tariff at. This is illustrated in Table 2.4, where the distribution tariff, managed by RAH, and the average distribution tariffs, for west, east and all of Denmark, can be seen.

	Annual consumption (kWh) and customer category (B and A)		
	250,000	1 M	1 M
DKK/MWh	B low	B high	A low
RAH	**133.1**	**114.2**	**52.8**
DK1	101.1	87.8	36.7
DK2	121.6	92.7	36.0
All of Denmark	109.4	90.0	36.4

Table 2.4: Distribution tariffs for RAH and Danish DSOs in general. These are 2018 costs which originates from Danish Energy [2018b].

In Table 2.4 only the three different customer groups B low, B high and A low are included, as these are the groups which DH plants are usually placed in, according to annual electricity consumption or electricity grid connection level. As it can be seen from the table, the distribution tariff level is rather high for RAH compared to the average prices for west, east and all of Denmark. This is true for all three customer groups shown in the table.

From the tariffs and fixed payments seen in Table 2.3 and 2.4, it is obvious that the prices for tariffs and fixed payments are relatively high for the various customer groups using the DSO RAH. For this study it is relevant to keep in mind, that the tariffs and fixed payments which Ringkøbing DH plant must pay to RAH, are relatively high, compared to other places in Denmark. This has an influence on how expensive it is for Ringkøbing DH plant to run their EB and electric HP, for example.

Furthermore, the tariffs and fixed payments seen in Table 2.3 and 2.4 are costs from 2018 and are outdated. They are however included in this chapter to give an overview of what the price level is for the DSO RAH compared to all other Danish DSOs. An overview of the currently valid tariffs which Ringkøbing DH plant is subject to in 2019, is illustrated in Table 2.5.

2019 tariffs applicable to Ringkøbing DH plant	**Price level [DKK/MWh]**
Transmission tariff (TSO)	44.0
System tariff (TSO)	36.0
Distribution tariff (DSO)	38.6
Total	118.6

Table 2.5: 2019 tariffs excl. VAT, which Ringkøbing DH plant are subject to. RAH customer type according to Andersen [2019b] from Ringkøbing DH plant: A low (bev)[1]. TSO tariffs originate from Energinet [2019a] and DSO tariff originates from RAH [2019].

Apart from the specific tariffs and fixed payments, the electricity tax also influences operation and prioritization of technologies and was in 2019 lowered by 150 DKK/MWh, significantly increasing the economic feasibility of electric HPs among other electricity consuming activities. The flat decrease of the electricity tax does however not provide any incentives for flexible operation and could result in consumers using electricity for e.g. HPs and electric vehicles in an undesirable way, resulting in addition peak load imbalances. This argument was raised by the Danish Ecological Council back in 2012 in discussions on potential electricity tax decreases and dynamic taxes and tariffs [Ingeniøren, 2012].

The EB scheme has remained unchanged, a strong political indication of the prioritization of technologies, limiting the potential for EBs to contribute as a potential source of flexibility.

[1]The customer type: A low (bev), is exempted from paying an energy saving contribution. According to Nielsen [2019] from RAH, heat production plants do not pay energy saving contributions, as they are imposed in connection with the sale of heat to the end customer.

Theoretical framework 3

This chapter first introduces the concept of flexibility and how it is applied in existing research, before outlining its relevance and utilization in this study. Afterwards, varying perspectives with regards to economic theory, market design and political economy are presented, with the purpose of recapitulating their application and downfalls in the context of RE systems and the design of market incentives. Finally, the innovative democracy approach is presented as a way of thinking, and the influence of markets as political and societal constructed entities is discussed.

3.1 Flexibility

The concept of flexibility is discussed avidly in both academic research, governmental regulation, and political strategies. According to the most recent Danish Energy Agreement from 2018, *"Denmark must have the most integrated, market-based and flexible energy system in Europe"* [Danish Ministry of Energy, Utilities and Climate, 2018, pp. 13]. Despite these high ambitions for flexible energy systems and the large quantities of existing literature regarding flexibility, no universal definition of flexibility in energy systems seems to exist and the concept is applied in a variety of different contexts. Others, such as Hillberg et al. [2019] and Papaefthymiou et al. [2018] also point out that a general definition for flexibility is lacking. This section aims to provide an overview of existing literature and flexibility definitions, and outline how flexibility relates to and is applied in this project.

3.1.1 The difficulty of measuring flexibility

Flexibility is applied and discussed in an energy system perspective and in the interplay of various critical sectors such as heat, electricity, transport, industry, but it is also used solely to describe the flexibility of the electricity sector, e.g. the ability of power plants to maintain and balance voltage and frequency.

Since actually defining and measuring flexibility is a difficult task, Papaefthymiou et al. [2018] argues that it is easier to detect signs of inflexibility than to provide an accurate assessment of flexibility:

> *"Instead of measuring flexibility, we often rely on signs of inflexibility which are visible today already, such as recurring severe frequency excursions, structural RE sources curtailment, high levels of re-dispatch, area control errors, negative market prices, price volatility, loss-of-load and subsidized overcapacity."*
>
> [Papaefthymiou et al., 2018, pp. 1027]

While the symptoms of inflexibility provided by Papaefthymiou et al. [2018] focus solely on the power sector, the notion that flexibility of a system is difficult to observe or measure, and how signs of inflexibility are much more apparent, is a very interesting take on the concept.

3.1.2 Flexibility - a term with many varying definitions

According to Papaefthymiou et al. [2018], before the RE transition started the primary type of flexibility needed was power system flexibility. Papaefthymiou et al. [2018] also points out that there are different ways of defining power system flexibility in literature, however most link it primarily to system balancing or stability. Therefore, some examples of variations of flexibility definitions based solely or primarily on power system flexibility for systems without comprehensive RE integration, can be seen in the following:

> *"Power system flexibility is the extent to which a power system can adapt electricity generation and consumption to maintain system stability."*
>
> [Papaefthymiou et al., 2018, pp. 1027]

> *"Flexibility is the capability of the power system to maintain balance between generation and load under uncertainty."*
>
> [Hsieh and Anderson, 2017, pp. 1]

> *"Flexibility is the capacity of the electricity system to respond to changes that may affect the balance of supply and demand at all times."*
>
> [Hillberg et al., 2019, pp. 1]

Traditionally, power system flexibility has been provided primarily by conventional power plants at the supply side of the system. However, as VRE is increasingly being integrated in the energy system and conventional power plants are gradually being phased out, a need for flexible emerges which exceeds the previous definitions. There is now a need for flexibility in more sectors of the energy system, not only on the supply side of electricity generation, and a need for new flexibility sources such as demand-side flexibility, energy storage and flexibility enablers such as grids and markets. Different suggestions for flexibility definitions which includes an energy system with various RE sources dominantly included in the technology mix can be seen below.

Papaefthymiou et al. [2018] offers a broad definition on flexibility and IRENA [2019] offers a flexibility definition with a focus on power systems with VRE integrated in the system:

> *"The readiness of systems to integrate higher variable renewable energies shares."*
>
> [Papaefthymiou et al., 2018, pp. 1027]

"The capability of a power system to cope with the variability and uncertainty that solar and wind energy introduce at different time scales, from the very short to the long term, avoiding curtailment of power from these variable renewable energy sources and reliably supplying all customer energy demands."

[IRENA, 2019, pp. 4]

The definition provided by IRENA [2019] does resemble the definition from Papaefthymiou et al. [2018], however it is more detailed and has a key focus on avoiding power curtailment from the variable RE sources. As mentioned, flexibility is the capability of the power system to cope with variability and uncertainty of RE, and there are a number of different strategies which can assist in that. IRENA [2019] provides a very extensive catalogue of strategies and technical applications for increasing the flexibility in a system, however a simple and intuitive categorization is instead provided by Li et al. [2018], in which power system flexibility is defined to be a result of grid side flexibility, demand side flexibility and generation side flexibility. This underlines how flexibility of a system can come from many different sources and is not simply a matter of having flexible production units. Realizing how flexibility can arise from many different sources is an important insight.

3.1.3 Flexibility: how it is defined in this study

In this project, the focus for flexibility is not solely on the electricity sector or on the heat sector, but it is on increasing the flexibility potential for both sectors by increasing sector integration, through the use of P2H technologies in the DH sector such as EBs and HPs. In this study, flexibility is therefore defined as follows:

Flexibility in the energy system is the ability to maintain a stable relationship between energy production and demand in any given time.

Even though the definition is broad, it covers the most fundamental task which flexibility in the energy system must enforce; maintain a stable relationship between energy production and demand. This is true for fossil fuel driven energy systems and for RE driven systems. However, the role of flexibility is much more demanding for energy systems supplied by RE.

If the flexibility of the energy system is increased it will help to diminish some of the challenges associated to RE technologies, e.g. the challenging and to some extent unpredictable electricity production fluctuations that RE technologies can cause. Furthermore, if it is possible to utilize the VRE production to a greater extent, it will also allow for integration of additional RE capacity in the energy system. [IRENA, 2019]

It is evident that it is more difficult to maintain a stable relationship between electricity production and supply than it is for heat production and supply. This is due to several different factors such as storage possibilities and the time factor for which balancing is needed. However, the heat sector has the ability to assist the electricity sector in increasing the flexibility by sector integration. This also provides benefits for the heat sector, which gains flexibility by increasing the different types of heat production possibilities it has.

As previously mentioned, many different flexibility enablers exist, something that should be exploited to a greater extent as the RE share of the energy system increases [IRENA, 2019]. As previously mentioned in Chapter 1.2, one type of these flexibility enablers is P2H technologies, which when integrated in the DH sector in combination with storage capacity has potential for increasing the flexibility of both the heating- and the electricity sector. This is further investigated in Chapter 6.

3.2 Market design and political economy

Understanding markets and the involved actors and authorities are an important prerequisite to discuss competitive conditions among energy technologies. In Chapter 1 it was outlined how increased flexibility will require co-operation from a multitude of actors and alignment of contrasting interests in the design of new market structures. This section will serve as an introduction to the prevailing schools of thought within the field of economic theory and political economy, in the light of energy planning and the transition to flexible RE systems.

The influence and optimal design of markets is an avidly discussed topic among researchers, politicians and economists in the pursuit of negating the effects of climate change. Traditionally, markets are considered to consist of a buyer, a seller, and a product or service. Market design however also relates to the economic arrangements and environment for which technologies compete against each other, both renewable and conventional fossil fuel-based technologies [Hvelplund, 2011]. Several formal markets have been established with relevance to the diffusion of RE technologies including the Nord Pool electricity market, the CO_2 quota market, the regulating power market, markets for ancillary services, etc. The role of markets, and the question of whether "free" market arrangements should form organically, or if guidance and institutional arrangements from policy makers are required, is a question of ideology and which economic principles one follows and supports. Highly related to the topic of economic theory is the act of balancing relationships between individuals and society or markets and state. This is often denoted as political economy, which in brief is the study of how a country is managed or governed [Foldvary, 2011].

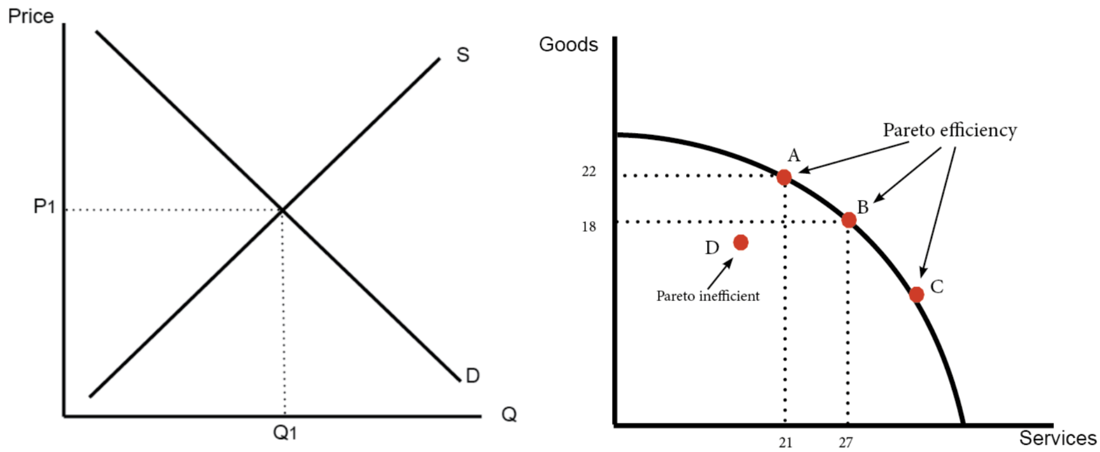
Neo-classical economic theory, also sometimes referred to as mainstream economy, due to it being the dominant way of thinking among modern economic scholars, is built on the relationship between supply and demand and the hypothesis of efficient or perfect markets. Neo-classical economy relies on three fundamental assumptions which guide all other theorems developed within a neo-classical framework and way of thinking:

1. People have rational preferences among outcomes.
2. Individuals maximize utility and firms maximize profits.
3. People act independently on the basis of full and relevant information.

[Weintraub, 2013]

Following these three fundamental assumptions leads to several immediate conclusions and effects. One is that since products are assumed to be homogeneous and actors are assumed to behave rationally on the basis of full information, there is no or at least very limited need for an institutional framework and guidance e.g. in the form of support and incentive schemes, taxes and tariffs, or prohibitions and other legislation.

The idea of free markets and the assumption that markets are formed and exist naturally is prevalent. In such a perfect or efficient market, it is assumed that products will only be evaluated according to one feature: price [Becker, 2007]. This leads to a very distinctive relationship between supply and demand as a result of price, as illustrated in Figure 3.1a. Another key component of neo-classical economic theory is efficiency of markets, which in short means maximizing net benefits [Keohane and Olmstead, 2006]. A market is considered to be in Pareto efficiency, when the state is such that no changes can be made which would make one individual better off without worsening the conditions for another [Mock, 2011; Ng, 2012], illustrated in Figure 3.1b.

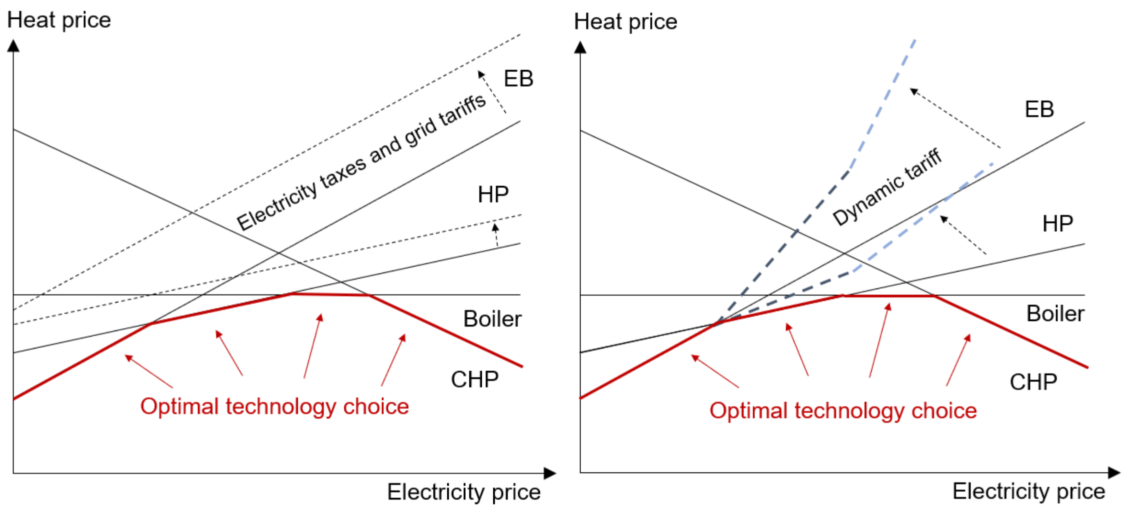


(a) Supply and demand curve [Pettinger, 2019a].

(b) Pareto efficiency [Pettinger, 2019b].

Figure 3.1: Key neo-classical economic principles.

While the principle of Pareto-optimum has obviously been applied in economics, it can also be used as an argument in engineering and planning when considering technical alternatives and optimal distribution and allocation of technologies. This is relevant and has been used as an argument when debating topics such as optimal implementation of wind turbines, electric vehicles, or the choice of optimal production technology in DH, as illustrated in Figure 3.2.



(a) Effect of flat rate taxes and tariffs. (b) Effect of dynamic tariffs.

Figure 3.2: Optimal choice of heat production technology in DH [Skytte, 2016].

The basic principle illustrated in Figure 3.2 illustrates how DH companies aim to optimize their operation strategy based on cost-minimization by utilizing the least-cost technologies first. This is illustrated by the red line indicating the least expensive heat technology to use for various changing electricity prices. For P2H and CHP technologies, this depends on the electricity price, and is furthermore influenced by the tax and grid tariff level as well as the structure of these expenses.

In Figure 3.2a a simple flat rate volumetric electricity tax and grid tariffs are included, and the principle of how this increases the heat price, thus limiting the incentive for P2H operation can be seen. Taxes and tariffs would however not necessarily have to be applied at a flat volumetric rate; the basic principle of a potential dynamic tariff is shown in Figure 3.2b. At low electricity prices the VRE production from e.g. wind turbines is typically high and there is a need to integrate electricity, to reflect this the tariff rate might be lower. Furthermore, the tariff could be higher during hours of high electricity prices to restrict consumption when there is a lack of VRE production. The interrelation and dynamics of market structures such as taxes and tariffs are important components of the market design and as illustrated in Figure 3.2a, a disadvantageous tax and tariff schemes could lead to an undesired decoupling of the heat and power markets.

The Nord Pool electricity market is an example of a market established on the basis of predominantly neo-classical economic principles. The Nord Pool spot market was implemented as part of a liberalized electricity market, prior to this the market was based on fixed price tariffs [Energinet, 2016]. While the previous constellation of fixed price tariffs was not a free market, it was defended and sustained for a long time by the argument that the electricity sector is a natural monopoly. The Nord Pool spot market functions as an opportunity for buyers and sellers to meet, and the price is established according to supply and demand for electricity. However, recent developments have resulted in challenges for the existing Nord Pool spot market, a market that was implemented nearly two decades ago, and not designed with negative pricing in mind due to wind power and the merit-order-effect, but instead designed to accommodate the marginal production prices of power plants [Morales and Pineda, 2017].

Neo-classical economist would generally argue that the market is capable of balancing itself, also in the context of negating climate change. In short, the market should be capable of finding the optimum level of pollution abatement, an optimum which is greater than zero but less than 100 % due to increasing marginal costs relative to benefits. This optimum, where the obtained benefits relative to costs are the greatest, is defined as the efficient level of pollution abatement [Keohane and Olmstead, 2006].

In an effort to negate pollution, an emission trading scheme was implemented in the European Union, also known as the CO_2 quota system. The purpose of the system is to negate the effects of pollution by incorporating it in a market-based system. In this context pollution would be considered an externality, an unwanted side effect to an activity, in this case energy production or consumption. The market might not incorporate this effect on its own and thus costs would not resemble the true production cost and price signals would be misleading if the externality costs are not included. Unfortunately, the CO_2 quota system has not succeeded in causing significant changes due to an excess amount of available quotas and low prices [Laing et al., 2013; Muûls et al., 2016].

The concept of externalities and how they should best be accounted for in a Pareto efficient manner, is an important topic of economic theory and political economy. An often applied argument is that imposing or altering taxes is inefficient in economic terms, however this assumes an existing state of Pareto equilibrium and complete markets with perfect information [Ng, 2012]. Greenwald and Stiglitz [1986] instead describes markets as generally being incomplete with imperfect information and thus rarely in Pareto equilibrium. According to Greenwald and Stiglitz [1986], interventions such as tax policy changes can in many cases result in Pareto improvements. This does lead to the realization that individuals' perception and attitude towards policy changes and incentive schemes rely heavily of ones understanding of political economy, or in other words, the world view of individuals. In the context of climate change, Stern [2007] argues that the occurring climate changes are *"a result of the biggest market failure in history"*, suggesting that the externalities caused by energy usage have not been properly incorporated into the market.

Building upon the ideas of imperfect markets and in contrast to neo-classical economists, Krugman [2009] presents the argument that markets in general are inefficient and opposes the description of markets as inherently stable and part of an economy in which rational individuals interact in perfect markets. Furthermore, Krugman [2009] describes how human rationality leads to bubbles and bursts, one example being the economic crisis of 2008, and that one takeaway from the economic downfall is acknowledging the imperfections, irrational, and unpredictable behavior of markets. Because of this, Krugman [2009] argues that policy advice should be cautious and that we should not place unconditional faith in the market and its ability to solve all issues on its own, causing a need for economic safeguards.

While neo-classical economists would argue that markets typically and preferably develop naturally, Fligstein [2001] argues that markets are unstable and are formed and shaped by historical concrete actors with specific interests, both economic and political. The stability of the market is a result of present market structures that are sustained due to the desires from dominating existing suppliers, institutions and organizations, whom desire to sustain the current market structure, such as regulation, to their own benefit and interests. The suggestion that markets are not as such stable and perfect, but instead a result of the market structures and -conditions is the foundation of the innovative democracy theory presented in the following section.

3.3 Innovative democracy

As described in Section 3.2, there are different views and beliefs on how political economy should function. There are therefore also different contending political economy paradigms which according to Hvelplund [2011] have been and still are:

1. The neoclassical approach.
2. The concrete institutional approach.
3. The innovative democracy approach.

The neo-classical approach relies primarily on the market structure as it is, as described in Section 3.2. If new technologies wish to enter the market, neo-classical economic theory implies that they should do so when they can be competitive in the existing market. In general, there is no direct support for RE- and energy conservation technologies to enter the market. According to Hvelplund [2011], this approach is generally the paradigm adopted in policy suggestions from the Ministry of Finance.

The concrete institutional approach considers the neo-classical approach to energy planning to be too simple. In contrast to the neo-classical approach, the concrete institutional approach recognizes that the market is not static but embedded in an artificial institutional setting which can be modified, if so desired by the involved actors. However, it assumes that RE- and energy conservation technologies will naturally be implemented by all actors in the energy system over time, and it does not expect any resistance to occur in the market due to a principle of ecological modernization. Therefore, this approach does not as such support changes to political processes, redesign of markets, or public regulation tools.

Finally, the innovative democracy approach, just like the concrete institutional approach, considers the neo-classical approach to energy planning to be too simple. However, it also sees a need to support changes to political processes, contradictory of the concrete institutional approach. This is thought to be necessary, since in this approach it is believed that RE- and energy conservation technologies will meet resistance from fossil fuel technologies when being implemented in the existing market. The innovative democracy approach therefore attempts to create a level playing field for all types of technologies in the market.

A comparison of the neo-classical- and the innovative democracy approach, based on Hvelplund [2011], can be seen in Figure 3.3.

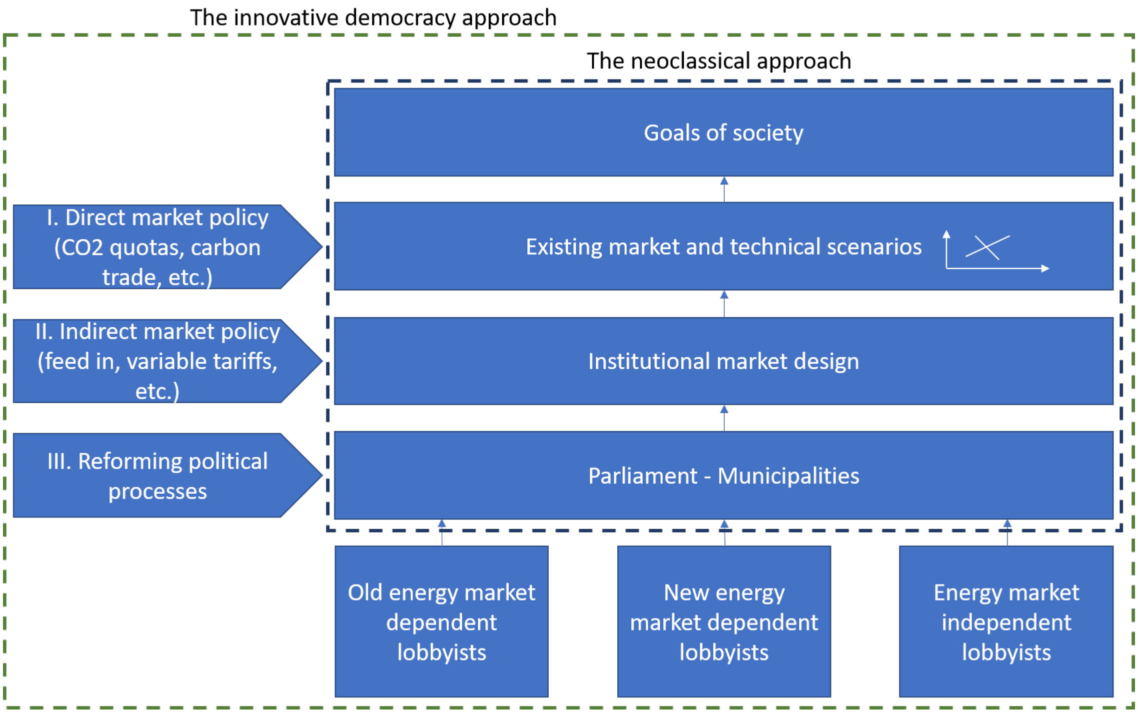


Figure 3.3: The principle of the neoclassical approach compared to the innovative democracy approach, based on Hvelplund [2011].

From Figure 3.3 the principle of the neo-classical approach can be seen and is compared to the innovative democracy approach. From the figure it can be seen that the neo-classical approach relies on the parliament and the municipalities to set the premises for the institutional market design. The existing market and technical scenarios solely depend on the institutional market design to function and operate. Finally, the goals of society rely on the existing market and technical scenarios to be fulfilled.

In Figure 3.3 it can also be seen how the innovative democracy approach relies on the same structure as the neoclassical approach. However, more elements and methods for influencing the overall approach are present in the innovative democracy approach. It can be seen that old and new energy market dependent lobbyists and energy market independent lobbyists have influence on the decision making, which takes place in the parliament and in the municipalities. The old energy market dependent lobbyists are lobbyists such as large power production companies and large oil-, coal-, and gas companies. The new energy market dependent lobbyists are lobbyists such as wind- and solar companies and energy conservation companies. The energy market independent lobbyists are e.g. energy non-governmental organizations, the public arena and public discussions.

It can also be seen that it is possible to influence the parliament and municipalities, the institutional market design and the existing market and technical scenarios, by different outside influences and measures. It is possible to reform the political processes adopted by the parliament and the municipalities. It is also possible to affect the institutional market design by using indirect market policy, such as introducing feed-in tariffs, variable tariffs, etc. Finally, it is possible to affect the existing market and technical scenarios by using direct market policies, such as CO_2 quotas, carbon trading, etc.

It can therefore be seen that the neo-classical- and the innovative democracy approach differ in more than one way. Another difference between the two approaches, which is not illustrated in Figure 3.3, is the set-up of the institutional market design. This is illustrated for the two different approaches in Figure 3.4.

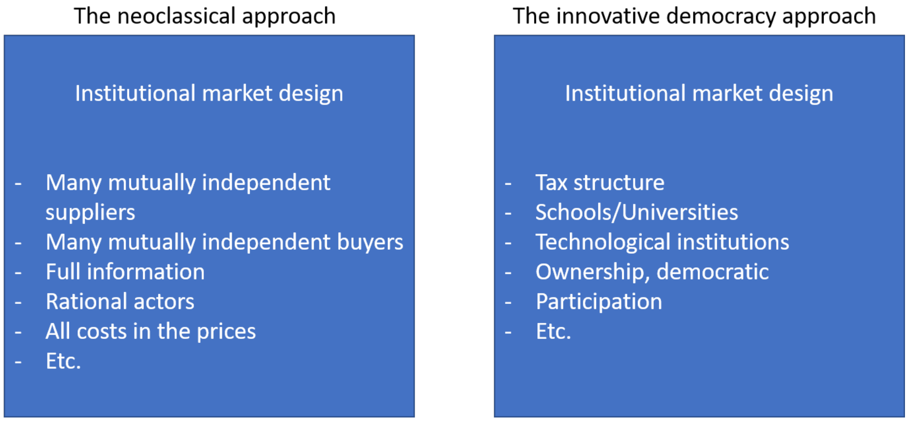


Figure 3.4: The different institutional market designs for the neoclassical- and the innovative democracy approach, based on Hvelplund [2011].

As seen in Figure 3.4, the institutional market design for the neo-classical approach and the innovative democracy approach consists of different elements. It can be seen that for the neoclassical approach it is very important to have an institutional market design which consists of clear and transparent actors and information. It is for example important to have many mutually independent suppliers and buyers and to have rational actors. It is also important to have the full information regarding the different aspects of the market design and to have transparent prices in the market. In short, the institutional market design strives to be "perfect".

The institutional market design for the innovative democracy approach consists of a tax structure. It also consists of schools/universities and technological institutions which can offer independent research units and test centers for RE- and energy conservation technologies. This can provide useful knowledge regarding the possibilities and potentials of RE- and energy conservation technologies to the public and to the various actors such as the parliament and municipalities. Furthermore, different types of ownership and participation of/in RE- and energy conservation technologies is encouraged. This ensures that many different types of actors get associated with RE technologies, which helps to increase the knowledge and awareness of RE.

3.3.1 Examples of successful innovative democratic processes

In Denmark, innovative democratic processes have been the steppingstone to the initial successes of both wind power and decentralized CHP implementation.

According to Hvelplund [2011], an increased amount of wind power capacity was installed in Denmark in the 1980's and the 1990's due to a successful policy arising from successful innovative democratic processes. Measures such as efficient grassroots movements, open and active public debates, public support, establishments of public wind power test stations and the development of favorable tariff and tax structures made it possible for wind turbines to have a realistic chance of entering the market.

Successful innovative democratic processes also resulted in the development of decentralized co-generation in Denmark. From 1990 to 2001, the power production from decentral CHP units increased from 1 % to more than 30 %. Even though the advice from the Ministry of Trade, the Ministry of Energy and large power companies was to implement nuclear power in Denmark, decentralized CHP co-generation ended up being installed all throughout Denmark. This was made possible due to the active involvement and support of decentralized CHP from grassroots organizations and favorable subsidies and municipal guarantees given to decentralized CHP production. [Hvelplund, 2011]

These examples of prior application of innovative democracy processes in the Danish energy market have proven it to be a successful approach when seeking to implement changes to the market and to increase the amount of RE in the energy system. It is therefore thought to be important to be aware of these helping factors when considering the subject of increasing flexibility in the energy sector and increasing the capacity of P2H technologies in DH plants, in order to be able to integrate a larger part of electricity produced from RE sources in the heating sector. Based on historic events regarding implementing RE, it is likely that measures such as; I. direct market policy, II. indirect market policy, III. reforming political processes and influence from different lobbyists on the parliament, according to Figure 3.3, will be necessary.

3.4 Focus areas going forward

As previously seen in this chapter, there has been a focus on theory which regards defining the concept of flexibility, market design and political economy, and innovative democracy. In Figure 3.5 it is illustrated how the different theories presented in this chapter interplay and how it can be related to the innovative democracy approach presented in Section 3.3. The boxes which are not faded out, are in focus in this study and the boxes which are faded out are not further investigated. The entire structure and all the boxes illustrated in Figure 3.5 are important in order to understand the overall setting and the market which technologies must govern in, however due to limitations of this study only parts of the whole are further investigated in detail.

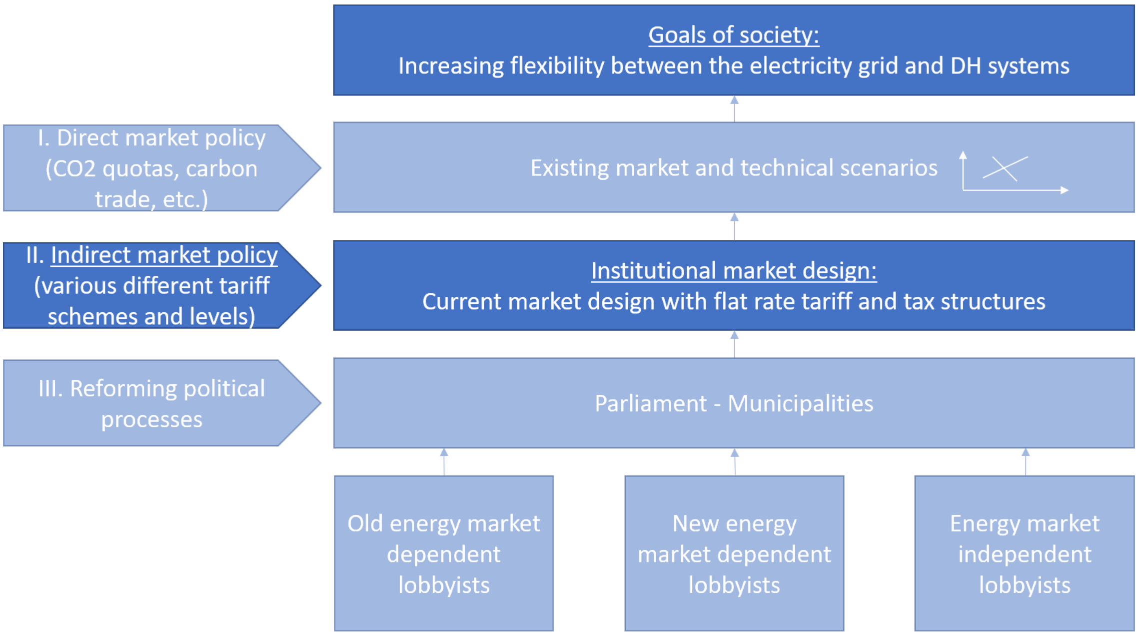


Figure 3.5: Theory focus areas incorporated in the innovative democracy approach from Figure 3.3.

