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A study of load profiles, flexibility and system investments

Doctoral thesis

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“Anyone who has never made a mistake has never tried anything new.”

- Albert Einstein -

Preface

The work with the thesis has been conducted partly at the Department of Electric Power Engineering at NTNU in Trondheim, and partly at the Norwegian Water Resources and Energy Directorate (NVE) situated in Oslo.

The project has been financed by two research centres on renewable energy (FME[1]); the Center on Zero Emission Buildings (ZEB), and the Center on Sustainable Energy Studies (CenSES). My main supervisor has been Professor Gerard Doorman, with co-supervisors Dr. Igor Sartori and Professor Asgeir Tomasgard.

The work consists of four main parts: load modelling of ZEBs, building optimisation of ZEBs, load aggregation and energy system analysis with ZEBs.

During the work of this PhD, I have discovered that in order to utilise the possibilities offered by smart grids and demand side management, the grid needs to understand the buildings, and the buildings need to understand that they are a part of a larger energy system. I hope by this thesis that actors involved in the building sector will gain knowledge on the effects of ZEBs on the energy system, and that actors working with the electricity grid and the overall energy system, will have increased understanding of the load profiles of buildings, which is essential for evaluating their ability to offer flexibility.

Oslo/Trondheim, Feb 2017

Karen Byskov Lindberg

[1] FME – Forskningssenter for Miljøvennlig Energi

"The important thing is to not stop questioning. Curiosity has its own reason for existence. One cannot help but be in awe when he contemplates the mysteries of eternity, of life, of the marvelous structure of reality. It is enough if one tries merely to comprehend a little of this mystery each day."

- Albert Einstein -

Acknowledgments

There are many persons, who in different ways have made it possible for me to accomplish this PhD. First of all I would like to thank my main supervisor Professor Gerard Doorman at the Department of Electric Power Engineering at NTNU for your continuous support and guidance throughout the whole PhD period. Your open-door policy and scientific insights are highly appreciated, and your rational attitude has helped me in finding the path through all the trees in the woods of this thesis.

I also wish to thank the three persons who initially made this thesis possible. My late boss Dr. Tor Arnt Johnson at NVE for his encouragement and backing, which gave me the confidence to pursue a PhD degree. The leader of the Research centre on Zero Emission Buildings (ZEB), Professor Anne Grete Hestnes for her positive respond, as I contacted her with the first draft of my PhD proposal. The leader of the Research centre on Sustainable Energy Studies (CenSES), Professor Asgeir Tomasgard for accepting me as a PhD student within the center, and for finding good solutions to any financial request.

Financial support is of vital importance for any research to be carried out. I highly acknowledge the financial support from the NVE, and the ZEB and CenSES research centres. Being a PhD student of the ZEB and CenSES research centres also allowed for meeting with other PhD with a different scientific background, which has broadened and enriched my own opinions and ideas.

Co-supervisor Dr. Igor Sartori at SINEF Building and Infrastructure for your inspiring enthusiasm on zero energy buildings. Thank you for introducing me to work of the IEA Solar Heating and Cooling Programme (SHC) Task 40 “Net Zero Solar Homes”, which boosted the start of my PhD.

Professor Magnus Korpås at the Dept. of Electric Power Engineering for being a valuable discussion partner and giving constructive feedback, which helped completing several of my papers. Thank you for being a great motivator, especially towards the end of this PhD.

Co-author and office colleague, David Fischer at the Fraunhofer ISE, for our discussions on heat pumps, PVs and smart controls, and on how to incorporate the characteristics of these technologies in optimisation models. It is a privilege working with you!

Dr. Volker Wittwer and Head of Smart Grids Department Dr. Christoph Wittwer at the Fraunhofer Institute for Solar Energy Systems (ISE) who made my stay at ISE possible. Colleagues at Fraunhofer ISE; especially Kristin Goldbach, Niklas Kreifels, Felix Braam, Thies Stillahn and Bernhard Wille-Haussmann. I really miss the working environment and our ice-cream breaks on the roof-top!

Master students Astrid Ånestad, Jorge E. Chacón and Tore Dyrendahl, who I have been co-supervising. Without your dedicated work, this thesis would not have accomplished all its aspects and research questions. Thank you for good cooperation and interesting discussions along the way.

Colleagues at the Department of Energy at NVE; especially Torgeir Ericson, Ingrid H. Magnussen, Benedicte Langseth, Eirik Øyslebø, Harald Endresen and Christer Skotland, for good cooperation and constructive feedback. I am especially grateful to Ellen Skaansar for introducing me to the world of economics, and for our never-ending discussions on the crossroads between the laws of economics and thermodynamics. I highly value your sharp and critical mind, which unquestionably improved my work.

PhD colleagues at the NTNU; Camilla Thorrud Larsen, Stig Ottesen, Pernille Seljom and Carl Fredrik Tjeransen for support and cooperation especially during the courses and exams. Especially Camilla for improving my equations writing and fighting my coding-fears, and Pernille for the good cooperation on the TIMES analysis – I could really learn more on text condensing from you!

Fellow researchers in the IEA SHC Task 40 "Net Zero Solar Homes", which work is continued in the IEA ECB Annex 67 "Flexible buildings". The meetings within the task were a great inspiration, which resulted in several common publications. Special thanks go to Jaume Salom, Federico Noris, Joakim Widén, Eike Musall, Søren Ø. Jensen and Björn Bergström.

Data from the real world is vital for the quality of all research. I greatly appreciate the help from Drammen Eiendom, Kjeldsberg Eiendom and Agder Energi for granting access to measured energy consumption data of their buildings, and to Cathrine Grini at Entro AS for providing measurements.

I am grateful to Ida Bryn and Jon Erling Fonneløp, who read and commented on the text of this thesis.

Friends; especially Bente & Kjell Haugseth who invited me as their own daughter to stay whenever I was in Trondheim. Karianne Sæter and Bente Wallervand Ofte for their support and everlasting friendship. My fellow engineering friends with whom I am grateful to share friendship since the day of matriculation at NTNU: Karen Nybakke, Ida Mathilde Falck, Solveig H. Ulseth, Ingeborg Dårflot, Ragnhild Stockholm and Anne Sofie Ravndal Risnes. I admire your talents and urge to support women in the engineering business. Good neighbours at Kolsås who clapped along the way: Sara Kittilsen, Grete Finnema, Astrid Eikeland, Ulla E. M. Damhaug, Marianne Spilde and Brit Torill Haugen.

Good neighbours and friends in Freiburg; especially Katharina, Katharina, Jutta, Clementine, and Lisa– thank you for welcoming me with open arms into your neighbourhood. Frau Springsklee for teaching Eirik German and introducing him to coffee with unlimited amounts of sugar. Anja Martis & Alex Maier, and Petra & Hans Jörg Lerchenmüller for kindly renting out their houses to the Norwegian family (with three boys!). You made our year in Freiburg to an unforgettable experience for the whole family.

Family; my parents for bringing me up in a home filled with discussions on politics and environmental challenges, which lit my engagement for energy and environmental issues. My father for making me believe that any target is possible – also for girls. My late mother for walking the path for female engineering leaders by being a role model showing that women can achieve what they aspire for. My fantastic sister Marie who has helped me open my mind to see the beauty of life. My parents in law for your support in our hectic everyday life. I am especially grateful to my late mother in law Jytte Thorud, for her unconditional support and love.

And last but not least; my husband and our three fantastic boys. Eirik, Halvor and Eskil, you give such joy to my life – I would simply be lost without you. Thank you for dragging me out of my mental PhD bubble every day and showing me what the real meaning of life is. My incredible husband, Bjørn Thorud, for our late night discussions on PV, smart grids or other PhD issues. But most of all, thank you for your patience, understanding and support along this winding path towards the PhD. You make me a better person.

Summary

This thesis investigates the impacts of introducing energy efficient and electricity generating buildings, called ZEBs, into a power system with a high share of renewables. Detailed knowledge of electricity demand is essential for power system planning and operation. EUs 20-20-20 targets will increase the development of more energy efficient buildings as all new buildings shall be “nearly net zero energy buildings” (ZEBs) by 2020. The result from this ambition is that ZEBs, with lower energy demand and onsite power generation, will significantly change the way buildings are integrated in the power system. System operators must consequently prepare for changes in load profiles.

This PhD entails extensive research on the hourly load profiles of ZEBs, by investigating the differences between the existing building stock and new energy efficient buildings. Whether heat is supplied by a thermal source or electricity is essential for the total electric profile of a building. Hence, the heat load and electric specific load are evaluated separately. The different topology and utilisation of the buildings called for evaluation of eleven different building categories, of which nine non-residential and two residential building types. To assess the impact on the power system of a large implementation of ZEBs, a methodology for aggregating the total load profile of the Norwegian building stock is developed. The methodology allows for evaluation of the effect of introducing any percentage of highly energy efficient buildings in the energy system.

The building’s *net electric load profile*, which reflects how the building interacts with the electricity grid, is influenced by two main factors. First, which energy technologies are available within the building, and second, how the technologies are operated/controlled, i.e. if a smart control is applied and how it is designed. A ‘smart’ energy management system can utilise the available energy technologies within the building in a least-cost way, but still such that the energy demand is met.

To evaluate the cost-optimal net electric load-profile, an optimisation model is developed which minimises investment and operational costs over the building’s total lifetime. The model can choose between ten different energy technologies and, identifies the main factors that affect the energy system design within ZEB buildings. With the hourly or sub-hourly (15 min) operational time resolution, the *net electric load profile* can be evaluated for different technology designs and tax schemes.

The following are some of the main results obtained in this PhD work:

Load modelling

- The annual heat demand of passive energy efficient buildings is about 50-60 % lower when compared to existing buildings, but the shape of the hourly heat load profile is similar for the two. Hence, the heat profile is determined by the operational pattern of the buildings, whereas the total heat consumption is dependent on the standard of the building.
- The electric specific demand of passive energy efficient buildings does not differ substantially from existing buildings, about -6 % for offices, and the shape of the hourly load profile is similar. Consequently, the electricity load of buildings seems to be less dependent on the technical standard of the building than the thermal load.

ZEB optimisation

- Results show that PV is always as part of the ZEB's energy system design. Hence, on a building level, ZEBs have large exports of electricity to the local grid in summer, and import in winter.
- The *net electric load profile* of ZEBs are determined by the choice and size of energy technologies, i.e. the design within the building, and how they are operated.
- Each member state in the EU is free to decide their own definition of ZEBs. The results in this work show that the energy technology design of the building is influenced by the following elements of the ZEB definition:
    - ➢ the *metric* of the weighting factor (primary energy (PE) or CO_2)
        - Using PE or CO_2 is of lesser importance than the value of the weighting factors.
    - ➢ the *value* of the weighting factors
        - A high PE for electricity will lead to smaller PV capacity in ZEBs
        - For all-electric ZEBs (heated by heat pumps), the value of the PE for electricity does not matter as long as it is > 0.
    - ➢ the *level* of ZEB ('strictly' or 'nearly' ZEB)
        - the ZEB level is the most important factor for the size of the PV.
    - ➢ what *energy consumption* is included (partly operational, all operational, or all operational & embodied)
        - including less energy consumption in the ZEB balance will lower the PV size.
- Therefore, when policy makers determine the elements of their national definition of ZEB, it is of vital importance to be aware of how these elements influence the ZEB building's interaction with the surrounding power grid.

Aggregated system analysis

- A large implementation of ZEBs has two effects on the Norwegian energy and power system; 1) decreased demand in winter due to the passive building standard, and 2) increased electricity production due to the on-site PV generation.
- Initial analyses on the operation of the *Nordic electric power system in 2030* with the EMPS model, show that a large implementation of ZEBs in Norway lowers the electricity prices, which reduces the thermal power production (coal, oil and bio) and stimulates to increased consumption (dependent on the demand elasticity). Furthermore, the reduced electricity prices and increased power availability leads to increased export out of the Nordic region. About 70-80 % of the increased power availability is exported out of the region due to the characteristics of the hydropower production. The peak prices are also reduced.
- Initial analysis on the investments in the *Scandinavian energy system towards 2050* with the TIMES-model, of a large implementation of ZEBs in Denmark, Sweden and Norway is performed. The findings show that the energy system surrounding the ZEB buildings will adapt to this forced change. As in the power system analysis, electricity prices are found to decrease, which lowers the incentives for investment in new wind capacity and CHP capacity. In the building sector, the lower electricity prices increases the role of electric heating, and the consumption of district heat and biomass is reduced. In this analysis, the export from Scandinavia in 2050 is also increasing.

Abbreviations

CHP	Combined Heat and Power (μ-CHP - micro combined heat and power)
DER	Distributed Energy Resources
DHW	Domestic Hot Water (or hot tap water)
DR	Demand Response
DSM	Demand Side Management
EEX	European Energy Exchange
EMPS	EFI's Multi-area Power market Simulator
G	The value of a building's energy balance
GHG	Green House Gas Emissions
HP	Heat pump
MFH	Multi-family house
PEnr	Non-renewable Primary Energy factors (kWh_{PEnr} / kWh)
PEtot	Total Primary Energy factors (kWh_{PEtot} / kWh)
PV	Photovoltaic modules (solar power)
RES	Renewable Energy Sources
SFH	Single Family House
ST	Solar thermal modules
TIMES	The Integrated MARKAL EFOM System
ZEB	net Zero Energy Building (or net Zero Emission Building). Net ZEB means that the building is net zero on an annual scale, but importing and exporting energy within the hour, day or season.

Definitions & Terms used

Building's energy balance	Equals: (weighted energy imports) – (weighted energy exports) = *G*, where *imports* are energy imported to the building, and *exports* are energy exported to the electricity grid or heat exported to the district heating grid.
Building's energy system	Energy system within a building, consisting of technologies for generating heat or electricity.
Building's energy system design	The choice and size of energy technologies within a building.
Electricity consumption	Electricity consumed within the building, including both electric specific demand and electricity used for heating, if heated by electricity.
Electric specific demand	Amount of electricity needed for lighting, electric appliances and fans&pumps, i.e. demand that cannot be met by other energy carriers than electricity.
Energy demand	Sum of electric specific demand and heat demand, i.e. the total energy demand of the building.
Energy consumption	Consumption of energy carriers, such as wood, electricity, district heat, or natural gas.
Energy system	Energy system for a region/country; embracing all energy carriers, energy production technologies and end-use categories. The energy system comprises the power system, district heating system, gas grids, transportation sector, building sector and industry sector.
Heat demand	Amount of energy that is needed to heat a building (space heat demand) and to provide domestic hot water (DHW). The heat demand can be covered by various energy carriers (e.g. bio, gas and electricity).
Load profile	Hourly or sub-hourly energy demand or energy consumption. In this thesis, load profiles for electric specific demand, heat demand and total electricity consumption are developed.
'nearly ZEB'	A building which has a positive energy balance, $G > 0$. (i.e. the weighted annual energy imports are larger than the weighted energy exports).
'no ZEB'	A building without requirement for becoming a ZEB. (i.e. the energy balance G is not subject to any target).
'strictly ZEB'	A building which has a strictly zero energy balance, $G = 0$. (i.e. the weighted annual energy imports equals the weighted energy exports)
Power system	Electric energy system of a region/country; embracing electricity production technologies, transmission lines and electricity consumption. The power system is a part of the energy system.
Weighting factor	Primary energy factors (kWh_{PE} / kWh_i) or CO_2 factors (g_{CO2} / kWh_i) for different energy carriers, *i*.
ZEB level	The level of ZEB reflects whether the building is 'nearly' or 'strictly' ZEB. In this work the ZEB level is related to the energy balance of the building, *G*, without applying any ZEB target ('no ZEB') in the following way: $\textit{ZEB level} = (G_{\text{'no ZEB'}} - G) / G_{\text{'no ZEB'}}$

Contents

1 Introduction

Energy system analysis on an aggregated level is important when assessing implementation of new policies. The recast of the EUs Energy Performance of Buildings Directive (EPBD) demands all new buildings to be nearly Zero Energy Buildings by 2020. The concept of Zero Energy Buildings (ZEB) affects the energy system in two ways; lower energy consumption due to energy efficiency measures, and increased production due to on-site energy technologies. This thesis investigates how the energy system, including the power system, is affected by a large implementation of such energy efficient and energy producing buildings.

1.1 Motivation

Large-scale introduction of renewable electricity production is an important element to combat greenhouse gas emissions (GHG) and increase security of energy supply. However, their intermittent production pattern calls for large back-up technologies and flexibility measures of the demand. Accordingly, flexibility mechanisms for moving or cutting loads have emerged, often classified as direct load control, demand side management (DSM) or demand response (DR).

Buildings are said to contribute to 40 % of the GHG emissions on a global scale. This includes both direct emissions from the use of gas or oil for heating purposes, and indirect emissions through the use of electricity and/or district heat. In 2010, EU launched the concept of nearly Zero Energy Buildings (ZEB) through the EPBD, to make the buildings a part of the solution, both with regard to GHG emissions and security of supply, by incentivising on-site local energy production[2] as well as energy efficiency measures (European Parliament 2010).

In Norway, buildings account for approximately 36 % of the domestic energy consumption (Statistics Norway 2013), but the emissions buildings are causing only account for 2 % of the national GHG emissions as 99 % of the electricity mix is renewable hydropower (Lindberg & Magnussen 2010). Nevertheless, Norway is connected to the Nordic power system, which also includes thermal production capacity to meet the electricity demand. Therefore, even though introduction of ZEBs in Norway contribute little to the national emission target, this thesis investigates how it will affect the aggregate Nordic energy system.

[2] Also called distributed energy resources (DER).

The initial experiences with ZEBs show that PV integrated in the façade and roof of the building has so far always been a part of the solution in order to meet the ZEB requirements[3]. This leads to challenges for the surrounding energy system because the ZEB buildings tend to export electricity in summer and import electricity in winter. Hence, with a Northern European climate, the electric power system serves as a seasonal storage, receiving electricity in summer when there is export from the ZEBs, and providing electricity to the ZEBs in winter.

The system integration of ZEBs must answer to the reduced heat demand in winter, and increased on-site electricity production in summer. This means that the existing production facilities will need to adapt, both with regard to operation and investment decisions. Norway and Sweden have large hydropower reservoirs that can provide the seasonal storage capacity demanded by the ZEBs. Hence, it is of interest to study how and to what extent hydro production and the utilisation of the hydropower reservoirs are changed with a large introduction of ZEBs.

An important input parameter to aggregate power system analyses[4] is the load profile of buildings' total electricity demand. A large-scale introduction of energy efficient and energy producing ZEB buildings changes the aggregate electric load profile. How it will change depends inter alia on the characteristics of the current load profile in today's system (cf. Figure 1-1), on the energy technologies implemented in the ZEBs, and if flexible DSM mechanisms are applied.

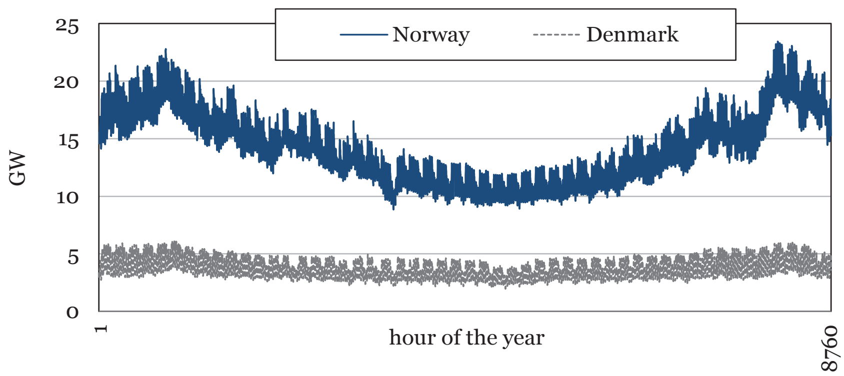


Figure 1-1 Electric load in Norway (5 mill. people) and Denmark (6 mill. people) in 2012.(Nord Pool AS)

Traditionally, the measured aggregate electricity load is used for predicting the electricity load profile, see e.g (Boßmann et al. 2013; Goude et al. 2014; Kadurek et al. 2013; Sajjad et al. 2014; 50Hertz et al. 2014; FINGRID et al. 2014). However, with increased use of electric heating, energy efficiency measures, electric vehicles and local on-site PV, the measured load as is seen today becomes less representative.

To analyse an implementation of ZEBs towards 2050 creates a need for establishing a baseline development of the future energy demand of the building stock, transportation sector and industry. Figure 1-2 depicts some of the possible drivers for the future electricity demand.

[3] The definition of a ZEB is explained in detail in Section 2.1.
[4] Power system analysis means in this thesis production dispatch and power balance on an hourly level, and does not include reliability analyses or power flow analyses.

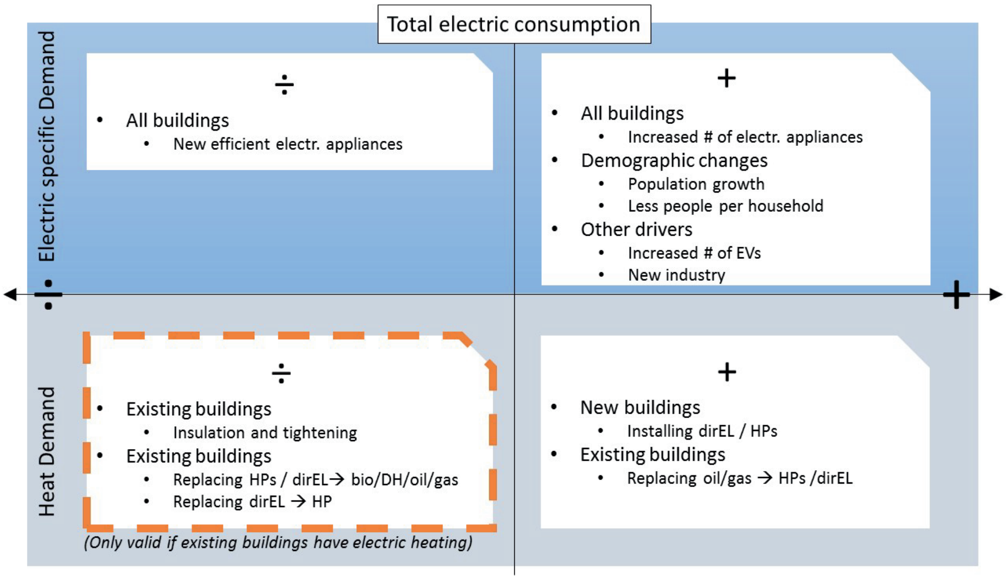


Figure 1-2 Examples of drivers that decreases (÷) or increases (+) the future electricity consumption.

Ideally, prediction of the aggregate electric load profile for buildings should take into account:

- *Macro-economic aspects* such as population growth and income parameters, which influences e.g. the size of the building stock and number of electric appliances. A macro-economic approach can also detect rebound-effects of the electric demand.
- *Building aspects* such as the technical standard of the building envelope, which influences the heat demand.
- *Technology aspects* such as heat technology choice (electric heating will influence the electric load, whereas using wood or bio fuels will not), and development of more energy efficient appliances.
- *Flexibility aspects,* i.e. DSM mechanisms or direct load controls, either carried out by the building owner on a building level, or activated by the grid owner on an aggregate level.
- *Time aspects*. Incorporating long-term trends (decade, annual, seasonal) in a methodology that predicts the load with an hourly or sub-hourly time resolution.

Combining the macro-economic top-down aspects with the technical bottom-up aspects in one unified load prediction methodology is a challenging task. Several different approaches exist, for instance advanced top-down econometric models as found in (Ettestøl 2003), or energy consumption as a result of macro-economic development of the national economy as in (Norwegian Minstry of Finance 2013), or bottom-up like approaches that investigates the building stock according to persons per household and/or energy consumption per dwelling or m^2 as found in (Mata et al. 2012; Barton et al. 2013; Sartori et al. 2009; Sandberg et al. 2011; Rosenberg & Espegren 2013). However, these approaches forecast the annual energy demand, and lacks the hourly time resolution that is needed for power system analysis.

This thesis seeks to understand the impact of the technical aspects on the aggregate electric load, with an hourly time resolution, while treating the macro-economic top-down aspects in a simplified manner.

Although rebound-effects and income effects are not incorporated, the approach is able to take into account population growth by forecasting the size of the total building stock. The advantage is the possibility of analyzing the effect of energy efficiency measures, temperature dependency and heat technology choice of the building stock, on the *hourly* aggregate electric load.

To incorporate the heat technology aspect, the heat load and the electric specific load of the buildings have to be treated and analysed separately. The electric specific demand is demand that cannot be met by other energy carriers than electricity, i.e. appliances and lighting.

The work on hourly electric specific load of buildings is wide and can be found in e.g. (Richardson et al. 2008) (Widén 2008) (Yao & Steemers 2005) (Fischer et al. 2015) (Livik et al. 1999) (Morch et al. 2013) or (Pedersen 2007b). These are mostly bottom-up approaches that predict hourly loads either per building, per dwelling, per household or per heated area (m^2), by use of measured hourly load traces.

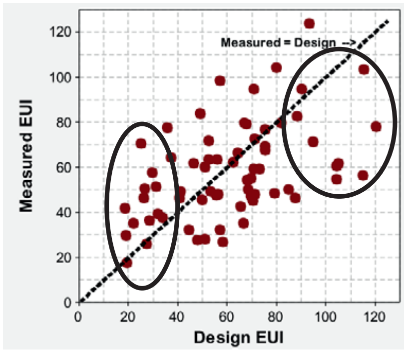


Figure 1-3 Measured energy consumption vs. calculated energy consumption. (Turner & Frankel 2008)

Another approach, mostly used by building engineers, uses dynamic building simulation models to simulate the hourly load profiles of heat demand, cooling demand and electricity demand. Figure 1-3 shows that actual energy consumption within buildings naturally differs from calculations carried out by advanced building simulation models, but that the errors tend to increase the more energy efficient the buildings become (Turner & Frankel 2008) (Tommerup et al. 2007) (Langseth et al. 2011) (Borg 2015).

As the energy system, and especially the electricity grid, is designed to handle the actual load of the buildings, measurements of buildings are essential for determining their real energy consumption. Hence, this thesis entails extensive work on load profiles, based on hourly measurements of heat and electric specific demand of over 200 buildings.

The heat technology that is implemented in buildings has a major impact on the aggregate electric load profile, and hence a deeper understanding of the elements that influences the choice of heat technology within ZEBs is required. In order to study this issue in detail, this thesis contains the development of a cost-optimal modelling tool of a ZEB, with the financial perspective of the building owner.

1.2 Scope and Research Questions

The main objective of this PhD thesis is to investigate the impacts of introducing Zero Energy Buildings into an energy system with a high share of renewable energy production, while taking into account DSM possibilities offered by smart grids. To achieve this, it is essential to establish reliable load profiles of ZEB buildings. As the aggregate electric load is affected by the heat technologies within ZEBs, the financial investment decisions of ZEB buildings are investigated. Lastly, the work contains a load profile aggregation methodology that incorporate for both energy efficiency measures and heat technology options.

The work of this thesis is divided into four main parts: modelling of load profiles of ZEBs, building optimisation model of ZEBs, aggregation of load profiles on a national level, and aggregate system analyses with ZEBs.

The research questions and research tasks are as follows:

Question 1: How does the load profiles for ZEB buildings differ from the existing building stock?
Task 1: Estimating hourly load profiles of ZEBs and existing buildings, separated on heat and electric specific demand.

Question 2: How does the electric load profile of a ZEB look from the perspective of the power grid?
Task 2: Estimating the net electric load profile of a ZEB building while taking into account its optimal economic behaviour.

Sub-question 2.1: How does the design of the ZEB definition (i.e. weighting factors and ZEB-level) impact the choice and sizing of the energy technologies within ZEBs, and thereby its net electric load?
Sub-task 2.1: Analysing the cost-optimal energy investments within a ZEB building in order to identify the determining factors for the building's energy system design.

Question 3: How is the aggregate national electric load profile affected by a large roll out of ZEBs?
Task 3: Developing a load profile aggregation methodology by use of the hourly bottom-up load profiles from Task 1 combined with knowledge on the existing and future trends of the building stock.

Question 4a: How is the management of the hydropower reservoirs in Norway affected by a large introduction of ZEB buildings?
Task 4a: Analysing the impact of ZEBs on the *operation* of the Nordic power system by use of a Nordic EMPS model.

Question 4b: How are the investments in power plants, transmission lines and end-user technologies altered with a large introduction of ZEBs?
Task 4b: Analysing the impact of ZEBs on the *investments* in the Scandinavian energy system by use of a Scandinavian TIMES model.

1.3 Contributions

The EUs Energy Performance of Buildings Directive (EPBD) requires all new buildings to be nearly zero energy buildings by 2020. This thesis contributes to the discussion on how these buildings will interact with and influence the energy system that the ZEB buildings are a part of. The main *modelling contributions* are presented as follows:

- The development of hourly load profiles for heat and electric specific demand of nine different non-residential building types in Norway, and their prospective changes when the buildings become more energy efficient. This is the essential basis for being able to analyse future system load profiles with a large ZEB deployment.

- The development of a mixed integer linear optimisation model (MILP) to find the cost-optimal energy system design of a ZEB. Energy market conditions as seen from the building owner's perspective are implemented, including feed-in-tariffs, self-consumption tariffs and peak grid tariffs. With a 15 min time resolution, the cost-optimal operation of the energy technologies are found, which enables investigation of the ZEB's net electric load profile (consumption minus on-site production). Hence, the model identifies the most important factors that influence the ZEB building's interaction with the electricity grid.

- A load forecast methodology is developed where building loads, determined in energy use per heated floor area, is coupled with forecasted building stock projections. The bottom-up aggregation methodology enables analysis of decreased heat demand and choice of heat technologies, and hence the effect on the aggregate hourly electric load profile in Norway of a large roll out of ZEBs.

Based on the load profile modelling and cost-optimal MILP model, the following *building analyses contributions* are:

- How the cost-optimal choice and size of energy technologies within ZEB buildings is influenced by the weighting factors, the building's load characteristics, energy prices and technology costs, for both Norwegian and German market conditions.

- How the grid impact of ZEB buildings is affected by the politically determined definition of ZEB, i.e. the ZEB level, and the metrics and value of the weighting factors.
  - The *ZEB-level* directly affects the size of the on-site PV capacity, and thus the building's peak export value from the building to the grid.
  - A lower *weighting factor for electricity* increases the required PV capacity for ZEBs with non-electric heating (e.g. bio or gas), and hence increases its grid impact.
  - The value of the *weighting factor for electricity* is irrelevant for an all-electric ZEB heated by electricity.

Based on the mathematical modelling of load profiles and the load aggregation methodology, the following *system analyses contributions* are:

- The effects on the aggregate electricity load in Norway when replacing existing buildings with ZEB buildings.
- The consequences of a large implementation of ZEBs in Norway in 2030 on the operation of the Nordic power system
- The consequences of a large implementation of ZEBs in Scandinavia towards 2050 on the investments in the Scandinavian energy system

1.4 List of publications

Research Task 1: Load profiles of ZEB building's heat and electricity demand

No. I K.B. Lindberg and G. Doorman, *"Hourly load modeling of non-residential building stock"*, conference proceedings, IEEE PowerTech conference in Grenoble, France, 16 – 20 June 2013

No. II K.B. Lindberg, J.E. Chacón, G. Doorman, D. Fischer, "*Hourly Electricity Load Modelling of non-residential Passive Buildings in a Nordic Climate"*, IEEE PowerTech conference in Eindhoven, Netherlands, 29 June – 2 July 2015

Research Task 2: Net electric load profiles and optimal investments of ZEBs

No. III K.B. Lindberg, A. Ånestad, G. Doorman, D. Fischer, C. Wittwer and I. Sartori, *"Optimal Investments in Zero Carbon Buildings"*, conference proceedings, 1st International conference on Zero Carbon Buildings (ZCB2014), Birmingham, UK, 11-12 September 2014

No. IV K. B. Lindberg, G. Doorman, D. Fischer, M. Korpås, A. Ånestad and I. Sartori, "*Methodology for optimal energy system design for Zero Energy Buildings using mixed-integer linear programming*," Energy and Buildings, Vol. 127, pp. 194-205, September 2016

No. V K. B. Lindberg, D. Fischer, G. Doorman, M. Korpås, and I. Sartori, "*Cost-optimal energy system design in Zero Energy Buildings with resulting grid impact: A case study of a German multi-family house*," Energy and Buildings, Vol. 127, pp. 830-845, September 2016

No. VI D. Fischer, K. B. Lindberg, H. Madani and C. Wittwer, "*Impact of PV and variable prices on optimal system sizing for heat pumps and thermal storage*," Energy and Buildings, Vol. 128, pp. 723-733, Sept 2016

Research Task 3 and 4: Aggregate energy system analysis and power system analysis with ZEBs

No. VII K. B. Lindberg, T. Dyrendahl, G. Doorman, M. Korpås, E. Øyslebø, H. Endresen and C. Skotland, "*Large Introduction of Zero Energy Buildings in the Nordic Power System*," in 13th International Conference on the European Energy Market, Porto, Portugal, 6-9 June 2016

No. VIII P. Seljom, K. B. Lindberg, A. Tomasgard, G. Doorman and I. Sartori, *"Impact of Zero Energy Buildings on the Scandinavian energy system"*, Energy, Vol. 118, pp. 284-296, 2017

Other publications related to the PhD work are listed in the following.