In the top of Figure 3.5 it can be seen how the theory regarding flexibility is incorporated as one of the goals of society. Society presumably has many different goals, however the main goal in focus in this study is increasing the flexibility between the electricity grid and the DH sector. Furthermore, the theory regarding market design and political economy is represented in the institutional market design box in the middle of the figure. Here there is a focus on the how the current market design is set up with flat rate tariff and tax structures. Finally, the theory regarding innovative democracy is in part represented in the overall structure of Figure 3.5, but also by enabling changes to the institutional market design in the form of indirect market policy. Specifically, various tariff schemes and levels will be further investigated and tested, which is further described in Chapter 5.2 and 6.

Methodology 4

This chapter first presents the overall mixed methods research approach applied in this study and the applicability of such an approach for the context investigated. This is followed by the process of tool selection, a description of the main quantitative method applied in the study, as well as important methodological considerations and the quantitative assessment criteria. Finally, the applied qualitative methods are presented in addition to the process of data collection and analysis.

4.1 Mixed methods research approach

A mixed methods research approach is applied in this study; a simple and immediate definition of such a research approach is *"A research approach whereby researchers collect and analyze both quantitative and qualitative data within the same study"* [Shorten and Smith, 2017, pp. 1]. This very simple definition does however only capture the basic premise of what constitutes mixed methods research without diving into what makes mixed methods research applicable to a research study. The diversified methodological approach of a mixed methods research study enables researchers to draw on the strengths and weaknesses of both quantitative and qualitative research, enabling researchers to explore diverse perspectives, uncover relationships, and ultimately provide a more coherent picture of the research area than a single-method approach [Shorten and Smith, 2017].

Greene et al. [1989] outlines how the purpose of mixed methods research design varies, with the five primary purposes being:

- Triangulation
- Complementarity
- Development
- Initiation
- Expansion

[Greene et al., 1989, pp. 259]

The purpose of combining quantitative and qualitative research in this study is primarily of complementary nature since it is primarily being used to *"measure overlapping but also different facets of a phenomenon, yielding an enriched, elaborated understanding of that phenomenon."* [Greene et al., 1989, pp. 258]. Thus, the mixed methods research of this study is used both to obtain a deeper understanding of overlapping themes and to uncover additional important themes.

As indicated already, mixed methods research includes a broad range of methodological approaches and is not simply a predetermined recipe to follow. Instead, the research question and practical demands of the problem should guide the methodological choices, enabled by the adaptiveness and flexibility of the mixed methods research approach [Greene et al., 1989]. Mixed methods research is considered to be relevant in this specific study due to the multifaceted research question of energy system flexibility and makes it possible to look at this research question through different lenses. It was established in Chapter 3 that energy system flexibility is a complex issue and achieving the necessary degree of flexibility will require the co-operation of a multitude of actors. Thus, optimization is not only a matter of improving technological solutions, but also involves political, institutional and organizational perspectives, indicating the need for a diversified methodological approach.

4.2 Energy system analysis tool selection

One of the focal points of this study is the complex interrelation of the electricity market, energy policy and heat production in a DH setting. To investigate the potential for flexible operation of P2H technologies in DH, and the contribution to energy system flexibility, an energy system analysis is conducted. A wide range of tools for energy system analysis exist, differing with regards to their purpose and applied methodology as indicated in several reviews of tools for energy system analysis and -planning [Connolly et al., 2010; Ringkjøb et al., 2018; Lyden et al., 2018; Ferrari et al., 2019].

It is not possible to determine one tool being "the best", since that relies on the context and specific problem investigated, e.g. some are more suited for large national or regional analyses while others are better suited for local and site-specific analyses. Other important distinctions include calculation time steps, planning/modelling time horizon, energy sectors included, and whether it is a simulation or optimization tool. Some examples of widely applied tools include, but is not limited to: EnergyPLAN, HOMER, Balmorel, TRNsys16, RETScreen, and energyPRO. In essence, the tool selection is highly dependent on the specific needs of the study, and researchers should make careful considerations before deciding on a tool; a decision which is closely related to the scope and purpose of a study.

The purpose of this study's energy system analysis is to investigate the potential for increased flexible operation of P2H technologies and the influence of energy policy in the form of electricity tariffs. This is done by modelling and simulating the operation of Ringkøbing DH plant and testing how altering tariff schemes influence production and operation. For the purpose of this analysis a number of characteristics are necessary for the applied tool, including:

- Able to model DH at a local level including typical P2H technologies.
- Hourly calculation time steps.
- Possibility of including spot market and adhering both production and consumption accordingly.
- Able to simulate and optimize for a minimum of a one-year period.
- Possibility of including existing and potential future energy policy such as taxes and tariffs.

To simulate different system configurations and varying taxes and tariffs the software energyPRO, developed by EMD International A/S [2019a], is utilized. EnergyPRO is capable of optimizing systems according to existing conditions such as weather, fuel prices, taxes, and subsidies. EnergyPRO is also capable of modelling a variety of different technologies, both fossil fuel-based and renewable, in addition to different storage technologies. Furthermore, the possibility of simulating operation according to both existing and potential future market conditions makes energyPRO a relevant choice of modelling tool for this specific study. As discussed in Sections 3.2 and 3.3, the market design and market conditions greatly influence the prioritization and utilization of technologies and ensuring desired changes such as increased integration of VRE could require political efforts due to the shortcomings of the market on its own.

EnergyPRO is chosen due to its emphasis on modelling and simulating local or site-specific energy systems such as a DH system. Furthermore, energyPRO has strong sector integration properties, highly relevant when investigating the potential for increased coupling of electricity and heating sectors. Finally, energyPRO is a proven and widely applied tool, utilized in many peer-reviewed studies, and is often the preferred choice for analyses focused on the DH sector. Examples of this include; a study on policy incentives for flexible DH in the Baltic countries [Møller Sneum et al., 2018], an analysis on the use of booster HPs in combination with central HPs in DH [Østergaard and Andersen, 2016], and simulations of DH systems in Finland with an increasing share of HPs [Kontu et al., 2019].

Thellufsen and Lund [2016] investigated the role of local and national energy systems in the integration of RE in Denmark, a topic highly related to this study, however the approach and methodology differed significantly. Based on EnergyPLAN simulations of Copenhagen and Sønderborg Municipality Thellufsen and Lund [2016] investigated the potential for integration of RE in municipalities using the heat and transport sector. However, this study did not look into how this can be facilitated and how changing policies or incentive tools influence the results; partly a limitation in the modelling tool EnergyPLAN. However, the study does present an interesting methodology to evaluate how well municipal and national energy strategies integrate and raises the question of how to balance local and national energy strategies. While it is difficult to conduct a similar analysis in which an entire municipality's energy system is modelled using energyPRO, it is very capable of analyzing the influence of policy- and incentive measures.

4.3 Quantitative techno-economic analysis

As mentioned in Section 4.2, energyPRO is the chosen energy system analysis tool which will be used to model Ringkøbing DH plant. EnergyPRO is an energy system simulation model, a tool designed for techno-economic analysis of heating, cooling, and CHP projects, enabling the use of both renewable, fossil-fuel based, and storage technologies. An important strength of energyPRO essential to this study, is the ability to include detailed models for production units based on functions, e.g. the HP can be modelled as a function to accommodate for varying COP values as a result of fluctuating ambient temperatures.

The electricity spot market is included, in addition to other factors influencing operation costs such as O&M costs, policy incentives (e.g. taxes and tariffs), and fuel costs. An overview of all included economic assumptions can be seen in Appendix C. This allows energyPRO to optimize operation and activate production units according to a least-cost principle.

The techno-economic analysis of this study, seen in Chapter 6, applies hourly calculation steps for a one-year period, due to the coherence with the spot market and additional data such as the electricity production from wind turbines in Ringkøbing-Skjern Municipality. While energyPRO is capable of calculating for both shorter time intervals (e.g. 15 minutes) or plan for multi-year periods, the delimitation to an hourly one-year simulation is a result of the scope of this study. The focus is to investigate the flexibility potential and interaction of the DH sector and time differentiated flexible tariffs and dynamic tariffs due to temporal diurnal and seasonal fluctuations of heat demand, electricity demand and spot prices. Therefore, simulations over a long-time horizon are not expected to provide additional valuable information to this study.

The default optimization principle of energyPRO is to minimize operational expenditures, a result of a least-cost prioritization strategy based on a priority list method. This is done by calculating a net heat production cost (NHPC), equal to the short-term marginal production costs for every production unit for every hour. The production unit with the lowest net heat production cost is activated first, followed by the second lowest if the demand (in this case heat demand) is still not fulfilled. As an alternative to this economic optimization, it is possible to apply custom operation strategies.

The energyPRO model in this study operates on a basis of perfect foresight, meaning that energyPRO is able to foresee electricity prices and demands for the entire optimization period as a result of the input time series. While this is a limitation of the tool and not entirely in accordance with real-life scenarios, it is not very different from practical operation where spot market prices are available 24 hours prior to activating and heat demand and wind power production can be fairly accurately predicted due to weather forecasts. It is possible to include predictions for the electricity price in energyPRO, which could to some extent negate this effect of perfect foresight and introduce a level of uncertainty to the simulation, similarly to real-life production planning.

4.3.1 Time series

Various time series are included in the model, including; electricity spot prices for DK1 2018, ambient temperatures and solar radiation representing values for an average year, time series for the HP regarding heat production and electricity/fuel consumption. Furthermore, electricity production from wind power and total electricity consumption in 2018 for Ringkøbing-Skjern Municipality are utilized for a subsequent analysis in Excel in which the wind power production and electricity consumption is correlated to the production outputs from energyPRO.

The time series regarding electricity production from wind power in Ringkøbing-Skjern Municipality consists of hourly data from 2018, which is provided by Energinet. The time series regarding electricity consumption in Ringkøbing-Skjern Municipality also consists of hourly data, however, since Energinet were unable to provide this data, it is modelled based on monthly electricity consumption for Ringkøbing-Skjern Municipality in 2017. The monthly values are then converted to hourly time-steps by distributing the monthly electricity consumption based on the hourly distribution profile of electricity consumption in DK1.

For more information regarding the various time series used in the energyPRO model, see Appendix A.

4.3.2 Electricity market delimitation

As previously mentioned, the techno-economic analysis includes the electricity market in the form of the spot market. This is an important delimitation, since other markets for ancillary services, such as the regulating power market, could be relevant for analysis. However, the spot market is by far the most important market where the bulk of electricity is traded. Comparing only the regulating power market and the spot market in 2018, electricity at the spot market amounted to 98.5 % of bought electricity [Energinet, 2019b]. Therefore, the majority of balancing and integration of VRE is likely going to be at the spot market in the future, even with increasing wind production.

Figure 4.1 shows the development of wind power production in DK1 and DK2, where a clear tendency of increasing wind power production can be observed.

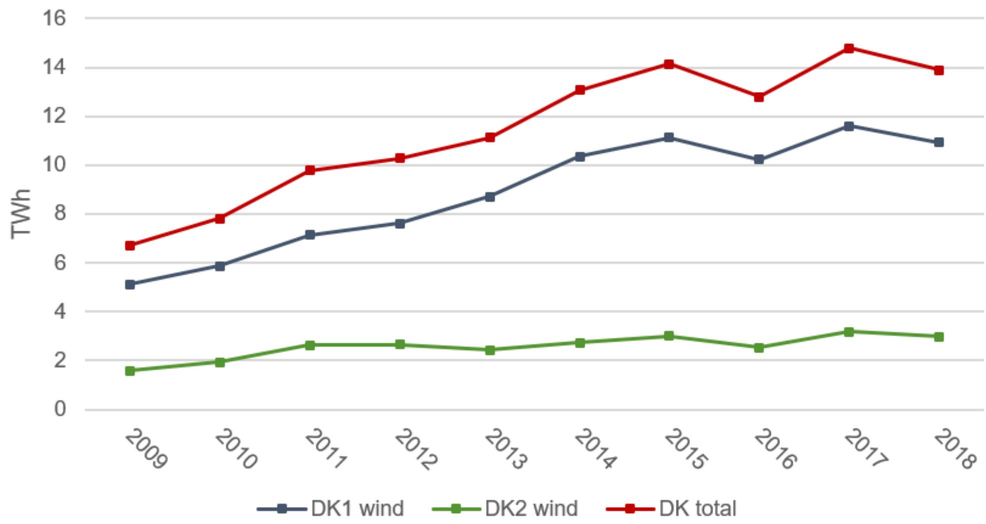


Figure 4.1: Wind power production in Denmark, based on data from Energinet [2019b].

Wind power production fluctuates, and the regulating power market is used to adjust to production spikes, and thus some might expect the annual down regulation to increase alongside the wind power production. This has however not been the case; Figure 4.2 illustrates the total annual down regulation purchased from 2009 - 2018.

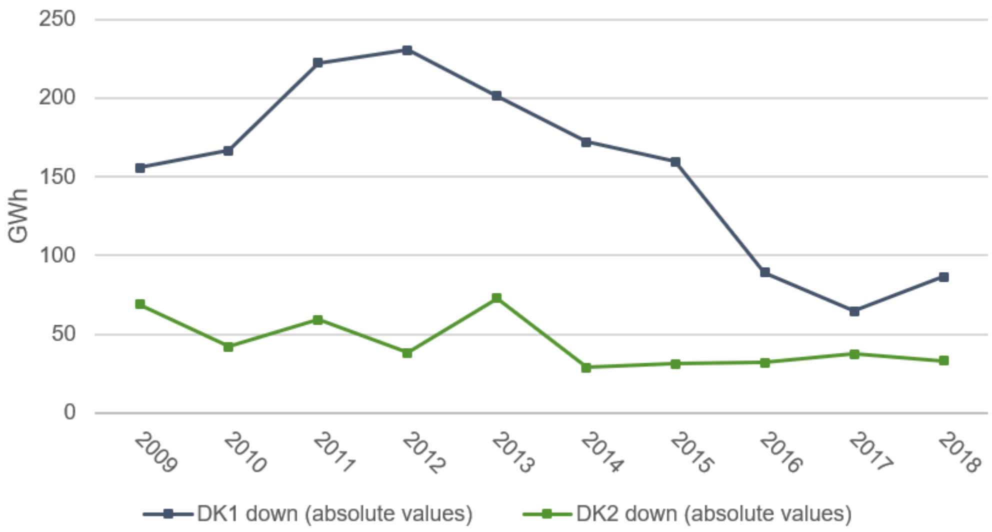


Figure 4.2: Danish regulating power market, based on data from Energinet [2019b].

The tendency from the previous Figure 4.1 is not observed for the regulating power market; down regulation does not appear to increase despite large increases in wind power production. Therefore, there is no direct argument to be made with regards to the regulating power market becoming significantly more important to grid balancing simply as a result of increased wind power production. This is likely due to a combination of factors. Firstly, in a study on the balancing market it was concluded that *" (...) the impact of VRE on the balancing system to be less dramatic than sometimes believed."* [Hirth and Ziegenhagen, 2015, pp. 1036]. Hirth and Ziegenhagen [2015] further argues that an appropriate market design would lead to wind and solar power not only consuming, but also providing balancing power. Secondly, the incoherent development of the VRE production and the regulating power market could be because of increased accuracy of the wind and solar power production prognoses, and a result of a larger balancing area, reducing the balancing needs, as determined in a study by Frunt [2011].

While the delimitation of the electricity market to consist of the spot market is important, so is the actual spot prices, since the prices fluctuate quite significantly on a year to year basis, as illustrated in Figure 4.3.

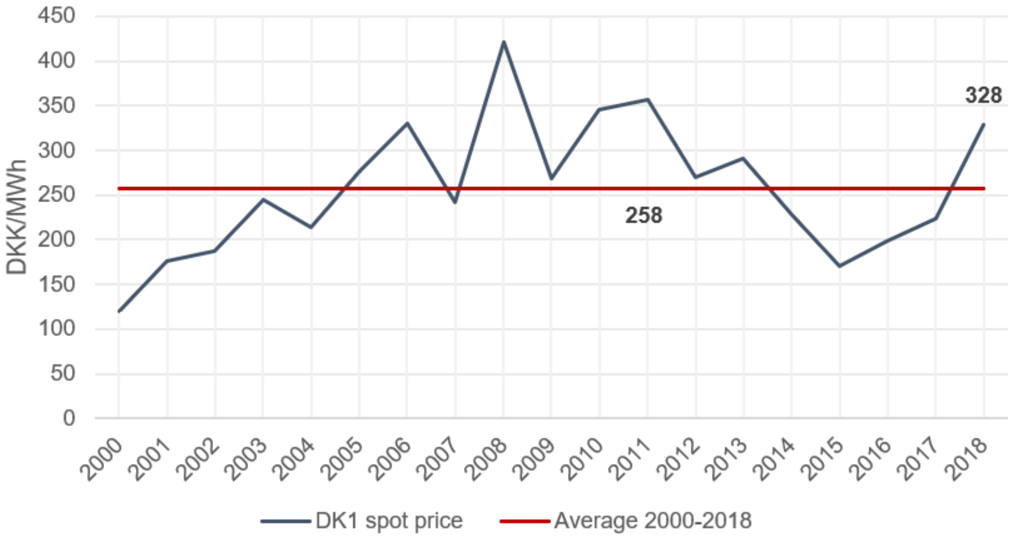


Figure 4.3: Historic spot prices for DK1 from 2000 - 2018, based on data from Energinet [2019b]. Prices do not include the effect of inflation.

Predicting the future development of spot prices is difficult. As seen on Figure 4.3, the year to year fluctuations can be quite high and no clear pattern can be observed. The spot prices have been increasing since 2015, and as a result of this the 2018 spot price is higher than the average for the period 2000 - 2018. The spot price from 2018 is however used in the techno-economic analysis.

In addition annual fluctuations, the spot prices also fluctuate on an hourly basis. The techno-economic analysis of this study will include the spot market prices from 2018; the hourly fluctuations are illustrated in Figure 4.4.

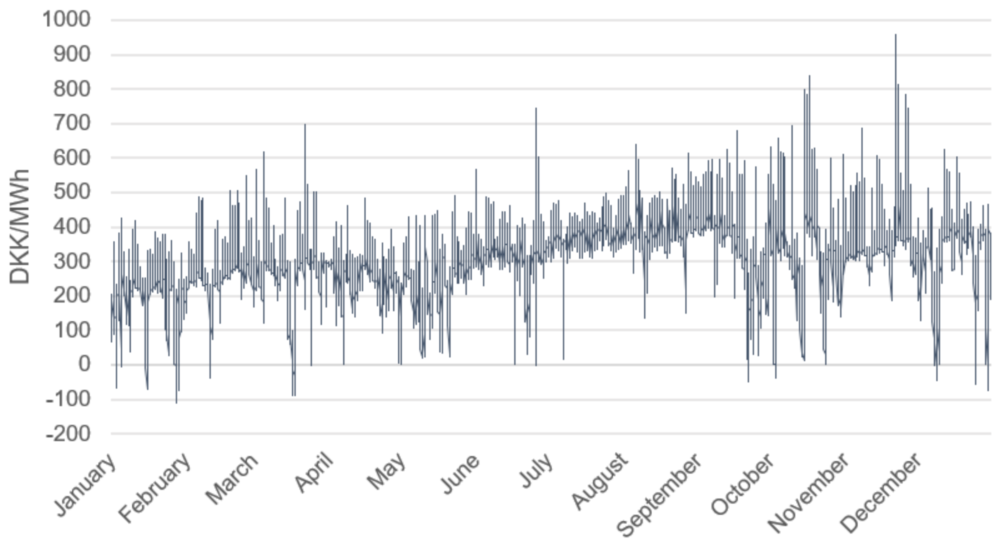


Figure 4.4: Spot prices for DK1 in 2018, utilized for the energy system analysis, based on data from Energinet [2019b].

The positive and negative peaks of the spot prices are largely a result of the variable wind power production. One takeaway from Figure 4.4 is that while the high and low spot price peaks are drastic, the sustained periods of either very high or very low prices are short, as seen in Figure 4.5.

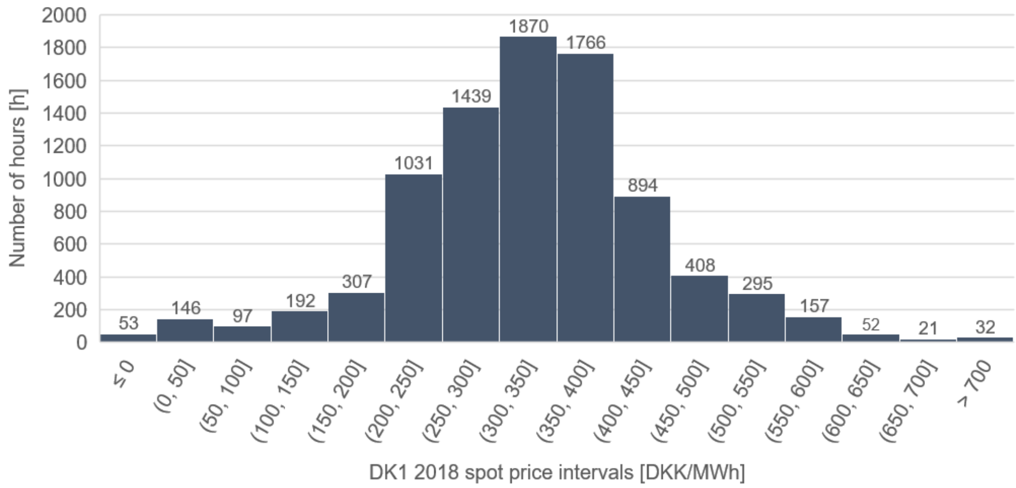


Figure 4.5: Histogram of spot price for 2018 DK1, based on data from Energinet [2019b].

In 2018 there was a total of 53 hours with negative spot prices, and 296 hours with spot prices above 500 DKK/MWh. This puts high demands on the energy system with regards to flexibility, and balancing these rapid fluctuations relies on a mix of production- and demand-side flexibility, realized through flexibility enabling energy policy measures.

4.3.3 Analytical framework

Based on the energyPRO model of Ringkøbing DH plant, it is possible to analyze the effect of different tariff levels and schemes on the operation of the DH plant and P2H technologies; this is done in the techno-economic analysis in Chapter 6. The different tariff schemes investigated in the analysis are described in Chapter 5.2.

The techno-economic analysis in Chapter 6 is mainly divided into two parts after the model introduction and the Reference scenario are examined; an investigation of different tariff levels for each tariff scheme and a cross comparison of the investigated tariff schemes.

In the first part of the analysis, the tariff schemes are analyzed within their own category by comparing the influence of different tariff levels. This is done based on the following results from the model:

- Annual heat production and heat price overview.
- Annual production hours for the P2H technologies.
- Annual tariff expenses for the P2H technologies.

The annual heat production and heat price overview is meant to give a general overview of a tariff schemes' influence on the operation of Ringkøbing DH plant. The heat price evaluated is a marginal heat production cost, meaning that only the short-term operational expenses are included, e.g. O&M costs, fuel expenditures, taxes, and tariffs. Long-term expenses such as investment costs are not included since no new investments are made and such long-term expenses do not influence the operation strategy of the system. The simple approach for the heat price calculation is seen in Equation 4.1.

$$\text{Heat price} = \frac{\text{Annual operation expenses}}{\text{Annual heat demand}} \tag{4.1}$$

Where,

Heat price	[DKK/MWh]
Annual operation expenses	[DKK]
Annual heat demand	[MWh]

The overview of the production hours for the P2H technologies demonstrates how the tariff scheme and level influences annual production hours for each P2H technology. The production hours are split into two categories; hours with excess electricity produced by wind power and production hours with a deficit of electricity produced by wind power. For every hour it is determined whether there is an excess or deficit of electricity produced from wind power, compared to the electricity consumption of Ringkøbing-Skjern Municipality. Finally, the relationship between the amount of production hours in the excess electricity category and the total amount of production hours for each technology is evaluated. This does not take into account how the rest of the municipality might react to a changed tariff structure, since the model developed for this study is unable to determine what this effect might be. The impact of this delimitation is discussed in Chapter 8.

From the overview of tariff expenses, paid by the DH plant based on electricity consumption of the P2H technologies, it can be seen how the tariff scheme and level influences the total operation expenses. The total tariff expense is important to consider, since it is problematic if it decreases too much compared to the Reference scenario, in other words what the DSO earns in tariffs today.

Based on these characteristics, one of the tested tariff levels for each tariff scheme is selected, on the premise of it being the most promising level for integrating more P2H production, which can increase the flexibility of both the heat- and electricity sector. The method for selecting the most promising level for each tariff scheme is based on a compromise between production hours for the P2H technologies, and the tariff expenses for the DH plant.

A compromise has to be made since it is necessary to consider both the viewpoint of the DH plant and the TSO/DSO. If the focus was solely on the DH plant, it would be most desirable to completely remove the tariffs on the P2H technologies, which would enable more P2H production than they currently have and thereby increasing flexibility. However, this is not optimal seen from the TSO's and DSO's point of view, since this would result in a major reduction in tariff income which covers the expenses associated to the electricity transmission and distribution grid. Therefore, a compromise between the two parameters, production hours and tariff expenses, must be made. If the most promising level to choose for each tariff scheme is not clear based on a compromise between the two parameters, the relationship between the production hours with excess electricity and the total amount of production hours for the P2H technologies is taken into account. When considering this relationship, it is important that the percentage of production hours in hours with excess electricity is at the same level or higher, than the percentage of production hours for the Reference scenario.

The method for choosing the most promising tariff level for each of the tariff schemes is based on the following:

- Find an acceptable level[1] between annual production hours and the total tariff expense for the P2H technologies.
- Evaluate the distribution of production hours, how large is the percentage of production hours which occur in hours with excess electricity and how does this percentage compare to the result from the Reference scenario and to the other tariff levels.

In the second part of the analysis, after the three most promising tariff levels are chosen, they are cross compared to each other. This is done to compare the effects of the different tariff schemes with each other and with the Reference scenario. The cross comparison section also looks into how the different tariff schemes influence the peak export electricity capacity to assess whether the tariff schemes are capable of reducing this strain on the grid. This is combined with an assessment of the annual import/export balance. Finally, the tariff schemes' influence on the production pattern of the electric HP and EB is assessed on both an hourly and a weekly basis, to determine how the tariff schemes can alter the production pattern.

4.4 Qualitative assessment and data collection

Qualitative research generally enables researchers to investigate phenomena in their natural context [Silverman, 2014]. This study utilizes a combination of interviews, site visits to various DH systems in Ringkøbing-Skjern Municipality, and existing literature, to obtain a thorough understanding of the included stakeholders' roles, perceptions, and perspectives. The stakeholders included have vastly different roles influencing their perspective, something that is important to be aware of when conducting such research. The purpose of including qualitative research in this study, is to seek an understanding of barriers for P2H flexibility, as perceived by the key stakeholders participating in the conducted interviews.

4.4.1 Data collection

The qualitative data set consists of a combination of interviews, site visits, and literature. A total of 10 interviews have been conducted as a part of this study. An overview of the interview persons and their representative organization can be seen in Table 4.1.

[1] An acceptable level is perceived as the level between annual production hours and the total tariff expense for the P2H technologies, which maintains a level relationship between the two parameters, meaning that one parameter does not obtain priority over the other.

Interview person	Organization	Description
Anders Bavnhøj Hansen	Energinet	Danish TSO
Anders N. Andersen	EMD International A/S	Software/consultancy firm
Børge Outzen	Ringkøbing-Skjern Municipality	Heat planning department
Henning Donslund	Ringkøbing-Skjern Municipality	Energy 2020 strategic energy planning
Jens Fossar Madsen	Radius Elnet	DSO on Zealand
Jens Holger Helbo Hansen	Ministry of Taxation	The Danish Ministry of Taxation
Jesper Skovhuse Andersen	Ringkøbing DH company	DH company
Martin Halkjær Kristensen	Hvide Sande DH company	DH company
Nathaniel Bo Jensen	Danish Energy Agency	Agency under the Ministry of Energy, Utilities and Climate
Søren Dyck Madsen	CONCITO	Danish green think tank

Table 4.1: Interview persons included in this study and their representative organization.

In addition to the interviews, site visits have been conducted at three different DH plants in Ringkøbing-Skjern Municipality: Ringkøbing, Hvide Sande, and Spjald DH plants. The purpose of both the interviews and site visits were to obtain insights into the current operation of DH systems, insights and experiences from flexible grid tariffs, and perceptions regarding barriers to increased utilization of P2H technologies in the DH sector. Coupled with existing literature and research on flexible grid tariff schemes and P2H in DH, this forms the data foundation for the qualitative assessment of barriers and dynamics of P2H flexibility in Chapter 7.

Interviews have been conducted as semi-structured interviews based on interview guides. The semi-structured approach ensures that an overall structure is coherent throughout the interview, while at the same time allowing both parties to explore potential topics of interest uncovered during the interview [Kvale, 1996]. The semi-structured approach aligns well with the exploratory nature of the study and especially the qualitative assessment, where the primary focus is to determine the barriers and interesting dynamics of P2H flexibility, which involves the uncovering of new aspects.

4.4.2 Structuring qualitative data

A challenge often associated to qualitative research is that the collected data is typically in macro-form, e.g. interview transcriptions, audio recordings, or field notes. Before any meaningful results can be drawn from such data it must first be processed, condensed and categorized according to relevant themes. For this process the software NVivo has been utilized in this study, a tool built to organize and structure qualitative data [NVivo, 2019].

NVivo manages imported interview transcripts and notes, which can then be categorized according to themes using a system of nodes. The process of categorization for this study started with two very broad categories: 1) Barriers and 2) Potentials. During the analysis of the collected data, new themes emerged and were grouped accordingly within the two original categories and new sub-categories. By the end a total of 10 and 5 nodes had emerged respectively, forming the primary thematic findings of the qualitative assessment in Chapter 7.

Flexibility enablers 5

The following chapter first presents the flexibility enabling technologies essential to this study, focusing on P2H technologies, followed by flexibility enabling energy policy, focusing on electricity tariff schemes. The emphasis on P2H technologies and electricity tariff schemes is a logical by-product of the project scope, along with the focus on the interplay of DH and the potential contributions to electricity grid flexibility. From Chapter 3.1, it is evident that flexibility is a complicated term and in general not a well-defined concept. Therefore, the flexibility definition for this study, presented in Chapter 3.1.3, is applied to limit the scope of flexibility enablers investigated in this study.

5.1 Flexibility enabling technologies

This section presents an overview of the most common P2H technologies; EBs and electric HPs, in addition to storage technologies for DH systems. These are also the flexibility enabling technologies included in the energyPRO model developed in this study. The P2H technologies also represent sector integration between the electricity- and heat sector, which enables flexibility between the two sectors. The technology descriptions include both a brief technical description of working principles, economic parameters, and efficiencies, as well as implementation examples. The purpose is to outline typical operation strategies, interaction of P2H technologies and storage, and their expected roles in future energy systems.

5.1.1 Electric boilers

EBs are used to produce hot water or steam, which can be used directly in a DH system or stored as heat for later use. EBs typically have a capacity in the scale of several megawatts and are traditionally used as peak load units due to the lower efficiency compared to HPs [Danish Energy Agency, 2016]. EBs can regulate very quickly and usually have a startup time of a few seconds and are able to ramp up production from 0-100 % in 30 seconds [Andersen, 2019b; Danish Energy Agency, 2016] EBs are thus well-suited to provide grid ancillary services but are also able to operate on the spot market.

Technical description

EBs can be separated into two types, separated by the type of heating technology utilized:

- Electrical resistance: Electricity powers a heating element, heating the surrounding water. This is more or less the same technology as what can be found in typical household electrical water boilers. Electrical resistance boilers are connected to the low voltage grid and can be found in sizes ranging from a few kilowatts up to a couple of megawatts.

- Electrode boilers: Electricity runs between electrodes, heating the surrounding water. Typical sizes for electrode boilers are from 5 - 60 MW and are connected directly to the high voltage grid.

While the two types of EBs are based on different technologies, the difference from an energy system point of view is negligible. Therefore, the designation EB will for the purpose of this study be used to encompass both of the previously described types.

The efficiency of an EB is around 98 - 99 % due to the losses being resistive, and therefore heat producing as well. One thing to note is that an EB converts a high-quality energy resource (electricity) to a low-quality energy resource (heating). This is important to keep in mind when considering the efficiency, since compared to for example a HP, the efficiency is quite low.

Potential for flexible operation

The primary strength of EBs is the potential to facilitate efficient use of wind and other variable RE resources, which could prove to be very important in the transition to RE systems. This is due to a combination of factors; primarily the ability of EBs to ramp up quickly and the low investment cost relative to electrical capacity. EBs are primarily operated at hours of very low electricity prices, and their high-power consumption makes them highly relevant for balancing the fluctuating renewable electricity production, and for integrating the electricity and heating sectors.

The fast ramp up times also make EBs highly relevant for providing ancillary services or as a participant on the regulating power market.

Economy

Compared to HPs, the investment cost is relatively low. Table 5.1 provides an overview of economic parameters for medium and large scale EBs for use in DH systems.

	EB 1 - 5 MW		**EB > 10 MW**	
Investment cost	150,000	EUR/MW	70,000	EUR/MW
Fixed O&M cost	1,100	EUR/MW/year	1,100	EUR/MW/year
Variable O&M cost	0.8	EUR/MWh	0.8	EUR/MWh
Lifetime	20	years	20	years

Table 5.1: Overview of economic parameters for EBs [Danish Energy Agency, 2016].

Taxes and tariffs have a significant influence on the operation of EBs because of the high electricity consumption. Table 5.2 provides an overview of the tax and tariff costs incurred when operating the EB in Ringkøbing's DH system.

Electricity tax (EB scheme)	219	DKK/MWh	[SKAT, 2019b]
Transmission tariff	44	DKK/MWh	[Energinet, 2019a]
System tariff	36	DKK/MWh	[Energinet, 2019a]
Distribution tariff	38.6	DKK/MWh	[RAH, 2019]

Table 5.2: Overview of taxes and tariffs relevant to the EB installed in Ringkøbing DH plant.