Co-operation with the Smart Grid Department at Fraunhofer ISE:

2016 D. Fischer, A. Flunk, N. Kreifels, B. Wille-Haussmann, K. B. Lindberg, B. Stephen, and E. H. Owens, "*Modelling the Effects of Variable Tariffs on Domestic Electric Load Profiles by Use of Occupant Behaviour Submodels*," IEEE Trans. Smart Grid, Mar 2016, DOI: 10.1109/TSG.2016.2544141

2014 D. Fischer, K. B. Lindberg, S. Müller, E. Wiemken, and B. Wille-Haussmann, *"Potential for Balancing Wind and Solar Power Using Heat Pump Heating and Cooling Systems"*, 4th Solar Integration Workshop, Berlin, Germany, 10-11 November 2014

2014 D. Fischer, J. Scherer, A. Haertl, K.B. Lindberg, M. Elci, and B. Wille-Haussmann, *"Stochastic Modelling and Simulation of Energy Flows for Residential Areas"*, Conference proceedings VDE-Kongress 2014 Smart Cities: Intelligente Lösungen für das Leben in der Zukunft, Germany, Oct 2014

2014 D. Fischer, T. Rivera Toral, K. B. Lindberg, B. Wille-Haussmann and H. Madani, *"Investigation of Thermal Storage Operation Strategies with Heat Pumps in German Multi Family Houses"*, Presented at the Renewable Energy Research Conference (RERC2014) in Oslo, Norway, 16-17 June 2014, Energy Procedia, vol. 58, pp. 137-144, 2014

Work related to the IEA Solar Heating and Cooling Programme (SHC) Task 40 "Net Zero Energy Solar Buildings":

2014 F. Noris, E. Musall, J. Salom, B. Berggren, S. Ø. Jensen, K. B. Lindberg and I. Sartori, *"Implications of Weighting factors on Technology Preference in net Zero Energy Buildings"*, Energy & Buildings, vol. 82, pp. 250–262, 2014

2014 J. Salom, J. Widen, J. A. Candanedo and K. B. Lindberg, *"Analysis of grid interaction indicators in Net Zero Energy Buildings with sub-hourly collected data"*, Special issue of Advances in Building Energy Research, http://dx.doi.org/10.1080/17512549.2014.941006

2014 J. Salom, A. J. Marszal, J. Widén, J. A. Candanedo and K. B. Lindberg, *"Analysis of Load Match and Grid Interaction Indicators in net Zero Energy Buildings with simulated and monitored data"*, Journal of Applied Energy, vol. 136, pp. 119-131, 2014

2014 J. Salom, A. J. Marszal, J. A. Candanedo, J. Widén, K. B. Lindberg and I. Sartori, *"Analysis of Load Match and Grid Interaction Indicators in net Zero Energy Buildings with High-Resolution Data"*, Technical Report of IEA Task 40 of the Solar Heating and Cooling Program (SHC), Available: http://task40.iea-shc.org/data/sites/1/publications/T40A52--LMGI-in-Net-ZEBs--STA-Technical-Report.pdf

Work related to the Research Centre on Zero Emission Buildings (ZEBs):

2016 I. Sartori, S. Merlet and K.B. Lindberg, *"Zero Village Bergen: Mismatch Between Aggregated PV Generation and Electric Load in a New Zero Emissions Neighbourhood in Nordic Climate"*, In 12th REHVA World Congress CLIMA conference, Aalborg, Denmark, 25-28 May, 2016

2013 T.H. Dokka, I. Sartori, M. Thyholt, K. Lien and K.B. Lindberg, "*A Norwegian Zero Emission Building Definition*", In Passivhus Norden, The 6th Passive House Conference in the Nordic countries, Göteborg, Sweden, 2013

Work related to load profile modelling at SINTEF Energy Research:

2013 A.Z. Morch, H. Sæle, N. Feilberg, and K.B. Lindberg, "*Method for Development and Segmentation of Load Profiles for Different final Customers and Appliances"*, conference proceedings, ECEEE Summer Study on energy efficiency, in Toulon/Hyères, France, 3 – 8 June 2013

1.5 Thesis structure

This thesis is a collection of the eight publications produced during the PhD which are provided in Appendix E to L. Appendix A and D elaborates on findings that were not included in the articles, whereas Appendix B and C present the details of the load aggregation methodology. The remainder of the thesis is organised as follows.

Chapter 2 presents the context and background for the research carried out in this thesis. Chapter 3 presents and discusses the main results of the articles, and is divided into four main parts as seen in Figure 1-4, i.e. load profiles, building optimisation, load aggregation and system analyses. The main conclusions of the thesis are outlined in Chapter 4, together with recommendations for future research.

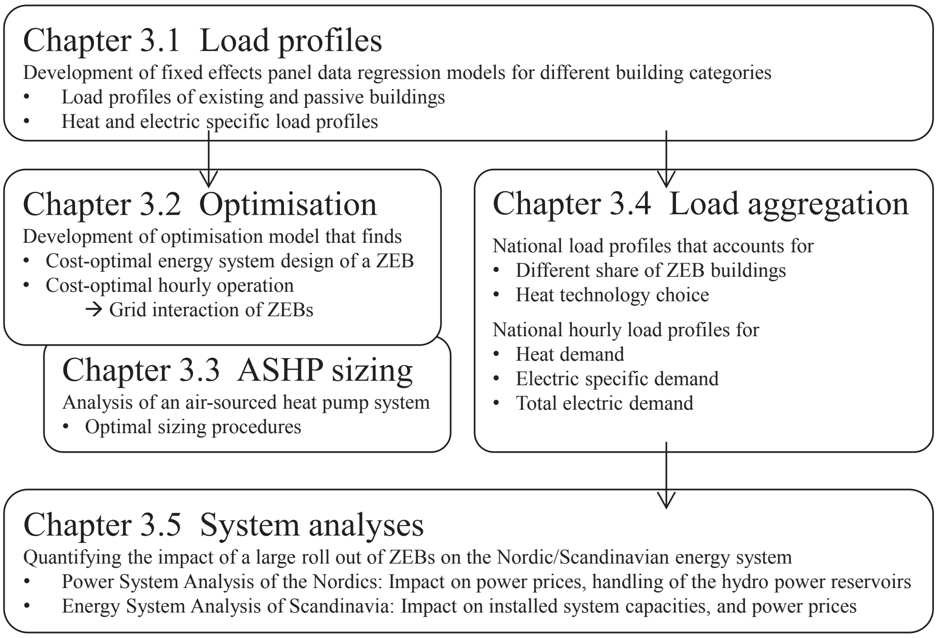


Figure 1-4 Guide to the reader of Chapter 3 that includes the main results of the thesis.

2 Research context and background

This chapter explains the background for the research carried out in this thesis, and gives an overview of the current research within ZEBs and their grid impact, demand side management in general, energy system analyses and load profile aggregation with references to relevant literature.

Chapter 2.1 explains the intricacies of the definition of Zero Energy Buildings, including the challenges for policy makers when designing the ZEB definition, and challenges for private building owners and the electric power grid in order to reach the goals of ZEBs. As the ZEBs will be built in an environment of smart grids and smart homes, the implications of flexible demand and utilisation of storage are outlined in Chapter 2.2. Lastly, a short introduction of what the terms *power system analysis* and *energy system analysis* mean in this thesis, is given in Chapter 2.3.

2.1 Definition of Zero Energy Buildings

The definition of a 'nearly ZEB' in the EU's EPBD is as follows *"a nearly zero-energy building means a building that has a very high energy performance. The nearly zero or very low amount of energy required should be covered to a very significant extent by energy from renewable sources, including energy from renewable sources produced on-site or nearby"* (EN 15603:2008 n.d.). Generally speaking, a nearly ZEB is an energy efficient building with low energy demand, that to a high extent is covered by renewable on-site production.

The framework of how to calculate the energy balance of ZEB is given by Eq.(1), where the balance equals the weighted annual energy imports to the building, subtracted the annual weighted energy exports from the building[5].

$$\begin{array}{ccccc} \text{weighted energy consumption} & - & \text{weighted energy production} & = & \text{energy balance} \\ \text{weighted energy imports} & - & \text{weighted energy exports} & = & \text{energy balance} \\ \sum_i f_i \cdot y_i^{\text{import}} & - & \sum_i f_i \cdot y_i^{\text{export}} & = & G \end{array} \quad (1)$$

The weighting is done by use of weighting factors f, which are unique for each energy carrier. Using primary energy factors (PE), lead to a Zero Energy Building (ZEB), whereas using CO_2 factors lead to a Zero Emission Building or Zero Carbon Building (ZCB). However, in the following, whenever using

[5] Whether the balance is calculated based on energy consumption&production or energy imports&exports gives the same answer of the energy balance G. Using imports&exports indirectly accounts for the self-consumption of on-site energy production, whereas using consumption&production the self-consumption is calculated explicitly.

ZEB, it embraces both ZEB and ZCB. When the balance is zero ($G = 0$), the building is a 'strictly' ZEB. However, if the balance is nearly zero ($G > 0$), it is a 'nearly' ZEB, and if $G < 0$ it is a plus energy building.

According to the EPBD, each member state shall design their own definition of the 'nearly zero energy building'. The definition contains three elements, determining the weighting factors (both the metric and the value), and how 'near' zero the ZEB target should be, i.e. the value of G. The third and last element is what energy consumption to include in the energy balance. The ZEB definitions in most European countries do not include all energy imports in the energy balance[6], as energy used for elevators or equipment, such as computers or IT-servers, are dependent on the user and should not be a part of the energy balance of the building (Dokka et al. 2013). On the other hand, some research institutions claim that not only all the energy consumed by the building, but also embodied energy of the materials and construction of the building should be included (Kristjansdottir et al. 2014).

Summed up, the definition of ZEB that each EU member state is free to decide, has the following elements:

1) the *metric* and *value* of the weighting factors (PEnr., PEtot or CO_2)
2) the *level* of ZEB ('strictly' or 'nearly' ZEB)
3) what *energy consumption* is included (partly operational, all operational, or all operational & embodied)

2.1.1 Freedom of choice of the ZEB definition

Figure 2-1 illustrates the energy balance of a ZEB, where the weighted energy imports are shown on the x-axis, and the weighted energy exports on the y-axis. Hence, all buildings lying on the dashed ZEB-balance line are 'strictly' ZEBs. The grey point depicts a reference building without on-site energy generation. In order to move towards the dashed ZEB-balance line, energy efficiency measures can be applied (moving to the left) together with on-site production (moving upwards). Further reduction of the *weighted* energy imports can be enabled by replacing the heat technology with bio heating, as bio often has the lowest weighting factor. A 'nearly' ZEB may have less energy efficiency measures and/or lower production capacity, and lies hence in the blue shaded area of the figure.

In this simple illustration, two different weighting factors are discussed; PEnr, and CO_2 factors, with the metric values taken from the draft of the European standard (prEN 15603:2013 2013)[7]. Making bio energy the preferred heat technology choice in all ZEB buildings would create a massive need for bio energy. Hence, some countries have decided on more politically motivated factors, e.g. Switzerland and Denmark, where bio energy is given a higher value in order to make district heating or heat pumps more attractive. However, when increasing the weighting factor for bio energy, the ZEB balance is harder to reach, and larger on-site production size is required, unless the ZEB level is reduced accordingly (cf. Figure 3-11 in Chapter 3.2).

[6] E.g. the Danish ZEB definition only includes lighting of the electric specific demand (Hansen & Hansen 2015).
[7] An overview of weighting factors for different sources is given in Table 4 of Article V.

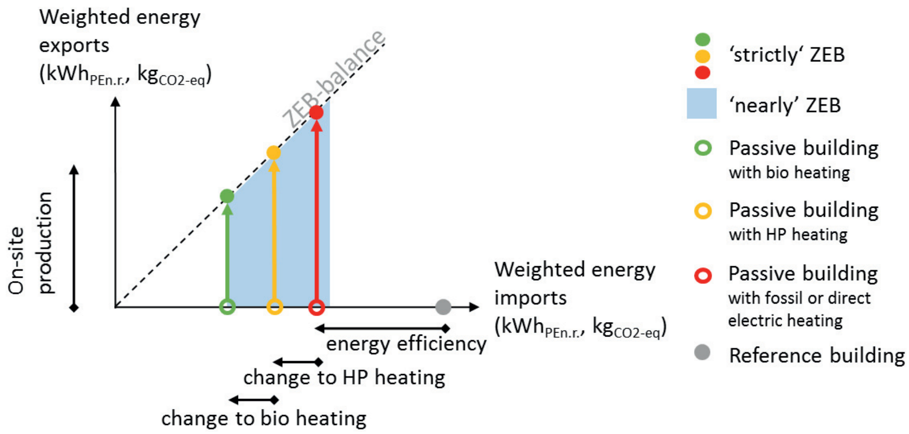


Figure 2-1 'Nearly' ZEB, using non-renewable PE factors or CO_2 factors. (Based on (Sartori et al. 2012)*).*

2.1.2 ZEB's grid impact: Challenges for the power system

This section displays that the challenges for the power system of implementing ZEBs are both on an instantaneous level and on a seasonal level.

The illustration in Figure 2-1 show that the building cannot reach the 'strictly' ZEB target without producing and exporting energy. Unless the building is attached to a district heating grid, export of electricity to the power grid is inevitable[8]. In the literature, the on-site energy generation in ZEBs often tends to consist of large PV installations, see e.g. (Noris et al. 2014; Salom et al. 2014; Milan et al. 2012; Lu et al. 2015; Hamdy et al. 2013; Dar et al. 2014). Even though the on-site electricity generation also can be provided by micro-wind turbines or micro-CHPs, building integrated micro wind turbines have challenges with noise and vibrations (Wilson 2009), and a ZEB with CHP still needs to compensate for its gas or bio imports. Solar thermal (ST) can provide heat in summer time, but cannot contribute to the energy exports from the building unless it is attached to a district heating grid. Even though some case studies have ST installed, it contributes little to reach the ZEB balance, and hence the building still needs PV to produce enough energy exports (Noris et al. 2014).

In northern European countries, heat demand occurs in winter when PV generation is low., thereby making the building import energy in winter and export in summer. To fulfil the ZEB target of the building, the power system must serve as a seasonal storage that is 'charged' in summer and 'discharged' in winter. Electricity must be consumed the instance it is produced. This requires that there is enough electricity demand in the rest of the energy system (e.g. industry or other buildings, which can utilize the produced electricity from ZEBs in summer. In winter, the capacity of power plants and the capacity of the electric distribution grid must be able to provide the ZEB buildings with electricity.

Mismatch issues occurring on an hourly or instantaneous timescale is another challenge of the ZEBs. Due to the often large PV installations, local grid challenges, such as over-voltages, may occur in

[8] It is, however, possible to reduce the amount of export by use of storage or flexible demand. This is elaborated in Section 2.2.2.

summer if many ZEBs are located within a geographically small area (Baetens et al. 2012). To ease the hourly mismatch problems of the individual ZEB buildings, research on local energy systems for small areas are emerging (see e.g. (Zidan & El-Saadany 2013; Sperling & Möller 2012; Kayo et al. 2014)). The idea is to exploit the characteristics of different energy sources and technologies, e.g. PVs, micro-CHPs and micro-wind, with various energy demand profiles, e.g. service buildings and residential buildings, and adding smart controls. Having a local energy system perspective rather than a building perspective (Sperling & Möller 2012), showed that the seasonal mismatch problems of the local area can be reduced, even though the mismatch problems of the individual buildings are unchanged.

2.2 Demand Side Management

The concept of flexible demand emerged with peak load challenges and fluctuating electricity prices, and has become even more pertinent with increased intermittent renewable power production. The utilisation of flexible demand can ensure market clearing in hours of power shortage or power surplus, and thus help balancing supply and demand (Ericson 2007). The European Network of Transmission System Operators for Electricity (ENTSO-E) goes as far as describing flexible demand as *"a key component in the successful evolution of the power system from a conventional based generation system to one that has significant contributions from intermittent sources of generation and power intensive loads. To achieve the EU's 2030 and 2050 energy policy and decarbonisation targets, DR uptake must therefore be broad and deep."* (ENTSO-E 2014)

In the literature, the utilisation of flexible demand is referred to as both Demand Side Management (DSM) and Demand Response (DR), and sometimes management of on-site energy production together with storage is included in the definition of "flexible demand". Since the notations are not clearly defined, only DSM is used in the following.

2.2.1 Flexible building loads

Due to the mismatch challenges, the introduction of ZEBs increases the need for power balancing mechanisms even further. However, the buildings can also be a part of the solution to overcome the mismatch issues by exploiting the flexibility possibilities of the electric load.

The flexibility of the electric load seen from the grid perspective is often illustrated by three mechanisms; load shifting, load shaving and valley filling and load reduction (see Figure 2-2). Load shifting means moving the consumption from one time to another, while load shaving means cutting the load for a short time period and not consuming it on a later point in time. Valley filling is the opposite of load shaving, i.e. new load is activated to increase the electricity consumption.

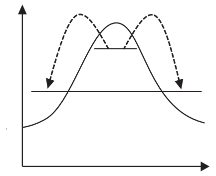
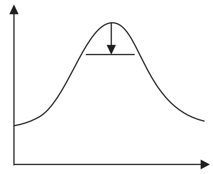
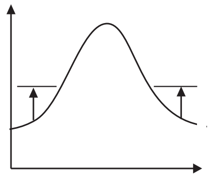
Load shifting	Load shaving	Valley filling
		
Moving loads from one time to another.	Cutting load at a certain instance (and not using it later).	Increasing load at certain instances (which normally is not active).
E.g. washing machine, or if electric heating: heating the building earlier or later.	E.g. turning off electric heating, and using gas or bio instead.	E.g. turning on electric heating if normally heated by gas or bio.

Figure 2-2 DSM mechanisms: load shifting, load shaving and valley filling.

Once the flexibility potential is found, the next question is how it can be activated. Studies investigating the flexibility potential of households show that despite a theoretical flexibility potential of about 55 % of the electric specific load, in practice only 5-10 % is shifted due to the occupant's behavioural preferences (Throndsen 2015) (Fischer et al. 2016). This is illustrated in Figure 2-3 where only a small part of a typical residential load is shifted from peak price hours to off-peak price hours.

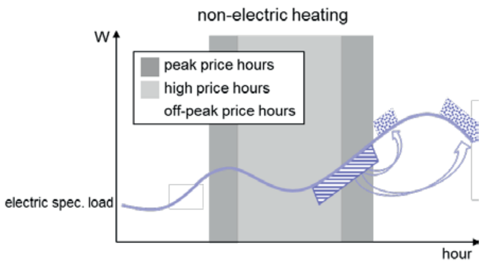


Figure 2-3 Load shifting of the electric specific load for a typical household.