From this it is evident, that the combined cost of producing 1 MWh of heat is fairly substantial; even if the cost of electricity is assumed to be 0 DKK/MWh. The total tax and tariff expense amounts to 337.6 DKK/MWh, whereas the typical short-term marginal cost for a natural gas boiler is around 400 DKK/MWh according to Andersen [2019b] from Ringkøbing DH plant. This means that except for periods of very low or negative electricity prices, EBs will mostly not be relevant for operation based on the spot market given the current tax and tariff structure.

Installed capacity and examples

According to the Danish Energy Agency [2017], in 2017 a total of 49 EBs were installed in Danish DH systems, with a combined capacity of 587 MW and an average size of 12 MW.

Examples of EBs installed in Danish DH systems were seen at site visits to Ringkøbing- and Hvide Sande DH plants. According to Andersen [2019b] from Ringkøbing DH plant, they have a 12 MW EB from 2011 installed in their DH system and according to Kristensen [2019] from Hvide Sande DH plant, they have a 6 MW EB from 2011 installed in their DH system.

5.1.2 Electric heat pumps

HPs as a technology are able to move heat from a low-temperature level to a higher temperature level, at relative high efficiencies compared to other conventional heat production units.

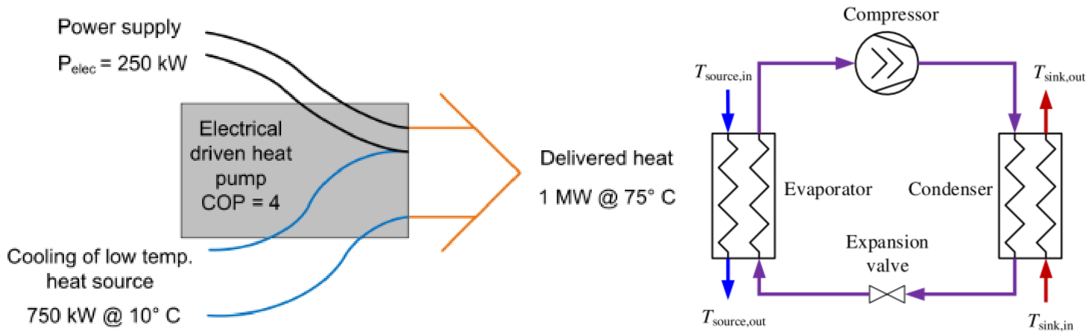
Technical description

In general, two types of HPs exist, a compression HP and an absorption HP. Compression HPs are usually driven by an electric motor but can also be driven by a gas motor. Absorption HPs are driven by a high temperature heat source, usually in the form of steam or hot water. Due to the focus on P2H technologies in this project, absorption HPs are not further investigated since they do not utilize electricity as the drive energy.

Working principle of a compression heat pump

Compression HPs usually have a coefficient of performance (COP) of around 3 - 5 [Danish Energy Agency, 2016]. This means that the heat output produced by the HP is 3 - 5 times greater than the amount of drive energy used, which can either be electricity or gas. The COP factor depends on the efficiency of the specific HP, the temperature of the heat source and the heat sink, and the temperature difference between heat source and heat sink.

The working principle of a compression HP is illustrated in Figure 5.1a and 5.1b.



(a) Drive energy and heat output for a HP. (b) Working principle for a HP.

Figure 5.1: The COP and working principle explained for a HP, based on the Danish Energy Agency [2016].

In Figure 5.1a the principle of the COP for a HP is illustrated. It can be seen that 250 kW of electricity is the drive energy for the HP. The HP uses a low temperature heat source, this can either be air or water depending on the type of HP. Since the HP in the figure has a COP of 4, the output is 1 MW of delivered heat.

In Figure 5.1b it can be seen that in general a HP consists of an evaporator, a compressor, a condenser and an expansion valve. A refrigerant is utilized to transfer the heat from the heat source to the heat sink. The refrigerant evaporates at low temperatures and condenses at higher temperatures, which is utilized in a HP. The most common refrigerant for large compression HPs in Denmark is ammonia (N_3), however there are also large HPs in Denmark which use carbon dioxide (CO_2), isobutane (C_4H_10) and propane (C_3H_8) [Grøn Energi, 2017].

In the evaporator heat from the heat source is transferred to the refrigerant. This causes the refrigerant to boil and evaporate. The compressor then moves the evaporated refrigerant from the evaporator at a low pressure to the condenser at a high pressure, by using drive energy such as electricity or gas. In the condenser the refrigerant condenses and transfers heat at a higher temperature to the heat sink. Finally, the condensed refrigerant on the high-pressure side is led through an expansion valve to the low-pressure side. After this step the process repeats itself.

As previously mentioned, a HP requires a heat source to extract heat from. Many different heat sources can be utilized, and they can be spilt into two broad categories; air/gas and water. An ideal heat source has a high temperature which does not vary in temperature throughout the year and is constantly accessible. Grøn Energi [2017] has categorized different heat sources form high temperature to low temperature heat sources, which can be seen in Figure 5.2.

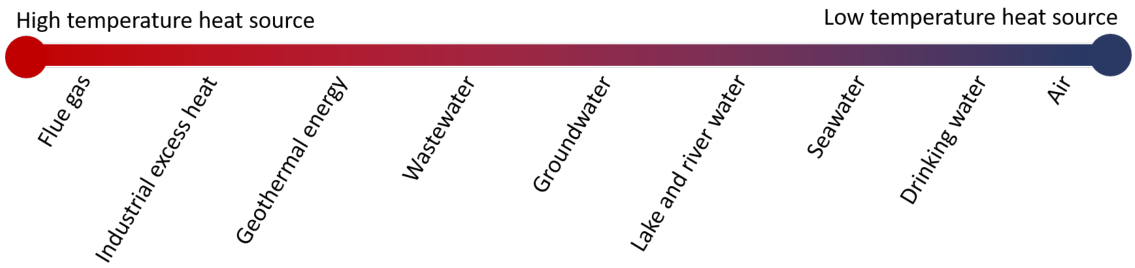


Figure 5.2: High to low temperature heat sources which can be utilized in HPs [Grøn Energi, 2017].

In general, when utilizing a higher temperature heat source, a higher COP value can be achieved. However, the high temperature heat sources, such as flue gas, industrial excess heat and geothermal energy, are usually the most difficult to utilize, since they are not accessible everywhere. While low temperature heat sources such as water and air cannot reach as high COP values as HPs which utilize high temperature heat sources, the low temperature heat sources are very often readily available and accessible.

Potential for flexible operation

Compression HPs, just like EBs, can use electricity to operate. An electric HP therefore contributes to sector integration of the electricity and heating sectors. Currently, HPs primarily run as baseload technologies, mainly due to high investment costs. However, if the incentive to do so was there, certain types of HPs could technically be able to run similarly to EBs and be capable of flexible operation. According to Pedersen [2019] from Solid Energy A/S, who is the manufacturer of the HP installed in Ringkøbing DH plant, HPs generally have a ramp up time of a few seconds up to 45 minutes, depending on the HP type and system layout. The HP installed at Ringkøbing DH plant is however able to ramp up in seconds [Pedersen, 2019].

Economy

Table 5.3 provides an overview of economic parameters for large scale HPs for use in Danish DH systems.

	Compression HP	
Investment cost	700,000	EUR/MW$_{th}$
Fixed O&M cost	2,000	EUR/MW$_{th}$/year
Variable O&M cost	3.3	EUR/MWh
Lifetime	25	years

Table 5.3: Overview of economic parameters for HPs [Danish Energy Agency, 2016].

Taxes and tariffs related to the operation of the HP in Ringkøbing DH system are listed in Table 5.4.

Electricity tax	259	DKK/MWh	[SKAT, 2019a]
Transmission tariff	44	DKK/MWh	[Energinet, 2019a]
System tariff	36	DKK/MWh	[Energinet, 2019a]
Distribution tariff	38.6	DKK/MWh	[RAH, 2019]

Table 5.4: Overview of taxes and tariffs relevant to a HP installed in Ringkøbing DH plant.

The electricity tax for 2019 is 884 DKK/MWh. However, if electricity is used to produce heat, 625 DKK/MWh of the tax is reimbursed. A final electricity tax of 259 DKK/MWh is therefore achieved. [SKAT, 2019a]

Installed capacity and examples

According to the Danish Energy Agency [2017], in 2017 a total of 21 HPs were installed and operational in Danish DH systems, with a combined capacity of 22.3 MW_{th}.

According to Andersen [2019b] from Ringkøbing DH plant, their 4.5 MW_{th} air-to-water natural gas driven HP was installed in 2017 and was in operation by August 2018. It is possible to convert the HP so that it in the future can run on either natural gas or electricity. [Andersen, 2019b]

In Kloster DH plant, which is operated by Ringkøbing DH plant, a 1.4 MW_{th} air-to-water HP has recently been approved for installation [Andersen, 2019b].

5.1.3 Thermal storage technologies

Thermal storage capacity is an integral component of DH systems. Thermal storage for DH systems is typically used to balance production on a daily or weekly basis, however technologies for longer storage times exist, which is typically denoted as seasonal storage. This section will focus on the well-established and mature technologies of large-scale hot water tanks and seasonal pit storage. Other types of storage exist, including borehole-, aquifer- and electro thermal energy stores, however, the application of these in Danish DH systems is limited and the technologies are mostly at an experimental- or pilot phase [Danish Energy Agency, 2018c], and they will therefore not be further explained in this study.

The role of storage in Danish DH systems has traditionally been to complement the production from CHP technologies and allow for short-term optimization according to the electricity market [Danish Energy Agency, 2018c]. Previously storage also allowed DH companies to utilize the 3-part tariff, which incentivized varying production and consumption of electricity, but this has been phased out [Danish Energy Agency, 2018c]. The possibility of altering production according to the electricity market is still relevant but is increasingly used to exploit low electricity prices through P2H technologies as opposed to high electricity prices and sale of electricity from CHP production. Furthermore, thermal storage allows for increased utilization of fluctuating RE production, for example from solar thermal collectors.

Technical description

Large-scale hot water tanks
This type of thermal storage is predominantly constructed as insulated steel hot water tanks due to cost efficiency and proven operation. Storage tanks are typically connected to the DH plant or solar thermal collectors for charging and are able to supply the nearby DH grid when discharging. During charging, hot water is supplied at the top of the tank while cold water is drained from the bottom. The process is reversed when discharging. Storage capacity is dependent on the temperature difference of the stored water, which is typically around 55 °C. The storage temperatures for the input water in the top of the tank typically ranges from 65 - 90 °C. Losses depend on size and height/diameter ratio, but typically range from 1 - 2 % per week. [Danish Energy Agency, 2018c]

Pit thermal energy storage
This type of thermal storage is in essence a very simple construction; a large pit in the ground lined with plastic thermal insulation used as a reservoir for hot water and covered by a floating insulating lid. Water is stored at temperatures upwards of 90 °C for later utilization in the DH grid, enabling utilization of a variety of energy sources, including solar thermal collectors, excess heat, CHP, waste incineration and P2H technologies. Heat loss of a pit thermal energy store depends on the size, shape, weather and operation strategy. As an example, SUNSTORE4, a 6,000 MWh pit storage in Marstal, has a calculated heat loss of 2,475 MWh/year. [Danish Energy Agency, 2018c]

Potential for flexible operation

Storage in general is a critical component for integrating RE technology in DH systems and makes it possible to balance differences in production and consumption. Thermal storage is currently an important addition to P2H technologies, in order for them to operate in a flexible way which is both beneficial for the electricity and heating sector. In the future it is expected that thermal storage technologies will continue to play an important role, to make it feasible for P2H technologies and RE sources, such as wind power and photovoltaics, to operate flexibly. In this study it is not investigated whether large-scale hot water tanks or seasonal pit thermal energy stores have a higher potential for increasing flexibility between the electricity and heating sectors. The two types of thermal stores are however both introduced as they are both commonly used in Danish DH systems and both provide increased flexibility to the DH systems and to the electricity and heating sectors.

Economy

Table 5.5 provides an overview of economic parameters for a large-scale hot water tank and a pit thermal energy storage typically used in Danish DH systems.

	Hot water tank 175 MWh		Pit thermal storage 4,500 MWh	
Investment cost	3,000,000	EUR/$GWh_{capacity}$	580,000	EUR/$GWh_{capacity}$
Fixed O&M cost	8.6	EUR/$MWh_{capacity}$/year	3	EUR/$MWh_{capacity}$/year
Variable O&M cost	0	EUR/MWh_{output}	0	EUR/MWh_{output}
Lifetime	40	years	20	years

Table 5.5: Economic parameters for hot water tanks and pit thermal energy storage [Danish Energy Agency, 2018c].

From the investment costs for both the hot water tank and for the pit thermal storage it is evident that there are economic benefits of scale, which is also stated by the Danish Energy Agency [2018c].

5.2 Flexibility enabling tariff schemes

In Section 3.2 and 3.3 it is outlined how the existing regulatory framework and market conditions significantly influence choice and prioritization of technologies. Tariffs make up an important part of the current institutional market design, and for the purpose of this study, being aware of the role and influence of tariffs is essential.

Tariffs are regulated locally and nationally, by the DSOs and TSO, to a level which balances grid maintenance costs, with a stated purpose of being cost-reflective. This means that the price level, in theory at least, should be cost-reflective. However, the current fixed price structure might not be suitable for the on-going transition towards VRE and for ensuing changes to the electricity market. In hours with excess renewable electricity the marginal cost for supplying additional electricity on the distribution- and transmission grid is very low [Hansen, 2019a; Madsen, 2019a]. On the other hand, supplying electricity during peak load when grid capacity is limited is very expensive, and likewise are investments in increased grid capacity when needed. This leads to the question of how tariff rates which are either too high or too low influences the operation of the energy system.

Based on the fundamental supply and demand principles introduced in Chapter 3.2, a higher tariff rate is expected to decrease the demand for electricity, and while tariffs to some extent are necessary to finance the operation of the electricity grid, they need to reflect these costs to provide a proper price signal, as previously mentioned.

In a report analyzing the current status for taxes and tariffs, the Danish Ministry of Taxation outlines why the current tariff structure in their opinions is undesirable; primarily a result of the lacking correlation between the specific costs producers and consumers incur to the DSO through their use of electricity [Danish Ministry of Taxation, 2017]. According to Hansen [2019b] from the Danish Ministry of Taxation, the marginal costs of distributing additional electricity in hours of excess capacity is almost equal to zero, which amounts to approximately 80 % of hours annually. However, in the remaining 20 % of hours where there is a risk of capacity shortage, pretty much all costs related to grid stability and maintenance are incurred. This means, that at least in theory, the current structure with equal tariff payments throughout the year is distorting and provides inaccurate price signals. A very primitive hypothetical approach to negate this would be to have zero tariffs for electricity consumption for 80 % of the hours annually and distribute the tariff expense for the remaining 20 % of the year.

In practice, too high tariff rates limits the incentive for flexible operation and thus hinders integration of VRE in hours of excess production and does not provide incentive for demand curtailment in hours with limited grid capacity. Tariffs can also cause consumers, e.g. DH companies, to consider island mode operation, as is the case for Hvide Sande DH plant, located in Ringkøbing-Skjern Municipality. Hvide Sande DH plant have bought three wind turbines, and plan on operating these partly in island operation mode, to avoid paying excess taxes and tariffs on the electricity they consume. While this is possibly business economically sensible from the perspective of DH companies, such island mode operation is also an example of sub-optimizing locally as opposed to nationally.

The following subsections will describe the flexibility enabling tariff schemes investigated in this study and argue why these could result in increased flexibility of the energy system.

5.2.1 Flat rate tariff reductions

A flat rate tariff adjustment would not change the structure of the existing tariff scheme but would decrease the threshold for when operation of EBs is feasible and could thus work to integrate more renewable electricity. It can be argued that since neither electric HPs nor EBs are critical heat production units in the Danish energy system, an agreement ensuring flexibility in which the DSO is allowed to disconnect at will could be made with a lower tariff rate to compensate for this option.

In Table 5.6 the original tariff rates for the transmission, system and distribution tariffs, which are valid for Ringkøbing DH plant, can be seen in the form of a 0 % tariff reduction.

Reduction	**Transmission tariff [DKK/MWh]**	**System tariff [DKK/MWh]**	**Distribution tariff [DKK/MWh]**	**Sum [DKK/MWh]**
0%	44.0	36.0	38.6	118.6
20%	35.2	28.8	30.9	94.9
40%	26.4	21.6	23.2	71.2
60%	17.6	14.4	15.4	47.4
80%	8.8	7.2	7.7	23.7
100%	0.0	0.0	0.0	0.0

Table 5.6: Flat tariff rates investigated.

In Table 5.6 it can also be seen that tariff reduction levels of 20, 40, 60, 80 and 100 % will be tested in the techno-economic analysis in Chapter 6. While flat rate tariff reductions might appear unfeasible due to a lack of income for grid maintenance and expansion, this could be counteracted by restructuring the tariff payment from volumetric energy payments to larger fixed payments or subscription fees. So, while one scenario which will be investigated is a zero-grid tariff system, this does not necessarily entail zero income for the DSO and TSO. It is therefore a way of investigating the maximum potential for flexible operation of P2H technologies, assuming only tariff structures are altered.

5.2.2 Fixed time-of-use tariffs

For fixed time-of-use (TOU) tariffs, a fixed structure is necessary to know what the tariff level is at any given time of the year. Fixed TOU tariffs are becoming popular to implement by the various DSOs, and as previously mentioned in Chapter 1.2, currently fixed TOU tariffs are already implemented by the DSOs Radius and Konstant. Other DSOs such as N1, who is the DSO for central Jutland, where among others Aalborg and Silkeborg are included, are in the process of replacing all their electricity meters with electricity meters which can be read remotely. This will also enable N1 to introduce fixed TOU tariffs.

Radius and Konstant use the same fixed time tariff structure developed by Danish Energy [2015]. The time tariff structure is developed primarily based on knowledge and methods used by Energinet, attempting to assess when during the year and during the day the electricity grid is strained [Danish Energy, 2015]. An alternative fixed tariff time structure is created in this study to compare to the already implemented fixed tariff time structures by the two Danish DSOs. The low-, high-, and peak load hours for the alternative fixed tariff time structure are chosen based on the 2018 spot price for electricity. In Figure 5.3 it can be seen how the different levels of load hours are chosen for the alternative time structure.

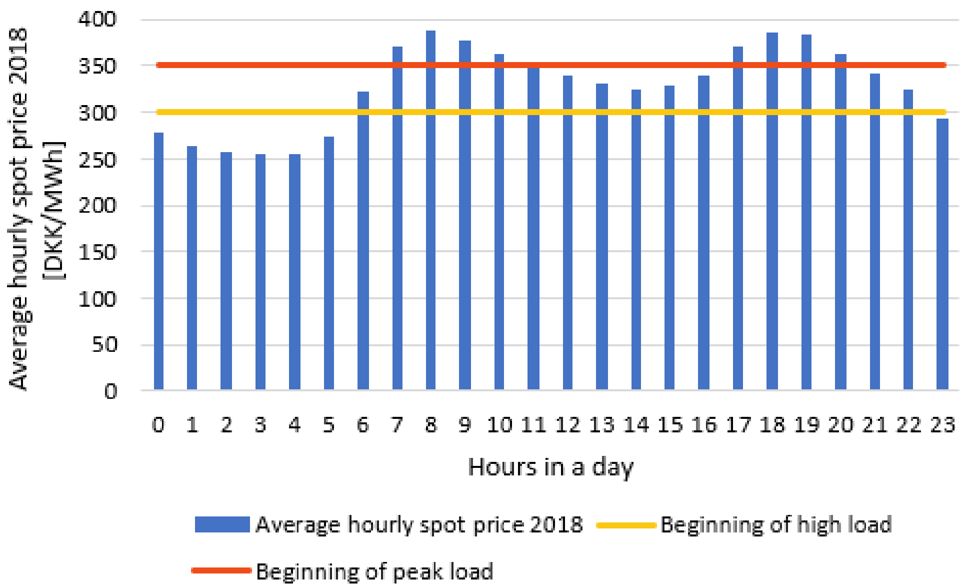


Figure 5.3: Average hourly spot prices for 2018 illustrated along with the beginning levels for classifying the different load periods.

In Figure 5.3 the average hourly spot price is calculated for each hour of the day in 2018. A pattern can be seen where the average spot price is higher in the morning period and in the evening period. On the basis of this, it is chosen to classify all the hours where the spot price is lower than 300 DKK/MWh as low load hours. It is also chosen to classify hours with a spot price between 300 - 350 DKK/MWh as high load hours and hours with a spot price higher than 350 DKK/MWh as peak load hours. This is illustrated by the yellow and red lines on Figure 5.3. From Figure 4.5 in Chapter 4.3.2, it can be seen that for the year 2018, 3,265 hours were hours with a spot price below 300 DKK/MWh, 1,870 hours were hours with a spot price between 300 and 350 DKK/MWh and 3,625 hours were hours with a spot price above 350 DKK/MWh. In Table 5.7 the exact hours classified as low-, high- or peak load hours can be seen.

In Table 5.7 the different fixed tariff time structures can be seen. The tariff time structure designed by Danish Energy and currently implemented by the DSOs Radius and Konstant can be seen, along with the alternative TOU structure created for the purpose of this study. An explanation of elements included in Table 5.7 can be seen in Table 5.8.

	Danish Energy TOU structure			**Alternative TOU structure**
	Winter	Summer	All year	All year
Time	Weekdays		Weekends/holidays	All days
0-1	🟢	🟢	🟢	🟢
1-2	🟢	🟢	🟢	🟢
2-3	🟢	🟢	🟢	🟢
3-4	🟢	🟢	🟢	🟢
4-5	🟢	🟢	🟢	🟢
5-6	🟢	🟢	🟢	🟢
6-7	🟡	🟢	🟢	🟡
7-8	🔴	🟡	🟢	🔴
8-9	🔴	🟡	🟢	🔴
9-10	🔴	🟡	🟢	🔴
10-11	🔴	🟡	🟢	🔴
11-12	🔴	🟡	🟢	🔴
12-13	🔴	🟡	🟢	🟡
13-14	🔴	🟡	🟢	🟡
14-15	🔴	🟡	🟢	🟡
15-16	🔴	🟡	🟢	🟡
16-17	🔴	🟡	🟢	🟡
17-18	🔴	🟡	🟢	🔴
18-19	🔴	🟡	🟢	🔴
19-20	🔴	🟡	🟢	🔴
20-21	🟡	🟡	🟢	🔴
21-22	🟡	🟡	🟢	🟡
22-23	🟡	🟡	🟢	🟡
23-24	🟡	🟢	🟢	🟢

Table 5.7: Comparison of the fixed TOU tariff structures developed by Danish Energy and the alternative fixed TOU structure developed for this study.

Winter	From October to March
Summer	From April to September
🟢	Low load hours
🟡	High load hours
🔴	Peak load hours

Table 5.8: Explanation of Table 5.7.

Based on the two different fixed TOU tariff structures illustrated in Table 5.7, three different TOU scenarios are included for analysis in Chapter 6. The three different TOU scenarios are illustrated in Figure 5.4. For each of the three different TOU scenarios, two main factors vary; the TOU structure and which tariff types are affected by the TOU structure. For each of the three scenarios either the Danish Energy fixed TOU structure or the alternative fixed TOU structure is used. Similarly, either all three tariff types (transmission-, system- and distribution tariff) are affected by the fixed TOU structure or only the distribution tariff controlled by the DSO is affected. The first fixed TOU tariff scheme illustrated in Figure 5.4 by the blue lines, "Danish Energy TOU structure, distribution tariff only", is the tariff scheme which is currently implemented by the DSO Radius.

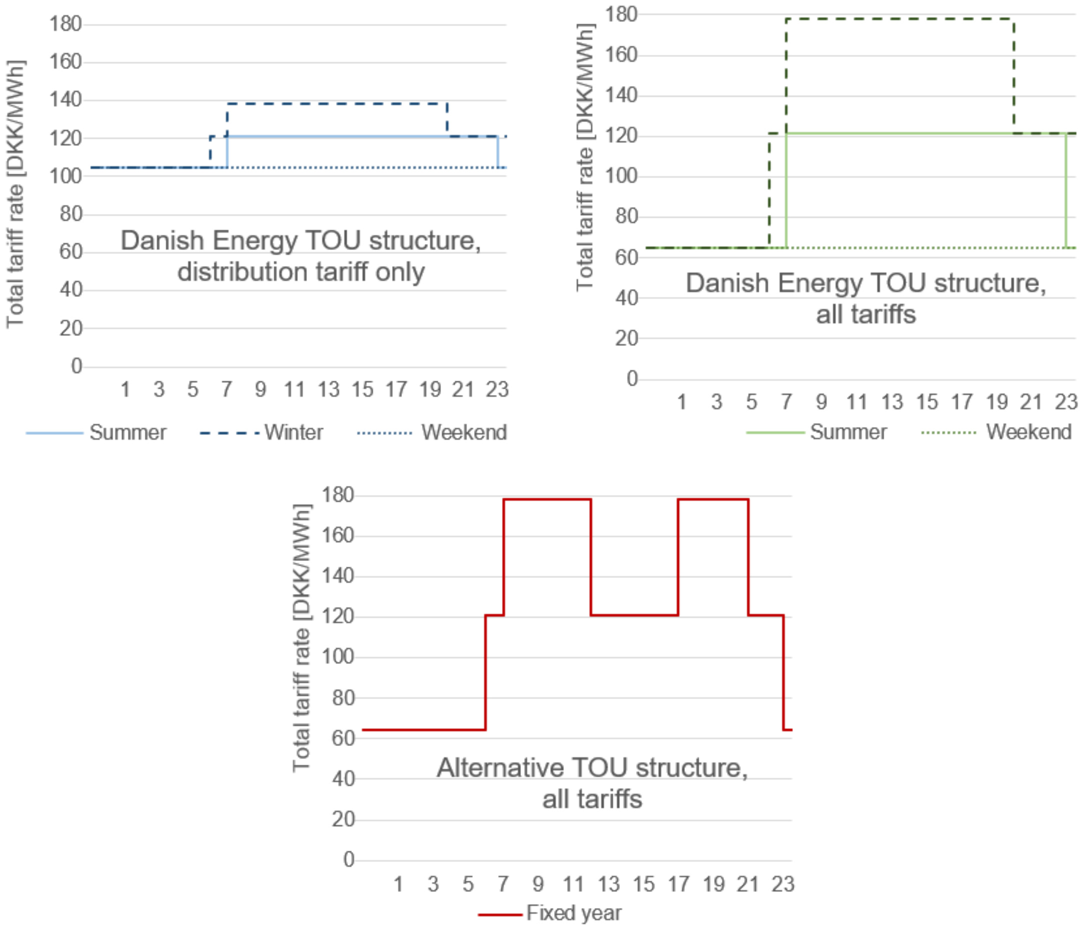


Figure 5.4: Overview of the three fixed TOU tariff scenarios included in the analysis.

Going forward, the three scenarios will be denoted the following for the sake of simplifying the scenario terms:

● Danish Energy TOU structure, distribution tariff only	DE TOU (dist.)
● Danish Energy TOU structure, all tariffs	DE TOU
● Alternative TOU structure, all tariffs	Alt. TOU

The difference between DE TOU (dist.) and DE TOU is whether the transmissions- and system tariff paid to Energinet fluctuates alongside the distribution tariff. For DE TOU (dist.) only the distribution tariff varies while the transmission- and system tariff paid to Energinet remains a flat rate. For DE TOU the transmission- and system tariff varies as well, following the same structure as the distribution tariff. The tariff rates for the distribution-, transmission- and system tariffs included in Figure 5.4, can be seen in Table 5.9.

	Distribution tariff Radius [DKK/MWh]	Transmission tariff Energinet [DKK/MWh]	System tariff Energinet [DKK/MWh]
	● ● ●	● ●	● ●
Low load	24.7	22	18
High load	41.2	44	36
Peak load	58.2	66	54

Table 5.9: Tariff rates used in the three scenarios illustrated in Figure 5.4.

The distribution tariff rates seen in Table 5.9 originate from Radius [2019]. The distribution tariff rates from Radius are applied since together with the DSO Konstant, Radius is one of the two only Danish DSOs to implement fixed TOU tariff rates so far. The transmission- and system tariff rates seen for the high load period in Table 5.9, originates from Energinet [2019a]. The low- and peak load transmission- and system tariffs seen in the table are calculated based on the original tariff rates from the high load. This is only done for the sake of this study, the tariff rates for the transmission- and system tariffs for the low- and peak load are therefore not actual tariff rates used by Energinet. In this study, the low load transmission- and system tariff rates are calculated by decreasing the high load tariff levels by 50 %. The peak load transmission- and system tariff rates are calculated by increasing the high load tariff levels by 50 %.

5.2.3 Dynamic tariffs

Dynamic tariffs are, as opposed to fixed TOU tariffs, not based on a fixed time scheme. Such a structure could prove to be well-suited for future RE systems with uncertain future VRE production and electricity prices. However, a dynamic tariff scheme is also significantly more complicated than a fixed TOU tariff scheme and relies on more sophisticated control mechanisms and automation on both consumption and production side, depending on how they are implemented. DH companies are familiar to adjusting their production according to price signals such as spot prices, which makes the introduction of flexible tariffs easier compared to in residential areas where knowledge, awareness, and ability to adjust electricity demand accordingly is lower.

In this study, dynamic tariff rates are generated as a function of the hourly spot price by calculating a percentage of the spot price, meaning that tariff rates will increase as the spot price increases and vice versa. This should, in theory, provide a greater incentive to utilize VRE since tariff rates will be low when there is a high share of renewable electricity being produced. This will also to a greater degree reflect the low marginal costs of supplying electricity when excess electricity is available, and it will reflect the high costs in peak load hours. Three tariff levels of 20 %, 30 %, and 40 % of the electricity spot price are proposed in this study, and they are illustrated in Figure 5.5.

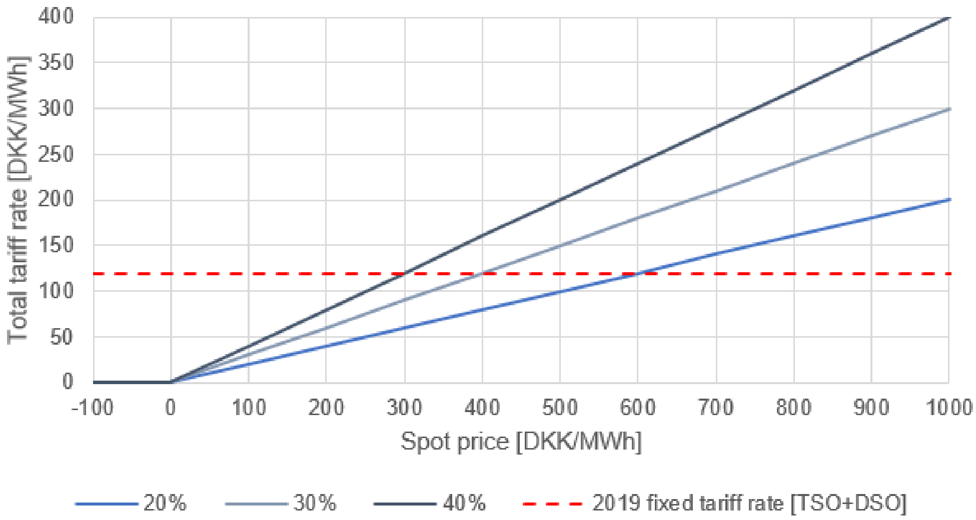


Figure 5.5: Dynamic tariff rates as a function of the 2018 spot prices for the three dynamic tariff scenarios compared to the total tariff rate for the Reference scenario for comparison.

Figure 5.5 correlates the spot price to the resulting total tariff payment compared to the 2019 tariff rate in Ringkøbing-Skjern Municipality, illustrated by the red dotted line. From this it can be seen that for the 40 % scenario, the total tariff payment is lower, compared to the 2019 tariff rate, at spot prices below 300 DKK/MWh. For the 30 % scenario it is lower until 400 DKK/MWh and for the 20 % scenario it is lower until 600 DKK/MWh. It can also be seen from the figure that if the spot price is negative, the total tariff rate for the three scenarios does not become negative but remains at 0 DKK/MWh.

Figure 5.6 illustrates how the dynamic tariff rates will fluctuate hourly depending on the electricity spot price.

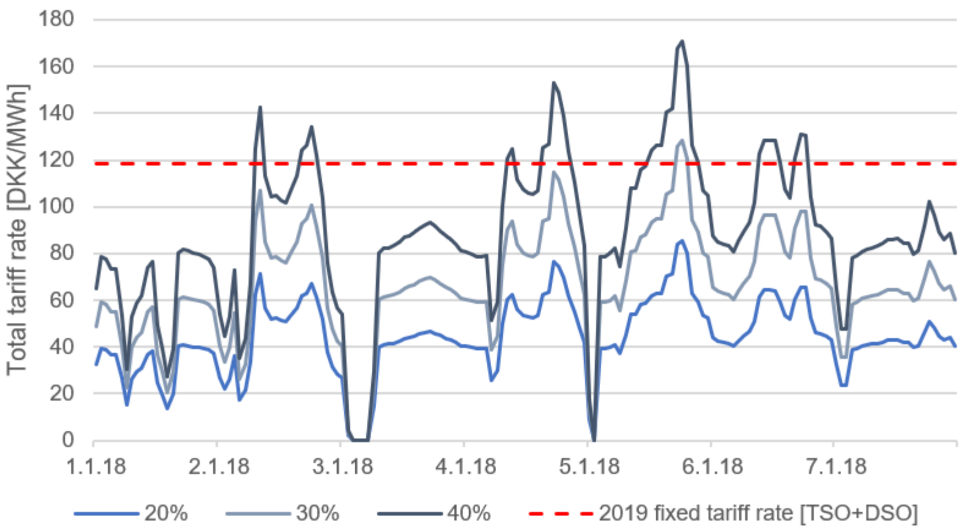


Figure 5.6: Overview of the total dynamic tariff rates for the three scenarios and the total flat rate tariff for the Reference scenario for the first week of January 2018.

Results for a single week is not sufficient to assess the influence of the three dynamic tariff levels. Therefore, duration curves of the resulting total tariff rates correlating to the spot prices of 2018 is shown in Figure 5.7.

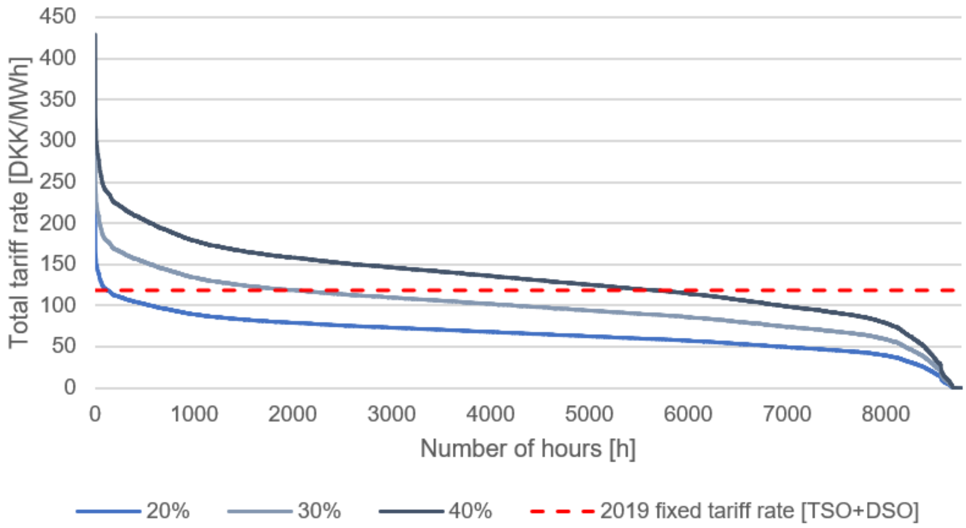


Figure 5.7: Duration curves for the total dynamic tariff rates for the three scenarios and the total flat rate tariff for the Reference scenario.

From Figure 5.7 it can be seen that the total tariff rate for the 20 % scenario is lower than the total tariff rate for the Reference scenario, represented by the red dotted line, for a majority of hours during the year. For the 30 % scenario the total tariff rate is higher than for the Reference scenario for approximately 2,000 hours of the year. For the 40 % scenario the total tariff rate is higher than for the Reference scenario for approximately 6,000 hours of the year. The three different scenarios, 20, 30 and 40 % of the electricity spot price therefore represent three relatively different scenarios compared to each other and to the Reference scenario.

In reality, a dynamic tariff structure based on the electricity spot price would allow DH companies to plan their production in advance, since spot prices are published 24 hours in advance and tariff rates could therefore also be determined in advance. This would make the practical implementation of such a tariff scheme fairly simple.

5.2.4 Summary

From the previous chapter it is learned that EBs and electric HPs coupled with heat storage can provide a potential for increasing flexibility for both the DH sector and for the electricity sector. To test how new tariff schemes might assist in realizing and enhancing this potential, three different tariff schemes are included for further analysis; 1) reduced flat rate tariffs, 2) fixed TOU tariffs, and 3) dynamic tariffs with rates varying according to the electricity spot price. Table 5.8 provides a complete overview of the tariff schemes included for further analysis in Chapter 6.

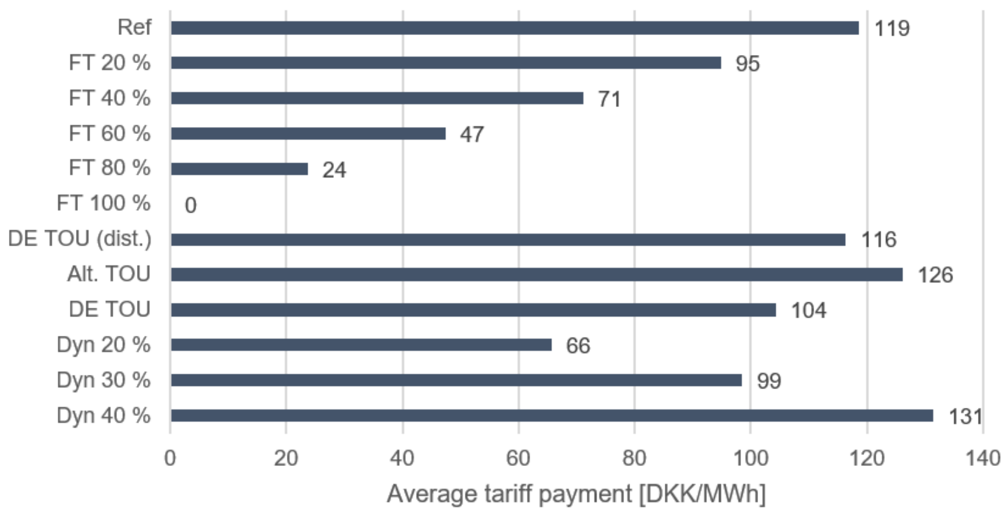


Figure 5.8: Overview of annual average hourly tariff payments for the various tariff schemes.

In Table 5.8 each average tariff payment is calculated based on all the hourly tariff rates for a year. It can be seen that the average tariff payment varies significantly for the different tariff schemes. It is important to note that the included numbers are averages, e.g. the various fixed TOU and dynamic tariff schemes will have very varying tariff rates depending on the actual time of use. The Reference scenario and the five flat rate tariff schemes do however not have any fluctuations and are simply a fixed payment per MWh electricity. The average tariff payment is especially important to inflexible technologies with a high number of production hours, since they will experience both periods with high and low tariff payments.

Techno-economic analysis using energyPRO 6

This chapter first presents the energyPRO model of Ringkøbing DH system and the resulting operation of the Reference scenario prior to any changes in tariff scheme. Afterwards, the model results for the three investigated tariff schemes; flat rate tariff reductions, fixed TOU tariffs, and dynamic tariffs are presented, with the purpose of assessing the potential for flexible operation and the business case for P2H technologies. Furthermore, the most promising tariff level for each tariff scheme is chosen and cross compared to each other. To determine the significance and impact of key assumptions a sensitivity analysis is conducted and finally the key findings with regards to flexibility are summarized.

6.1 EnergyPRO model description

The energyPRO model represents Ringkøbing DH plant. The model is based on the DH plant as it was observed at the site visit in the beginning of 2019, however with a few alterations. According to the director of Ringkøbing DH plant, Andersen [2019b], Ringkøbing DH plant has two CHP units; an engine and a turbine. Currently, the CHP engine is operational, and the CHP turbine is also technically able to operate, however it is at the end of its technical lifetime and is no longer used at the DH plant. Furthermore, the DH plant has an air to water HP. This HP currently runs on natural gas; however, it is possible for it to also have the option of running on electricity, but for this it needs to be connected to the electricity grid. According to Andersen [2019b] this is rather expensive; however, the plant expects to make the connection in 2020.

The energyPRO model is therefore based on the current DH plant in Ringkøbing, however with one less CHP unit and a HP which has the option of either running on natural gas or on electricity. A graphical overview of Ringkøbing's DH plant modelled in energyPRO can be seen in Figure 6.1.

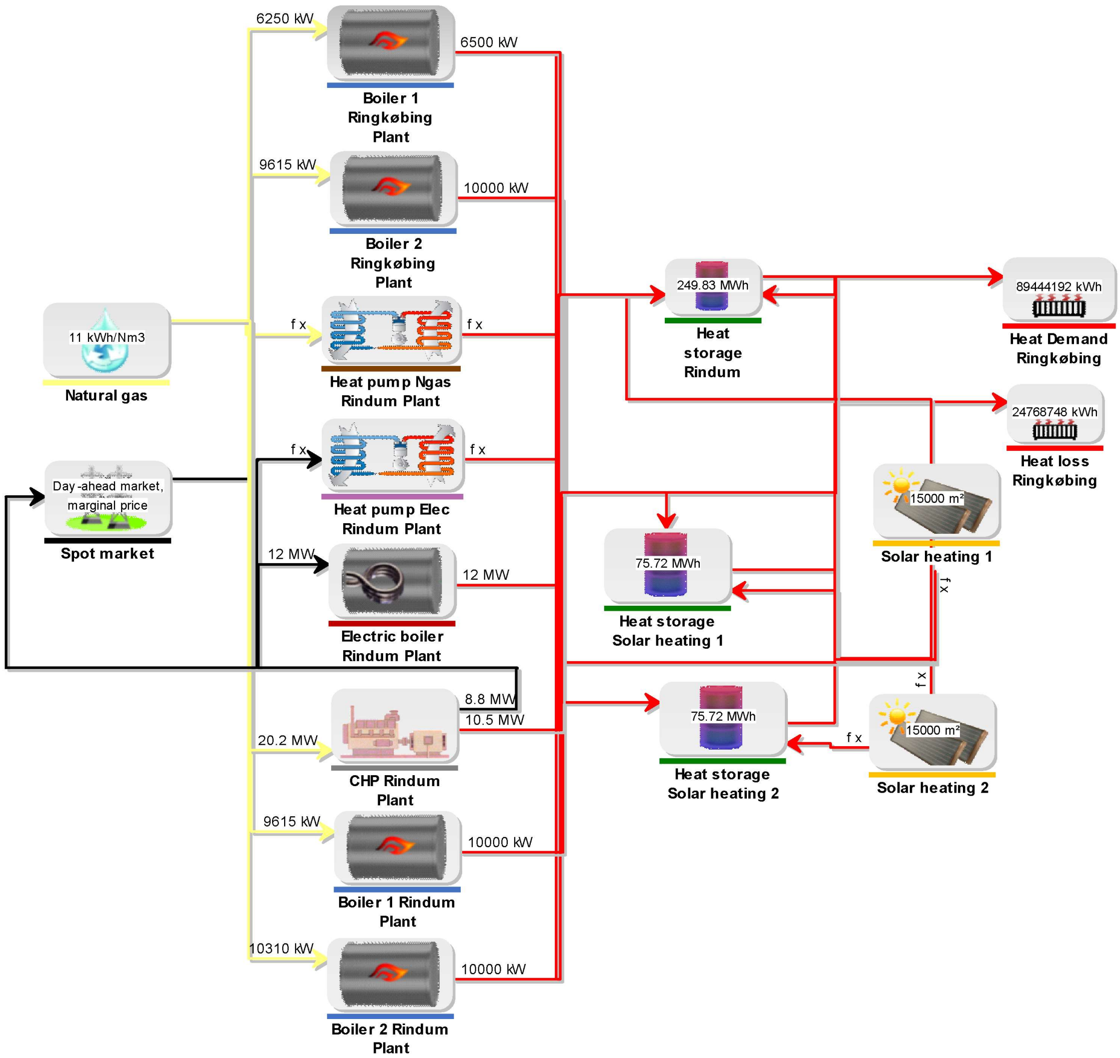


Figure 6.1: Graphical overview of Ringkøbing DH plant as modelled in energyPRO.

Ringkøbing DH plant is split into three locations; Ringkøbing plant, Rindum plant, and two solar heating fields located close to each other and to the Rindum plant. This has no influence on the energyPRO model, since in reality the heat distribution grid allows heat to be transported between the different sites, each technology in Figure 6.1 is however still named after the technology type and its physical location.

From Figure 6.1 it can be seen that Ringkøbing DH plant includes various different technologies; natural gas boilers, a natural gas CHP engine, an EB, an air to water HP able to run on either natural gas or electricity, hot water storage tanks and solar heating. Furthermore, it can also be seen that natural gas, electricity and solar energy are the only fuel types/energy sources used in the DH plant. In the energyPRO model, all the different heating technologies can utilize all three hot water storage tanks, which is also the case in reality according to Andersen [2019b]. As explained in Chapter 4.3.2, the only type of electricity market included in the energyPRO model is the spot market. Finally, it can be seen that there is also an annual heat demand which must be met and an annual heat loss, due to heat loss in the DH pipes connecting the DH plant with the heat consumers.

In Figure 6.2 the NHPC for each of the mentioned technologies above can be seen. For the technologies connected to the electricity grid, such as the EB, the CHP engine and the electric HP, the NHPCs vary depending on the electricity spot price.

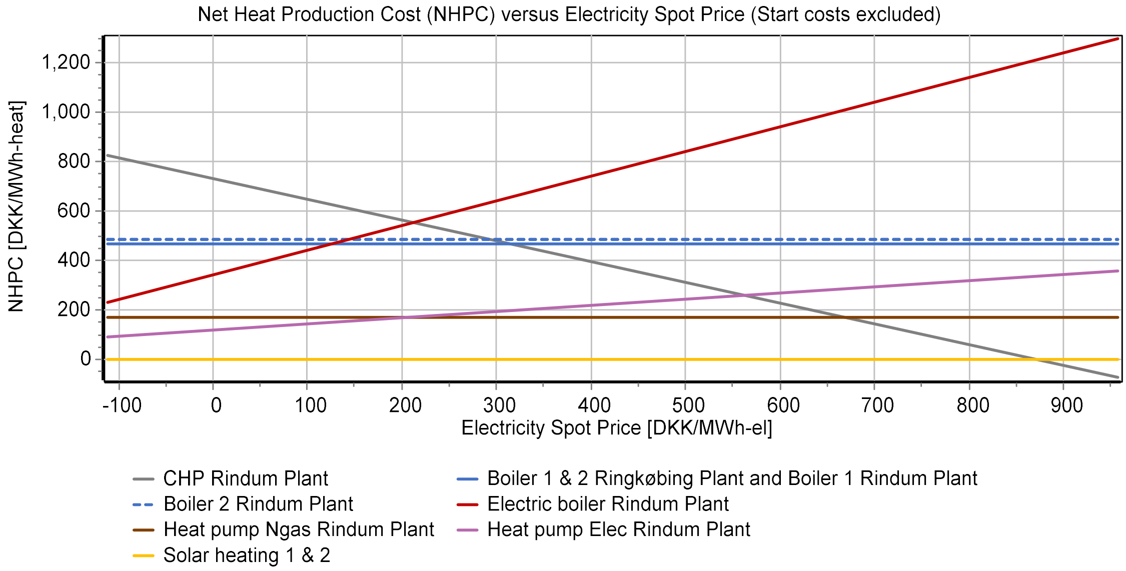


Figure 6.2: NHPC cost for the various heating technologies relative to the electricity spot price.

The NHPCs illustrated in Figure 6.2 are a result of all the different costs included in the operation strategy in the energyPRO model. These costs include:

- Fuel cost (fixed natural gas price).
- Electricity costs.
- Electricity revenues.
- All taxes, tariffs and CO_2 quotas.
- Variable O&M costs.

For each technology the NHPC is calculated and illustrated in the figure. It can be seen that if the specific technology is not connected to the electricity system, its NHPC does not vary according to the electricity spot price and remains constant. Solar heating is included at a cost of 0 DKK/MWh and as seen on Figure 6.2 this results in the CHP plant having a lower NHPC at electricity spot prices above 870 DKK/MWh. This does however not align entirely with how operation would work in reality, where solar heating has limited options for curtailment and normally is a must-run technology. In the model this only occurs for two hours in 2018 and the effect on the results is therefore very limited.

The technologies that are not connected to the electricity grid are prioritized by energyPRO in the following order:

1. Solar heating 1 & 2.
2. Ngas HP Rindum plant.
3. Boiler 1 & 2 Ringkøbing plant and Boiler 1 Rindum plant.
4. Boiler 2 Rindum plant.

For the technologies connected to the electricity grid, the prioritization depends on the electricity price. It can be seen for the electric HP that the electricity spot price must be below 192 DKK/MWh for it to be the cheapest heat source apart from solar heating. For the EB it can be seen that the NHPC is not cheaper than either the natural gas- or the electric HP at any given electricity spot price for 2018. However, the EB is a cheaper heat source than the natural gas boilers at an electricity spot price of around 125 DKK/MWh and is cheaper than the CHP engine at an electricity spot price of around 210 DKK/MWh.

6.1.1 Results from the Reference scenario

In Figure 6.3 an overview of the annual heat production for the Reference scenario and the resulting heat production price can be seen.

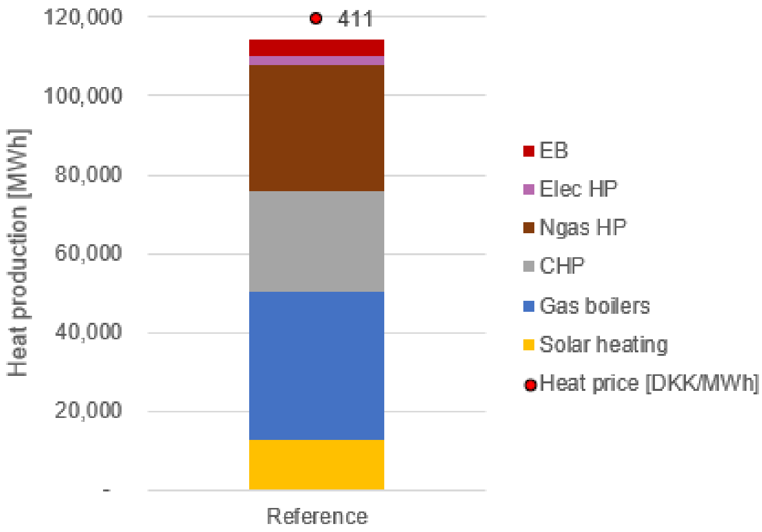


Figure 6.3: Overview of the annual heat production and the short-term marginal heat production cost for the Reference scenario.

From Figure 6.3 it can be seen that the natural gas HP, the CHP engine and the natural gas boilers are responsible for the majority of the annual heat production, equivalent to 83 %. The natural gas HP is responsible for 28 %, the CHP engine is responsible for 22 % and the natural gas boilers are responsible for 33 % of the annual heat production. Solar heating also provides part of the annual heat production, equivalent to 11 %. The P2H technologies are only responsible for a limited amount of the annual heat production, equivalent to 2 % for the electric HP and 3 % for the EB.

The Reference scenario refers to the results of the model when no changes to the cost level or structure of 2019 tariffs have been made. Therefore, this is how the system is expected to behave and optimize by default. In Table 6.1, the annual heat production from the Reference scenario is compared to the actual heat production for Ringkøbing DH plant, monitored by EMD International A/S [2019b]. The annual heat production for each technology in the Reference scenario shown in Table 6.1 is equivalent to the annual heat production illustrated in Figure 6.3.

Annual heat production	Reference scenario [MWh]	EMD [MWh]
Solar heating	12,670	15,591
Gas boilers	37,749	61,170
CHP engine	25,631	19,060
CHP turbine	n/a	597
Ngas HP	31,898	11
Elec HP	2,444	n/a
EB	3,964	7,168
Sum	**114,356**	**103,596**

Table 6.1: The annual heat production from each heat production unit for the Reference scenario compared to data from EMD International A/S [2019b].

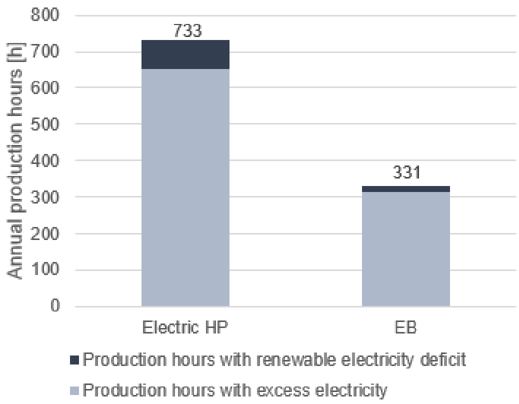
In Table 6.1 the annual heat production for technologies included in the Reference scenario is compared to the measured heat production data from 2018 monitored by EMD International A/S [2019b]. The input data for the Reference scenario is a mix of time series from 2018 and prices from 2019.

It can be seen that the sum of annual heat production for the Reference scenario and data from EMD are relatively close to each other. Several factors such as differences in tax and tariff levels, included technologies, and included electricity markets, cause the variations in annual heat productions. It can be seen from the table that the natural gas HP is not able to run in full load operation mode in 2018, according to the data from EMD. In the Reference scenario the natural gas HP is responsible for a large part of the annual heat production for Ringkøbing DH plant.

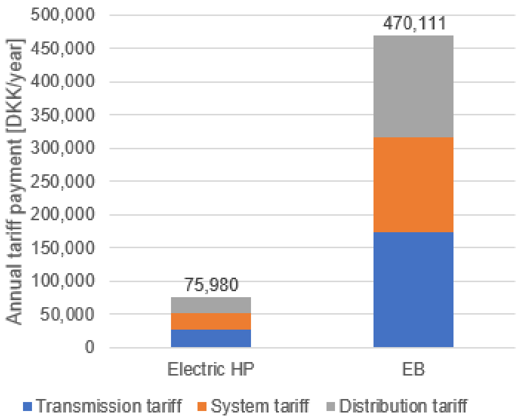
The HP is able to run on electricity in the Reference scenario, which was not the case in 2018 based on the data from EMD and according to Andersen [2019b]. Furthermore, the CHP turbine is not included in the Reference scenario, since according to Andersen [2019b] it is no longer in operation. It can also be seen from the data from EMD that the CHP turbine had no significant share of the annual heat production. Furthermore, it can be seen that the annual heat production for the EB is higher according to the data from EMD compared to the Reference scenario. This is due to the limited amount of electricity markets included in the Reference scenario. According to Andersen [2019b], the EB in Ringkøbing DH plant is mostly used when there are favorable special regulation bids, therefore the EB produces more heat in reality than in the Reference scenario.

Finally, the production from the natural gas and electric HP in the Reference scenario accounts for the reduced heat production seen from the gas boilers compared to the data from EMD, where it can be seen that the gas boilers account for a large part of the annual heat production. Even though the annual heat production from the Reference scenario does not entirely match the heat production from the data from EMD, the model representing the Reference scenario is assumed to sufficiently represent Ringkøbing DH plant, taking all the differences between the two data sets mentioned above into account.

In Figure 6.4a and 6.4b, results regarding the annual production hours and tariff expenses for both the electric HP and the EB can be seen for the Reference scenario.



(a) Annual production hours.



(b) Annual tariff expenses.

Figure 6.4: Annual production hours and tariff expenses for the P2H technologies for the Reference scenario.

From Figure 6.4a it can be seen that the electric HP has a total of 733 production hours. Of those hours, 89 % of the production hours are within hours with excess renewable electricity and 11 % are within hours with renewable electricity deficit. The EB has a total of 331 production hours, where 95 % of them are within hours with excess renewable electricity and 5 % are within hours with renewable electricity deficit. There is a total of 8,760 hours in a year, and in Figure 6.5 it is illustrated how many of those hours are hours with excess electricity and hours with RE electricity deficit.

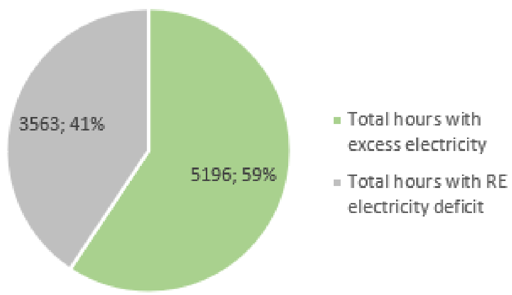


Figure 6.5: Total amount of hours in a year and the distribution of which of them are hours with excess renewable electricity or hours with a renewable electricity deficit.

From Figure 6.5 it can be seen that 59 % of the total amount of hours in 2018 were hours with excess electricity available and 41 % of the hours were hours with a deficit of renewable electricity being produced compared to the total electricity consumption in Ringkøbing-Skjern Municipality. It can be seen from Figure 6.4a that the electric HP and the EB are only producing heat in a small amount of the total hours with excess electricity, illustrated in Figure 6.5. There is therefore a large potential for increasing the operation hours for the P2H technologies while ensuring that they operate when it benefits the electricity grid.

From Figure 6.4b it can be seen what the annual tariff expenses are for the electric HP and for the EB in the Reference scenario. It can be seen that the total annual tariff expense is much larger for the EB than for the electric HP. This is partly due to the heat capacity of the EB being much larger than the heat capacity of the electric HP. The EB has a heat capacity of 12 MW and the electric HP has a heat capacity of 4.5 MW. Furthermore, the tariff expense depends on the electricity consumption and the electric HP has a COP of around 3.7 while the EB has an efficiency of 100 %, meaning that the electric HP uses less electricity to produce the same amount of heat as the EB does.

In the following, results from the energyPRO model are presented when changes are made to the tariff levels and schemes, introduced in Chapter 5.2. These results will also be compared to the results from the Reference scenario, which have been reviewed in this section.

6.2 Results from flat rate tariffs

When testing flat rate tariffs, the current tariff scheme used by the DSO RAH, operating in Ringkøbing-Skjern Municipality, is tested for various tariff reductions. Having a flat tariff rate simply means that the tariff level is constant throughout the year. The tariff reductions, which will be tested in this chapter, are introduced and explained in Chapter 5.2.1 and consist of a 20 %, 40 %, 60 %, 80 % and 100 % tariff reduction.

The annual heat production overview and utilization of P2H technologies in the DH system with flat rate tariffs can be seen in Figure 6.6.

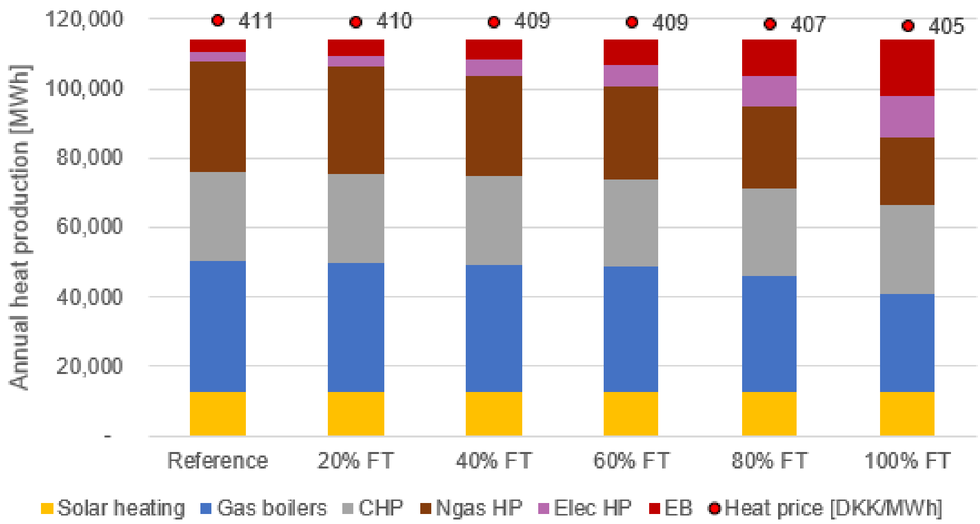


Figure 6.6: Overview of annual heat production and short-term marginal heat production cost for various flat rate tariff reductions.

From Figure 6.6 it can be seen that the larger the flat rate tariff reduction is, the more annual heat production the electric HP and EB has. The most extreme scenario is the 100 % flat rate tariff scenario. In this scenario all the tariffs are set to be 0 DKK/MWh for the electric HP and for the EB, which results in the P2H technologies being responsible of 25 % of the annual heat production. In the Reference scenario the P2H technologies are responsible for 6 % of the annual heat production. The marginal heat production price for each tariff reduction is also illustrated in the figure, where it is named heat price. This illustrates how the marginal heat production price is lowered as the tariff levels are lowered, as a result of an improved business case for the P2H technologies.

In Figure 6.7 and 6.8 the annual production hours for the EB and the electric HP can be seen. The annual production hours are spilt into hours with excess and deficit of electricity produced by RE.

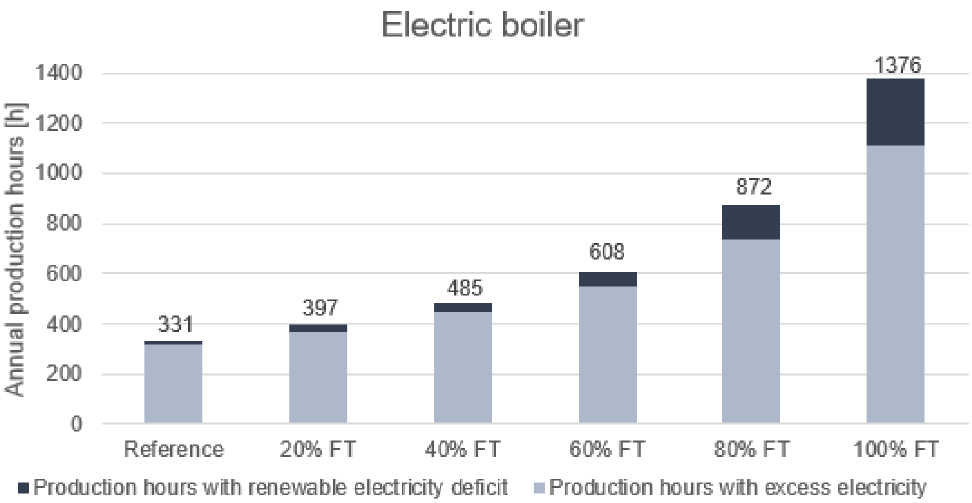


Figure 6.7: Annual production hours for the EB in hours with excess and deficit of electricity produced by RE for the various levels of flat rate tariffs.

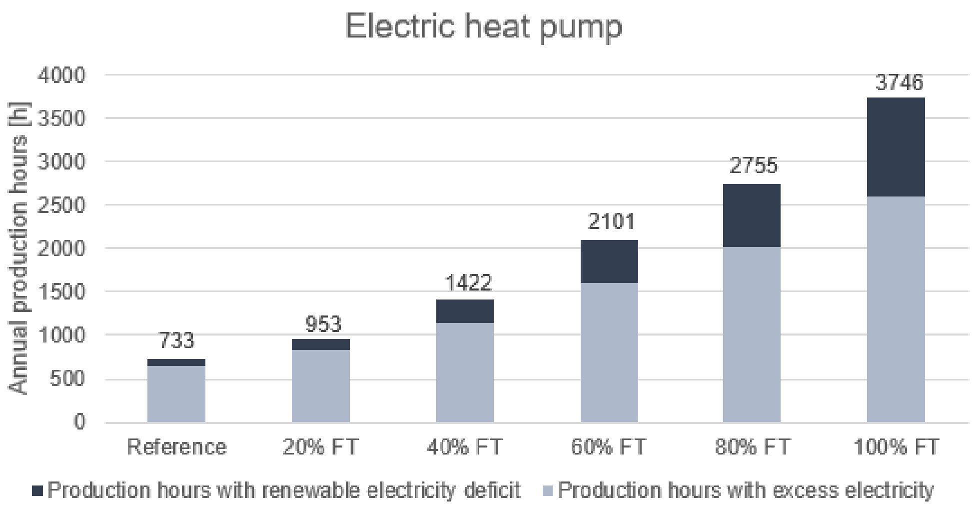


Figure 6.8: Annual production hours for the electric HP in hours with excess and deficit of electricity produced by RE for the various levels of flat rate tariffs.

Generally from Figure 6.7 and 6.8, it can be seen that lowering the level of the flat rate tariffs increases the annual production hours for the EB and the electric HP. However, even though both technologies gain more production hours when lowering the tariff levels, the relationship between excess/deficit production hours from the Reference scenario is not maintained. For both the EB and the electric HP, the more the tariff levels are lowered, the less favorable the distribution between production hours in excess hours and deficit hours becomes.

In Figure 6.9 and 6.10 the annual tariff expense from the EB and the electric HP is illustrated.

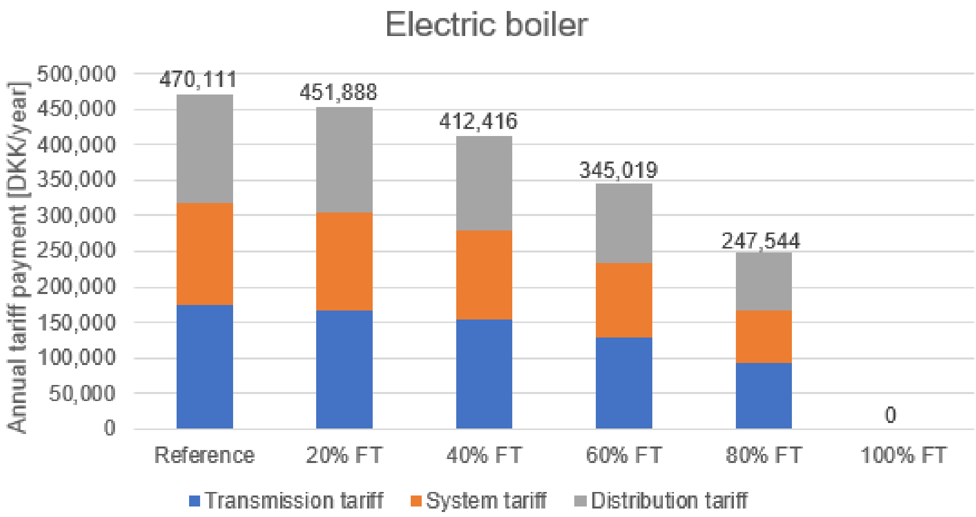


Figure 6.9: Annual tariff expense for the EB depending on the tariff reduction.

For the EB it is observed that the annual tariff expenses are reduced as the flat tariff levels are reduced. However, it is important to point out that for the 20 % - 80 % tariff level reductions, even though the tariff rates are reduced by 20 %, 40 %, 60 % and 80 %, the annual tariff payments are not reduced by the same percentage, but by less compared to the Reference scenario. This is due to an increase in production hours for the P2H technologies. An overview of how much the annual tariff expenses are reduced, depending on the tariff level reduction, is shown below.

20 % tariff level reduction:	4 % annual tariff payment reduction
40 % tariff level reduction:	12 % annual tariff payment reduction
60 % tariff level reduction:	27 % annual tariff payment reduction
80 % tariff level reduction:	47 % annual tariff payment reduction

A similar result is however not observed for the tariff level reduction of 100 %, as for this scenario there is no annual tariff expense and it is therefore reduced by 100 % compared to the Reference scenario.