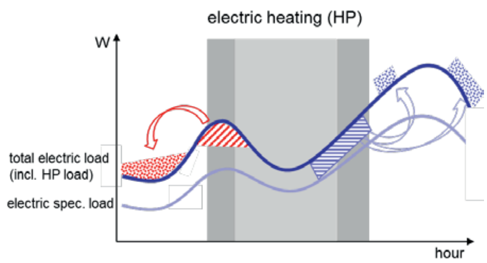


Figure 2-4 Load shifting of the total electric load, incl. electric heating, for a typical household.

Therefore, the largest flexibility potential lies in the electric loads for heating, i.e. electricity used for heating or cooling purposes. Because of the thermal mass of the buildings, these loads can be switched off for a short time period without affecting the comfort of the users (the higher thermal mass, the longer shut-off time). For European conditions, electricity used for heating is said to increase the load shifting potential. Traditionally, heat demand in European buildings is met by natural gas, oil or district heating. Hence, electric heating will shift the electric load profile upwards.

There are two motivations for load shifting from the power system perspective. The first addresses peak load problems of local electric grids in order to avoid or postpone new grid investments. If the local grid is initially designed to handle only the electric specific load of the buildings, adding electric heating will increase the peak load challenges. Even though the heat demand of ZEB buildings is relatively low, it still accounts for about 40-50 % of the building's total energy demand (depending on building type). Hence, the flexibility potential increases with electric heating, but the peak load of the building is also increased (dark blue line in Figure 2-4). As it is the difference between the total and electric specific demand that can be shifted for heating purposes, the peak load of the building cannot be further reduced than what was initially possible to shift of the electric specific load. This means that in a local grid originally designed to handle only the electric specific load of the buildings, adding electric heating will only add a problem before solving it, rather than solving the initial problem. On the other hand, if the electricity grid is initially designed to handle electric heating (like in e.g. Norway or Sweden), the load shifting potential by use of electric heating loads is large. One should however notice, that the more energy efficient the building is, the lesser flexible it is due to the reduced heat demand.

The second motivation for load shifting addresses fluctuations of the RES production in the power system, i.e. increasing electricity consumption when the wind is blowing, or reducing loads when the wind is not blowing and/or the sun is not shining. Increased use of electricity for heating in short time periods is however only applicable to heating systems that have alternative technologies installed, e.g. bio boiler or gas boilers. Hence, the highest potential for valley filling and load shaving is in district heating grids or local heating grids[9], as they more easily can switch from electric heating to alternative heating (load shaving) and vice versa (valley filling). Note however, that such switching between fuels requires waterborne hydronic heating systems within the buildings.

Summed up, as the flexibility is the possibility to change, i.e. shift or move, the electric consumption profile, relative to a 'business as usual' profile (De Coninck & Helsen 2013), it is important to know the characteristics of the present load of the local grid before adding electric heating and DSM mechanisms.

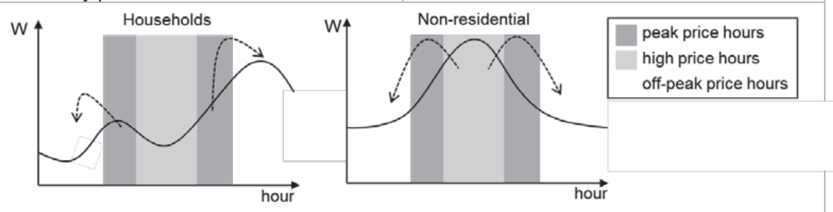
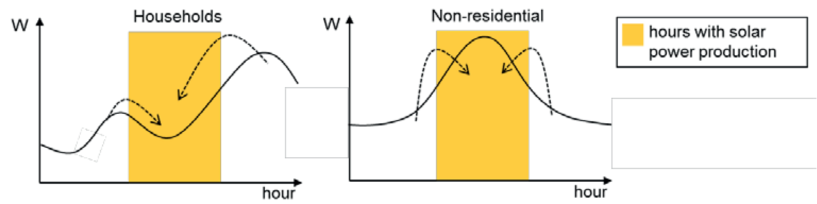
2.2.2 On-site production

On-site production within ZEBs, especially solar PV, changes the load profile seen from the grid's perspective dramatically, as the building both consumes and produces electricity. Hence, the building imports and exports electricity to the power grid, creating a net electric load, $P_{NET} = P_{load} - P_{PV}$. Along with the PV production, the incentive for moving loads also changes.

Table 2-1 shows how consumers are motivated to shift their loads. In most European countries, the end-consumer is not exposed to real time prices and receives a constant electricity price throughout the year. However, if exposed to hourly real time prices, they will have incentives to shift their loads to avoid peak price hours, thus moving load from periods with high prices to periods with low prices. If on-site PV is applied to the building, the customers would like to increase their self-consumption by shifting loads from afternoon/night to midday, i.e. the load shifting takes place in the opposite direction.

[9] In theory, individual buildings with two or more parallel heat production systems can provide the same fuel switching. However in practice, it can be cost intensive for single buildings to install several parallel heat production technologies.

Table 2-1 Incentives for shifting/moving electric building loads with and without on-site PV production.

<table>
<tr><th></th><th>Incentive</th><th>Action</th></tr>
<tr><td rowspan="2">hourly electricity price</td><td>Saving cost by moving load from hours with high electricity prices to hours with lower electricity prices.</td><td>Moving load from peak hours (day) to off-peak hours (at night)</td></tr>
<tr><td colspan="2">
</td></tr>
<tr><td rowspan="2">on-site PV
(both with and without hourly electricity price)</td><td>Saving costs by increasing self-consumption of on-site PV (at midday)</td><td>Moving load from afternoon/night to midday</td></tr>
<tr><td colspan="2">
</td></tr>
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2.2.3 Increasing flexibility through storage

In the literature, the main focus of DSM has been on utilising storage possibilities rather than utilising flexible building loads. This section briefly elaborates on the potential for load shifting by use of batteries or heat storage.

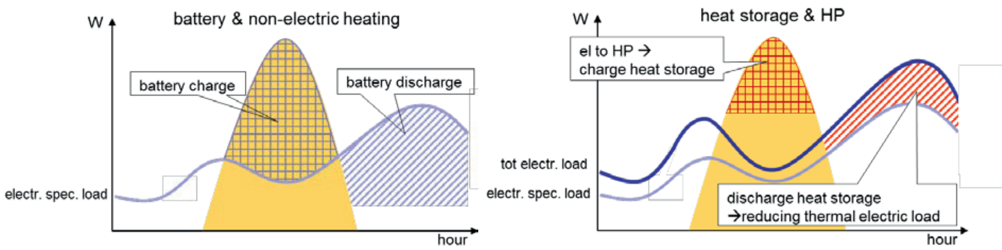

Figure 2-5 Load shifting of ZEB with battery (left). Load shifting of ZEB with heat storage (right).

The presence of storage increases the possibility of moving the electric loads (cf. Chapter 2.2.1), and to self-consume more of the on-site power production (cf. Chapter 2.2.2). Figure 2-5 shows the concept of how to utilise a battery (left) and a heat storage (right) in a residential ZEB with PV generation. The left graph depicts a household with non-electric heating and a battery. Here, the battery stores electricity generated by the PV from day to night, thereby reducing the electric specific load in the evening. In the case where a heat storage and a heat pump cover the heat load, the storage is charged by a HP which utilises the PV electricity during the day. The heat storage is depleted when covering the heat load in the evening. As the figures indicate, a battery targets the total electric load of the building, whereas a thermal storage only targets the thermal electric load[10]. Hence, the load shifting potential is larger for a battery than a thermal storage, as it can serve both electric specific demand and (thermal electric) heat demand of the building.

The available flexibility offered by a storage depends on 1) the size and type of storage (whether it is a battery or a thermal storage), and 2) how it is operated in relation to the rest of the building's energy system, i.e. which control strategies are applied.

2.2.4 Flexibility needs from a system perspective

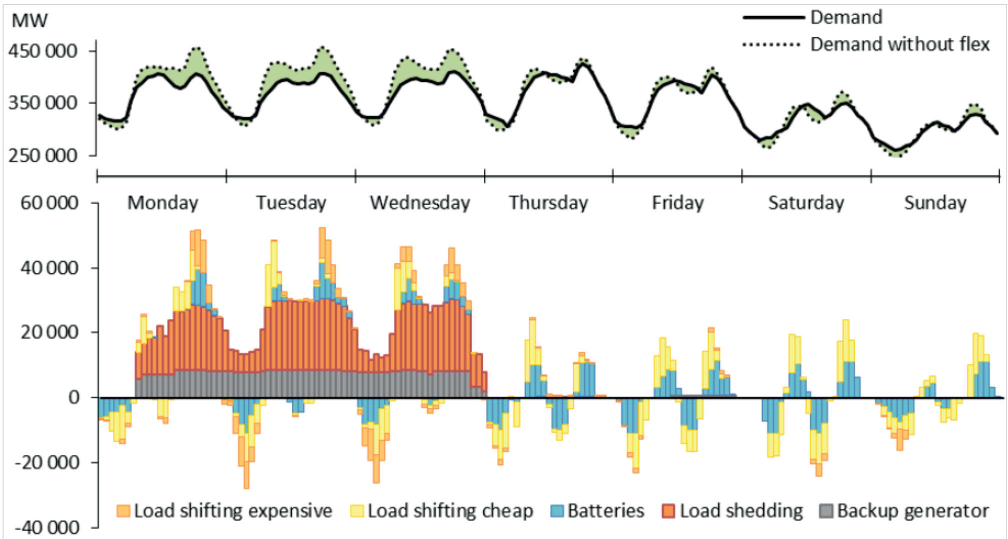

Figure 2-6 Simulated need for flexibility[11] of a winter week in 2030.(Västermark et al. 2015)

From a system perspective, the need for load shaving occurs when the sun is not shining or the wind is not blowing, and opposite, the need for valley filling occurs when there is too much wind or sun that needs to be consumed. Hence, with more renewables in future, the need for flexibility will increase. Especially wind production can experience longer periods of unforeseen low wind speeds, hence creating a need for load shifting and/or load shaving up to three consecutive days (Västermark et al. 2015) (Cochran et al. 2014). Figure 2-6[12] suggests that *load shifting* (orange & yellow) is activated on a daily basis, moving loads from morning and evening to night. Whereas *load shaving* (red) is activated over a period of three consecutive days. However, when compared to the flexibility that end-users can offer, it tends to be at its lowest when the need for flexibility is at its highest (Olsen et al. 2013), i.e. in the morning and afternoon on a cold winter day in a Nordic climate. This challenge needs to be investigated further, and a first step would be to identify and quantify the building loads that are able to offer flexibility, such as seen in (Olsen et al. 2013).

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[10] The electric load of a HP or direct electric heating is often denoted as "thermal electric load".
[11] The flexibility mechanism called "load shedding" in the figure corresponds to "load shaving" in this thesis.
[12] The analysis includes most of the countries in Europe, excluding Spain, Portugal, Ireland, and East-European countries east of Austria, Slovakia, Poland and the Baltic states.

2.3 Energy system analysis and power system analysis

This chapter explains what the terms *energy system analysis* and *power system analysis* denotes in this thesis, and elaborates on the difference between them.

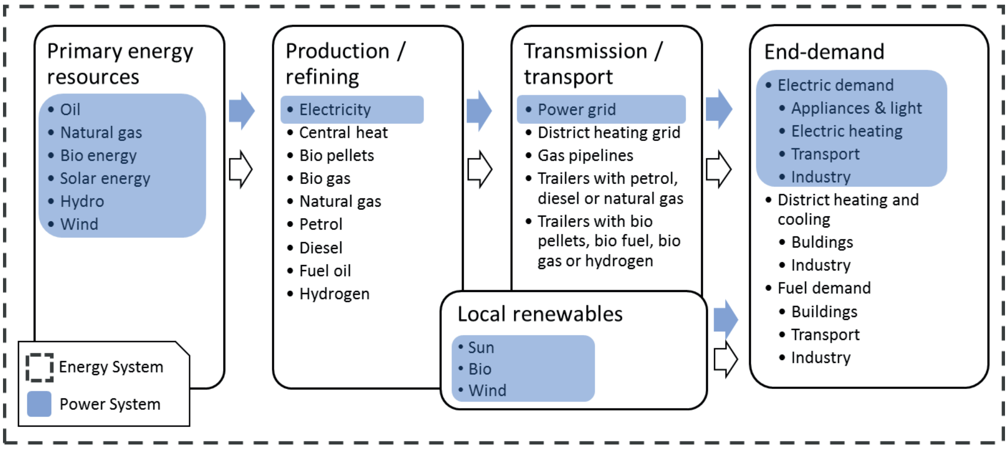

Figure 2-7 System boundaries for Energy System and Power System.

2.3.1 Energy system and power system

The *power system* embraces electricity production, electricity transformation and transmission, and electricity demand (in buildings, industry or EVs). Whereas the *energy system* embraces all energy carriers in addition to electricity, from primary resources to end-consumption. This is illustrated in Figure 2-7.

There are two main directions for aggregated system modelling tools. The first finds the optimal operation of, or simulates, a given system. As endogenous investments are commonly not included, analysis of future power systems must assume the size of the installed production capacity and the capacity of transmission lines at the time of the analysis (either today or future years). The second direction deals with medium and long-term investments decisions of e.g. new power production plants, transmission lines or heat technologies.

As electricity must be consumed the instant it is produced, it is mainly the operation of the power system that is investigated in the first category, often with hourly or sub-hourly time resolution. Medium- and long-term investments decisions are usually conducted over a longer time frame, ranging from 20 up to 50 years, with an annual or seasonal time-resolution. Such models can therefore be developed for the entire energy system including all energy carriers in addition to electricity. Table 2-2 lists examples of modelling tools being used in the Nordic countries today, categorised by the system of investigation, and the objective. The two models used in this thesis are the EMPS model of the Nordic countries, and a TIMES model developed for the Scandinavian countries.

Table 2-2 Energy system and power system modelling tools used in the Nordic countries – a simple overview.

		Objective	
		Short and Medium term Operation / Simulation of a given system	Medium and Long term Investment decisions
System	*Power system*	EMPS, BID, TheMA	
	Power and district heating system	WILMAR, RAMSES, EnergyPLAN, TRNSYS	Balmorel
	Total energy system		MARKAL, TIMES

2.3.2 Aggregate load profiles

Load input required for *power system analysis* and *energy system analysis*, is elaborated in the following.

The power system analysis requires a *total electric load* of the system, which is to be met. This load includes electricity demand in industry, appliances and lighting in buildings (electric specific demand), and if present, electricity for heating and electric vehicles. In the energy system analysis on the other hand, the heat technologies installed in buildings is a model result, as the model finds the most economic way to serve the demand by endogenous investments of both production technologies as well as end-user technologies (e.g. boilers or HP). Hence, energy system analysis requires load profiles for *electric specific demand* and *heat demand* separately. Summed up, the total electric load profile is a model output from the energy system analysis, but is a model input in the power system analysis. However, they both require a projection of the underlying heat and electric specific demand of the buildings. (This is elaborated in Chapter 3.4.)

In power system analysis, as mentioned in Chapter 1.1., the measured electric load from the European Energy Exchange (EEX) is traditionally used as load input. However, there are some studies that incorporate the impact of electric heating and electric vehicles on long-term forecasts of the aggregated hourly *total electric load*. (Veldman et al. 2013) and (Boßmann et al. 2013) take today's electricity load profile from the EEX, and add changes to this according to assumed future development of EVs and heat pumps, but do not account for energy efficiency measures.

In energy system analysis, the electric specific demand is commonly obtained from the measured electric load from the EEX or NordPool power exchange, whereas the heat demand is taken from building simulation models. Studies with hourly time resolution can be found in (Hedegaard et al., 2012; Hedegaard et al., 2013; Henning & Palzer 2014). However, as they rely on building simulations to determine the heat demand, they might tend to overestimate the impact of energy efficiency measures (cf. Chapter 1.1 on the discrepancy between measured and simulated energy demand of buildings).

As opposed to most European countries, 80 % of the heat demand in Norway is covered by electricity (Lindberg & Magnussen 2010), and hence, the measured electric load from Nord Pool contain both electric specific demand and thermal electric demand. Therefore, heat and electric specific demand of buildings in Norway have to be predicted separately by a bottom-up methodology. With increasing electric heating in future, this will also apply for European conditions.

3 Results and discussions

This chapter gives a brief presentation of the eight articles that constitute the main contribution of the thesis. The first two articles estimate the heat and electric specific load of existing buildings compared to passive buildings using experimental data. Article III, IV and V investigates the cost-optimal energy system design within ZEB buildings and how their grid interaction depends on the choice of energy technologies within the building, both for Norwegian (III and IV) and German conditions (V). The sixth article analyses the cost-optimal system design of a heat pump coupled to an electric back-up heater and a heat storage for German conditions. Chapter 3.4, describes the methodology for calculating the national aggregate electric load profile of Norway, which is used in the system analyses of the last two articles that analyse the implications of a massive introduction of energy efficient and energy generating ZEB buildings. The seventh article investigates the operation of the power system in the Nordic countries in 2030 using the EMPS power system modelling tool, while the eighth article investigates cost-optimal investment decisions in the Scandinavian energy system towards 2050 using the TIMES modelling framework. Each section concludes with a discussion and in some cases specific conclusion for the particular group of articles.

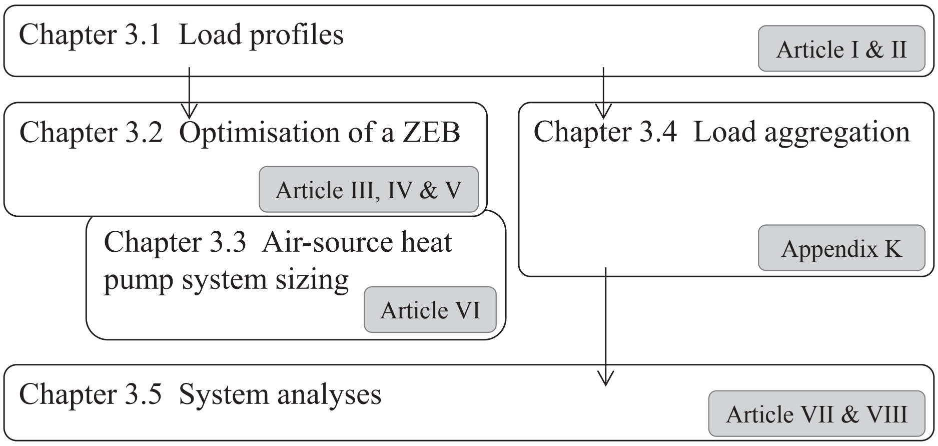

Figure 3-1 Guide to the reader (see also Figure 1-4)

3.1 Hourly load profiles of ZEBs compared to existing buildings

In the first two articles, regression models are developed to predict heat and electricity demand of non-residential buildings in Norway. Hourly measurements of heat and electricity consumption of over 200 non-residential buildings scattered around Norway have been analysed. The results for schools and office buildings are shown in the articles, whereas the regression models of the remaining buildings are presented in Appendix B. The analysis uses a panel data fixed regression method to evaluate the difference between average existing buildings and energy efficient passive buildings.

The concept of the load prediction methodology is depicted in Figure 3-2. Based on the methodology first developed by Pedersen (Pedersen 2007a), regression models are established for each building category's heat and electric specific load. After the regression models have been established and the model parameters estimated, the hourly heat load profiles and electric specific load profiles can be predicted on the basis of temperature data and geographic position.

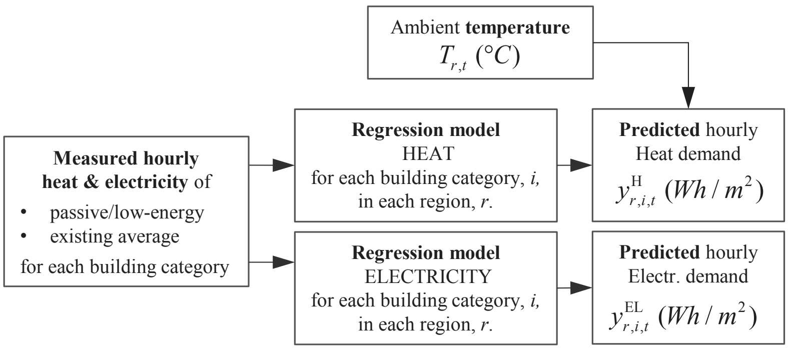

Figure 3-2 Concept of load prediction methodology for heat and electricity demand.

3.1.1 Article I: Heat load profiles

This article investigates different model formulations to explain the dynamics of a building's heat demand. The analysis uses hourly measured heat consumption[13] of existing school buildings scattered across Norway, and compares them to a passive school building.

The most significant explanatory variables were found to be the ambient temperature, and the 24 hour moving average of the ambient temperature. The results of the estimated parameter values indicate that the temperature dependency for a passive school is lower compared to the average existing school building. This means that when temperature drops, the gradient for heat consumption is lower for passive buildings, and will thus add less stress on the electricity or district heat grid. Comparing predicted load profiles of a passive and an average existing school, with equal outdoor temperature as seen in see Figure 3-3, shows that the maximum diurnal amplitude of the heat load in winter, is reduced by 48 %. The findings of the *heat load* profile illustrates that heat consumption in passive school buildings is almost

[13] It is assumed that the building's consumption of district heat, or electricity used in an electric boiler, equals the building's heat demand (space heat & DHW).

halved compared to average existing school buildings, both in terms of annual energy demand and in terms of peak loads on a cold winter day.

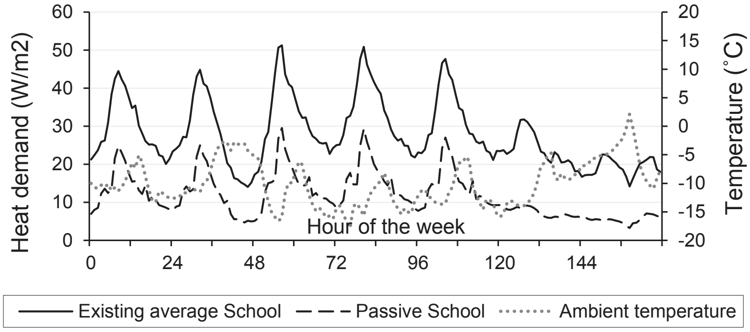

Figure 3-3 Predicted heat load profile for a cold week in winter of existing and passive school buildings.

3.1.2 Article II: Electric specific load profiles

Article II investigates different model formulations for the electric specific demand of schools and office buildings. The analysis uses hourly measured electricity consumption[14] from existing buildings, and compares them to passive buildings.

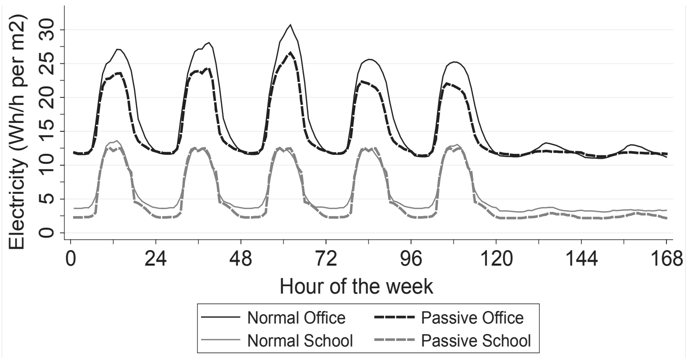

Figure 3-4 Predicted electric specific load profile for a week in summer of average existing (normal) and passive school and office buildings.

Findings for the *electric specific load* profiles show that cooling demand is present in both existing and passive offices, but the temperature dependency is about 30 % lower for passive office buildings. The characteristic bell shape of the load profile is similar, however the peak load is reduced by 12-13 % even though the base load consumption is unchanged (see Figure 3-4). The total energy demand of passive offices and schools is respectively 27 % and 55 % lower when compared to the average existing buildings. The reduction of electric specific demand is however less obvious, at 6 % for offices and

[14] It is assumed that if the building is heated by a hydronic heating system, the consumption of electricity will reflect the building's electric specific demand. (See definitions on page ix.)

29 % for schools[15]. By this, we may conclude that electricity demand is less affected, compared to heat demand, when buildings become more energy efficient.

3.1.3 Discussion of the building's load profiles

There are several uncertainties to the methodology applied in Article I & II. First, the buildings in the sample all have hydronic heating systems. As many of the buildings in Norway are heated by direct electricity, the sample might not be fully representative of the Norwegian building stock. On the other hand, as buildings heated by electricity do not have separate meters for heating, it is not possible to separate the electricity used for heating, for such buildings, especially electricity used for hot tap water which is independent on outdoor temperature. Further, the measured electricity load of buildings with hydronic heating system is assumed to reflect their electric specific demand. This approach thus assumes that there is no electric heating in the building. However, investigating the data of the electric specific load, it was identified that some buildings had a seasonal pattern of their electric load, indicating that there might be e.g. electric coils for ventilation heating or for floor heating of bathrooms, or additional electric radiators installed. This was especially evident for the electric load of the existing school buildings. However, as the DHW demand is included in the heat measurements, the regression model for the electric load was able to correct for this effect (cf. "heating effect" in Article II).

The sample size of the passive buildings is too small, only consisting of one school building and two offices. With more passive buildings in the sample, the level of the load profile might change however, the shape of the profiles will be similar. Another aspect is the uncertainty of the heated area (m^2) of each building, which determines the level of the load profiles. Hence, if the real size of the heated area is smaller than specified in the meta data, the load profile would be shifted upwards, and vice versa. Further, measured data on solar irradiation at the actual site of the individual buildings would probably lead to higher goodness of fit (R^2) of the heat load models, however, the predictions might not be significantly improved.

3.1.4 Load profiles of all building categories

Appendix B presents the regression models developed for average existing buildings of the remaining non-residential building categories; kindergarten, hotel, nursing home, hospital, university, cultural and sport buildings, and shops & malls. The load profiles of households are based on Pedersen's (Pedersen 2007a) regression model, which uses the daily mean temperatures as explanatory variable. The model parameters are modified so that hourly temperatures are used.

The appendix also elaborates on the constructed regression models for passive buildings, for all building categories. First, the differences between the existing and passive buildings for schools and offices were identified. Secondly, the same reduction of the model parameters was applied to the regression models of the average existing buildings of the remaining building types, to find the passive load profile of each building type.

[15] A heating effect was observed when analysing the electric specific load profiles of the existing school buildings in Norway. This is the main reason for the large reduction of the electric specific demand in the results. However, when removing this heating effect, the reduction of the electric specific demand for schools is lower.

In total, 44 load prediction models are developed, i.e. 2 load types (heat and electricity), for 11 building categories, and for 2 technical standards (existing and passive).

Table 3-1 Overview over regression models developed, by building category and standard (existing or passive).

	Existing Buildings		Passive Buildings	
	Load models by experimental data	Constructed load models based on	Load models by experimental data	Constructed load models based on
1 School	✓		✓	
2 Office	✓		✓	
3 Shops	✓			Shops
4 Kinderg	✓			Kinderg
5 Hotel	✓			Hotel
6 NursHome	✓			NursHome
7 Hospital	✓			Hospital
8 Univ		Office		Office
9 Cult_Sport		NursHome & Hospital		NursHome & Hospital
10 SFH	✓*	*based on Pedersen		*based on Pedersen
11 Apartm	✓*			

3.1.5 General conclusion on building's load profiles

The findings of article I and II, and the fact that the electric specific demand of Swedish households according to the Swedish Energy Agency has been relatively stable since 1990, suggests that it is mainly the heat demand that is reduced when buildings become more energy efficient, whereas the electric specific demand is less affected. Hence, it is assumed that the electric specific demand is similar in existing and passive buildings when performing the load aggregations in Section 3.4.

3.2 Optimal Zero Energy Buildings

Performing power system analysis requires knowledge of the electric load of the buildings seen from the grid's perspective, i.e. the *net electric load profile* of the building. The characteristic of the net electric profile of a building is dependent on whether it is heated by electricity or by other energy carriers. To identify what influences the choice of energy technologies from the building owner's perspective, i.e. the *energy system design* of the building, an optimisation model is developed using mixed-integer linear programming. Total discounted costs throughout the building's lifetime are minimised with a financial perspective, which simultaneously finds the optimal investments of the building's energy system, and its optimal operation.

Three case studies are performed using this model:

1) Norwegian ZEB building with hourly time resolution (article III and IV)
2) German ZEB building with hourly time resolution (article V)
3) German building with 15 min resolution, investigating the design of an air-sourced heat pump system (article VI)

The only modelled DSM mechanisms is the use of heat storage, which enables load shifting of the thermal electric load.

The market price of electricity varies from hour to hour and from year to year. Rather than constructing an electricity price signal, the hourly electricity prices from 2012 are used as input in the case studies. 2012 was a year with close to average 'normal' climatic conditions, but also contained short periods of cold weather and high inflow of water. Hence, the electricity price for 2012 is reasonably representative for a normal climatic year, while also having a representative share of peak prices and low prices. For future conditions with more renewable energy in the production mix, constructed electricity price time series should be used. (see examples in e.g. (Ravnaas et al. 2010) (Henden 2014))

Even though the market price in Germany and Norway in 2012 was similar at 3-4 ct/kWh, the electricity price for end-consumers in Norway (at 8 ct/kWh) is 67 % lower when compared to Germany (at 24 ct/kWh) due to tax differences. In Norway, there is also an additional fee for maximum load (power tariff) for non-residential buildings and industrial consumers, which is incorporated in the modelling tool.

3.2.1 Article III: Optimal investments of a Norwegian ZEB

In Article III, the first edition of the MILP optimisation model is presented together with a case study of a Norwegian school building of 10 000 m^2. The load profiles of hourly electric specific and heat demand are obtained from the regression models of a passive school building from Article I and II.

The results show that the most cost-optimal way to serve a Norwegian school building with heat is through a heat pump (HP). When the building is obliged to be a ZEB, this change to a bio pellets boiler with on-site PV production. Even though the weighting factor for electricity at 130 g_{CO2}/kWh is relatively low compared to European conditions, it is still much higher than for bio energy at 7 g_{CO2}/kWh. According to Equation (1), using a bio pellets boiler for heating rather than a HP, leads to smaller weighted energy imports, and consequently to lower weighted energy exports, and smaller PV size. As there are no investment subsidies for PV in Norway, the saved cost from a smaller PV size makes it cost-efficient to reduce the weighted energy imports to the building rather than increasing the exports (green dot in Figure 2-1). This is despite the low electricity price, which favours HP as heat technology.

The grid impact of the 'strictly ZEB' building heated by bioenergy is evaluated by the maximum hourly import and export of electricity. Here, the peak export is 1,6 times higher than the peak import, indicating that the building would need 60 % higher grid connection capacity due to the on-site PV. However, when compared to the reference building ('no ZEB') with a heat pump, the peak electricity import value is higher than the ZEB's peak export value, and the designed grid connection capacity is adequate.

The sensitivity analyses show that by applying a limit on the peak electricity export value, less energy efficient electric boilers are applied to generate heat in summer in order to consume more of the on-site PV rather than exporting it to the grid. However, as the building still needs to export the same amount of electricity in order to reach the ZEB balance, the PV size becomes larger, which again increases the total costs. If heating the ZEB with a heat pump, rather than bio energy, leads to higher self-consumption, but also higher grid impact. With higher prices for both selling and buying electricity, the optimal energy system design is unchanged, and despite the increased income of electricity export from the building to the grid, the summed effect is that total costs increase. Reducing the price differences between the selling price and buying price of electricity, the building owner becomes indifferent whether to self-consume or not. Hence, to retain the incentive for self-consumption of PV, the selling-price should be kept lower than the buying price.

Summed up, the cost-optimal energy system of a Norwegian ZEB is a bio pellets boiler combined with on-site PV. Further, additional grid connection capacity for ZEBs in Norway might not be necessary, as the grid is already designed to handle that buildings are heated by electricity. Please also see Chapter 3.2.4 which discusses how the weighting factors influence the heat technology choice.

3.2.2 Article IV: Methodology of optimal investments of ZEBs

The main intention of Article IV is to give a detailed description of the modelling framework. The MILP model developed for Article III, is here expanded to include district heating, gas boiler and CHP, and improved modelling of solar thermal heating and heat pumps. Further, the mathematical description of the electricity import and export from the building now includes feed-in-tariffs and self-consumption tariff. Lastly, the possibility of studying different ZEB levels is applied, through the possibility of relaxing the ZEB restriction (or vice versa: increasing the ZEB level gradually).

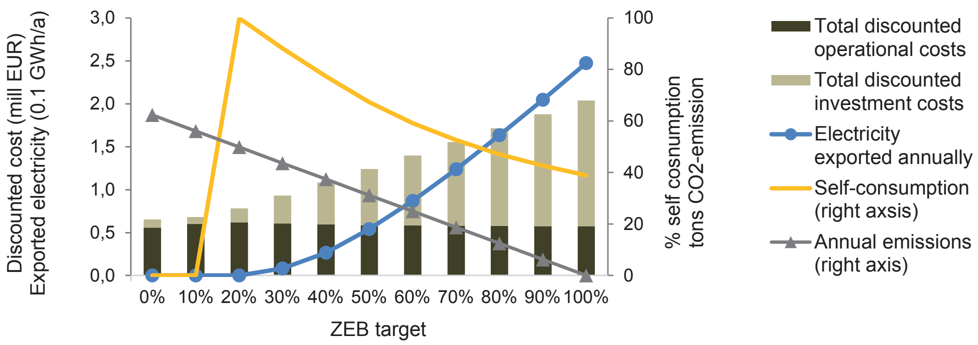

Figure 3-5 Increasing the ZEB level from 'no ZEB' (0 %), to 'nearly ZEB' (10-90 %) and to 'strictly ZEB' (100 %), for the Norwegian ZEB school building.

In order to show some brief results, the same case study of Article III with the Norwegian school building is used. The new analysis performed is the relaxation of the ZEB restriction. The findings show that the heat technology shifts from heat pump to bio pellets boiler at *'20 % nearly ZEB'* requirement. Further, as shown in Figure 3-5, the self-consumption of PV decreases when moving from *'nearly ZEB'* to *'strictly ZEB'*, and the total discounted costs (investments & operational) are 65 % higher in the *'strictly ZEB'* case when compared to the *'50 % nearly ZEB'*. The cost increase is mainly caused by the larger investment costs for PV capacity, which dominates the total cost increase although the discounted operational costs are 2 % lower due to the higher sales of exported electricity.

The net electric load curve of the Norwegian *'strictly ZEB'* is shown in Figure 3-6. Here, the peak export value is 1,5 times higher than the peak import value, and the building exports electricity in 26 % of the time.