In Figure 6.10 a different trend can be observed for the electric HP regarding the development of the annual tariff expenses.

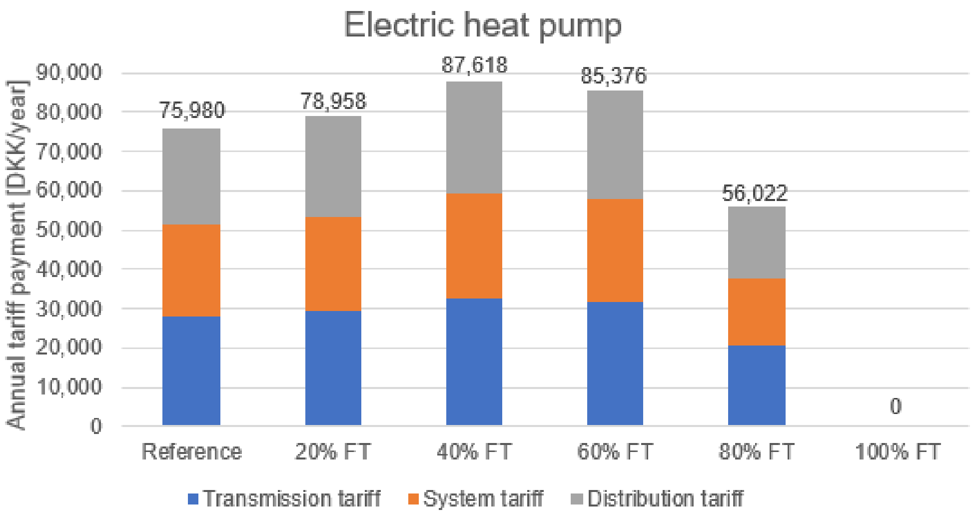


Figure 6.10: Annual tariff expense for the electric HP depending on the tariff reduction.

For the electric HP it can be seen that the annual tariff expenses actually increase compared to the Reference scenario, as the flat rate tariff levels are reduced. This is true for tariff level reductions of 20 %, 40 % and 60 %, as the electric HP is able to run in more hours of the year, due to it having a lower NHPC than the natural gas HP in more hours. For tariff level reductions of 80 % and 100 % the annual tariff expenses are lower than those of the Reference scenario. It is observed that out of all the scenarios including the Reference scenario, the annual tariff expense is highest for the 40 % tariff level reduction.

From the range of flat rate tariff levels tested, it is observed that it is possible to utilize the P2H technologies more than they are used in the Reference scenario. It is also possible to utilize even more of the hours with excess renewable electricity and thereby enabling flexibility in the electricity grid and in DH production to a greater extent. As a compromise between the EB and the electric HP, the flat rate tariff reduction of 40 % is chosen for further cross comparison and analysis in Section 6.5. Both the 40 % and the 60 % reduction are very suitable for the electric HP as they increase the annual production hours and increase the annual tariff expenses, which is favorable for the DSO. However, to limit the amount of production hours which occur in hours of renewable electricity deficit and to limit the loss of annual tariff expenses from the EB, the 40 % tariff reduction is chosen.

6.3 Results from fixed time-of-use tariffs

Fixed TOU tariff rates vary according to a predetermined schedule, with the purpose of increasing correlation between supply and demand of electricity and providing more accurate price signals to consumers. As described in Chapter 5.2.2, TOU tariff rates can vary both daily and seasonally; this analysis tests three different structures with differences in both seasonal and daily fluctuations.

Similarly to the Reference scenario, P2H utilization is generally low in the fixed TOU scenarios, this is illustrated in Figure 6.11

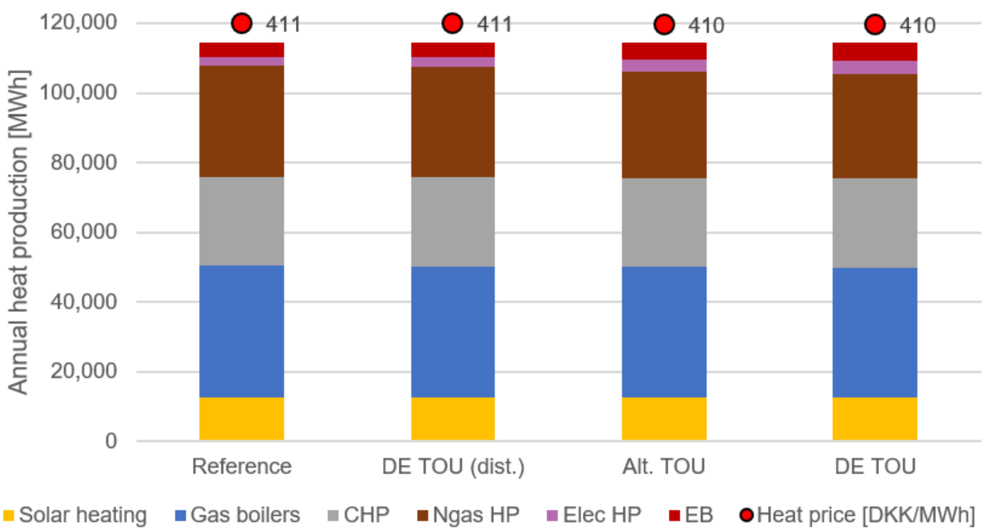


Figure 6.11: Overview of the annual heat production and short-term marginal heat production cost.

From Figure 6.11 it can be seen that especially the DE TOU (dist.) scenario has almost no differences in EB/HP production compared to the Reference scenario. This is due to the limited change in the price signal caused by this scenario, since the only change compared to the Reference scenario is implementing the fixed TOU structure for the distribution tariff, as done by the DSO Radius. It appears this change is not influential enough to cause significant changes to the prioritization of technologies and does not result in any significant savings for the DH plant, thus the heat production cost remains constant.

The Alt. TOU and DE TOU scenarios also include changes to the transmission and system tariffs as well as the distribution tariff, enabling a greater potential for altering price signals. However, the effect of this on the annual heat production remains limited with only slight increases in P2H heat production.

The slight increases in EB production is perhaps better illustrated in Figure 6.12. From this it is again apparent that only including a fixed TOU structure for the distribution tariff component of the total tariff payment has limited impact on the EB production hours. The Alt. TOU and DE TOU scenarios are better at enabling the EB to produce during low tariff periods. Even though the production hours increase, the distribution of production in hours with excess electricity compared to deficit remains almost the same with an advantage of 1 % for the Alt. TOU scenario.

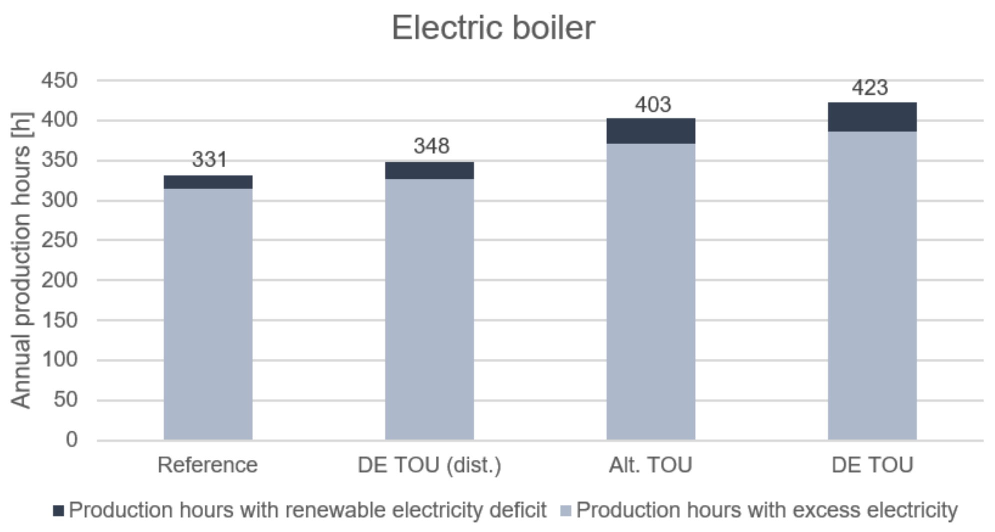


Figure 6.12: Annual production hours for the EB in hours with excess and deficit of renewable electricity.

A similar situation is observed for the operation of the electric HP, illustrated in Figure 6.13.

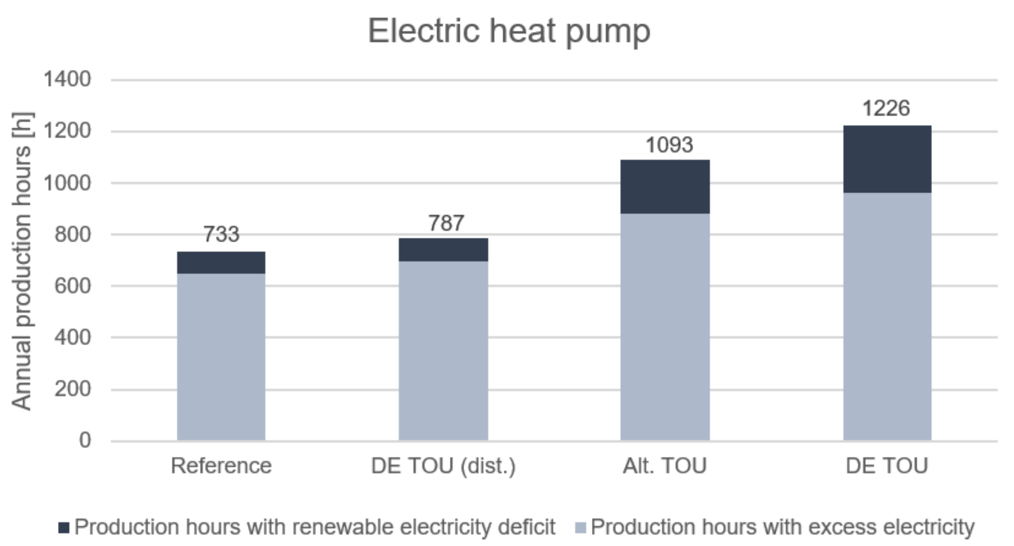


Figure 6.13: Annual production hours for the electric HP in hours with excess and deficit of renewable electricity.

The effect of the Alt. TOU and DE TOU scenarios might appear higher for the electric HP compared to the EB. This likely relates to how close the NHPC of the natural gas HP and the electric HP is, thus the periods with low tariffs provide a greater range of hours where the electric HP is preferable. Since these are the cheapest production units included in the model, apart from solar heating, one or the other will be in operation most hours.

Looking at the tariff expenses for the EB illustrated in Figure 6.14, it is seen how there is little difference between the Reference scenario and the DE TOU (dist.) scenario, while the expense for the Alt. TOU and DE TOU scenarios are lower due to an increase in production during low tariff periods.

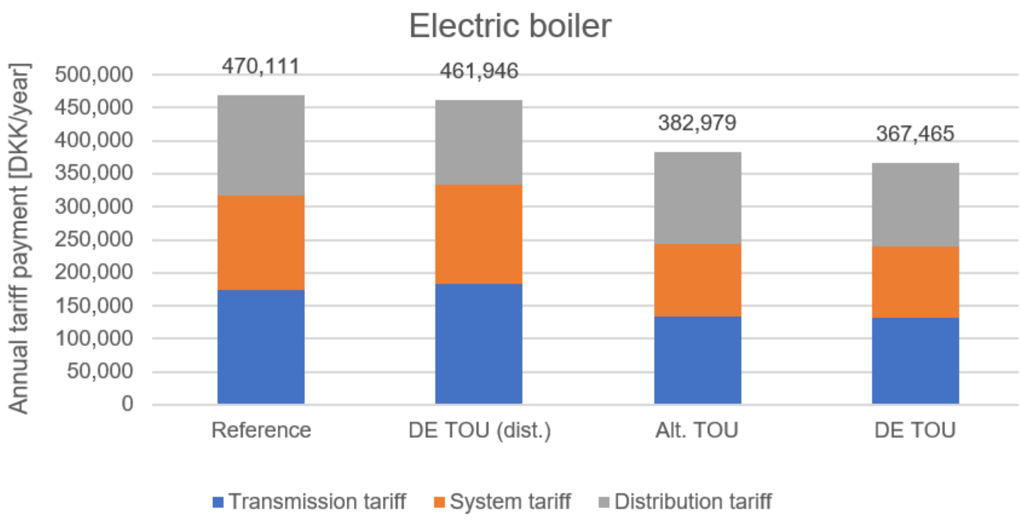


Figure 6.14: Annual tariff expense for the EB depending on the tariff structure.

The opposite effect can be observed for the electric HP in Figure 6.15.

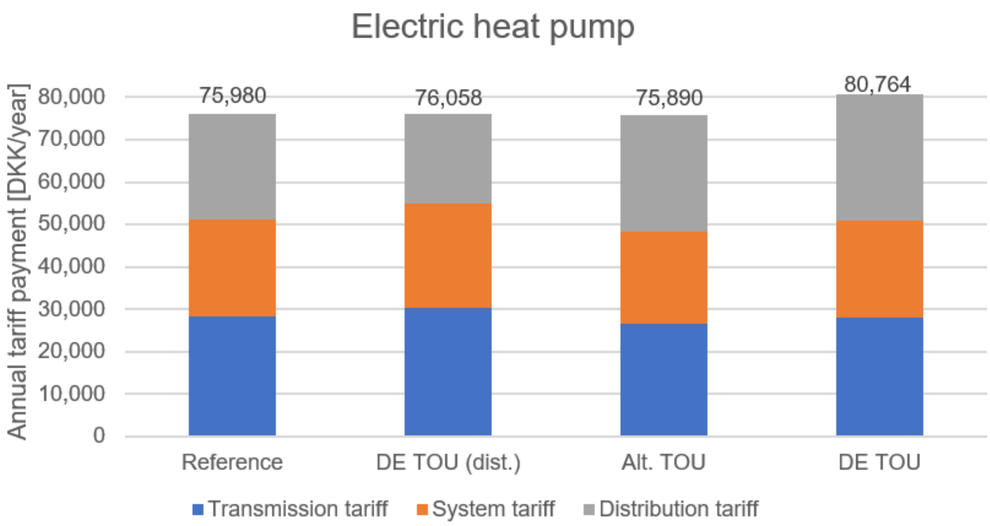


Figure 6.15: Annual tariff expense for the electric HP depending on the tariff structure.

From Figure 6.15 it is seen that the annual tariff expense remains very similar for the three different fixed TOU scenarios to the Reference scenario, and are even slightly higher for the DE TOU (dist.) scenario and for the DE TOU scenario. This is due to the increase in production hours for the electric HP mentioned earlier. It is worth noting that while the annual tariff expenses remains somewhat at the same level as for the Reference scenario, the annual heat production for the various scenarios increases compared to the Reference scenario and thus the payment per MWh decreases.

From this initial overview of fixed TOU tariff schemes in effect, several observations are made. Firstly, the introduction of fixed TOU variations for the distribution tariff component alone in the DE TOU (dist.) scenario has very limited effect on both operation hours and tariff expenses for P2H technologies. It is thus a way for the DSO to seemingly change the tariff structure without actually influencing tariff income significantly. The other two scenarios show a greater potential for integrating excess RE. The results of the two scenarios are similar, however due to the undesired increase in number of production hours in times of RE electricity deficit for the DE TOU scenario, the Alt. TOU scenario is chosen for further cross comparison and analysis in Section 6.5.

6.4 Results from dynamic tariffs

Tariff schemes can be dynamic in several ways, however for this study dynamic tariffs are included as a simple share of the hourly spot price, as described in Chapter 5.2.3. The specific dynamic tariff schemes which are investigated are 20 %, 30 %, and 40 % respectively of the spot price, distributed in accordance to current rates as transmission-, system- and distribution tariffs. Such a tariff scheme is likely possible to introduce, since the DH companies are used to adjusting their operation based on spot market prices and similar price mechanisms.

The production overview and utilization of P2H technologies in the DH system with dynamic tariffs, can be seen in Figure 6.16.

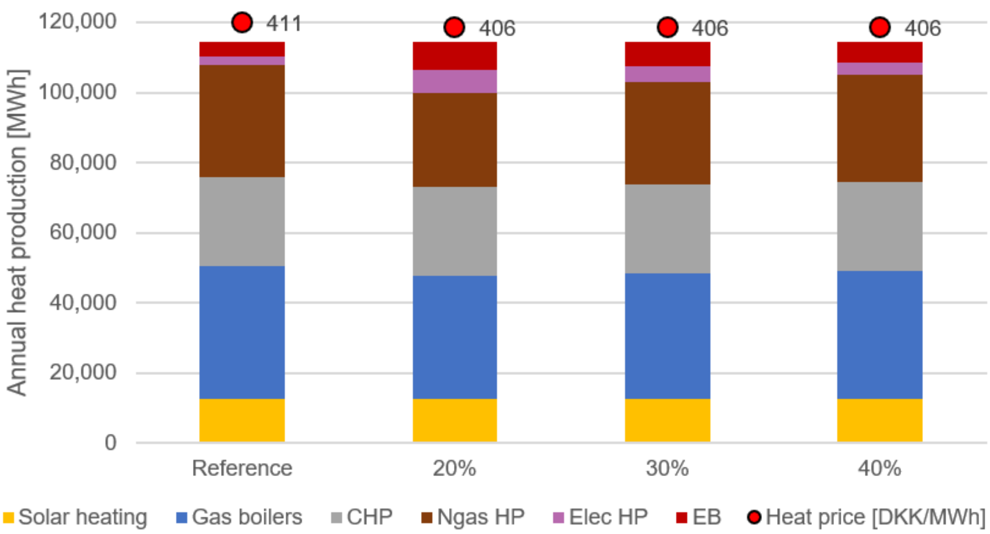


Figure 6.16: Overview of the annual heat production and short-term marginal heat production cost.

For all the scenarios the utilisation of both the electric HP and the EB increases compared to the Reference scenario, however, overall the annual heat production is still dominated by the natural gas HP and natural gas boilers. Dynamic tariffs lower the operation costs for the DH company; a result of the tariff costs being low during most operation hours for the EB and the electric HP. Dynamic tariffs thus seemingly present an increased incentive for utilization of P2H technologies in a DH system. Figure 6.17 and 6.18 illustrate how annual production hours increase and the extent of which they increase in hours with excess or deficit of renewable electricity.

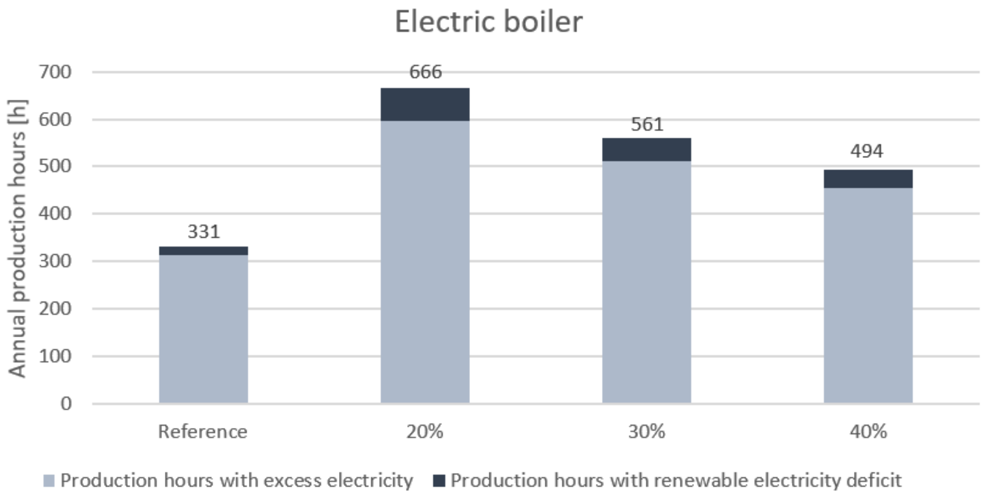


Figure 6.17: Annual production hours for the EB in hours with excess and deficit of renewable electricity.

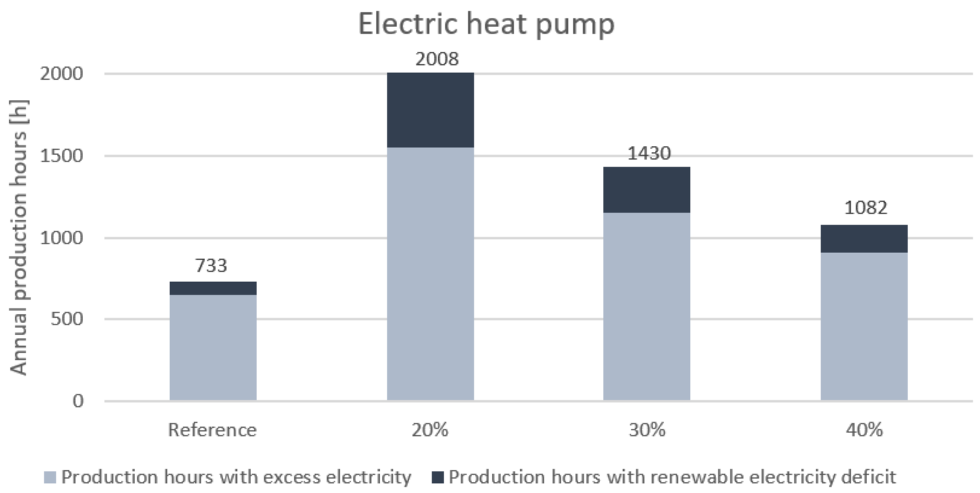


Figure 6.18: Annual production hours for the electric HP in hours with excess and deficit of renewable electricity.

The dynamic 20 % tariff scenario results in quite a significant increase in annual production hours; annual production hours for the EB doubles, and almost triples for the electric HP. It does however also result in the largest increase in production during hours when there is a deficit of renewable electricity. The effect on the annual tariff expenses can be seen in Figure 6.19 and 6.20.

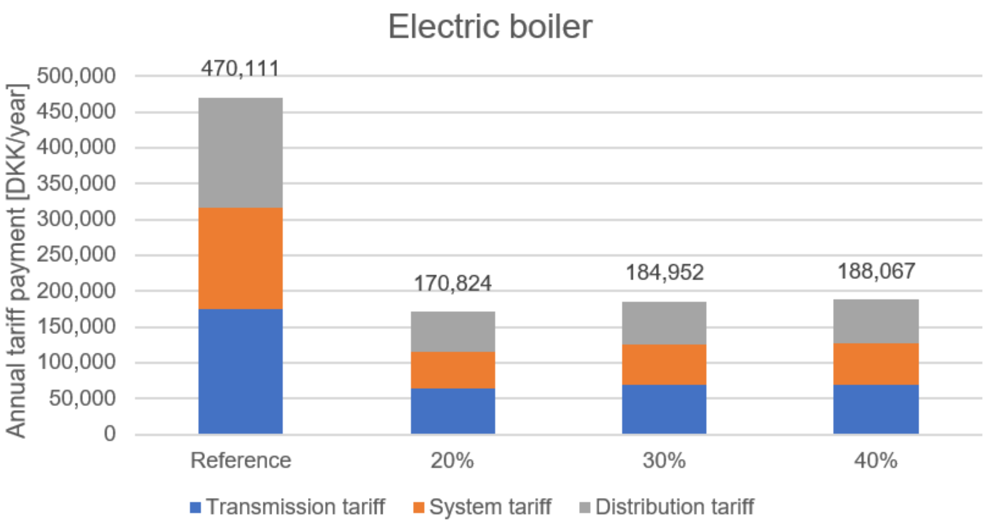


Figure 6.19: Annual tariff expenses for the EB in a dynamic tariff scheme.

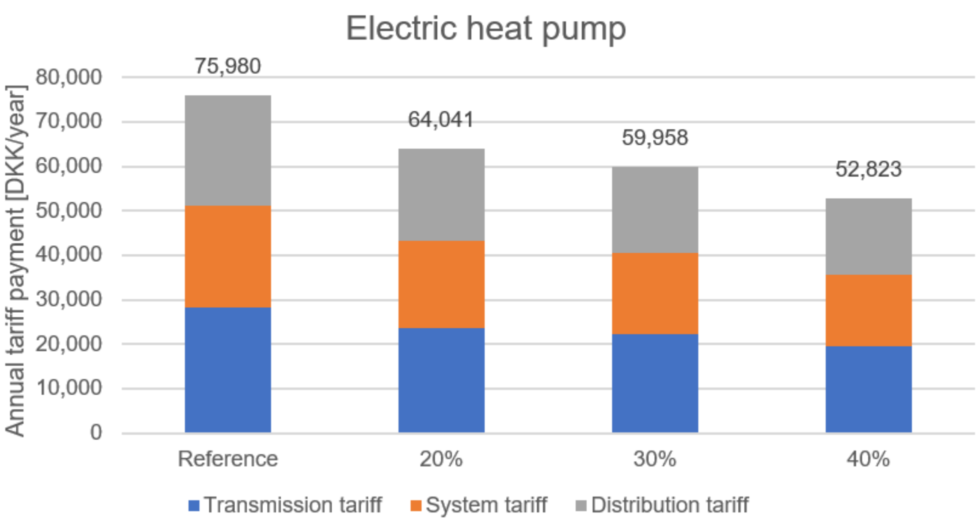


Figure 6.20: Annual tariff expenses for the electric HP in a dynamic tariff scheme.

The tariff expense for the EB decreases significantly compared to the Reference scenario, and the operation strategy seen in Figure 6.2 can help to explain why. The EB is only preferable to natural gas boilers below electricity prices of 125 DKK/MWh, and at such spot prices the total tariff payment in a dynamic tariff scheme is much lower than in the Reference scenario. The same applies to the electric HP, but the larger increase in annual production hours partly makes up for this reduction. Furthermore, the electric HP is the lowest cost solution up to 192 DKK/MWh, where the resulting tariff payment is slightly higher compared to the range the EB operates within.

Dynamic tariffs show promise for accommodating to fluctuations in VRE production. Lower tariff levels, to no surprise, results in the highest amount of annual production hours for the P2H technologies, however, they also result in the highest share of production during hours with renewable electricity deficit. Therefore, to strike a balance and limit this unwanted effect, the 30 % scenario is chosen for further cross comparison in the following section.

6.5 Cross comparison

To better illustrate the differences in operating the P2H technologies in the DH system, which occur between the different tariff schemes, the most promising tariff level for each tariff scheme is cross compared in this section.

The most promising tariff level for each of the tested tariff schemes as chosen in Sections 6.2, 6.3 and 6.4 are; the flat rate tariff reduction of 40 %, the fixed TOU tariff scheme for the alternative structure, and the dynamic tariff scheme with the tariff level being 30 % of the electricity spot price. In figures and text going forward in this chapter, these tariff levels and schemes will be denoted as the following:

Flat rate tariff reduction of 40 %	FT
Fixed TOU tariff for the alternative structure	TOU
Dynamic tariff, 30 % of the electricity spot price	DYN

In Figure 6.21, the annual production hours for both the electric HP and the EB can be seen for the Reference scenario and for the most promising tariff levels chosen.

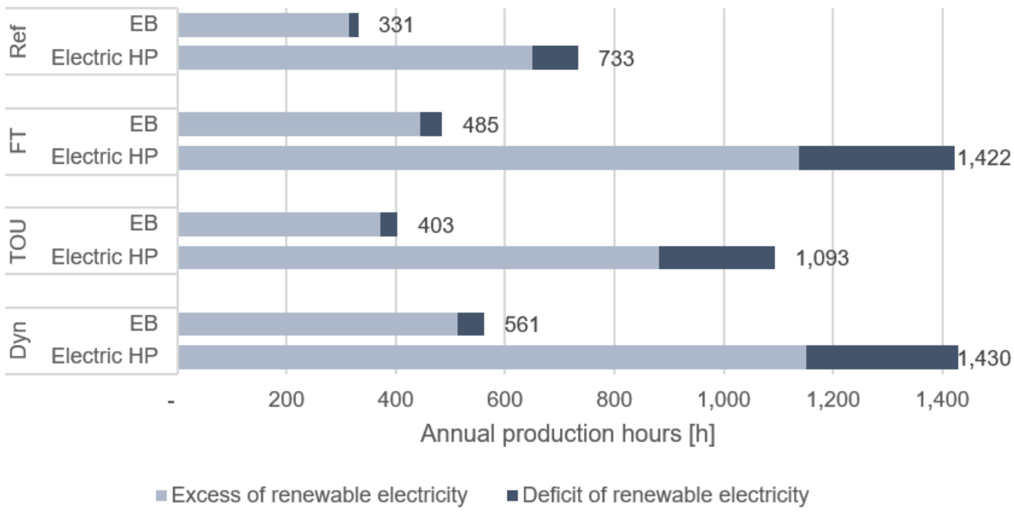


Figure 6.21: Annual production hours for the EB and the electric HP.

In Figure 6.21 it can be seen that the utilization of the P2H technologies varies depending on the applied tariff scheme. The highest utilization is found for the Dyn tariff scheme, followed by the FT reduction tariff scheme. Especially the EB is utilized more than in the Reference scenario and in the FT and TOU scenarios, as a result of the Dyn tariff scheme. This is a result of the low tariff rates during hours with low spot prices where EB operation is most relevant. However, depending on the individual perspective on flexibility and electricity consumption, this could be considered both a strength and a weakness of the Dyn tariff scheme.

In Figure 6.22 the annual tariff expenses are compared to each other, for the Reference scenario and the various chosen scenarios.

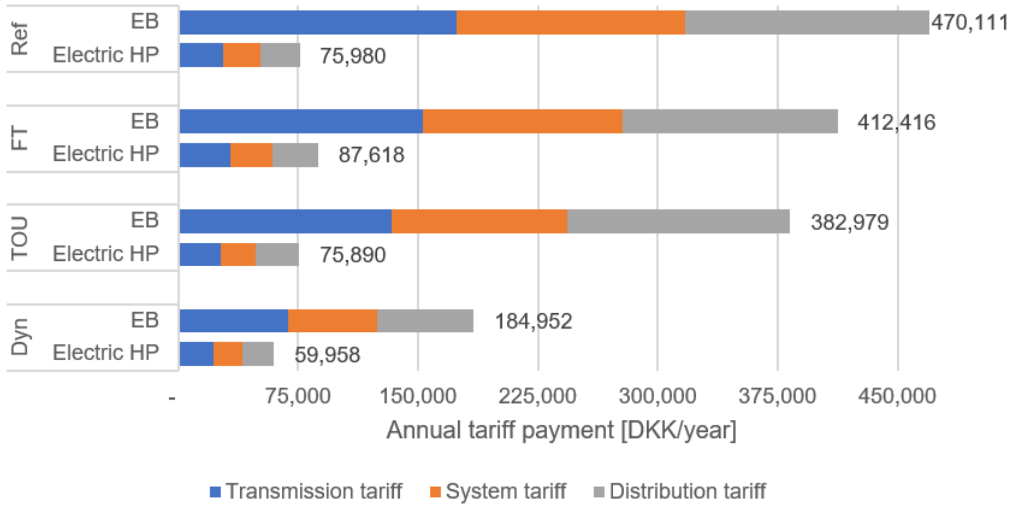


Figure 6.22: Annual tariff expenses for the EB and the electric HP.

The total annual tariff expense varies for the different tariff schemes, however, most significantly for the EB. An interesting observation is that despite the FT tariff scheme having the lowest average tariff cost throughout the year, as seen in Figure 5.8, the annual tariff payment for the EB is the highest, excluding the Reference scenario. The explanation is that during the hours where the EB is actually in operation, the tariff is lower, which is especially true for the Dyn tariff scheme. The most radical change in the annual tariff expenses is for the Dyn tariff scheme, where the decrease in the annual tariff payment for the EB and for the electric HP is much lower than for the other tariff schemes and for the Reference scenario.

As previously described, the wind power production in Ringkøbing-Skjern Municipality is at times very high, necessitating large grid capacity, at the expense of the DSO. Table 6.2 presents a simple comparison of how the different tariff schemes influences the peak excess wind production. This is a result of the difference between the wind power production and the electricity consumption of the municipality, combined with the consumption of the EB and the electric HP at Ringkøbing DH plant.

	Ref	**FT**	**TOU**	**Dyn**
Max export peak [MW]	386.0	385.2	386.0	384.5

Table 6.2: Maximum peak excess wind production.

From Table 6.2 it can be seen that the TOU tariff scheme fails to decrease the maximum exported capacity compared to the Reference scenario. The FT tariff scheme and the Dyn tariff scheme is able to obtain a minor reduction due to operation on the electric HP. However, while the wind power production for the specific peak hour was very high, the spot price was not low enough to incentivize operation of the EB.

Table 6.3 presents an overview of the export balance for the full operating year, and a balance including only the highest 5 % export load hours, e.g. the most critical hours with regards to grid capacity.

	Ref Sum	FT	TOU Difference	Dyn
Export [MWh]	513,810	-2,418	-1,140	-3,349
Top 5 % export [MWh]	136,761	-330	62	-374

Table 6.3: Electricity export balance.

Table 6.3 shows that all three tariff schemes reduce the annual exported electricity, with the largest reduction coming from the Dyn tariff scheme, followed by the FT tariff scheme, and finally the TOU tariff scheme with the smallest change. Looking at the hours where the top 5 % of the electricity is being exported, the TOU tariff scheme actually increases the need for electricity export during the most critical hours, which is an undesired effect. This indicates that the fixed time and tariff level structure does not follow the fluctuations from the wind production and the electricity consumption as desired. While the changes shown in Tables 6.2 and 6.3 might appear small, it needs to be considered in the context of the rest of the energy system as well. In the future other DH plants, industrial consumers, and even individual consumers, might react similarly to new tariff schemes, resulting in much more significant changes with a real impact on the electricity export balance and peak capacity requirements.

So far, the analysis of tariff schemes has focused on annual measurements, e.g. total annual production hours, costs, etc. However, there is more to the flexibility definition than investigating annual parameters, as outlined in Chapter 3.1. The temporal distribution, e.g. when are the technologies in operation, is just as, if not more important than the sum of annual heat production. This is investigated further in Figures 6.23, 6.24, 6.25 and 6.26.

Figures 6.23 and 6.24 illustrate how the tariff schemes alter the operation of P2H technologies throughout a year, plotted as aggregated weekly production relative to the weekly wind power production.

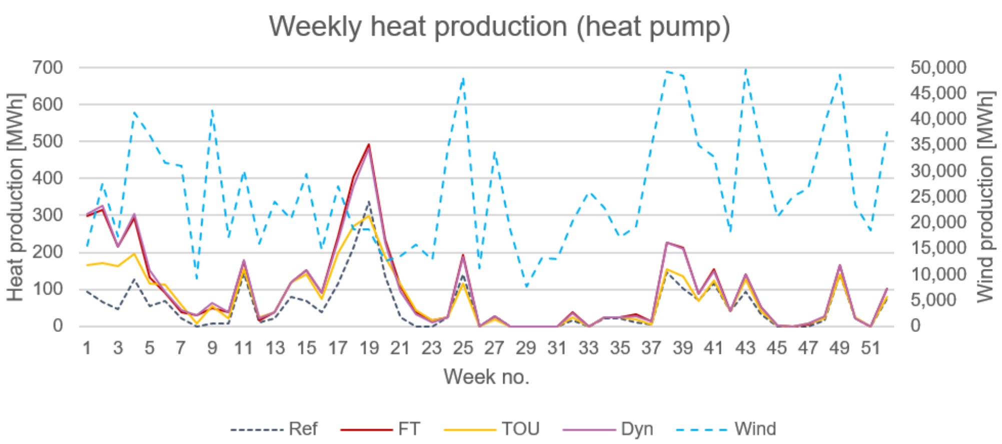


Figure 6.23: Weekly heat production from the electric HP and the weekly electricity production from wind power in Ringkøbing-Skjern Municipality.

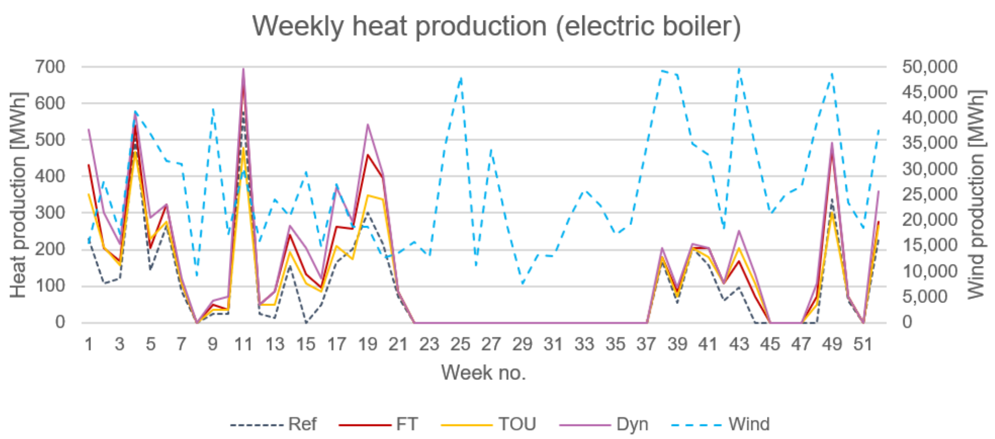


Figure 6.24: Weekly heat production from the EB and the weekly electricity production from wind power in Ringkøbing-Skjern Municipality.

In Figure 6.23 and 6.24 it is illustrated how the weekly heat production from the electric HP and the EB develops for the Reference scenario and for the various tariff schemes. It can be seen that during the summer weeks, week 27 - 37 for the electric HP and week 22 - 37 for the EB, the heat production is very limited for the electric HP and non-existing for the EB. This is partly due to a lower heat demand present in the summer and because of the solar heating, which is able to cover a larger part of the heat demand during the summer than during the winter.

It can also be seen that the FT tariff scheme and the Dyn tariff scheme have very similar production patterns. For the electric HP, they are very similar in both pattern and heat production level. For the EB they are also similar for the production pattern, however, the heat production level differs slightly and is generally slightly higher for the Dyn tariff scheme.

Generally, the different tariff schemes to some extent respond to the weekly electricity production from wind power. However, this is only to the extent of which spot prices and electricity production from wind power relates to each other. There is potential for the various tariff schemes to respond more depending on the wind production.

In Figure 6.25 and 6.26 the daily average production profile for the electric HP and the EB can be seen.

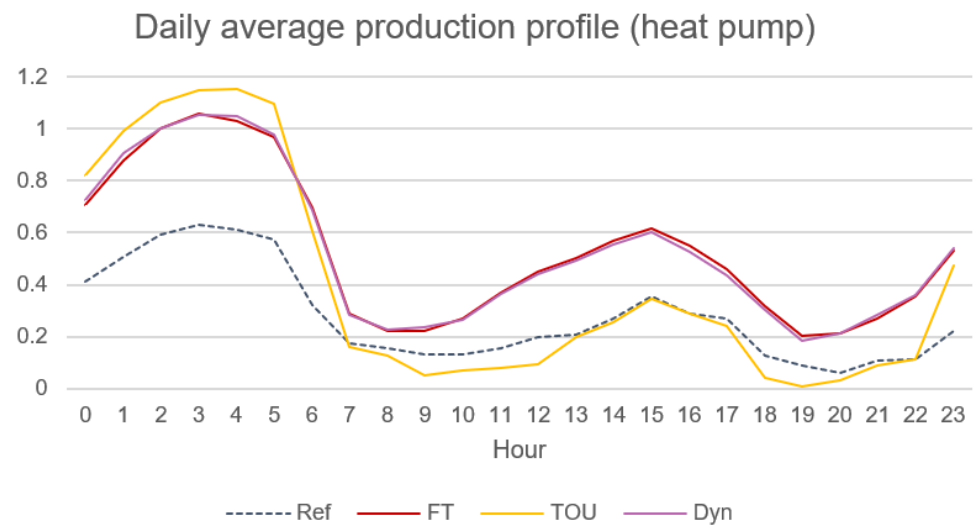


Figure 6.25: Daily average production profile for the various tariff schemes for the electric HP.

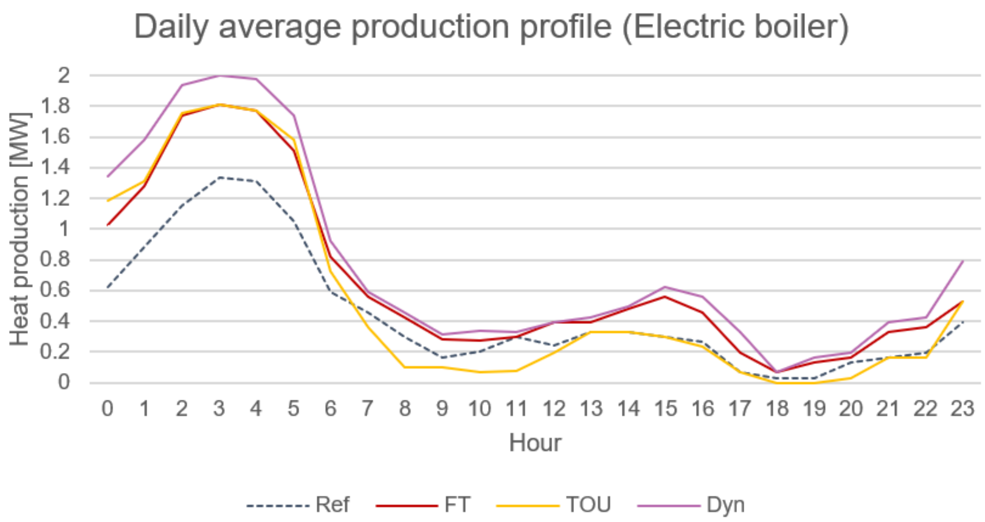


Figure 6.26: Daily average production profile for the various tariff schemes for the EB.

From Figure 6.25 and 6.26 it can be seen how both the electric HP's and the EB's production profiles take advantage of which hours during the day the hourly spot prices are low. As previously seen in Figure 5.3, the average hourly spot price is low during the evening/night and during midday. It is thereby not surprising that the electric HP and the EB take advantage of this and have most of their heat production during these times.

It can also be seen for the electric HP and EB that the TOU tariff scheme is the best out of the various tariff schemes and the Reference scenario, to distribute the heat production during an average day to match when it is costly and less costly to use electricity. This is illustrated by it having a lot of heat production during the evening/night and having very little heat production during the morning and evening periods. It can therefore be determined that the TOU tariff scheme functions as it is designed to, however it can be discussed if the effects seen from all the results of the fixed TOU tariff scheme are sufficient enough compared to the results from the FT- and Dyn tariff schemes.

From the cross comparison of the three tested tariff schemes presented in this section, it can be determined that all three tariff schemes increase the flexibility of the DH system and of the electricity grid. This is due to all three tariff schemes having increased production hours compared to the Reference scenario. A large part of these additional production hours are hours with excess renewable electricity available. All three tariff schemes therefore help, to some extent, to relieve the electricity grid in times of excess electricity.

For the TOU tariff scheme, it is observed that it functions as it is designed to, however it has the smallest effect on increasing the role of the P2H technologies in the DH system. The TOU tariff scheme could therefore work well as a starting point for introducing dynamic tariffs in DH systems and/or as a tariff scheme for the 0.4 kV electricity grid, where individual households are mostly connected and complex dynamic tariff schemes might prove to be infeasible.

The FT tariff scheme and the Dyn tariff scheme both work well for integrating the P2H technologies to a larger extent in the DH system. For the FT tariff scheme, it is seen that it is able to increase P2H technology production hours and that the annual tariff expenses increase slightly for the electric HP and decrease slightly for the EB. The effects of the FT tariff scheme are therefore significant compared to the limited change in annual tariff expenses. The Dyn tariff scheme is able to exploit the low spot prices and thereby limit its annual tariff payments, while still increasing production hours for the P2H technologies significantly compared to the Reference scenario. Both a flat rate tariff reduction and a dynamic tariff reduces operation costs for the DH company, which presents an improved business case for P2H technologies.

6.6 Sensitivity analysis

A sensitivity analysis of a lower CO_2 quota price of 119 DKK/ton CO_2 and of a model with no natural gas HP included, is carried out. The results of these two sensitivity analyses compared to the results from Section 6.5, where no changes are made to the model, can be seen in Table 6.4.

	No changes to the model				Sensitivity: lower CO2 quota price (difference)				Sensitivity: No Ngas HP included (difference)			
	REF	FT	TOU	DYN	REF	FT	TOU	DYN	REF	FT	TOU	DYN
EB: Annual production hours [h]	332	486	404	562	-43	-73	-52	-74	7	13	17	17
here of: hours with excess electricity	314	445	371	512	-37	-60	-44	-64	7	11	18	13
here of: hours with deficit of electricity	17	40	32	49	-6	-13	-8	-10	-	2	-1	4
HP: Annual production hours [h]	734	1,423	1,093	1,430	-175	-530	-352	-433	7,651	6,966	7,294	6,954
here of: hours with excess electricity	651	1,137	881	1,151	-147	-359	-227	-295	4,413	3,929	4,170	3,912
here of: hours with deficit of electricity	82	285	212	279	-28	-171	-126	-139	3,238	3,037	3,123	3,041
P2H share [%]	6	9	7	13	-1	-2	-1	-5	23	21	22	18
EB: Annuall tariff expenses [DKK/year]	470,111	412,416	382,979	184,952	-64,115	-58,728	-50,367	-47,444	9,279	11,356	16,000	8,302
HP: Annuall tariff expenses [DKK/year]	75,980	87,618	75,890	59,958	-18,443	-32,150	-23,820	-25,155	800,237	438,606	846,194	661,691
Heat price [DKK/MWh]	411	409	410	406	-19	-20	-19	-19	24	19	24	22

Table 6.4: Sensitivity analysis results for a lower CO_2 quota price and for the model with no Ngas HP included, presented as the difference to "No changes to the model".

6.6.1 A lower CO_2 quota price

Prior to the sensitivity analysis the CO_2 quota price is set to 200 DKK/ton CO_2 in the energyPRO model, chosen based on the quota price from 18-04-2019, as described in Appendix C. Danish Energy [2018a] suggests that a quota price of 200 DKK/ton CO_2 is a suitable price level for CO_2 quotas to efficiently integrate more RE without the need of subsidy schemes. It is however still a high quota price compared to the observed historic prices from 2017 - 2019, which have varied from 33 - 205 DKK/ton CO_2, as seen in Appendix C, Figure C.1. To investigate what effect the CO_2 quota price has on the annual production hours and tariff expenses for the EB and the electric HP, for the heat price and P2H share of the model, a sensitivity analysis is carried out where a lower CO_2 quota price is applied. The lower CO_2 quota price used is 119 DKK/ton CO_2 based on the 2019 price recommended by the Danish Energy Agency [2018b] for socio-economic calculations. The electricity spot price is not changed in this sensitivity analysis.

As seen from the results of the sensitivity analysis in Table 6.4, the lower CO_2 quota price generally results in less production hours for both the EB and the electric HP, thereby also lowering the P2H share of the system by 1 - 5 % depending on the scheme. This also causes the annual tariff expenses for both the EB and the electric HP to decrease, and thereby also causes the heat price to decrease by 19 - 20 DKK/MWh depending on the scheme.

Based on the results of the sensitivity analysis it can be seen that a higher CO_2 quota price results in an increase of the P2H share of the system. This is logical, since a higher CO_2 quota price increases the production price for natural gas based heating technologies, thereby increasing the number of hours in which it is less expensive to utilize P2H technologies.

6.6.2 Model without the natural gas heat pump

To evaluate how the DH system will operate if the HP is not able to run on natural gas but only on electricity, as is the case of most Danish DH systems who own a HP [Grøn Energi, 2017], the natural gas HP is excluded in this sensitivity analysis. The result of this can be seen in Table 6.4.

From the results it is clear that the HP by default opts for production based on natural gas rather than electricity, even with the included redesigned tariff schemes. According to Grøn Energi [2017], this is however not a familiar situation in most of the Danish DH systems, since natural gas HPs are not commonly installed in DH systems in Denmark.

There are no significant changes to the operation of the EB apart from a small decrease/increase in annual production hours of -1 - 18 hours. This is mostly because the EB rarely directly competes with the HP regardless of whether it is running on natural gas or electricity. It is primarily competing with the natural gas boilers as a peak load unit, therefore removing the natural gas HP does not influence that role significantly.

The electric HP on the other hand operates very differently in a system without a natural gas HP. In all the tested tariff schemes for this sensitivity analysis, the electric HP's annual production hours increases by 6,954 - 7,651 hours depending on the scheme. This results in the electric HP having more than 8,380 annual production hours for each scheme in the sensitivity analysis. This is due to the removal of the natural gas HP, which is the cheapest base-load production unit, apart from the solar thermal panels. Furthermore, the various increases in production hours for the electric HP results in the annual production hours for the electric HP being almost exactly equal among all the tested tariff schemes. This indicates that the tariff scheme does not influence the decision of whether to operate the electric HP or not. As a result of the increased heat production from the electric HP, the P2H share increases by 18 - 23 %.

Therefore, the tariff schemes tested in this study does not appear to unlock significant flexibility potentials for electric HPs in a similar system setting as Ringkøbing DH plant's, where the electric HP operates as a base-load production unit.

6.7 Key findings

In the following a summary of the key findings from the techno-economic analysis is presented. Key findings from the three different tariff schemes and their respective chosen levels are gathered below, along with important insights from the sensitivity analysis.

Flat rate tariff reduction of 40 %:

- Increases annual production hours by 47 % for the EB, while decreasing the annual tariff expense by 12 %.
- Increases annual production hours by 94 % for the electric HP, while increasing the annual tariff expense by 15 %.

Alt. TOU:

- Increases annual production hours by 22 % for the EB, while decreasing the annual tariff expense by 19 %.
- Increases annual production hours by 49 % for the electric HP, while decreasing the annual tariff expense by 0.1 %.

Dynamic tariff 30 % of spot price:

- Increases annual production hours by 69 % for the EB, while decreasing the annual tariff expense by 61 %.
- Increases annual production hours by 95 % for the electric HP, while decreasing the annual tariff expense by 21 %.

Sensitivity analysis - no Ngas HP included:

- The tested tariff schemes have almost no influence on the operation of the electric HP, thus failing to enable flexible operation.
- The altered system with no natural gas HP has very little influence on the EB in regard to the annual production hours and tariff expense.

The high efficiency and low marginal heat production cost of natural gas HPs reduce the incentive for DH systems to provide flexibility in the form of P2H operation. Natural gas

HPs do however function as a great source of flexibility at a local level, providing DH plants with an additional heat source.

In a system with an EB and electric HP and no natural gas HP, the EB and the electric HP does not react in the same way to the different tariff schemes. In such a system, the electric HP is not able to contribute with flexibility to the electricity grid and should therefore have its own form of flexibility enabling tariff scheme, e.g. a lower tariff payment for being interruptible in times of need.

From the results it is apparent that the current high fixed tariff payments hinder flexible operation of the EB; lowering these enables a greater potential for the integration of VRE and flexible operation. Looking at the results for the TOU tariff scheme alone, the effect appears to be very limited. Therefore, the TOU tariff scheme should be considered mostly as a bridging approach towards a dynamic tariff scheme, and not as a sufficient flexibility mechanism. The dynamic tariff scheme tested in this study enables the highest utilization of P2H technologies, while taking advantage of times with excess wind power production and low tariff rates as a result of low spot prices. The results therefore indicate that the dynamic tariff scheme enables the highest potential for flexibility of the system.

7 Barriers and dynamics of power-to-heat flexibility

In the following chapter barriers related to P2H flexibility are presented. These have been uncovered as a result of the conducted techno-economic analysis, interviews with various stakeholders, field visits and through literature; a methodological approach which is further described in Chapter 4.4. In Figure 7.1 the three focus areas of this study, from the innovative democracy approach presented in Chapter 3.4, Figure 3.5, can be seen along with the areas where various barriers seem to occur.

Figure 7.1: Barrier occurrences related to the main focus areas of this study of the innovative democracy approach.

In Figure 7.1 it is illustrated by the red crosses that the main barriers of P2H flexibility occur in two places. Firstly, barriers occur between the link of *indirect market policy* and *institutional market design*. This means that there are barriers related to introducing new tariff schemes and levels in the current institutional market design. It also means that there is a disconnect between the various new tariff schemes and levels and how they fit into the current institutional market design. Secondly, barriers occur in the link going towards the *goals of society*, since there is a disconnect between the current institutional market design and the goals of society. These barriers hinder the fulfillment of the goals of society, since the institutional market design is not capable of fulfilling these goals, due to the fact that the most favorable tariff schemes and levels, designed to fulfill the goals of society, are not implemented in the current institutional market design.

As previously mentioned in Chapter 4.4.1, interviews have been conducted as part of this study. The opinions and insights obtained from the interviews with stakeholders and organizations are used in this chapter to assess some of the most immediate and apparent barriers to P2H flexibility. In Figure 7.2 the organizations represented by interviewed stakeholders are categorized depending on whether they have direct influence, indirect influence or are simply subject to the institutional market design. It is important to keep in mind that Figure 7.2 does not represent an extensive overview of all organizations relevant to the topic of flexibility and DH. Instead, it is merely a categorization of the specific organizations involved in this study.

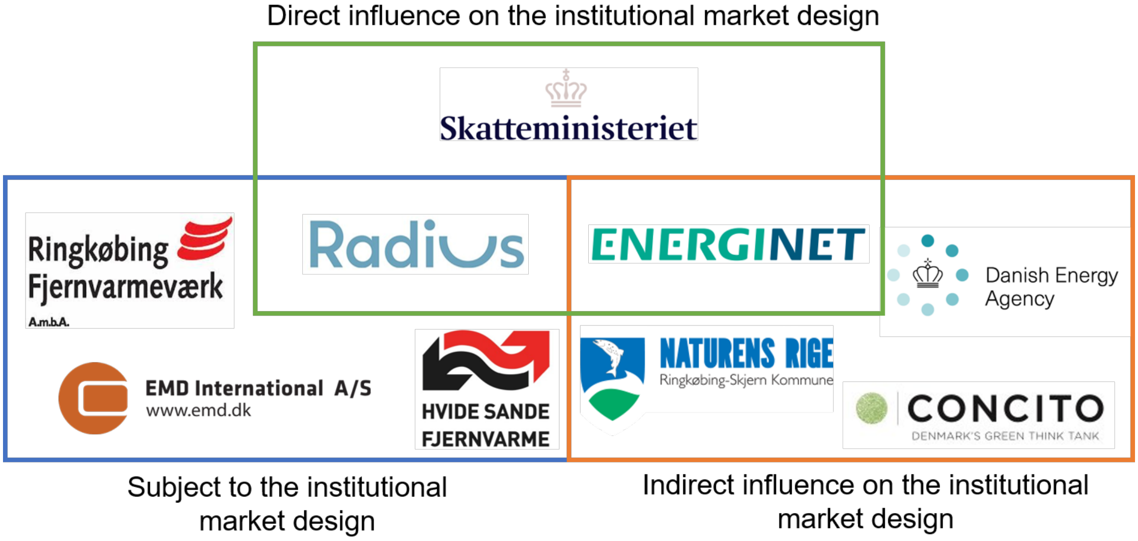


Figure 7.2: Organizations directly involved in discussions in this study on flexibility and DH, categorized according to their role and influence regarding institutional market design.

In Figure 7.2 three different boxes can be seen. It can also be seen that the *direct influence* box at the top of the figure, overlaps with both the *subject to* box and the *indirect influence* box. It can be seen that the Danish Ministry of Taxation (Skatteministeriet) is placed in the direct influence box. This is due to the fact that they have direct influence on changing tax and tariff levels and schemes within the institutional market design.

Furthermore, it can be seen that Radius and Energinet are also placed in the direct influence box, however, Radius is also placed in the subject to box and Energinet is also placed in the indirect influence box. Radius and Energinet both have direct influence on changing the tariff level and to some extent the tariff scheme, for the various tariff types which they control. However, Radius is also subject to the institutional market design and must adhere to any changes made by the Danish Ministry of Taxation, which are relevant to them. Energinet also has an indirect influence on the institutional market design e.g. in the form of research relevant for the market or as a part of research/focus groups for relevant changes to the institutional market design. An example of this is an ongoing project mentioned by Hansen [2019c] from the Danish Ministry of Taxation, conducted by a focus group consisting of Energinet alongside the Danish Ministry of Taxation and other parties.

Ringkøbing DH plant (Ringkøbing Fjernvarmeværk), Hvide Sande DH plant (Hvide Sande Fjernvarmeværk) and EMD International A/S are all subject to the institutional market design. They do not have any direct or indirect influence on the institutional market design, they are however subject to it. The two DH plants must pay and follow the tariff levels and schemes set by the local DSO, Energinet and the Danish Ministry of Taxation. EMD International A/S, partly being a consultancy firm, is also subject to the institutional market design, which they must use when consulting customers.

Finally, Ringkøbing-Skjern Municipality (Naturens Rige, Ringkøbing-Skjern Kommune), the Danish Energy Agency and Concito all have indirect influence on the institutional market design to some extent. Ringkøbing-Skjern Municipality are, according to Donslund [2019], in communication with the parliament and have ways of expressing wishes for changes or alterations to the institutional market design. The Danish Energy Agency are a part of the Danish Ministry of Energy, Utilities and Climate, however, they do not have direct influence on the institutional market design, their role is more of an administrative one and according to Hansen [2019c], they are also part of the previously mentioned research/focus group on future tariff schemes, along with the Danish Ministry of Taxation and Energinet. Concito brands themselves as "Denmark's green think tank" and offer research and opinions on climate change, greenhouse gas reduction and other similar topics to politicians [CONCITO, 2019]. They do therefore not have direct influence on the institutional market design but have indirect influence due to their communication with politicians.

An overview of how the organizations interviewed in this study relate to the institutional market design has now been presented. In the following, barriers related to P2H flexibility are presented and discussed to some extent, along with the opinions of stakeholders from the organizations seen in Figure 7.2

7.1 Lacking incentives for flexibility in district heating

The discussions with key stakeholders have outlined how the perception and need for flexibility differs widely depending on the context. The DH companies are primarily concerned with technology diversification and establishing a system that is resistant to future changes, e.g. price fluctuations for fuels and electricity, or regulatory changes, and considers that to be the main purpose of flexibility.

From the interviews with the DSO Radius and the TSO Energinet, the very local perception of flexibility from the DH companies collide with their focus as grid operators on balancing the electricity grid; two goals which as of current are not aligned. While the DH companies are capable of providing flexibility to a greater extent than what is currently happening, the incentive to actually do so is very limited.

Business-economic incentives

The techno-economic analysis in Chapter 6, found that the current electricity tax and tariff scheme limits the utilization of EBs in DH systems, and thus the incentive to invest in EBs, despite the potential for flexibility and integration of VRE. Similar findings can be seen in a study made by Nagel [2018], determining that reduced grid tariffs will significantly increase annual production hours for EBs, without reducing tariff income for the DSO.

On the topic of DH as a source of flexibility, Andersen [2019a] from EMD mentioned that *"As an energy systems advocate, I would prefer if DH companies invested in slightly larger production units and storage capacity so that fluctuations in wind production can be utilized better"*, indicating that the current tendency is sub-optimal, at least from an energy system perspective. This opinion is shared by Hansen [2019a] from Energinet, reinforcing the concern about DH companies investing in inflexible HPs for solely base-load operation.

Exemplifying the prevailing attitude among DH companies, Kristensen [2019] from Hvide Sande DH plant stated that *"I would rather operate a natural gas boiler at 400 DKK/MWh than invest in additional storage capacity or oversize a heat pump."* These conflicting statements highlight the disconnect between flexibility in an energy system perspective, as opposed to a local DH perspective. In essence, the DH companies are very capable of adjusting to the market structure to optimize business-economic operation, but since incorporating additional flexibility measures provides no business-economic incentives or long-term assurances, there is no desire to provide it.

Socio-economic incentives

In addition to the lack of business-economic incentive mechanisms, the assumptions for socio-economic assessments by the Danish Energy Agency [2018b] do not include flexibility as a societal benefit. The assumptions must be followed when DH companies seek approval for installing new production technologies or expanding their existing system. As such, these assumptions are very influential on the design of future DH systems.

The socio-economic assumptions include flexibility only in the context of determining what the applied socio-economic electricity price should be. Basically, for assessments conducted in accordance to these criteria, electricity production constitutes a socio-economic income, while electricity consumption constitutes a loss. How much of a profit or loss depends on what electricity price is applied, which again depends on the annual production hours of the specific production unit.

A flexible production unit consuming electricity for only a few hours annually can use a lower electricity price than an inflexible production unit consuming electricity for a majority of hours, resulting in a slightly lower economic loss to be included in the total project assessment. It is however still denoted as a loss. Furthermore, the socio-economic assumptions only include total annual production hours, disregarding time of operation or other energy system effects, based on the assumptions that extreme grid strains are distributed evenly throughout the year. In future energy systems with increasing VRE production and unpredictable production peaks, such assessment criteria could prove insufficient, and a need for greater recognition of flexibility enhancing technologies could emerge.

Socio-economy is traditionally a pivotal topic of energy planning, and also proved to divide the interviewed stakeholders in this study. Madsen [2019b] from Concito believes that to reach the RE goals, a break with the prevailing socio-economic principles is needed. *"My personal opinion is that, I do not at all believe we can reach the 2050 goal of zero net emissions based purely on socio-economic cost efficiency principles."* [Madsen, 2019b]. Hansen [2019c] from the Danish Ministry of Taxation and Hansen [2019a] from Energinet are however much more reserved to the thought of potentially implementing changes which could induce socio-economic losses. Going forward, balancing the need for business-economic incentives with societal costs will be critical towards realizing the RE goals and incorporating the needed flexibility measures.

7.2 Market development

Even though the tariff level differs according to the individual DSO, generally the tariff schemes does not. Currently, most of the DSOs in Denmark have a flat rate tariff scheme for their distribution tariffs. This does not open up new market possibilities for electricity consumers to be flexible. Generally, there is therefore no market where flexible electricity consumers can act and benefit from. This also means that generally there is no adequate market for flexibility, given the current institutional market design. However, as previously mentioned in Chapter 5.2.2, currently two Danish DSOs, Radius and Konstant, have implemented fixed TOU tariffs. This opens up possibilities for electricity consumers to be flexible to some extent. However, as seen from the results of the analysis in Chapter 6, the TOU tariff scheme and level currently implemented by Radius and Konstant does not significantly increase annual production hours for P2H technologies in a DH system. It is therefore not a sufficient change in tariff structure to incentivize P2H flexibility in a DH system setting.

Uneven distribution tariffs

Looking into the historic development of local electricity distribution tariffs, collected by the various DSOs in Denmark, it is clear that the price level of the distribution tariff differs quite significantly according to a comparison made by Danish Energy [2018b]. From this comparison it is also clear that the distribution tariff paid for electricity consumption in Ringkøbing-Skjern Municipality is higher than average in Jutland and in all of Denmark. According to Hansen [2019c] from the Danish Ministry of Taxation, *"Not all DSOs have been equally good at spending their money over the years. This has meant that some distribution electricity grids are better than others. Therefore, there are also different costs associated with the different areas and DSOs."*. However, according to Hansen [2019c], even in the light of this *"it is incomprehensible how large the difference is in tariff price levels throughout Denmark."*. It is therefore understandable that the distribution tariff levels differ for the various DSOs in Denmark, but it is hard to understand why they differ as much as they do according to Hansen [2019c].

Reacting to complex tariff schemes

Seen from a market development perspective, it is difficult to predict if any of the tested tariff schemes in Chapter 6 will be implemented in the future. As previously mentioned, fixed TOU tariff schemes are starting to be implemented by some DSOs, however, the time structure and level currently applied does not have much potential for changing the incentive to be flexible as a DH system. It is important to distinguish between electricity consumer types when assessing how they will react to a different tariff scheme. According to Madsen [2019a] from Radius, different customer types have different potentials for utilizing different tariff schemes, which vary in how complicated they are to understand and to react to. For example, when discussing the possibility of changing the tariff payment from DKK/kWh to DKK/kW, Madsen [2019a] thinks that *"A capacity tariff cannot be ruled out as a solution for large customers. Large customers are professional and are likely to understand a capacity tariff and will want to respond to it."*. Madsen [2019a] therefore believes that large customer types will be able to respond to complicated tariff schemes, however he does not believe payment in DKK/kW will be relevant to small-scale consumers.

The same tendency will likely also be true for other types of tariff scheme changes. According to Andersen [2019b] from Ringkøbing DH plant, they are used to reacting to different electricity markets and prices. An example of this is seen when they assess whether it is feasible or not to run their EB. They know that the price for electricity must not exceed a certain level before it is no longer feasible to operate the EB. Furthermore, they are also aware of different electricity markets which the EB can react to. According to Andersen [2019b], *"Our EB in Ringkøbing DH plant runs virtually only on special regulation bids"*. This was also observed at the site visit to Hvide Sande DH plant, where according to Kristensen [2019] they also mainly use their EB for special regulation bids. However, on the day of the site visit he was investigating if it could be feasible for the EB to run on the electricity spot market for a change. These insights into the knowledge and capability of DH operators provide a very positive outlook on whether large customer types, such as DH systems, are capable of handling and reacting to more complex tariff schemes in the future.

For all types of consumers, it is predicted that flat rate tariff schemes are easiest to understand and adhere to. Fixed TOU schemes are more complex and will require some simple control mechanisms to function properly, which would be realistic for large customer types to acquire. Finally, dynamic tariff schemes can be confusing and difficult to adhere to as an individual small-scale consumer. However, as previously mentioned, DH plants are better suited for such tariff schemes and with the right control systems and algorithms available, it is predicted that they will be able to understand and react to such schemes.

Special regulation

As previously mentioned, DH systems are aware of different electricity markets and are generally able to take advantage of them. This is especially apparent for how Ringkøbing and Hvide Sande DH plants run their EBs. As previously mentioned, they both mainly run their EBs on special regulation bids as opposed to the electricity spot market. This is problematic since the DH system operator focuses on how much money can be made from special regulation, which causes the EBs to have many hours out of operation, when they possibly could have run according to the spot market for a feasible spot price. This decreases the EBs annual operation hours and thereby acts as a barrier for increasing the P2H flexibility which EBs can provide.

Andersen [2019b] from Ringkøbing DH plant explains special regulation as when *"...the Danish TSO, Energinet, trades electricity with a German TSO, since in Germany there are problems with bottle necks from the electricity production from wind power in the north, which is not shut down, and the electricity consumption in the south of Germany. The German TSO then sells the excess electricity to Energinet as special regulation which is paid as bid."*. It can be discussed if it is problematic that Danish DH systems prioritize the use of their EBs to help the German electricity grid, before creating flexibility in the local or national electricity grid in Denmark. If one thinks of Denmark and the electricity interconnections to other countries, both current and planned connections, it is easy to forget why it is important to create flexibility locally as well as nationally. However, by focusing on firstly creating local flexibility which benefits a specific municipality, its neighbors or all of Denmark, it will likely help to reduce the costs for grid expansions within the country.

Special regulation also results in wind turbines being stopped to provide down regulation, something Donslund [2019] from Ringkøbing-Skjern Municipality finds especially unfortunate since it directly influences the achievement of the municipality's RE goals. Furthermore, since special regulation and the spot market are based on different principles and price mechanisms, at times wind turbines and EBs can win down regulation bids, while it is at the same time feasible to produce electricity on natural gas engines due to a high spot price.

DH companies follow the same tendencies

Finally, another barrier apparent for creating P2H flexibility is a tendency observed amongst DH systems, that they follow the same market development tendencies. This was pointed out by Kristensen [2019] from Hvide Sande DH plant, who thinks it is a shame that DH systems always seem to follow the same tendencies. This can be problematic if the changes, which the DH systems implement, are not in accordance with the goals of society. An example of this was observed when DH systems began to implement biomass boilers, since biomass was and still is exempted from tax, and is therefore a relative cheap fuel source. However, it is not desirable for society that the majority of DH systems produce heat from biomass, as biomass is a limited resource which should be prioritized in other sectors before being used for heat production [Mathiesen et al., 2012].