In future, one might experience higher peak power charges in order to reduce/cut/shave peak export or peak import values. Even though this was not explicitly investigated in this article, it is likely that the same trend as in the case of restricting the import/export values in article III will apply. That is, to avoid peak export in summer, the installed capacity of the heat storage and electric boiler will become larger, and the total costs will increase. However, as the heat demand in summer is small, the possibility of reducing export hours is limited.

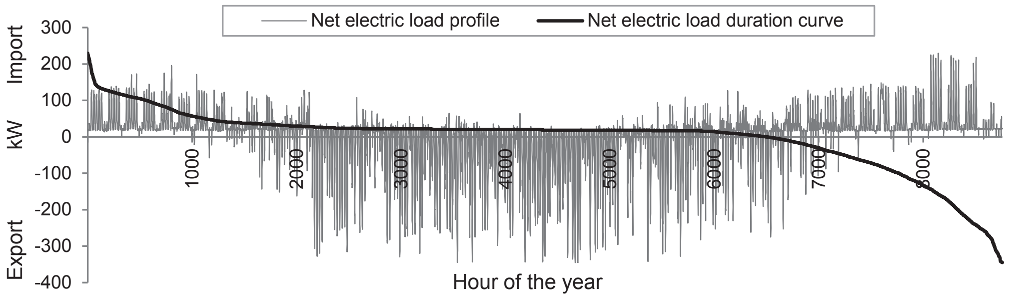

Figure 3-6 Hourly net electric load duration curve of the Norwegian ZEB school with PV and bio pellets boiler.

During winter, the peak import is caused by the electric boiler, which is activated during the hours of peak heat demand in winter when the bio pellet boiler is operated at its maximum, and the storage is empty. If peak loads were charged with a higher fee, using an electric top-up boiler as back-up might be rejected. Possible outcomes would be to increase the storage size so that it covers more of the peak load, or to install another back-up technology (bio boiler, or a gas boiler). A third possibility is to increase the size of the bio boiler, however this will lower the efficiency as it would run at part load all hours except peak hours.

3.2.3 Article V: Optimal investments of a German ZEB and its grid interaction

This article applies the MILP optimisation model from article IV on a case study of a German multi-family home. The load profiles of heat and electric specific demand are taken from SynPro. As opposed to the Norwegian case, the results show that the added system cost of the on-site energy production is almost negligible due to the feed-in tariff of PV electricity in Germany. Hence, it is cost-efficient to increase the on-site production (red dot in Figure 2-1), rather than decreasing the imports by replacing fossil heating with renewable energy sources (green dot). Consequently, the cost-efficient energy system design of a German ZEB building is a micro CHP fuelled by natural gas, with massive on-site PV generation. The choice of CHP is explained by the low price of natural gas at 5 ct/kWh, and the high electricity price at 24 ct/kWh, which favours self-consumption of CHP generated electricity.

The net electric load profile equals the electricity consumed subtracted the on-site electricity production. Hence, it both depends on the type of building (non-residential or residential), on the heating system (non-electric or electric, and, with or without storage) and on the size of the on-site PV capacity. Investigating the characteristics of the net electric load profile reveals the building's grid impact. In the *'strictly ZEB'* case, the peak export value is three times higher than the peak export value, and the building is exporting electricity in 38 % of the time. One way to ease the building's grid impact is to relax the ZEB requirement from *'strictly ZEB'* to *'nearly ZEB'*. The results show that the PV size is reduced, but the heat technology choice remains unchanged, i.e. moving downwards along the red vertical line in Figure 2-1. The effect on the duration curve of the net electric load is seen in Figure 3-7, where the export from the building is reduced, but the electricity imports are unchanged.

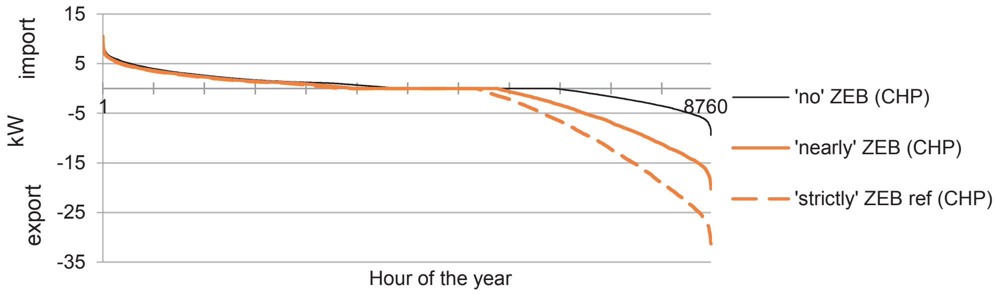

Figure 3-7 Net electric load duration curve of a ZEB, while relaxing the ZEB restriction from 'strictly' to 'nearly' to 'no' ZEB. All cases have a natural gas fuelled CHP as main heating technology.

The grid impact is further evaluated according to the main heating technology choice, as seen in Figure 3-8. Here, the net electric load duration curve is depicted for five *'strictly ZEB'* cases with respectively heat pump, bio boiler, gas boiler or CHP as main heating technology. The findings show that it is mainly the electricity exports that are affected by the main heat technology, especially the peak export values.

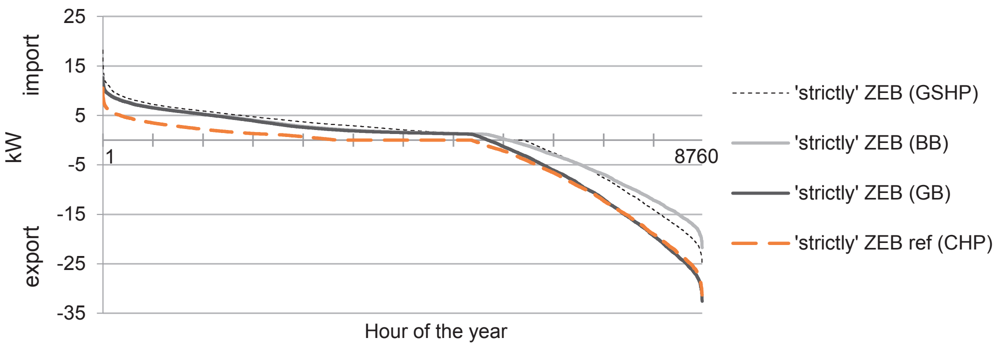

Figure 3-8 Net electric load duration curves of a 'strictly' ZEB with heat pump (HP), bio pellets boiler (BB), gas boiler (GB) or CHP as main heating technology.

The results of the sensitivity analyses show that the cost-optimal energy system design of a German ZEB changes from a CHP to a gas boiler to a bio pellets boiler when either *increasing* the natural gas price, *decreasing* the electricity price or the electricity weighting factor, or *removing* the feed-in tariff of PVs. That is, moving from the red dot towards the green dot in Figure 2-1.

The findings further show that the heat pump (HP) is not a cost-efficient technology choice for German ZEB buildings. Even with lower electricity prices or lower electricity weighting factors, the heat pump is still too expensive when compared to the bio pellets boiler, hence, there is only a narrow opportunity window for HPs.

One of the main takeaways from article V is that applying both the ZEB target and the FiTPV leads to fossil fuel based heating technologies with a large PV area. This contradiction should be addressed when the political definition of ZEB buildings is determined.

3.2.4 Discussion of the optimal ZEB

Robustness of heat technology choice

The model developed assumes that the building owners solely make their decision on cost, and hence, the input for investment costs of the technologies are critical for the model result. Even though the bio pellets boiler is the preferred heat technology of the Norwegian ZEB, the total cost with a heat pump is only about 10 % higher. Further, when the cost of PV is reduced, Article III shows that the profitability of the heat pumps increases. Thus, the choice of whether to use heat pump or bio boiler in the Norwegian case is not as clear as the CHP being the winner in the German ZEB.

The sensitivity analysis of Article V investigated the impact of lower electricity prices, increased gas price and lower weighting factor for electricity. The results show that using natural gas for heating ZEBs in Germany is a robust result, but whether it is used in a gas boiler or a CHP depends on the electricity price. A high electricity price increases the value of self-generated electricity from the CHP, but if the electricity price goes below the current end-user price, a gas boiler is preferred over the CHP.

The *choice* of heat technology depends on the technology costs, subsidies and the ZEB definition. However, Article VI confirms that the system *sizes* are mainly determined by the heat load profiles of the building. As the load profiles are predicted for the climatic year 2012, the system sizes might differ if another climatic year was chosen, however the choice of technologies would not be altered. The same conclusion applies for a ZEB office or hotel that have different load profiles of their energy demand. That is, a ZEB office in Norway would also have a bio pellets boiler and PVs, and a ZEB office in Germany would have a CHP and PVs, however, the sizing of the technologies will be adapted to fit their loads. Lastly, the model assumption of perfect foresight makes the technologies perfectly sized according to the peak load of the building. In real life, a safety margin is usually added, slightly increasing the back-up technology and storage.

In future, we might face more variable electricity prices and grid charges of peak load. The sensitivity analyses of Article VI show that the impact of curtailing or reducing peak import or export, leads to increased system sizes of the back-up technology and the storage, however, it does not seem to influence the choice of energy technologies.

Thermal storage in ZEBs

There are three possible purposes of the storage. The first is to increase the utilisation of the installed heat technology by charging the storage in hours of low demand and providing heat in hours of high demand. Secondly, if using electric heating, the storage can take advantage of the hourly price fluctuations, i.e. charging the storage in hours with low electricity price, and depleting it in peak price hours. The third purpose is to increase the utilisation of on-site energy production, charging the storage in hours with on-site production, and depleting it when not.

In the Norwegian ZEB with bioenergy, the storage is used for increasing the utilisation of the bio boiler, i.e. purpose #1. In the German ZEB with CHP, the storage enables the CHP to adapt its operation to the on-site PV so that the amount of exported electricity is minimised, i.e. purpose #1 and #3. In the case of a ZEB with heat pump, the storage is used for all three purposes; that is increasing the utilisation of the heat pump, utilising on-site PV production, and taking advantage of hourly electricity price variations. (cf. general reflections in Chapter 2.2).

The findings of Article III-V show that the thermal storage is sized to meet on a daily basis. In Article III, even with a storage almost free of charge did not give seasonal heat storage. The reason is assumed to lie in the losses that storing heat on a seasonal level would cause.

Future investment costs

In future we might face lower investment costs of PVs, heat pumps and storage. Article III showed that lower investments cost of PV in the Norwegian case increases the cost-competitiveness of the heat pump, and hence, with lower PV costs, the heat technology choice alters towards the cost-optimal choice of the *'no ZEB'*. For the German ZEB, the heat technology choice is equal for *'no ZEB'* and *'strictly ZEB'*, and hence, the heat technology choice of ZEBs in Germany is unchanged with lower PV investment cost. Additionally, reduced PV investment cost would make PV go beyond grid-parity, and lead to an infinite PV size as the owner would receive a net income on the investment.

Lower investment cost of heat pumps in the Norwegian ZEB will have the same effect on the technology mix as lower PV investment cost, i.e. increasing the cost-competitiveness of heat pumps. In the German ZEB, however, the high electricity end-use price makes the CHP profitable, and the HP investment costs would need to be substantially reduced in order for the HP to become profitable.

The findings during the development of the modelling framework of Article III to VI found that the investment cost of the storage has little impact on the utilisation of the storage and hence on the storage size.

The weighting factor for electricity

One of the main questions regarding the ZEB buildings, especially in Norway, is the value of the weighting factor for electricity. The average European value is 350 g/kWhel, whereas the large Norwegian hydro power makes the Norwegian weighting factor for electricity, f_{el}, maybe down to 2 - 3 g/kWhel. On the other hand, as Norway is connected to the Nordic power system, the marginal electricity production in Denmark or Germany might determine the weighting factor in Norway. Hence, a fundamental discussion on how the weighting factor for electricity influences the ZEB's grid impact is elaborated in the following.

Reducing the weighting factor for electricity would intuitively lead to reduced need of on-site electricity generation, as the imported electricity is "greener". However, as the findings in Article V show, the opposite effect occurs. Let us evaluate the weighted imports for electricity specific demand and heat demand separately.

The weighted imports for *the electric specific demand* must be compensated by weighted exports of PV electricity. As the energy carrier is the same, i.e. electricity, according to Equation (2), the amount of exported el, $y^{\exp}$, is unaffected by the weighting factor, f_{el}. Even though the weighted energy imports and exports (only for the electric specific demand) differ with the weighting factor of electricity, the amount of electricity imported and exported is the same.

$$f_{el} \cdot y_{el}^{\text{impEL.SPEC.}} \quad - \quad f_{el} \cdot y_{el}^{\text{expEL.SPEC.}} \quad = \quad 0 \tag{2}$$

The weighted imports for *the heat demand* of the building if heated by bio energy, ($f_{\text{bio}} \cdot y_{\text{bio}}$), is independent of the weighting factor for electricity, and hence also the weighted energy exports. Let us say that the weighted energy import of bio energy is 100 kg_{CO2}. For Equation (3) to hold with a lower f_{el} of the exported electricity, the amount of electricity export $y^{\exp}$ must increase.

$$100\ kg_{\text{CO2}} \quad - \quad f_{el} \cdot y_{el}^{\text{expHEAT}} \quad = \quad 0 \tag{3}$$

The contradiction of a lower f_{el} is hence as follows. When the imported electricity is less polluted, the exported electricity also displaces less pollution in the grid, making it more difficult to reach the strictly zero target. This is illustrated in Figure 3-9 for a ZEB heated by bio pellets, where the electricity ecports to compensate for the electric specific demand is unaffected by f_{el}, whereas the electricity exports compensating for the heat demand increases with a lower f_{el}. The same considerations applies for all buildings heated with non-electric heating.

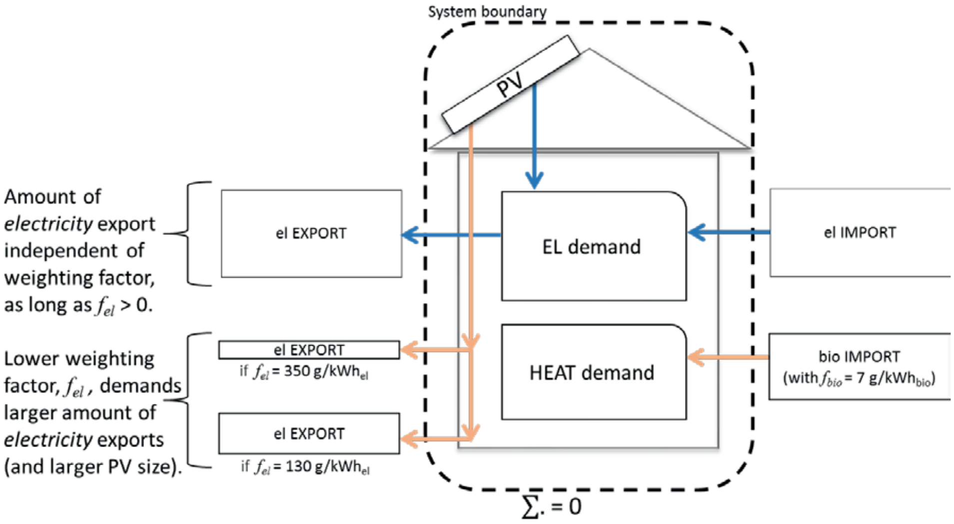

Figure 3-9 Influence of the electricity weighting factor on the required electricity exports for ZEBs with non- electric heating.

In the case of an all-electric building heated by a HP or an electric boiler, the weighted imports and exports to/from the building has equal weighting factor, and the building has to export equal amount of electricity as it imports if the ZEB target is strictly zero. Consequently, the required PV size of an all-electric ZEB is independent of the weighting factor of electricity.

The opportunity window for solar thermal (ST)

In all three articles on the optimal ZEBs, solar thermal (ST) is not a cost efficient technology choice. In the practical world, ST is often said to compete with PV as they occupy the same area of the building's façade or roof. However, the findings show that ST competes with the fuel costs of the heating technology within the building, and not with the PV. This is illustrated in Figure 3-10, where the solar thermal heat reduces the imported energy for heat generation in the building, and thereby the required PV size.

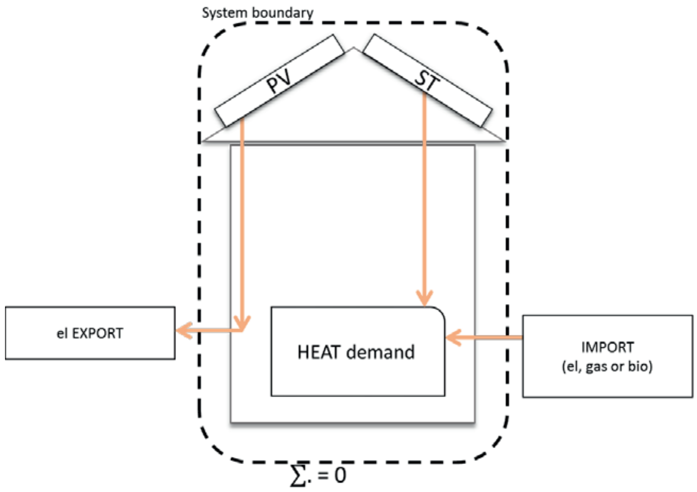

Figure 3-10 Impact of solar thermal heat (ST) on required weighted electricity exports.