Another current example of a recent tendency for DH systems, is the implementation of HPs, a useful tendency for electrifying the heating sector. However, if there are no incentives for flexible operation of the HPs, a large expansion and integration of HPs in Danish DH systems can become a challenge for the electricity grid and for society. If the institutional market design for HPs does not change, HPs will continue to run solely as base-load units, which also means that they will have production hours in most of the year. This means that in some hours the HPs will help to increase P2H flexibility, however most of the time the HPs will be a burden to the electricity grid, demanding electricity in periods where not enough renewable electricity is produced and in periods where the electricity grid is already under pressure, due to a large electricity demand from the rest of society.

In research carried out by Energinet [2018], it is demonstrated how the electricity consumption will likely increase in 2035 and 2050 due to increased electricity consumption from data centers, electrification of the transport sector, power-to-gas and others solutions, which will possibly be utilized even more in the future. Furthermore, Energinet and Danish Energy have collaborated on research regarding prosumers in the future energy system, resulting in the need for electricity grid reinforcements or expansions, or a need for new methods for controlling the load on the electricity grid, by for example introducing some sort of dynamic tariffs [Energinet and Danish Energy, 2019]. Based on this research, it is apparent that there are expectations regarding an increased electricity demand in the future and thereby measures are needed to diminish the effect from this on the electricity grid. It can therefore be problematic that DH systems all follow the same general tendencies, if the institutional market design is not set up to fulfill the goals of society, in this case increasing flexibility between the electricity grid and DH systems.

Discussion 8

The following chapter will first discuss key aspects of the modelling approach applied in this study and how an alternative approach or assumptions could have produced additional results and insights. Afterwards, the challenges of designing future tariff schemes suitable for application in RE systems are discussed. Finally, a discussion follows on how the cost for grid maintenance can be recovered in flexible tariff schemes, in addition to the practical implementation and operation of dynamic tariff schemes in future energy systems.

8.1 Methodological discussion

After having carried out the techno-economic analysis in Chapter 6, there are various methodological choices which can be discussed. Two of these are the electricity spot price and the natural gas price, which are used in the energyPRO model representing Ringkøbing DH plant.

The electricity spot price series chosen to use is from 2018. Even though the average spot price for 2018 is analyzed and compared to previous years in Chapter 4.3.2 and it is seen that the average electricity spot price is higher than the average annual spot price from 2000 - 2018, the results from the model are not tested for an altered spot price series. This is not done for two main reasons, 1) being that the electricity production time series from wind power production in Ringkøbing-Skjern Municipality is only available for 2018, and would therefore not match a spot price time series from another year than 2018 and 2) that it is assumed that a lower average annual spot price would simply be beneficial for the annual P2H utilization share.

Likewise, a natural gas price is included in the energyPRO model, it has however not been changed in the energyPRO model to determine its influence on the results. This is not done, since it is assumed that a higher natural gas price will be beneficial for the annual P2H utilization share and a lower natural gas price will be beneficial for the natural gas-powered heating technologies.

Furthermore, the natural gas price used is provided by Andersen [2019b] from Ringkøbing DH plant and represents an estimation of the average annual natural gas price in 2018. From data regarding the monthly natural gas prices paid by Ringkøbing DH plant in 2018, it is observed that the lowest monthly natural gas price is 1.625 DKK/Nm^3 and the highest monthly natural gas price is 2.415 DKK/Nm^3, which includes a handling payment of 0.01 DKK/Nm^3. Furthermore, it is observed that in six of those months the monthly natural gas price is lower than 2.00 DKK/Nm^3 and in the other six months the natural gas price is higher than 2.00 DKK/Nm^3. From these known monthly price variations, the average monthly natural gas price is 2.031 DKK/Nm^3, which is simplified to 2.00 DKK/Nm^3 in the energyPRO model. A time series of the monthly natural gas prices could have been used in the energyPRO model as an alternative to the fixed fuel price. It is however not expected to have influenced the main results from the model significantly, since there is an even distribution of months with a lower and a higher natural gas price than the natural gas price used in the model.

Another methodological choice made of this study which also influences the techno-economic analysis in Chapter 6, is the choice of modelling one specific DH plant. This choice makes it possible to investigate how one specific DH plant will react to various tariff schemes, however, it does not give any insight in how other DH plants or other large electricity consuming industries will react. It can therefore only be assumed that DH plants with similar prerequisites, will react similarly to the various tariff schemes as Ringkøbing DH plant has.

Furthermore, it can be discussed which modelling scale or approach is most insightful for this study. As previously mentioned, the modelling scale for this study has been small scale, as one specific DH plant has been investigated. This can also be denoted as a bottom-up modelling approach. However, a top-down modelling approach could have been taken by investigating large scale rather than small scale. A large-scale model could possibly include all of Denmark and possibly some of its neighboring countries, which are also connected to the Danish electricity grid. This is done by Sandberg et al. [2019], where *"this study analyses how different electricity grid tariff structures affect flexible use of electricity in future Nordic district heating"*, where several countries are included, consisting of Denmark, Norway, Sweden and Finland. From this type of model approach and scale, it is possible to see what the general large-scale effects of various tariff schemes are, for DH systems in all four countries. There are however also more uncertainties associated with the results. For a more small scale, bottom-up approach, like the one used in this study, it is possible to acquire more precise and insightful results for one specific type of DH plant, where it is more difficult to acquire a broader result for the effect on DH systems in general.

8.2 Designing future flexible tariff schemes

An important takeaway from this study is the immense variety of possibilities for designing future tariff schemes and including all in this single study is simply not possible. However, from Chapter 7 there appears to be a consensus among key stakeholders that tariff schemes will become more differentiated and complex in the future. Thus, at least touching upon the array of possibilities which have not been specifically included in this study so far seems appropriate.

This study has only investigated tariff changes in the context of a DH plant, but other consumers, both large- and small-scale e.g. industries or private households, likely have very different consumption patterns. Therefore, the results of this study are likely unable to be transferred directly to other electricity consumers, where additional adaptations could be necessary to achieve the desired changes.

All three tariff schemes investigated in this study (flat rate, TOU, dynamic), could be further differentiated in the future if needed. Such differentiations could include differences in tariff rates for different technologies, consumer types, locations, or local grid congestion levels. As an example, areas primarily with vacation houses with highly seasonal electricity demands might require one scheme, while areas with solely permanent housing would require a different scheme. TOU tariff schemes could become increasingly complex following some of the previously mentioned differentiation possibilities, which could perhaps to some extent increase the correlation between VRE production and electricity consumption. However, the nature of TOU schemes and the fixed structure will inevitably limit the potential for flexibility as electricity demand, VRE production, and thus grid strains, become increasingly difficult to predict. Peaks are expected to occur as the wind blows, and accounting for this with a system based on either a fixed tariff or a predetermined scheme will be difficult.

The dynamic tariff scheme investigated in this study is based on the electricity spot price, an approach with both strengths and weaknesses. It is a simple approach which at least to DH companies is easy to understand and adhere to. A challenge with such a scheme is how adjustments in the average price from one year to another would be made. E.g. if the average spot price increases or decreases significantly from one year to another, should the dynamic tariff rate also increase or decrease? And how would this work in a real-life scenario, since in this study, the spot prices for the entire year are known in advance and an appropriate dynamic tariff rate can be designed accordingly. Therefore, the principle of a dynamic tariff, where the essential effect is lower rates during high VRE production, can be tested based on a correlation to the spot price and an appropriate tariff level can be chosen based on the spot prices for a given year. However, choosing a correct tariff rate will be difficult without the luxury of perfect foresight of the spot prices for a whole year.

Some of the challenges related to a dynamic tariff scheme being based solely on the electricity spot price could perhaps be mitigated by having a different dynamic parameter. Optimally, such a parameter would be able to consider the fluctuating VRE production and provide an incentive for flexible operation. One possibility would be to have dynamic tariffs based on either the gross or residual electricity demand. Danish Energy has based their TOU tariff structure, previously described in Chapter 5.2.2, on the gross electricity demand for the 50 kV and 10 kV grid, and on the residual electricity demand for the 0.4 kV grid [Danish Energy, 2016]. This data, either real time or projected, could then be used as a dynamic parameter. Such an approach could however be insufficient for low voltage areas, where very local grid constraints are often the main challenge, and instead a dynamic measurement of the current grid strain could prove to be necessary.

The tariff schemes currently deployed, and the schemes tested in this study, are based entirely on electricity consumption as a volumetric measure. Actors such as Madsen [2019b] from Concito and Jensen [2019] from the Danish Energy Agency have however expressed how future tariff schemes could include an additional component reflecting the connected effect, expressed in a payment per kW instead of kWh. Part of the argument as to why such an approach might be beneficial is the cost of grid expansion in a situation of capacity shortage, and thus payments should not be made only in accordance to electricity consumption but should also take connected electrical capacity into account. Such an approach could however prove detrimental to production units that would otherwise enable flexibility, such as EBs, of which the primary purpose is to connect a large electrical capacity for a short period of time.

Future tariff schemes, whether they are dynamic or otherwise flexible to some extent, will likely increase the complexity; not necessarily an exclusively positive development. In a recent report, Energinet outlines the difficulty of balancing complexity and simplicity when designing financial incentives. *"There is a need for financial incentives that do not increase complexity more than necessary but can continue to meet the essential cost-effective potentials to lower the need for reinforcement in the electricity distribution grid."* [Energinet and Danish Energy, 2019]. Tariff schemes should recover the capital needed to cover grid expenses while providing a cost reflective price signal but should at the same time remain simple enough for consumers to understand and adhere to them. If a tariff scheme becomes so complex that consumers are unable to understand and thus adjust their consumption accordingly, it will likely be an ineffective scheme.

8.3 Ensuring tariff income in a changed tariff structure

All grid tariffs are based on the same essential prerequisites of being cost-reflective and sustaining the income necessary to maintain and operate the electricity grid, which is also essential in future scenarios with alternative tariff schemes.

The findings of this study have shown that changing the tariff structure can significantly influence the tariff income for the TSO and the DSO. Especially the dynamic tariff structure resulted in a drastic reduction in tariff income for the EB, and therefore if implemented in a larger scale would result in a substantial economic deficit. Such a system is however in line with the perspectives presented in Section 5.2, regarding low marginal supply costs during hours with excess electricity. Therefore, an important question to raise based on these analyses is whether the EBs potential for integrating VRE should be hindered by high tariff rates during hours of excess electricity, or should this expense to a greater extent be recovered elsewhere?

An opposing opinion to when tariffs should be high is expressed by Bjørn [2019] from Energinet, who thinks that *"when there is a lot of wind power in the system and the electricity grid is strained, the tariffs should be high. It is at these times that there are costs associated with the load of the grid."*. Implementing this way of thinking is supposedly in accordance with the principle of the TOU tariffs tested in the techno-economic analysis in Chapter 6.3, since it is a simple attempt at reducing the electricity consumption in times where the electricity grid is supposedly strained. However, this way of thinking contradicts the method for which the dynamic tariffs are designed in this study.

In the dynamic tariff schemes implemented in Chapter 6.4, the tariff level is dependent on the spot price. The lower the spot price, the lower the tariff payment and vice versa. This introduces a different way of thinking than previously provided by Bjørn [2019]. By implementing these dynamic tariff schemes, the tariff payment is high when the spot price is high and low when the spot price is low. By using the simple assumption that the spot price is low when there is a lot of renewable electricity production in a given time period, the dynamic tariff schemes results in a low tariff payment when the electricity grid is potentially strained, due to renewable electricity production, and a high tariff payment when the electricity grid is not excessively strained, due to no or little renewable electricity production. This way of thinking emphasizes that it is important to use electricity when there is excess renewable electricity being produced and incentivizes this through low tariff levels.

Taking both ways of thinking into account, it is thought to be true that at times with a high renewable electricity production there are costs associated to the electricity grid. However, as proven with the two different ways of thinking, it is also shown how there are two different approaches to avoiding the effects of excess renewable electricity in the grid, 1) by increasing tariff levels to pay for the strain on the electricity grid or 2) by incentivizing consumers to use the electricity so that the electricity grid is no longer strained. By having different opinions and possibilities for how to react to a strained electricity grid, there will also be opposing opinions on whether it is acceptable that the total tariff payment is reduced in times of excess renewable electricity production, as is the case of the dynamic tariff scheme tested in Chapter 6.4.

Going forward, tariff schemes could be diversified to a greater extent than what is the case today. Flexible production units could be subject to one tariff scheme, while units unable to operate flexibly are subject to a different scheme. This would align well with the results from the sensitivity analysis in Chapter 6.6, in which it is apparent that the electric HP will rarely operate flexibly and should thus not necessarily benefit from a favorable flexibility enabling tariff scheme.

Reduced income from new tariff schemes can be negated in different ways, while still maintaining the price signal from tariffs as a flexibility enhancing mechanism. One way would be to charge a larger fixed payment, similarly to how DH companies typically charge both a subscription fee and a volume-based payment. A fixed payment would not influence the operation strategy for a DH system, or in other words, the decision whether to run a P2H technology. Such a system with larger fixed payments or subscription fees would likely be favorable to large industries, such as e.g. DH companies, however as argued by Hansen [2019c] from the Danish Ministry of Taxation, such undesired effects for certain actors could potentially be negated by increasing other taxes affecting the industry to negate the price change. However, this becomes a complicated line of changes to the market design and foreseeing all desired and potentially undesired effects of such changes becomes difficult.

Conclusion 9

The transition to RE systems entails an increase in variable electricity production, and integrating these fluctuations places an increased demand for creating flexibility in the energy system. This study has investigated whether redesigned tariff schemes can incentivize flexible operation of P2H technologies, to better enable DH plants to realize their potential for providing flexibility to the energy system.

To shed light on this challenge, first a techno-economic analysis has been conducted based on energyPRO modelling, determining the influence of redesigned tariff schemes on the operation of P2H technologies for Ringkøbing DH plant. Secondly, a qualitative barrier assessment has been conducted in which the opinions and perceived barriers of key stakeholders such as grid operators, DH plants, and governmental entities have been analyzed, to determine critical barriers inherent in the current institutional market design.

The techno-economic analysis tested three different tariff schemes and various tariff levels within these. The tariff schemes tested were a flat rate tariff scheme, a fixed TOU tariff scheme, and a dynamic tariff scheme with hourly variations. A more thorough rundown of the key findings and the differences between these are presented in Chapter 6.7, however the primary findings are included here as well.

The flat rate tariff reduction enabled a greater utilization of both the EB and the electric HP, while only incurring a limited decrease in tariff income to the DSO/TSO, due to an increase in production hours. The effect of fixed TOU tariffs proved to be much more limited on both P2H operation and tariff income to the DSO/TSO. It could however function as a suitable first step in the transition towards flexible tariff schemes due to ease of implementation and low risk change to grid operators. Finally, dynamic tariffs provided the greatest potential for P2H utilization and especially the EB was able to benefit from very low tariff rates during hours of operation. It did however also result in the largest decrease in tariff income to grid operators, and accurately designing such dynamic tariff schemes for the future appears to be a challenge. It is important to note that the potential for flexible operation of the electric HP relied on the presence of the natural gas HP. In the sensitivity analysis it was concluded that without the natural gas HP as an alternative, the price signal provided by electricity tariffs proved to be insufficient to influence the operation of the electric HP.

The qualitative assessment established a general agreement among stakeholders that there is a need for new flexibility mechanisms, and that redesigning tariff schemes will be an integral part of the future. However, significant discrepancies in perceptions and opinions exist among stakeholders regarding what comprises the pivotal barriers to increased system flexibility, and how future tariff schemes should be designed.

Possibly the most important barrier to increasing P2H flexibility in DH systems is the lacking business-economic incentives to do so and the lacking long-term assurances for DH companies to invest in flexible P2H technologies; a result of how the current market design does not incorporate or reward flexibility measures. This is also the case for socio-economic assessments in which flexibility aspects are not considered to any substantial extent. The current lucrative market for special regulation further hinders the incentive for flexible operation of EBs in particular, due to it being disconnected from the traditional spot market, and at times result in sub-optimal operation of both wind turbines, EBs, and CHP units.

The results of this study indicate that increasing P2H flexibility is feasible within a DH setting through the use of redesigned tariff schemes. It has been shown what the direct effects of the various tariff schemes and levels are for a specific DH plant, and it is assumed that the findings will be comparable for other DH plants with similar prerequisites as Ringkøbing DH plant. Similar DH plants will therefore also likely be able to increase their P2H share in a way that increases flexibility for both the heating and electricity sector, if similar types of tariff schemes are implemented.

It is clear that Danish DH plants constitute an immense potential for creating flexibility through the use of their P2H technologies and that it is possible to facilitate changes in their operation based on the tariff scheme, however, the extent of how much of their potential can be reached depends on to what extent the associated barriers can be solved. Redesigning tariff schemes can assist in unlocking greater flexibility in the Danish DH sector through the use of P2H technologies, however the potential should not be overestimated and continuously exploring new flexibility mechanisms will be important.

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Time series and external conditions A

In this appendix, the various time series regarding the external conditions, energy demands, and wind production used in the energyPRO model, are described.

A.1 Ambient temperature

The ambient temperature data used in the energyPRO model originates from the Design Reference Year (DRY) data made by the Danish Meteorological Institute (DMI) [Wang et al., 2013]. The ambient temperatures are listed in degrees Celsius. The data is derived from weather data from 2001 - 2010 from zone 1. Zone 1 consists of the west coast of Jutland. The weather data from zone 1 is measured at station 6080 located at Esbjerg Airport, located around 75 km south of Ringkøbing DH plant situated on Kongevejen 19, 6950 Ringkøbing. Ringkøbing DH plant is located in zone 1.

Because of using DRY data, the data used in the energyPRO model does not represent the specific ambient temperatures of 2018, instead it represents a temperature data set with the purpose of depicting a typical year. This is advantageous in this study, since it is not desired to model a year with possible extreme ambient temperatures, since those results will not be comparable with the results from a normal year. In Figure A.1, the hourly ambient temperatures used in the energyPRO model can be seen.

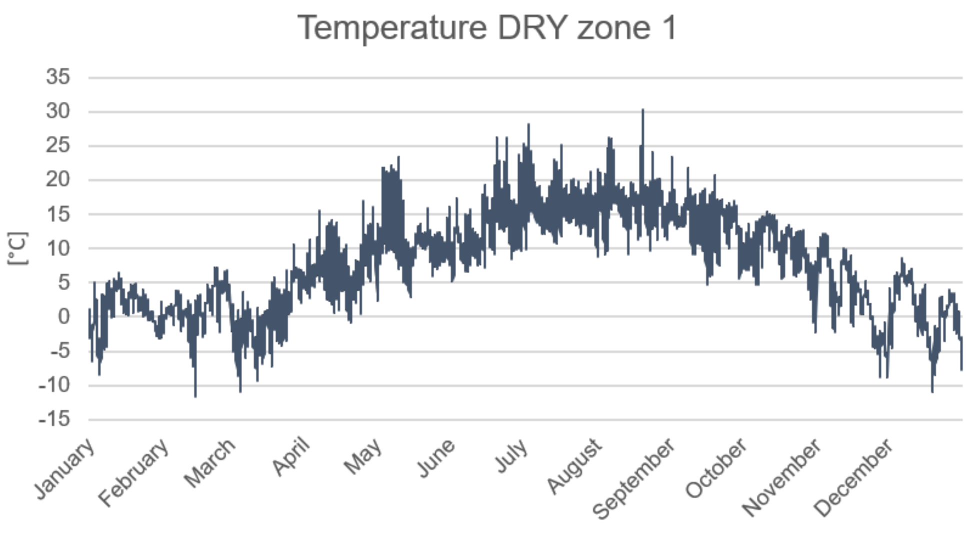

Figure A.1: DRY 2001-2010 zone 1 ambient temperature [Wang et al., 2013].

A.2 Solar radiation

The solar radiation data used in the energyPRO model also originates from the DRY data made by DMI [Wang et al., 2013]. The same advantages described in Section A.1 of using DRY data for the ambient temperatures are also valid for the solar radiation data.

The solar radiation is listed in W/m^2. The data consists of both diffuse and direct solar radiation. The data covers zone 2, which consists of the eastern, western and southern parts of Jutland and the western part of Funen. The DRY zones are different for the ambient temperature data and the solar radiation data. [Wang et al., 2013]

In Figure A.2, the various hourly solar radiation used in the energyPRO model can be seen.

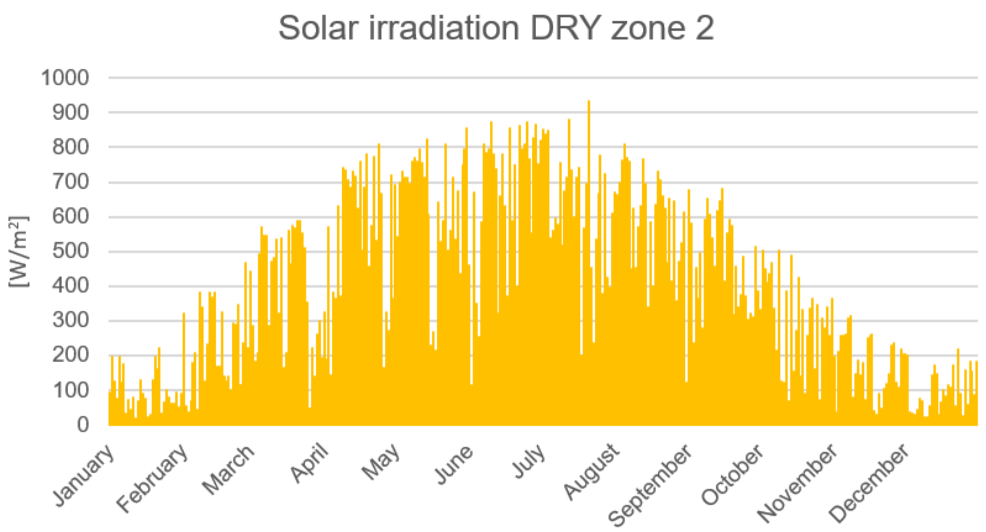

Figure A.2: DRY 2001-2010 zone 2 solar irradiation [Wang et al., 2013].

A.3 Heat demand

The hourly heat demand, which Ringkøbing DH plant must deliver to its consumers, is calculated based on the degree day method, used in the energyPRO model.

The annual heat demand which Ringkøbing DH plant delivered to its consumers in 2018 was 89,444.192 MWh excl. heat loss according to Andersen [2019b]. Using the degree day method enables calculation of hourly heat demand values. Input for this calculation include the annual heat demand, a time series of the hourly ambient temperatures, a dependent fraction of 70 % for space heating and 30 % for hot water [Danish Building Research Institute, 2009] and a reference temperature of 17 °C for when heating is needed. Furthermore, it is assumed that there is no space heating demand during the summer (June, July, August), but the demand for hot water remains the same. The degree day method calculation, used in the energyPRO model, is illustrated in Equation A.1.

$$\text{Hourly heat demand} = 0.8246\,\text{MW/degree} \cdot Max(17.0\,^{o}\text{C} - T_{\text{ambient}}(\_); 0) + 3.0632\,\text{MW} \tag{A.1}$$

In Equation A.1 the first part of the equation, 0.8246 MW/degree, is a factor which is calculated based on the annual heat demand for heating (70 % of the total annual heat demand) and the number of degree days during the year in the restriction period. The number of degree days during the year is calculated based on the hourly ambient temperature and the reference temperature of 17 °C. If the hourly ambient temperature is e.g. 10 °C, that specific hour counts for a 7 °C difference in temperature. That specific hour's contribution to the amount of degree days for that specific day is therefore:

$$\frac{7\,^{\circ}\mathrm{C}}{24\,\text{hours in a day}} = 0.29\,\text{degree days} \tag{A.2}$$

All the calculated hourly contributions to the amount of degree days for one day can then be added together to find the total amount of degree days for a specific day.

Furthermore, the second part of Equation A.1 finds the temperature difference for each hour of the time series T_{ambient}, for hours where the ambient temperature is below 17 °C. Finally, the third part of the equation consists of a constant, 3.0632 MW, which represents the hourly hot water demand, which is calculated based on the hourly heat demand for hot water divided by the number of hours in a year. Based on these three parts, the hourly heat demand for heating and hot water is calculated for all of 2018. The resulting hourly heat demand, which Ringkøbing DH plant must deliver to their consumers, is illustrated in Figure A.3.

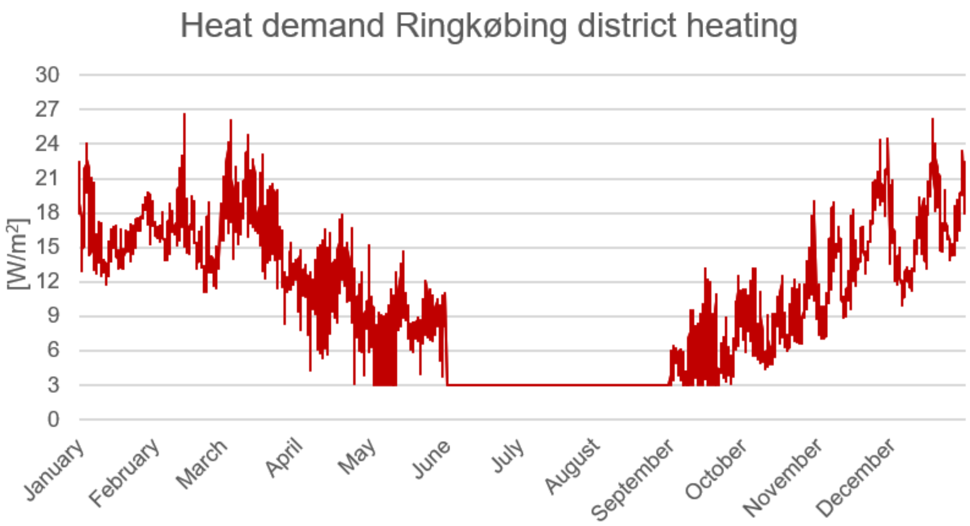

Figure A.3: Hourly heat demand for Ringkøbing DH plant's consumers in 2018.

From Figure A.3 it is illustrated how the hourly heat demand varies for 2018 based on the degree day method. It can be seen that during the months of June, July and August, the heat demand only covers the hot water demand, since it is assumed that there is no need for heating during the summer months.

A.4 Electricity demand

The hourly electricity demand for Ringkøbing-Skjern Municipality is modelled based on the monthly electricity consumption for Ringkøbing-Skjern Municipality for 2017. To convert this data to hourly values it is distributed according to the hourly electricity consumption from DK1 in 2017, supplied by Energinet. The 2018 data was not available during this study. This resulted in an approximation of the hourly demand for Ringkøbing-Skjern Municipality, which is used in the energyPRO model and can be seen in Figure A.4.

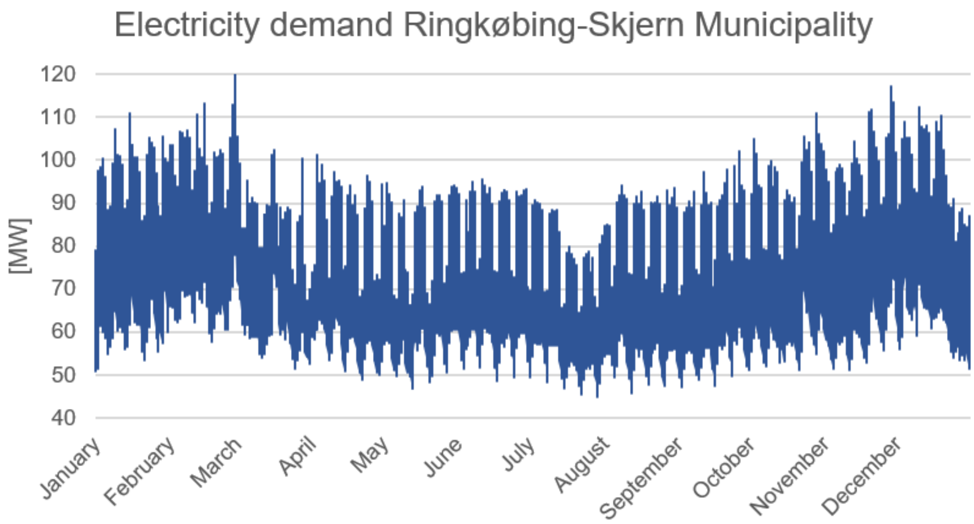

Figure A.4: Modelled electricity demand for Ringkøbing-Skjern Municipality.

A.5 Wind production

The hourly wind power production for wind turbines located in Ringkøbing-Skjern Municipality is generally not publicly available, however for this study Energinet has supplied an hourly data set for 2018. An illustration of this can be seen in Figure A.5.

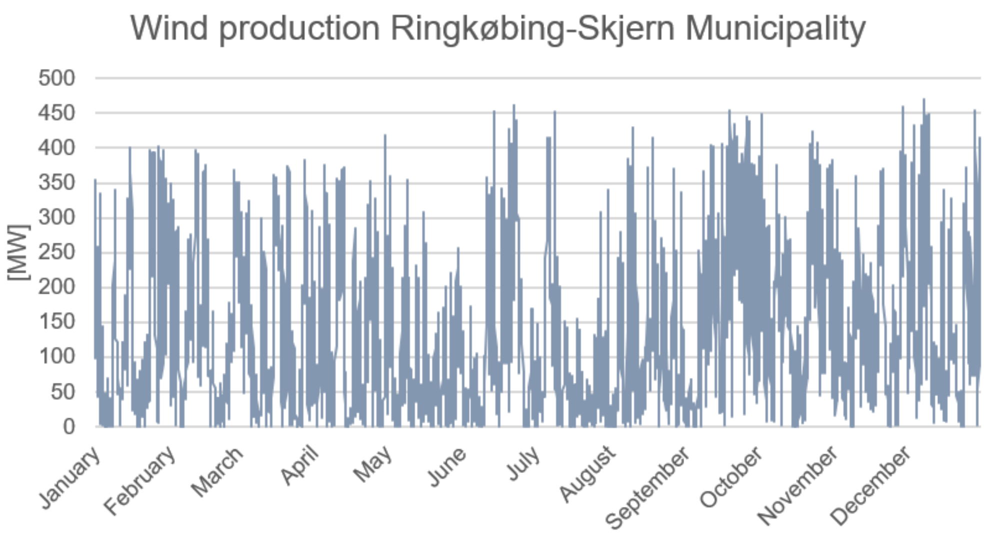

Figure A.5: Hourly wind power production in Ringkøbing-Skjern Municipality for 2018.

Production units and storage B

This appendix describes how the hybrid natural gas/electric HP, the solar heating and the thermal stores are modelled in the energyPRO model. The remaining technologies (natural gas CHP, natural gas boilers, and the EB) are not described in detail, however an overview of key parameters can be seen in Appendix C.

B.1 Heat pump modelling

The HP installed in Ringkøbing DH plant is an air to water HP capable of being powered by either natural gas or electricity, depending on which fuel/energy source is cheaper. Table B.1 provides an overview of how the efficiency and heat output varies according to the ambient temperature for both the natural gas and electric HP, according to the HP manufacturer Solid Energy A/S [2018]. The data from Table B.1 assumes a forward temperature of 70 °C.

	Natural gas HP		Electric HP	
Temp [°C]	**Efficiency COP**	**Production [MW]**	**Efficiency COP**	**Production [MW]**
-10	1.90	2.596	3.02	1.845
-8	1.93	2.774	3.09	1.987
-6	1.95	2.957	3.16	2.136
-4	1.98	3.146	3.24	2.293
-2	2.01	3.342	3.32	2.456
0	2.05	3.542	3.41	2.626
2	2.08	3.749	3.49	2.803
4	2.13	3.961	3.59	2.986
6	2.17	4.179	3.69	3.177
7	**2.19**	**4.291**	**3.74**	**3.275**
8	2.22	4.403	3.79	3.375
10	2.27	4.633	3.89	3.580
11	2.29	4.750	3.95	3.685
12	2.32	4.868	4.00	3.792
14	2.38	5.109	4.12	4.011
16	2.44	5.356	4.24	4.236
18	2.50	5.609	4.36	4.469
20	2.57	5.609	4.49	4.469

Table B.1: Output data for the hybrid electric/natural gas HP included in the energyPRO model. The data for the HP is supplied by the manufacturer, Solid Energy A/S [2018].

To model the HP in the energyPRO model, two production units are modelled, one powered by natural gas and the other powered by electricity. The operation of the two units is restricted to one unit at a time. The program Excel is used to produce time series for the heat output and fuel consumption, since these vary throughout the year depending on the ambient temperature due to it being an air to water HP. The data from Table B.1 is used to construct these time series for every hour of the year using linear interpolation and the hourly ambient temperature data described in Appendix A. The output, in the form of heat production, is a system output, meaning that energy consumption for defrosting and air-coolers is included, explaining why the heat production is higher at higher temperatures.

B.2 Solar heating

Solar heating included in the energyPRO model consists of solar heating 1 and 2, since the total capacity of solar heating is split up into two locations in Ringkøbing, located close to each other. Each solar heating location consists of 15,000 m^3 solar panels and each site is connected to a thermal storage tank.

The solar thermal panels installed in Ringkøbing DH are made by Arcon-Sunmark A/S and are of the HT model line. However, the specific model number is unknown, and it is instead assumed for this study that the solar thermal panels consist of HTHEATstore 35/10, which are flat plate solar thermal collectors for water heating. The technical specifications used in the energyPRO model regarding the solar panels can be seen in Table B.2.

Technical specifications for HTHEATstore 35/10		
Start efficiency (η_0)	0.737	-
Loss coefficient (a_1)	2.967	W/(m^2 °C)
Loss coefficient (a_2)	0.009	W/(m^2 °C)^2
Incidence angle modifier at 50° ($K_{\theta 50}$)	0.900	-

Table B.2: Technical specifications for the HTHEATstore 35/10 solar heating panel [SP Technical Research Institute of Sweden, 2016].

Furthermore, based on Andersen [2019b] the solar panels have an inclination of 30°. The inlet temperature to the solar thermal collectors on the collector side of the heat exchanger is around 40 °C and the outlet temperature from the collectors is around 75 C. Finally, there is a loss of 10 % in the pipes in the collector fields. [Andersen, 2019b]

Time series for the ambient temperature and the aggregated solar radiation used for modelling the solar thermal collectors is described in Appendix A.

To test the effect of modelling the solar thermal collector fields based on some of the other HT collector models, such as the HTHEATstore 35/08, the technical specifications of these were inserted and the results compared. The difference did however end up being negligible.

B.3 Thermal storage

Three thermal storage tanks are included in Ringkøbing's DH system, one large tank of 250 MWh at the Rindum location and two smaller tanks of 75 MWh each at the two solar collector locations. The technical specifications used in the energyPRO model regarding the thermal storage tanks can be seen in Table B.3.

Technical specifications	**Thermal store 250 MWh**		**Thermal store 75 MWh**	
Volume	5,000	m^3	1,500	m^3
Height	22	m	22	m
Insulation thickness	300	mm	400	mm
Storage temperature, top	89	°C	80	°C
Storage temperature, bottom	45	°C	36	°C
Thermal conductivity, insulation	0.037	W/(m°C)	0.037	W/(m°C)
Utilization	98	%	99	%

Table B.3: Technical specifications regarding the two types of thermal storage tanks included in Ringkøbing's DH system, provided by Andersen [2019b].

Furthermore, according to Andersen [2019b] all the heating technologies in Ringkøbing's DH system are able to store heat in any of the three thermal storage tanks.

EnergyPRO: technical and economic assumptions C

This appendix includes information regarding the assumptions for the energyPRO model directly from energyPRO. This information consists of:

- Catalogue of technical assumptions.
- Catalogue of economic assumptions.

The catalogues of technical- and economic assumptions are only included for the energyPRO model representing the Reference scenario. This is done, since the majority of the technical and economic assumptions are the same for the various different scenarios of the model which have been tested in Chapter 6. The various tariff schemes and levels vary for the different scenarios, however these variations are described in Chapter 5.2. The annual and fixed operation and maintenance costs for the various technologies included in the energyPRO model originates from the Danish Energy Agency [2016].

Furthermore, an assumption regarding the CO_2 quota price has been made. The CO_2 quota price is set to 200 DKK/ton CO_2 in the energyPRO model. The specific chosen CO_2 quota price is from 18-04-2019 based on European Energy Exchange [2019] and based on a currency exchange rate of 7.46 DKK/EUR from 13-03-2019 based on EuroInvestor [2019]. In Figure C.1 the historic CO_2 quota prices from 2017 - 2019 can be seen.

Figure C.1: Historic CO_2 quota prices from 2017 - 2019 [Ørsted, 2019].

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Catalogue of technical assumptions

1 Project Description

EnergyPRO model of Ringkøbing DH plant, Reference scenario.

2 External Conditions

Planning period: 01-2018 - 12-2018

2.1 Timeseries

DK1 Spotpriser 2018
Symbol:DK1Spot18

	[DKK/MWh] Average	Minimum	Maximum
January, 2018	229.01	-111.65	427.49
February, 2018	281.73	-36.62	549.03
March, 2018	282.37	-90.27	695.89
April, 2018	267.57	0.22	484.01
May, 2018	260.34	0.97	491.52
June, 2018	334.37	0.37	1,072.80
July, 2018	388.54	17.44	498.44
August, 2018	414.89	137.41	640.66
September, 2018	372.05	-50.65	681.10
October, 2018	354.22	-37.06	840.52
November, 2018	403.21	186.63	957.08
December, 2018	348.65	-73.91	624.83
All Period	**328.30**	**-111.65**	**1,072.80**

Time series moved on week basis

DRY 2001 2010 temperature zone 1
Symbol:Toutdoor2018

	[C] Average	Minimum	Maximum
January, 2018	1.1	-8.4	6.4
February, 2018	1.4	-11.6	7.2
March, 2018	0.1	-10.9	10.6
April, 2018	7.2	-0.9	16.9
May, 2018	11.8	2.3	23.4
June, 2018	13.8	5.2	26.3
July, 2018	17.0	9.9	28.1
August, 2018	17.1	8.8	30.3
September, 2018	14.1	4.7	23.4
October, 2018	10.0	-2.3	15.4
November, 2018	3.0	-8.9	12.1
December, 2018	0.9	-11.0	8.6
All Period	**8.2**	**-11.6**	**30.3**

Time series moved on week basis

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Wind production Ringkøbing Skjern 2018
Symbol:Wp2018

	[MWh]		
	Average	Minimum	Maximum
January, 2018	137.143	0.002	402.161
February, 2018	141.351	0.002	397.420
March, 2018	133.777	0.000	383.392
April, 2018	122.855	0.001	417.636
May, 2018	82.821	0.002	359.462
June, 2018	128.617	0.002	461.930
July, 2018	89.178	0.001	452.582
August, 2018	110.796	0.001	428.951
September, 2018	184.461	0.001	454.334
October, 2018	177.083	0.012	449.480
November, 2018	145.442	0.001	459.996
December, 2018	164.258	0.025	469.479
All Period	**134.636**	**0.000**	**469.479**

Time series moved on week basis

Electricity consumption RKSK
Symbol:EC_RKSK

	[MWh]		
	Average	Minimum	Maximum
January, 2018	79.596	50.855	110.816
February, 2018	85.196	57.698	120.260
March, 2018	74.709	0.000	105.397
April, 2018	73.347	49.011	101.209
May, 2018	71.094	46.857	94.631
June, 2018	73.228	48.600	95.701
July, 2018	66.644	44.998	90.863
August, 2018	71.372	45.741	94.236
September, 2018	72.488	47.200	102.162
October, 2018	78.101	51.075	110.853
November, 2018	80.189	51.261	117.272
December, 2018	80.489	51.566	112.439
All Period	**75.467**	**0.000**	**120.260**

Time series moved on week basis

Samlet solindstråling_ DRY_ zone 2_ det østlige_ vestlige og sydlige Jylland_ vestlige Fyn
Symbol:Rad_DRY_6065

	[W/m2]		
	Average	Minimum	Maximum
January, 2010	16	0	222
February, 2010	45	0	467
March, 2010	101	0	589
April, 2010	167	0	809
May, 2010	208	0	856
June, 2010	224	0	873
July, 2010	206	0	932
August, 2010	180	0	808
September, 2010	126	0	681
October, 2010	68	0	502
November, 2010	30	0	313
December, 2010	17	0	217
All Period	**116**	**0**	**932**

Time series moved on week basis

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Catalogue of technical assumptions

Elec HP heat production
Symbol:E_HP_HP

	[MW] Average	Minimum	Maximum
January, 2018	2.775	1.894	3.266
February, 2018	2.807	1.598	3.341
March, 2018	2.682	1.663	3.656
April, 2018	3.344	2.590	4.240
May, 2018	3.762	2.886	4.842
June, 2018	3.949	3.155	5.111
July, 2018	4.250	3.591	5.278
August, 2018	4.258	3.489	5.482
September, 2018	3.975	3.109	4.842
October, 2018	3.596	2.460	4.101
November, 2018	2.952	1.848	3.795
December, 2018	2.754	1.653	3.470
All Period	**3.429**	**1.598**	**5.482**

Time series moved on week basis

Elec HP elec consumption
Symbol:E_HP_EC

	[MW] Average	Minimum	Maximum
January, 2018	0.794	0.626	0.872
February, 2018	0.799	0.557	0.883
March, 2018	0.776	0.573	0.925
April, 2018	0.881	0.764	0.996
May, 2018	0.937	0.814	1.058
June, 2018	0.960	0.856	1.084
July, 2018	0.996	0.917	1.099
August, 2018	0.996	0.903	1.116
September, 2018	0.964	0.849	1.058
October, 2018	0.916	0.741	0.980
November, 2018	0.819	0.616	0.943
December, 2018	0.788	0.571	0.901
All Period	**0.886**	**0.557**	**1.116**

Time series moved on week basis

Ngas HP heat production
Symbol:Ngas_HP_HP

	[MW] Average	Minimum	Maximum
January, 2018	3.698	2.690	4.261
February, 2018	3.735	2.350	4.346
March, 2018	3.591	2.425	4.707
April, 2018	4.350	3.486	5.376
May, 2018	4.829	3.826	6.066
June, 2018	5.042	4.134	6.373
July, 2018	5.387	4.633	6.564
August, 2018	5.397	4.516	6.798
September, 2018	5.072	4.081	6.066
October, 2018	4.638	3.338	5.216
November, 2018	3.901	2.637	4.866
December, 2018	3.674	2.414	4.495
All Period	**4.447**	**2.350**	**6.798**

Time series moved on week basis

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Ngas HP fuel consumption
Symbol:Ngas_HP_FC

	[MW] Average	Minimum	Maximum
January, 2018	1.765	1.429	1.929
February, 2018	1.776	1.297	1.952
March, 2018	1.730	1.327	2.045
April, 2018	1.950	1.702	2.203
May, 2018	2.072	1.806	2.348
June, 2018	2.123	1.894	2.407
July, 2018	2.203	2.026	2.443
August, 2018	2.205	1.997	2.485
September, 2018	2.131	1.879	2.348
October, 2018	2.025	1.655	2.167
November, 2018	1.820	1.409	2.084
December, 2018	1.755	1.323	1.991
All Period	**1.964**	**1.297**	**2.485**

Time series moved on week basis

2.2 Indexes

No INDEXES is defined

3 Fuels

Natural gas 11.0000 kWh/Nm3

4 Demands

4.1 Heat demands

Demands
Heat Demand Ringkøbing: Symbol: HD1
Heat loss Ringkøbing: Symbol: HD7

Demand	**amount**	**Development**
Heat Demand Ringkøbing:	89,444,192 kWh	Not developing over the years
Heat loss Ringkøbing:	24,768,747 kWh	Not developing over the years
Total	**114,213 MWh**	

Demand		**Max demand**	**Min demand**
Heat Demand Ringkøbing	[kW]	26,648.1	3,063.2
Heat loss Ringkøbing	[kW]	2,827.5	2,827.5

Heat demands, Details

Heat Demand Ringkøbing:
Demand is fixed
Fraction of demand depending on Weather: 70.00 %
Reference temperature: 17.0 [°C]
Dependent Demand 0.8246MW/Degree
Formula for daily weather ratios Max(17.0-Toutdoor2018(_);0)
Independent Demand 3.0632 MW
Season for weather dependency: 01-09 to 31-05

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28-05-2019 10:48:31 / 5
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Heat loss Ringkøbing:

Monthly amounts

	kWh
January	2,103,647.00
February	1,900,068.38
March	2,103,647.00
April	2,035,787.50
May	2,103,647.00
June	2,035,787.50
July	2,103,647.00
August	2,103,647.00
September	2,035,787.50
October	2,103,647.00
November	2,035,787.50
December	2,103,647.00

5 Energy units

CHP Rindum Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [MW]	Heat[MW]	Heat [%]	Electric power [MW]	Electric power [%]
1	20.2	10.5	52.0	8.8	43.6

Boiler 1 Ringkøbing Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [kW]	Heat[kW]	Heat [%]
1	6,250.0	6,500.0	104.0

Boiler 2 Ringkøbing Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [kW]	Heat[kW]	Heat [%]
1	9,615.0	10,000.0	104.0

Boiler 1 Rindum Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [kW]	Heat[kW]	Heat [%]
1	9,615.0	10,000.0	104.0

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Boiler 2 Rindum Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [kW]	Heat[kW]	Heat [%]
1	10,310.0	10,000.0	97.0

Electric boiler Rindum Plant
Fuel type: (no fuel)

Min. Operation time: 0 hours

	Heat[MW]	Electric consumption [MW]
1	12.0	12.0

Heat pump Ngas Rindum Plant
Fuel type: Natural gas

Min. Operation time: 0 hours

	Fuel [MW]	Heat[MW]	Heat [%]
1	Formula	Formula	0.0

Formula, fuel (loadcurve 1):
Ngas_HP_FC(_)
Formula, heat (loadcurve 1):
Ngas_HP_HP(_)

Operation only allowed when no Production on unit: Heat pump Elec Rindum Plant

Heat pump Elec Rindum Plant
Fuel type: (no fuel)

Min. Operation time: 0 hours

	Heat[MW]	Electric consumption [MW]
1	Formula	Formula

Formula, heat (loadcurve 1):
E_HP_HP(_)
Formula, electricity consumption (loadcurve 1):
E_HP_EC(_)

Operation only allowed when no Production on unit: Heat pump Ngas Rindum Plant

Solar heating 1
Area and orientation
Total collector area 15000 [m²]
Latitude: 57 [°]
Inclination: 30 [°]
Orientation: 0 [°]

Time series
Aggregated radiation: Samlet solindstråling_ DRY_ zone 2_ det østlige_ vestlige og sydlige Jylland_ vestlige Fyn
Ambient temperatures: DRY 2001 2010 temperature zone 1

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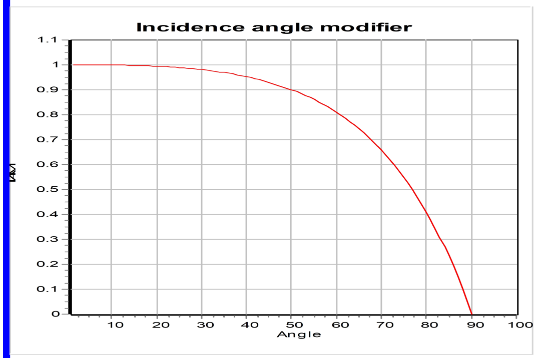
Catalogue of technical assumptions



Collector specification

Conversion factor (N0)	0.737
Loss coefficient (a0)	2.067 [W/m²°C]
Loss coefficient (a1)	0.009 [W/(m²°C)²]

Incident angle modifier	
-Coefficient a	3
-K-Theta at 50 degree	0.900
Collector forward temperature	75 [°]
Collector return temperature	40 [°]

Solar heating 2
Area and orientation

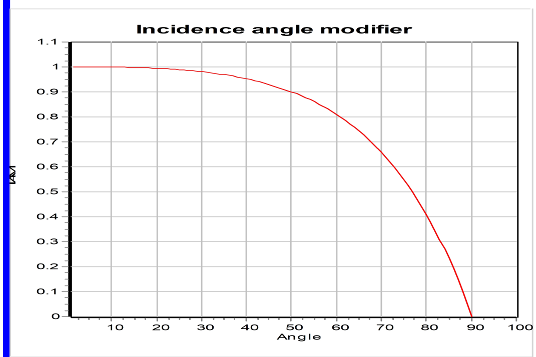
Total collector area	15000 [m²]
Latitude:	57 [°]
Inclination:	30 [°]
Orientation:	0 [°]

Time series

Aggregated radiation:	Samlet solindstråling_ DRY_ zone 2_ det østlige_ vestlige og sydlige Jylland_ vestlige Fyn
Ambient temperatures:	DRY 2001 2010 temperature zone 1

Collector specification

Conversion factor (N0)	0.737
Loss coefficient (a0)	2.067 [W/m²°C]
Loss coefficient (a1)	0.009 [W/(m²°C)²]



Incident angle modifier	
-Coefficient a	3
-K-Theta at 50 degree	0.900
Collector forward temperature	75 [°]
Collector return temperature	40 [°]

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Catalogue of technical assumptions

5 Storages

Heat storage Solar heating 1

Net volume:	1,500.0 [m3]
Temperature difference:	44.0 [°C]
Utilization:	99.0 [%]
Min Operation storage content:	0.0 [%]
Capacity:	75.7 [MWh]

Heat storage Solar heating 2

Net volume:	1,500.0 [m3]
Temperature difference:	44.0 [°C]
Utilization:	99.0 [%]
Min Operation storage content:	0.0 [%]
Capacity:	75.7 [MWh]

Heat storage Rindum

Net volume:	5,000.0 [m3]
Temperature difference:	44.0 [°C]
Utilization:	98.0 [%]
Min Operation storage content:	0.0 [%]
Capacity:	249.8 [MWh]

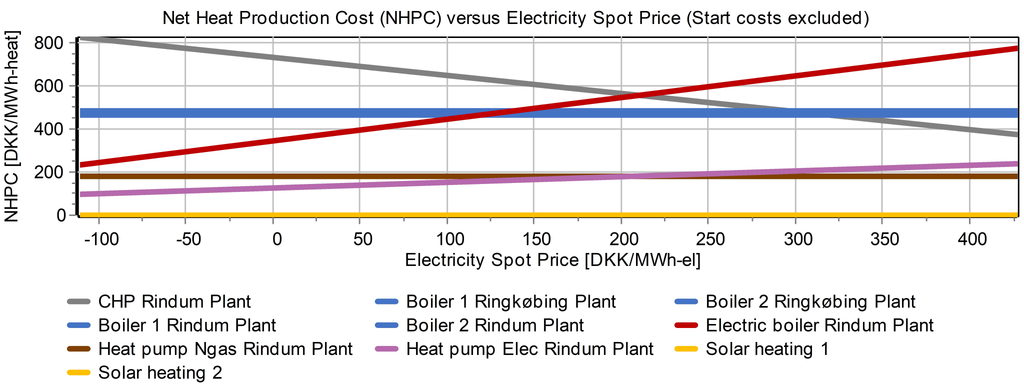
6 Electricity market

Spot market

Name of Extern time-series:	DK1 Spotpriser 2018
Name of Prognosis time-series:	DK1 Spotpriser 2018

7 Operation strategy

Operation Strategy is Calculated as Net Heat Production Costs



Note: Graph shows first month in calculation

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Catalogue of technical assumptions

Production to store allowed

CHP Rindum Plant	Yes
Boiler 1 Ringkøbing Plant	Yes
Boiler 2 Ringkøbing Plant	Yes
Boiler 1 Rindum Plant	Yes
Boiler 2 Rindum Plant	Yes
Electric boiler Rindum Plant	Yes
Heat pump Ngas Rindum Plant	Yes
Heat pump Elec Rindum Plant	Yes
Solar heating 1	Yes
Solar heating 2	Yes

Partial load allowed

CHP Rindum Plant	Yes
Boiler 1 Ringkøbing Plant	Yes
Boiler 2 Ringkøbing Plant	Yes
Boiler 1 Rindum Plant	Yes
Boiler 2 Rindum Plant	Yes
Electric boiler Rindum Plant	Yes
Heat pump Ngas Rindum Plant	Yes
Heat pump Elec Rindum Plant	Yes
Solar heating 1	Yes
Solar heating 2	Yes

Operation strategy mode

CHP Rindum Plant	Calculated
Boiler 1 Ringkøbing Plant	Calculated
Boiler 2 Ringkøbing Plant	Calculated
Boiler 1 Rindum Plant	Calculated
Boiler 2 Rindum Plant	Calculated
Electric boiler Rindum Plant	Calculated
Heat pump Ngas Rindum Plant	Calculated
Heat pump Elec Rindum Plant	Calculated
Solar heating 1	Calculated
Solar heating 2	Calculated

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Catalogue of economic assumptions

1 Project Description

EnergyPRO model of Ringkøbing DH plant, Reference scenario.

2 External Conditions

Currency: DKK

3 Payments

3.1 Revenues

Electricity production
Electricity production CHP Rindum V DK1Spot18(_) DKK/MWh

3.2 Operating Expenditures

Fuel costs	
Natural gas	2.0000 DKK/Nm3
Taxes and tariffs	
Natural gas boilers	
Energy tax	166.6800 DKK/MWh
CO2 tax	49.6800 DKK/MWh
NOx tax	0.0080 DKK/Nm3
Natural gas CHP	
Energy tax V_formel	2.1990 DKK/Nm3
CO2 tax V_formel	0.3910 DKK/Nm3
NOx tax	0.0290 DKK/Nm3
Methane tax	0.0670 DKK/Nm3
Feed in tariff	3.0000 DKK/MWh
Electric boilers	
Electricity tax EB	219.0000 DKK/MWh
Transmission tariff EB	44.0000 DKK/MWh
System tariff EB	36.0000 DKK/MWh
Distribution tariff EB	38.6000 DKK/MWh
Heat pump Elec	
Electricity tax HP	259.0000 DKK/MWh
Transmission tariff HP	44.0000 DKK/MWh
System tariff HP	36.0000 DKK/MWh
Distribution tariff HP	38.6000 DKK/MWh
Heat pump Ngas	
Energy tax HP Ngas	2.1990 DKK/Nm3
CO2 tax HP Ngas	0.3910 DKK/Nm3
NOx tax HP Ngas	0.0080 DKK/Nm3
Ngas transmission costs	0.2954 DKK/Nm3
CO2 quotas	200.0000 DKK/ton CO2
OM costs	
Ngas motor	
Fixed OM Ngas motor	656,480.0000 DKK/Year
Variable OM Ngas motor	40.2000 DKK/MWh
Ngas boiler	
Fixed OM boiler	544,580.0000 DKK/Year
Variable OM boiler	8.2060 DKK/MWh
Heat pump	
Fixed OM HP	123,463.0000 DKK/Year
Variable OM HP electric	24.6180 DKK/MWh
Variable OM HP Ngas	59.6800 DKK/MWh
Electric boiler	
Fixed OM electric boiler	98,472.0000 DKK/Year
Variable OM electric boiler	5.9680 DKK/MWh

Electricity costs	
Electricity consumption electric boiler	DK1Spot18(_) DKK/MWh
Electricity consumption HP	DK1Spot18(_) DKK/MWh

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Catalogue of economic assumptions

APPENDIX: Formulas

Payment formulas

Electricity production	
Electricity production CHP Rindum V	EP(CHP Rindum Plant;All Periods)
Fuel costs	
Natural gas	ImportedFuel(Natural gas) / HeatValue(Natural gas)
Taxes and tariffs	
Natural gas boilers	
Energy tax	HP(Boiler 1 Ringkøbing Plant) + HP(Boiler 2 Ringkøbing Plant) + HP(Boiler 1 Rindum Plant) + HP(Boiler 2 Rindum Plant)
CO2 tax	HP(Boiler 1 Ringkøbing Plant) + HP(Boiler 2 Ringkøbing Plant) + HP(Boiler 1 Rindum Plant) + HP(Boiler 2 Rindum Plant)
NOx tax	((FC(Boiler 1 Ringkøbing Plant) + FC(Boiler 2 Ringkøbing Plant) + FC(Boiler 1 Rindum Plant) + FC(Boiler 2 Rindum Plant))) / HeatValue(Natural gas)
Natural gas CHP	
Energy tax V_formel	(HP(CHP Rindum Plant) / 1.2) / HeatValue(Natural gas)
CO2 tax V_formel	(HP(CHP Rindum Plant) / 1.2) / HeatValue(Natural gas)
NOx tax	FC(CHP Rindum Plant) / HeatValue(Natural gas)
Methane tax	FC(CHP Rindum Plant) / HeatValue(Natural gas)
Feed in tariff	EP(CHP Rindum Plant;All Periods)
Electric boilers	
Electricity tax EB	HP(Electric boiler Rindum Plant)
Transmission tariff EB	EC(Electric boiler Rindum Plant;All Periods)
System tariff EB	EC(Electric boiler Rindum Plant;All Periods)
Distribution tariff EB	EC(Electric boiler Rindum Plant;All Periods)
Heat pump Elec	
Electricity tax HP	EC(Heat pump Elec Rindum Plant;All Periods)
Transmission tariff HP	EC(Heat pump Elec Rindum Plant;All Periods)
System tariff HP	EC(Heat pump Elec Rindum Plant;All Periods)
Distribution tariff HP	EC(Heat pump Elec Rindum Plant;All Periods)
Heat pump Ngas	
Energy tax HP Ngas	(FC(Heat pump Ngas Rindum Plant) - ((0.5 * FC(Heat pump Ngas Rindum Plant)) / 0.67)) / HeatValue(Natural gas)
CO2 tax HP Ngas	FC(Heat pump Ngas Rindum Plant) / HeatValue(Natural gas)
NOx tax HP Ngas	FC(Heat pump Ngas Rindum Plant) / HeatValue(Natural gas)
Ngas transmission costs	(FC(CHP Rindum Plant) + FC(Boiler 1 Ringkøbing Plant) + FC(Boiler 2 Ringkøbing Plant) + FC(Boiler 1 Rindum Plant) + FC(Boiler 2 Rindum Plant) + FC(Heat pump Ngas Rindum Plant)) / HeatValue(Natural gas)
CO2 quotas	ImportedFuel(Natural gas) * 3.6 * 56.69 / 1000
OM costs	
Ngas motor	
Fixed OM Ngas motor	1 / 12
Variable OM Ngas motor	EP(CHP Rindum Plant;All Periods)
Ngas boiler	
Fixed OM boiler	1 / 12
Variable OM boiler	HP(Boiler 1 Ringkøbing Plant) + HP(Boiler 2 Ringkøbing Plant) + HP(Boiler 1 Rindum Plant) + HP(Boiler 2 Rindum Plant)
Heat pump	
Fixed OM HP	1 / 12
Variable OM HP electric	HP(Heat pump Ngas Rindum Plant) + HP(Heat pump Elec Rindum Plant)
Variable OM HP Ngas	FC(Heat pump Ngas Rindum Plant) / 2
Electric boiler	
Fixed OM electric boiler	1 / 12
Variable OM electric boiler	HP(Electric boiler Rindum Plant)
Electricity costs	
Electricity consumption electric boiler	EC(Electric boiler Rindum Plant;All Periods)
Electricity consumption HP	EC(Heat pump Elec Rindum Plant;All Periods)

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D EnergyPRO: energy conversion and operational income

In this appendix, information regarding the annual energy conversion and the operational income can been seen, supplied by the energyPRO model of the Reference scenario for Ringkøbing DH plant. This consists of energyPRO prints of:

- Energy conversion, annual.
- Operational income.

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Energy conversion, annual

Calculated period: 01-2018 - 12-2018

Heat demands:

Heat Demand Ringkøbing	89,444,192.0 kWh
Heat loss Ringkøbing	24,768,747.4 kWh
Total	114,212,939.4 kWh

Max heat demand	29.5 MW

Heat productions:

CHP Rindum Plant	25,641.4 MWh/year	
Boiler 1 Ringkøbing Plant	25,642.8 MWh/year	
Boiler 2 Ringkøbing Plant	12,124.5 MWh/year	
Boiler 1 Rindum Plant	41.5 MWh/year	
Boiler 2 Rindum Plant	0.0 MWh/year	
Electric boiler Rindum Plant	3,893.3 MWh/year	
Heat pump Ngas Rindum Plant	31,898.3 MWh/year	
Heat pump Elec Rindum Plant	2,444.1 MWh/year	
Solar heating 1	6,334.9 MWh/year	
Solar heating 2	6,334.9 MWh/year	
Heat Storage Loss (total for site)	-142.7 MWh/year	
Total	114,213.0 MWh/year	100.0%

Electricity produced by energy units:
Spot market:

	All periods [MWh/year]	Of annual production
CHP Rindum Plant	21,490.0	100.0%

Electricity consumed by energy units:
Spot market:

	Of annual [MWh/year]
Electric boiler Rindum Plant	3,893.3
Heat pump Elec Rindum Plant	640.6
Total	4,533.9

Peak electric production:

CHP Rindum Plant	8,800.0 kW-elec.

Hours of operation:
Spot market:

	Total [h/Year]	Of annual hours
CHP Rindum Plant	2,451.0	28.0%
Electric boiler Rindum Plant	326.0	3.7%
Heat pump Elec Rindum Plant	734.0	8.4%
Out of total in period	8,760.0	

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Energy conversion, annual

Production unit(s) Not connected to electricity market:

	Total [h/Year]	Of annual hours
Boiler 1 Ringkøbing Plant	3,953.0	45.1%
Boiler 2 Ringkøbing Plant	1,224.0	14.0%
Boiler 1 Rindum Plant	5.0	0.1%
Boiler 2 Rindum Plant	0.0	0.0%
Heat pump Ngas Rindum Plant	7,257.0	82.8%
Solar heating 1	2,098.0	23.9%
Solar heating 2	2,098.0	23.9%
Out of total in period	8,760.0	

Turn ons:

CHP Rindum Plant	251
Boiler 1 Ringkøbing Plant	9
Boiler 2 Ringkøbing Plant	12
Boiler 1 Rindum Plant	0
Boiler 2 Rindum Plant	0
Electric boiler Rindum Plant	58
Heat pump Ngas Rindum Plant	191
Heat pump Elec Rindum Plant	121
Solar heating 1	332
Solar heating 2	332

Full load operating hours:

CHP Rindum Plant	2,442
Boiler 1 Ringkøbing Plant	3,945
Boiler 2 Ringkøbing Plant	1,212
Boiler 1 Rindum Plant	4
Boiler 2 Rindum Plant	0
Electric boiler Rindum Plant	324
Heat pump Ngas Rindum Plant	5,989
Heat pump Elec Rindum Plant	591
Solar heating 1	800
Solar heating 2	800

Fuels:

By fuel

	Fuel consumption
Natural gas	9,075,320.6 Nm3

By energy unit

CHP Rindum Plant	49,329.2 MWh	=4,484,476.3	Nm3
Boiler 1 Ringkøbing Plant	24,656.5 MWh	=2,241,502.5	Nm3
Boiler 2 Ringkøbing Plant	11,657.7 MWh	=1,059,792.2	Nm3
Boiler 1 Rindum Plant	39.9 MWh	=3,626.6	Nm3
Boiler 2 Rindum Plant	0.0 MWh	=0.0	Nm3
Electric boiler Rindum Plant	0.0 MWh	=0.0	----
Heat pump Ngas Rindum Plant	14,145.2 MWh	=1,285,922.9	Nm3
Heat pump Elec Rindum Plant	0.0 MWh	=0.0	----
Solar heating 1	0.0 MWh	=0.0	----
Solar heating 2	0.0 MWh	=0.0	----
Total	99,828.5 MWh		

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Operation Income from 01-01-2018 00:00 to 31-12-2018 23:59

(All amounts in DKK)

Revenues								
Electricity production								
Electricity production CHP Rindu	:	21,490.0 MWh	at	408.74*	=	8,783,804		
Electricity production Total							**8,783,804**	
Total Revenues								**8,783,804**
Operating Expenditures								
Fuel costs								
Natural gas	:	9,075,320.6 Nm3	at	2.0	=	18,150,641		
Fuel costs Total							**18,150,641**	
Taxes and tariffs								
Natural gas boilers								
Energy tax	:	37,808.8 MWh	at	166.68	=	6,301,968		
CO2 tax	:	37,808.8 MWh	at	49.68	=	1,878,341		
NOx tax	:	3,304,921.4 Nm3	at	0.008	=	26,439		
Natural gas boilers Total							**8,206,748**	
Natural gas CHP								
Energy tax V_formel	:	1,942,533.0 Nm3	at	2.199	=	4,271,630		
CO2 tax V_formel	:	1,942,533.0 Nm3	at	0.391	=	759,530		
NOx tax	:	4,484,476.3 Nm3	at	0.029	=	130,050		
Methane tax	:	4,484,476.3 Nm3	at	0.067	=	300,460		
Feed in tariff	:	21,490.0 MWh	at	3.0	=	64,470		
Natural gas CHP Total							**5,526,140**	
Electric boilers								
Electricity tax EB	:	3,893.3 MWh	at	219.0	=	852,633		
Transmission tariff EB	:	3,893.3 MWh	at	44.0	=	171,305		
System tariff EB	:	3,893.3 MWh	at	36.0	=	140,159		
Distribution tariff EB	:	3,893.3 MWh	at	38.6	=	150,281		
Electric boilers Total							**1,314,378**	
Heat pump Elec								
Electricity tax HP	:	640.6 MWh	at	259.0	=	165,926		
Transmission tariff HP	:	640.6 MWh	at	44.0	=	28,188		
System tariff HP	:	640.6 MWh	at	36.0	=	23,063		
Distribution tariff HP	:	640.6 MWh	at	38.6	=	24,729		
Heat pump Elec Total							**241,906**	
Heat pump Ngas								
Energy tax HP Ngas	:	326,278.9 Nm3	at	2.199	=	717,487		
CO2 tax HP Ngas	:	1,285,922.9 Nm3	at	0.391	=	502,796		
NOx tax HP Ngas	:	1,285,922.9 Nm3	at	0.008	=	10,287		
Heat pump Ngas Total							**1,230,571**	
Ngas transmission costs	:	9,075,320.6 Nm3	at	0.295	=	2,680,850		
CO2 quotas	:	20,373.4 ton CO2	at	200.0	=	4,074,681		
Taxes and tariffs Total							**23,275,273**	
OM costs								
Ngas motor								
Fixed OM Ngas motor	:				=	656,480		
Variable OM Ngas motor	:	21,490.0 MWh	at	40.2	=	863,897		
Ngas motor Total							**1,520,377**	
Ngas boiler								
Fixed OM boiler	:				=	544,580		
Variable OM boiler	:	37,808.8 MWh	at	8.206	=	310,259		
Ngas boiler Total							**854,839**	
Heat pump								
Fixed OM HP	:				=	123,463		
Variable OM HP electric	:	34,342.3 MWh	at	24.618	=	845,440		
Variable OM HP Ngas	:	7,072.6 MWh	at	59.68	=	422,091		
Heat pump Total							**1,390,994**	
Electric boiler								
Fixed OM electric boiler	:				=	98,472		
Variable OM electric boiler	:	3,893.3 MWh	at	5.968	=	23,235		
Electric boiler Total							**121,707**	
OM costs Total							**3,887,917**	

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Operation Income from 01-01-2018 00:00 to 31-12-2018 23:59

Electricity costs								
Electricity consumption electric b	:	3,893.3 MWh	at	40.043*	=	155,899		
Electricity consumption HP	:	640.6 MWh	at	107.143*	=	68,640		
Electricity costs Total							**224,539**	
Total Operating Expenditures								**45,538,371**
Operation Income								**-36,754,567**

* Average price