The opportunity window for heat pumps

The findings of the case studies reveal that the choice of whether to use bio boiler or HP is made by the trade-off between the fuel & investment cost of the heat technology, and the cost of the required size of PV that compensates for the weighted energy imports. Apart from reducing the costs (fuel & investment) of the HP, the most promising way to make the HP favourable to the bio boiler, is to increase the weighting factor for bio energy. As seen in Article V, reducing the weighting factor for electricity leads to larger PV size without changing the heat technology.

Challenges of bio energy as the preferred heat technology of ZEBs

Without subsidies of PV solar panels, the findings show that bio energy is preferred for heating of ZEBs. However, if all ZEBs are to be heated by pellets boilers, there will not be enough bio energy available. To avoid an extensive use of bio energy, Denmark and Switzerland have increased the weighting factor of bio energy, in order to make alternative heating technologies, such as HP, attractive. There is however one drawback of this. When increasing the weighting factor of bio energy, the total weighted energy imports also increases, which again leads to increased PV sizes. This is illustrated in Figure 3-11, where the green arrow from Figure 2-1 is shifted to the right. Even though the yellow HP arrow now has the lowest weighted energy imports, it is still unchanged from Figure 2-1, and the PV size is equally large.

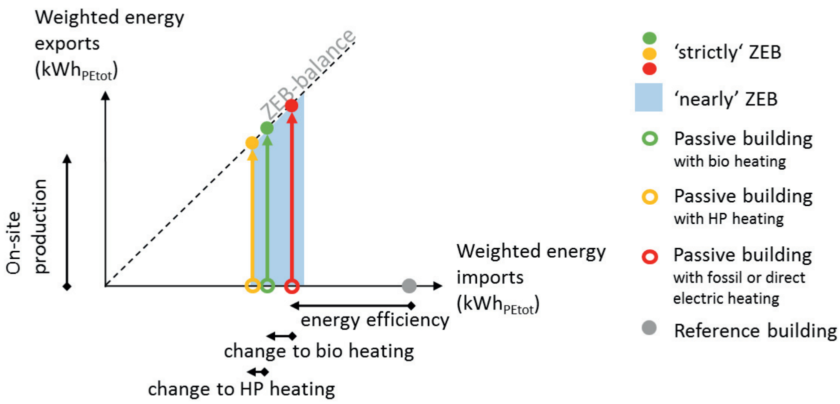

Figure 3-11 'Nearly ZEB', using Total PE factors. (Based on (Sartori et al. 2012)*).*

3.2.5 General conclusions on optimal ZEBs

The *net electric load profile* of the building equals the building's electric load minus the electric on-site production. In general, the characteristics of the net electric profile depends on:

- the energy system design within the building, i.e. installed capacity of the energy technologies, especially heating technology (electric or non-electric heating), on-site production (PV, CHP or solar thermal) and storage (batteries or thermal storage)
- the controls applied, i.e. the operational strategy of the building's energy system

The analyses of Article III – IV reveal that the value of the weighting factors has, together with costs and subsidies, a significant impact on the optimal design of the energy system of a ZEB. This in turn influences grid impact and total cost. Based on the analyses, the following conclusions are made:

- PV is always a part of the energy system of ZEBs
- Solar thermal is never a cost-optimal choice
- Lower weighting factors for electricity do not favour HPs, and in ZEBs with non-electric heating, it leads to increased PV size
- A target of *'nearly ZEB'* rather than *'strictly ZEB'* reduces the PV size, but leaves the heat technology unaffected.
- The larger PV size, the higher grid impact.
- Heat pumps have minor impact on the self-consumption of on-site PV, due to low heat demand when PV production is high, and because the majority of PV is consumed for electric specific demand.
- The storage is sized to meet fluctuations on a daily basis. Seasonal storage is not found to be cost-optimal regardless of investments costs.
- The financial costs of a Norwegian *'strictly ZEB'* is 65 % higher than for a *'50 % nearly ZEB'*, whereas the cost increase for a German ZEB is only 2 % due to the feed-in tariff of PV.

3.3 Optimal investments of a heat pump system of a German MFH

3.3.1 Article VI: Impact of PV and variable price on optimal system sizing

Article VI investigates how the system design of an air-sourced heat pump is influenced by more variable electricity prices and presence of on-site PV generation. In this work, the optimisation model from Article V is further developed to include temperature dependent maximum heat pump capacity, and is expanded from 1 hour to 15 min time resolution. A German multi-family house (MFH) is used as case study.

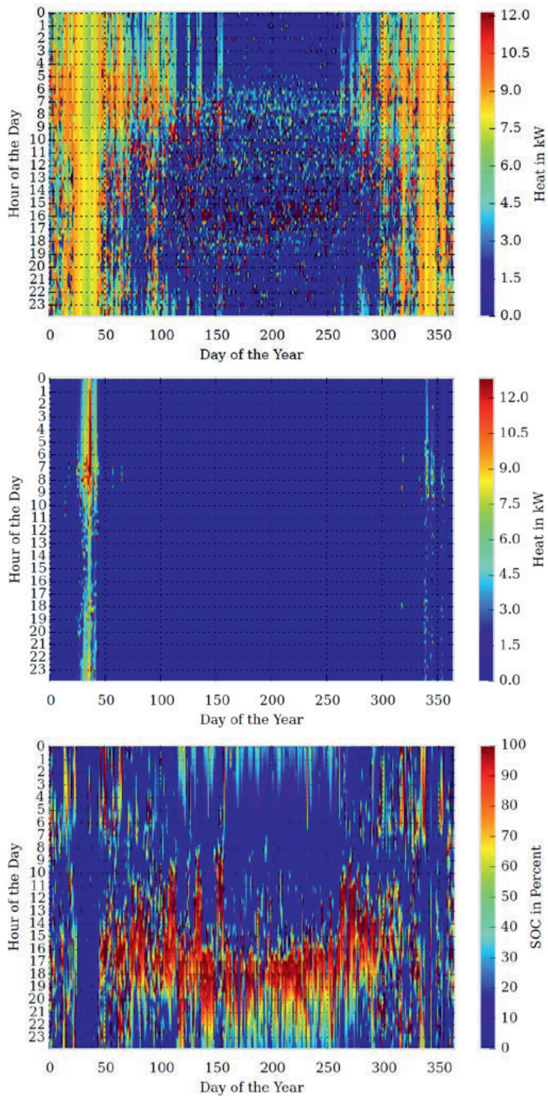

Figure 3-12 The operation of the HP (upper), the electric back-up (middle) and the state of charge (SOC) of the storage (lower).

Figure 3-12 shows carpet plots of the operation of the HP (upper), electric back-up (middle) and the storage (lower). The operation of the HP is at its highest in the cold days of the year, where it is operated at its maximum throughout the day. In the spring and autumn, the HP is mainly operated during afternoon peaks of the heat demand. In summer however, the operation of the HP occurs sporadically during the hours of the day with the highest COP (due to the highest outdoor temperature), to charge the heat storage which thus covers the demand at night.

Whereas the HP is used throughout the year, the electric top-up coil is only operated for a few hours during the coldest days.

During summer and spring/fall, the storage is charged in the afternoon when the COP of the HP is relatively high, and discharged in the evening/night and for the morning peaks. During the coldest days in winter, the storage is however hardly ever used, as the HP is operating at its maximum to cover the heat demand of the building, and cannot be used for charging the storage. Hence, the electric back-up is used to cover the peaks, rather than the storage.

The results described above are valid for the reference case with a flat electricity price. However, if applying variable electricity prices, with peak prices occurring in the morning and in the late afternoon, the storage is used more frequently, also during the coldest winter days, where it is charged by the electric back-up in hours with low prices, and discharged during high price hours.

The findings of the optimal system sizing is compared to the sizing recommendations given by HP manufacturers in the field. The article concludes that the configuration of existing HP systems in Germany today already have a HP size and storage size that can benefit from higher electricity price fluctuations or increased on-site PV production, i.e. they are seen as “smart grid ready”. Further, the article suggests that from a financial perspective of the building owner, it is not profitable to store heat longer than within 24 hours (a day).

3.4 Load profile aggregation methodology

Predictions of future aggregated electric load profiles are important for grid investment decisions and for energy systems planning. This chapter briefly presents the load aggregation methodology used to generate the load inputs in the system analyses presented in the next section. For a detailed description, please confer Appendix C.

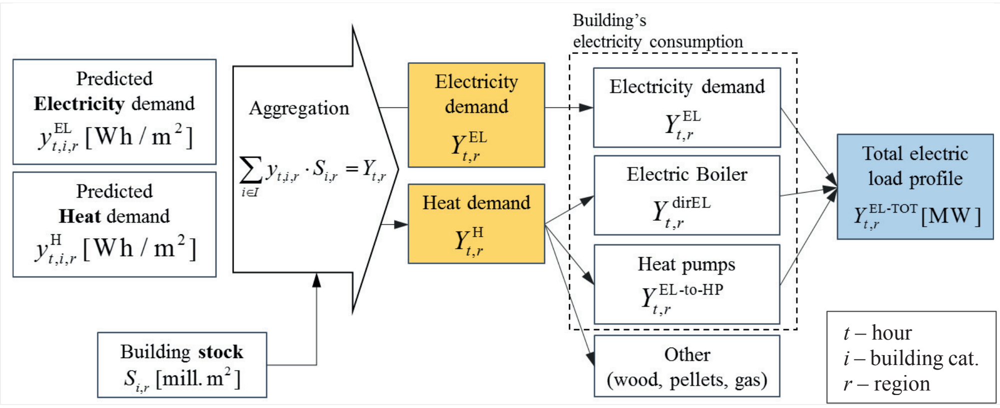

Figure 3-13 Load profile aggregation. Load input for energy system analysis (yellow), and for power system analysis (blue).

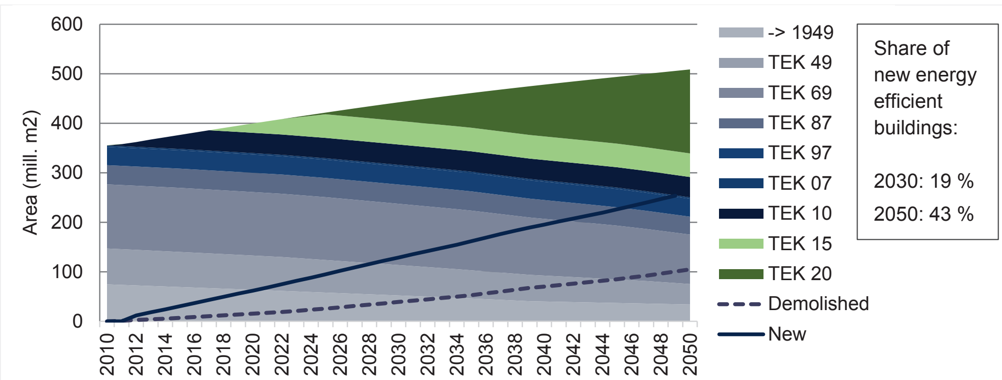

Figure 3-14 Forecast of the Norwegian building stock from 2010 to 2050. TEK denotes the technical standard. Buildings with TEK 15 and TEK 20 are regarded as new energy efficient buildings. (see App. C)

An overview of the aggregation methodology of the building stock is depicted in Figure 3-13. The methodology is based on the load profiles for each building category presented in Chapter 3.1 (Article I and II), while taking into account different development paths for ZEBs and their heating technologies

In line with the findings from Chapter 3.1, the electric specific demand for energy efficient buildings is assumed equal to that of existing buildings, but the heat profiles for traditional and ZEB buildings are treated separately. Based on the developed regression models for all building types in Appendix B, the temperature dependent heat demand is predicted for both passive and existing buildings, for each of the building categories, in each model region. The future load profiles are found by using the building stock projections as seen in Figure 3-14.

In the last step, the electricity consumption for heating is found by choice of heat technology (direct electric heating, heat pumps or other non-electric technologies such as bio or district heat) to cover the building's heat demand, accounting for the respective efficiency of the heat technology.

As the load profile regression models are developed for ZEB buildings and existing buildings separately, the total aggregate load profile can be calculated for different shares of the building stock being ZEBs. The step-wise aggregation methodology, can further provide inputs both to the power system analysis by using the *total electric load profiles* (blue box in Figure 3-13), and to the energy system analysis by using the *electric specific load* and *heat load separately* (yellow boxes in Figure 3-13).

3.4.1 Discussion of the aggregate load profiles

Similar reflections for the building's load profiles in Chapter 3.1 also applies for the aggregate load profiles presented here. That is, the aggregate heat demand and electricity demand are based on buildings with hydronic heating system, which might not be fully representative for the Norwegian building stock, and secondly, that the load profiles of the ZEB buildings are based on a small sample of passive buildings.

The prototype of the aggregate total electric load profile relies on the assumptions on the distribution of heat technologies within the building stock. As the data sources used (NVE 2015)(Bøeng et al. 2014) give the number of buildings that uses certain heat technologies, and not the amount of energy consumed for heating purposes, the numbers should be used with care. However, as the total heat consumption separated on energy carriers are calibrated against the annual energy consumption of buildings for 2012 (Statistics Norway 2013), the assumptions are regarded as satisfactory for the purpose of the aggregate system analyses in the following section.

3.5 Aggregate system analyses

The aggregate system analyses investigate the impact of a large implementation of ZEB buildings towards 2030 and 2050 on the electricity price, utilisation of the hydropower reservoirs, trade patterns and investments. In the power system analysis, the production capacities and the electricity demand are inputs. Hence, the PV capacities within ZEBs, and whether electricity is used for heating within ZEBs will influence these input parameters.

From Article III-V (see Section 3.2), the energy technology choice and sizes within the ZEBs are determined by several elements, e.g. the technology costs, subsidies of PV, the ZEB-level and weighting factors. Because these elements differ between the Nordic countries[16] (Norway, Sweden, Denmark and Finland), and further, that the inclusion of PV in the electricity mix would have a recursive effect on the weighting factor for electricity, called for a simplified evaluation of the ZEB definition.

To evaluate the system effects of ZEBs through clearly defined model cases, we wanted to make the ZEB definition independent of the heat technology choice. Hence, the simplified ZEB definition only includes energy imports for the building's electric specific demand[17]. Secondly, as Article III-V found that the most important on-site electricity generation technology is PV, it is assumed that PV is the main on-site generating technology of the ZEBs. Based on these two assumptions, the PV capacity is determined such that the annual PV generation equals the ZEB's electric specific demand. As both the import and export from the building is electricity, the challenge of the weighting factor for electricity is avoided (cf. Chapter 3.2.4). Hereby, the ZEB level in the system analyses is 'nearly'[18] rather than 'strictly' as energy imports for the building's heat demand is not accounted for.

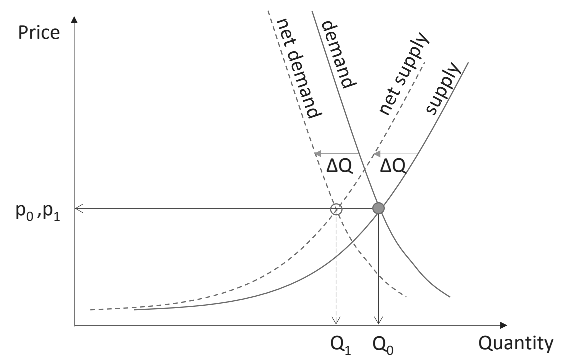

Figure 3-15 Price-quantity diagram of using electric load and PV production separately (solid lines) versus using the net electric load and net PV production (dotted lines).

Another aspect of the system analyses is whether to use *net electric load profiles* (electricity demand subtracted on-site PV self-consumption) and *net PV supply profiles* (PV production subtracted PV self-consumption), or to use the full electric demand profiles and PV production profiles. Figure 3-15 illustrates the two cases. Because the quantity of self-consumed on-site PV generation, ΔQ, reduces the load and generation equally in the same hour, the supply and the demand curve are equally shifted to

[16] The value of the weighting factors for bio and electricity are different in Sweden and Denmark, and Norway has not determined any weighting factors (Noris et al., 2014). Further, Denmark is the only Nordic country that has decided on a ZEB-definition, whereas Sweden, Norway and Finland are currently developing theirs (BPIE, 2015).
[17] The Danish ZEB definition includes heat demand and lighting, i.e. only part of the electric specific demand is included. Compared to the simplified definition of the system analyses that accounts for all the electric specific demand only, it is stronger than the Danish ZEB target.
[18] How 'nearly' depends on the energy demand of the building, and the heat technology choice. E.g. for the German MFH in Article V, the simplified ZEB definition corresponds to '80 % nearly ZEB' if heated by HP and '91 % nearly ZEB' if heated by bio energy.

the left, and the price in the market[19] is unaffected, leaving $p_1 = p_0$. Unless there is local storage and/or DSM mechanisms present to shift the load profile, the power price will not be affected and is consequently indifferent to the processing of the model inputs. Hence, the PV is treated as a central production technology in both the energy system analysis and in the power system analysis, i.e. the full electric load and PV production profiles are used as input.

To include DSM mechanisms or storage possibilities on an aggregated level is a challenging task. For example, should the storage be operated on a building level or on an aggregated level? And is it the cost for the consumer, or the society that should be minimised? Further, in order to make people actually move their loads, studies have shown that the power market's price differences from peak hours to low price hours is not enough, and hence we might see new business models[20] arising that offer other economic incentives for the end-consumers than the electricity market can do alone. Because they are not seen in the market yet, they are difficult to incorporate in the aggregate system analysis. Therefore, the system analyses of this thesis do not take into account local DSM or storage possibilities, and will hence serve as a starting point for evaluating the value of DSM and storage options in future work.

3.5.1 Article VII: Impact of ZEBs on the operation of the Nordic Power system

Article VII investigates the impact of a large introduction of ZEBs in Norway in 2030 on the Nordic power system by using the EMPS modelling framework. The analysis is a snapshot of the Nordic power system in 2030, with an assumed implementation of ZEB buildings in Norway only, accounting for 50 % of the Norwegian building stock. This assumption is highly unrealistic, but is made as a stress-test of the power system.

The model setup is based on NVE's 3-hourly version of the EMPS model, and includes assumptions on installed capacities of the power production and transmission lines within the Nordic countries, and towards surrounding countries such as Russia, Germany and UK (see Figure 3-16). A certain degree of demand flexibility is incorporated through the price elasticity[21] of the demand which is relatively large at -0,05 for Norwegian conditions due to electric heating, and that 85-90 % of the Norwegian consumers have price contracts related to the variable spot price (Bye & Hansen 2008). The price elasticity reflects that an increase of the price will decrease the electricity consumption, but the modelling framework does not indicate how this is done. I.e. it is not known if the reduced consumption relates to *load shifting* to a later point in time when prices are lower, or to *load shaving*, cutting the electric heating by using alternatives such as wood or gas.

The main findings of the power system analysis are as follows. An introduction of ZEBs in Norway will decrease electricity demand in winter, and increase PV production in summer. This leads to increased available electricity in Norway of in total 23-37 TWh annually, dependent on the heat technologies within the ZEBs. As could be expected, this results in lower power prices and reduced thermal power generation. The hydro power producers are able to adapt to the changes, which leads to decreased

[19] Although the cost for the end-consumer is lower when self-consumption is correctly accounted for, the conclusion holds because it is the market price that affects the unit-commitment and future investments in the overall energy system.
[20] See e.g. (Ottesen 2012) for discussions on business models applied in smart grids.
[21] See e.g. (Johnsen 2001)(Johnsen & Lindh 2001)(Bye & Hansen 2008) or (Holstad & Pettersen 2011) on estimated price elasticities for Norway and Sweden.

spillage of water and a slightly increased power production. The reduced power prices represent a benefit for the consumers and can be accommodated by larger and new industry, further electrification of transport, more exchange capacity towards Europe or reducing the nuclear power production in Sweden or Finland. About 70-80 % of the increased available electricity is exported out of the Nordic region, and hence the results rely on the assumption that it can be received by the surrounding countries at the given time. In a future with more RES in the surrounding European countries, this might not be viable, if all countries would like to export their production in the middle of the day. Further work should thus address the implications of increased deployment of PV electricity in Europe, which might reduce the possibility of receiving the exported power from the Nordics. Because of the EMPS model's superficial grid description, internal grid congestion within the model regions are not considered. Further work should focus on analysing the grid implications in more detail, both on the regional and distributional grid level.

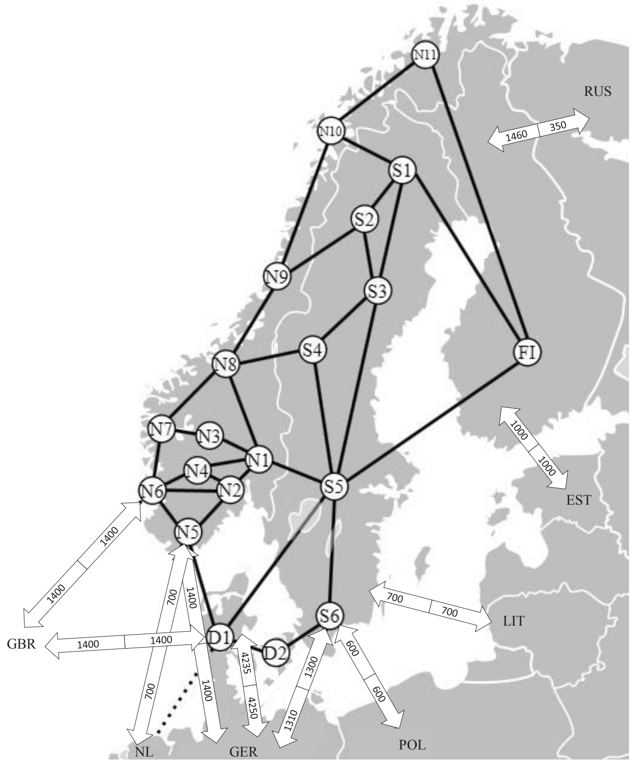

Figure 3-16 EMPS' model regions of the Nordic countries, and assumed transmission capacities (in MW) to surrounding countries of the power system in 2030.

It is however important to stress that a further increase of the already assumed power surplus of 36 TWh in the *BAU* case might not be carried out without taking other actions. I.e. it might not be profitable to maintain the existing production capacity of coal plants or nuclear power plants towards 2030. Generally, if the structure of the power market is to be maintained and to avoid price collapses due to increased non-dispatchable production, it is necessary to decommission existing thermal production. On the other hand, even though we might want to reduce the thermal power production, the capacity of the power plants is still needed to contribute to the electricity production in the few hours when the wind is not blowing and the sun is not shining.

Nevertheless, the findings indicate that the Nordic power system is capable of handling 17-27 % reduced net power demand in Norway, both regarding the Nordic energy balance and the operation of the grid on a central grid level.

3.5.2 Article VIII: Impact of ZEBs on investments in the Scandinavian energy system

Article VIII investigates the impact of gradually introducing ZEBs in all Scandinavian countries from 2010 to 2050, on the investments of the aggregate energy system. The analysis is performed by using the TIMES modelling framework, and the load profiles of the ZEBs are found by use of the aggregation methodology described in Section 3.4 (cf. yellow boxes in Figure 3-13). The implementation is similar to the introduction of new buildings as seen in Figure 3-14, and assumes that the share of the building stock being ZEBs hits 50 % in 2050.

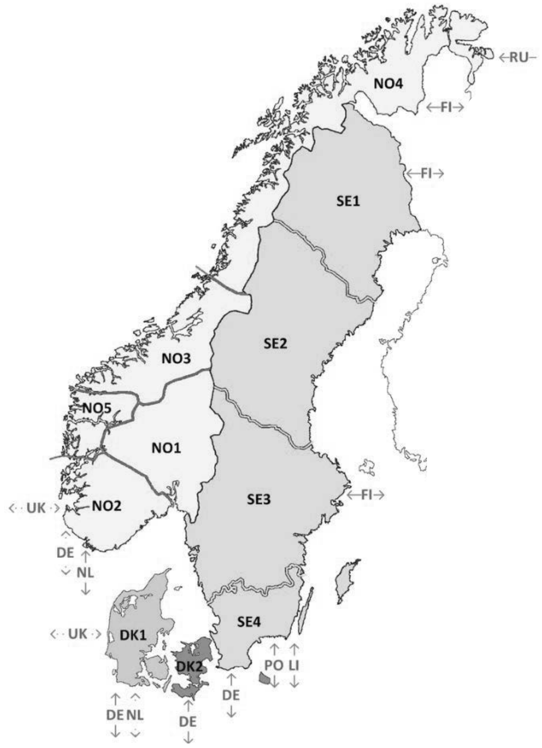

Figure 3-17 TIMES' model regions of the Scandinavian countries (Norway, Denmark and Sweden) and indication of transmission lines to surrounding countries.

In this study, the main objective is to investigate the investments in the energy system with a large implementation of ZEBs. The Scandinavian TIMES model is developed by PhD candidate Pernille Seljom, and is regionally divided into the Nord Pool price areas as shown in Figure 3-17. The time-horizon from 2010 to 2050 is divided into five-year periods where investment decisions are made within each period. Each period contains 12 two-hour steps for a representative day in four different seasons: winter, spring, summer and autumn, i.e. in total 48 time-slices.

The TIMES model contains investment decisions for production technologies, as well as end-use technologies. Hence, in contrast to the power system analysis in the previous section, the choice of heat technologies within the ZEBs is a model result. It is possible to shift the electric load through substitution of energy carriers for heating. For example, if an electric boiler is normally running, the model can choose to operate a bio pellet boiler at certain hours instead of the electric boiler, which thereby shaves the electric load (cf. Section 2.2 and Appendix D).

What drives the investments in the electric power system is the endogenous electricity consumption, the exogenous prices of oil, gas and coal, and the power prices of the surrounding countries. To meet the electricity consumption (for electric heating and electric specific demand), the model can choose to import electricity or to produce it. As the transmission capacity between the model regions and towards the surrounding countries are limited, a minimum amount of regionally produced electricity is required. When this is fulfilled, the choice of utilising power imports or building new power plants, is dependent on the import electricity price, the energy prices and the capital costs of the power plants.

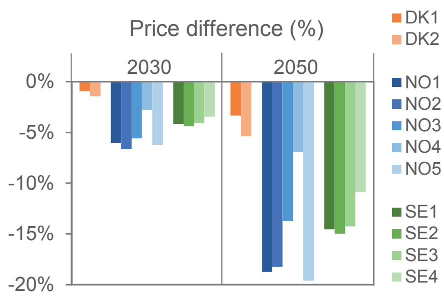

Figure 3-18 Annual average electricity price reduction from REF to ZEB case in 2030 and 2050, by model region.

A large implementation of ZEBs affects the cost-optimal investments and operation of the energy system surrounding the buildings in two ways; through the lower heat demand and through the on-site PV generation. Similar to the power system analysis, the increased power availability reduces the electricity price in all regions (see Figure 3-18). This affects investments both on the supply side and on the demand side. Investments in the electric production capacity is decreased, mainly wind (-51 %), but also CHP plants (-17 %) and non-flexible hydropower (-4 %). The investments of all heat technologies are reduced, especially bioenergy (-27 %) and heat pumps (- 29 %), however direct electric heating is unchanged. Hence, as the total heat demand is lower, the share of using direct electric heating increases from 16 % to 20 % with ZEBs.

Due to the increased share of direct electric heating, the findings show that with 50 % ZEBs in 2050, the total consumption of electricity is hardly changed from 319 to 315 TWh, despite that the heat demand is considerably decreased. The findings in Appendix D further show that the operation of the heating technologies is changed. With ZEBs, the direct electric heating technologies are operated more during daytime hours in spring, summer and fall, whereas the bioenergy increases its operation during night.

Summed up, a large implementation of ZEBs in Scandinavia, will lead to lower electricity prices, lower production capacity of wind and CHP, and increased use of electric heating relative to other heating technologies.

3.5.3 Discussions on the power system and energy system analyses

Data quality and method

As insulation and irradiation data for Norwegian conditions is poor and with uncertain quality (Byrkjedal et al. 2013), the time series of the PV production was simulated for a normal climatic year within each of the model regions taken from (Merlet 2013). Hence, the PV production is treated as deterministic, not varying between scenario years. It can however, be argued that the annual variations of PV production is rather low, e.g. (BP 2013) reports an annual variance of ± 8 % for German conditions, and hence that the error of making the PV production deterministic is rather low. Nevertheless, more knowledge on real measured solar power production in Norway is needed to evaluate the impact of ZEBs in an adequate way.

Choice of heating technologies

In the power system analysis, heating technologies within ZEBs (either direct electric heating, heat pumps, or non-electric heating) are assumed prior to the analysis, which influences the model input of electricity demand. The load profiles used for this analysis show that the heat technology is important both for the electric peak load and the annual electricity demand (cf. Appendix C). The model results show that when ZEBs are heated by HPs, the total electricity consumption is reduced by 3 % when compared to the reference case with no ZEBs at all. If all ZEBs have direct electric heating, the reduction is 0,7 %, i.e. almost negligible difference in the total electric consumption.

In the energy system analysis, the choice of heating technologies is a model result. The findings show that the share of the annual heat demand met by electricity is unaffected by the introduction of ZEBs (36 - 37 %), but as the heat demand is reduced, the heat generated by heat pumps is reduced by from 38 to 27 TWh, whereas the direct electric heating is maintained at 31 TWh. Hence, the allocation between them shifts from being dominated by HP to being dominated by direct electric heating.

The consequence for the total electricity consumption in 2050 for Norway is +1 % when compared to the reference case without any ZEB buildings. Hence, for Norwegian conditions, we may conclude that the rebound effect of electricity becoming cheaper, causes electricity being used less efficiently in direct electric heating technologies rather than in heat pumps. In Sweden and Denmark, the energy system analysis shows that the total electricity consumption is changed by +0,5 % and -4,1 %, respectively. In Denmark, electricity is not commonly used for heating, and hence introducing ZEBs does not reduce the electricity consumption. In Sweden however, the reduced electricity consumption follows the reduced heat demand of the buildings, leaving the rebound effect less present than in Norway. The reason for the differences lies is the electricity prices that experience larger reductions in Norway than in Sweden and Denmark as seen in Figure 3-18.

Presence of hydropower

In Norway, 99 % of the power mix is hydropower, where about 80 % of the hydropower plants are connected to reservoirs. In Sweden, 45 % of the power mix is hydropower, where 40 % of the plants are attached to reservoirs. Although the hydropower plants can adjust their production to daily and hourly variations, the annual hydropower production is determined by the inflow of water to the reservoirs only, regardless of whether the price on gas or coal is low, or the production of other RES is high.

Hence, if nothing else changes, when deploying a large amount of ZEBs with onsite PV production into the Scandinavian energy system, the production of hydropower remains unchanged, and hence the total power production will increase. Both system analyses show that increasing the supply and simultaneously decreasing the demand, lowers the electricity prices, and increases the power export to the surrounding countries. Due to the limited connection capacities from Norway towards UK, NL, DE, DK or SWE, the electricity prices decreases more in Norway than in Sweden and Denmark, who can reduce the annual production of their thermal power plants.

CHP plants and thermal power plants

In the reference case in 2030 of the *power system analysis*, the total thermal power production (sum of bio, gas, coal and oil) in Norway, Sweden and Denmark together is 40 TWh. In the TIMES model of the *energy system analysis*, these power plants are grouped in one technology called CHP, which in 2030 has a total power production of 37 TWh. As the findings from the *energy system analysis* show that the capacity of CHP plants are reduced by 7 % in 2030 and 17 % in 2050, further work should address the effect of reduced thermal capacity in more detail. Preferably separating the thermal electric back-up plants from the CHP plants that are attached to the district heating network in the TIMES model. As one of the main challenges of integrating intermittent renewable energy is to provide enough back-up capacity, this should be addressed in further work.

Validity of the results – future energy prices

The results show that compared to a system without ZEBs, the investments of wind, CHP and non-flexible hydropower are reduced with ZEBs, but that the total power production in Scandinavia increases from 367 to 382 TWh, and the net export increases from 30 to 52 TWh. However this relies on the assumption that the electricity price of the surrounding countries gradually increases from 2010 to 2050 (cf. Article VIII's Appendix A). Letting these electricity prices stay constant throughout the model horizon would reduce the capital investments of wind even further, making Denmark a region with net import in the reference case. In such a future, the introduction of ZEBs might lead to a more modest increase of the net electricity exports.

Future capital costs of PV

The energy system analysis show that PV is not a competitive technology even with investment costs declining from 2,1 EUR/Wp in 2015 to 1,5 EUR/Wp in 2050. As the cost for PV is still falling, we might face lower capital costs before 2050. However, the findings show that the cost must reach 1,0 EUR/Wp in Denmark (DK2) and even 0,3 EUR/Wp in Norway (NO4) in order to be economically attractive in the reference case in 2050, which might be a difficult to reach. On the other hand, the drivers in the PV market has shown to be less dependent on the power price and the power market, and is becoming more connected to the cost of alternative building materials (façade and roof), and people's urge to become environmental friendly (Thorud 2016). Thus, the cost of PV electricity seems less crucial for future PV investments.

The role of direct electric heating on "lost PV"

In the *energy system analysis*, the installed capacity of heating technologies in 2050 is 5 % larger than the peak heat load. This overinvestment is made to utilise the PV electricity in spring, summer and fall, through direct electric heating. As discussed in the optimal ZEB (Chapter 3.2.4) this is not a rational option for the building owner, as the building owner sizes the technologies to meet the heat demand in winter. The reason why the TIMES model chooses to do this must lie in the electricity prices becoming close to zero in the daytime hours, and that the model wants to use it rather than report it as “lost PV”. As building owners tend to choose one heat technology option, and not one for summer (using electric heating) and one for winter (using other heat technologies), the reported amount of lost PV in Article VIII might be underestimated. On the other hand, we might face similar conditions as in history, where boilers are only operated in winter and switched off in summer when DHW demand is met by direct electricity. In such a case, the electricity consumption would increase even more in spring, summer and fall than what is seen in the case with ZEBs (cf. Appendix D).

4 Conclusions

This chapter summarises the main findings of this thesis. Key conclusions within each of the four main parts are presented, followed by concluding comments that bring together all the different bits and pieces. For details and evaluation of the results, please confer the conclusions and discussion sub-sections in each of the Chapters 3.1 to 3.5. Ideas for future research are proposed at the end of this chapter.

4.1 Main results

Load profile modelling (Articles I & II)

The findings of Article I and II show that both the peak heat demand and the annual heat demand are about half as high for Norwegian ZEBs when compared to buildings in the existing building stock. Further, the heat demand is non-linearly dependent on the outdoor temperature. The temperature dependency is substantially decreased, about 40 – 70 % dependent on time of day, day type and building category.

Cost-optimal ZEBs (Articles III – VI)

The findings of Article III and IV show that the cost-optimal energy system design of a Norwegian ZEB is a bio pellets boiler combined with on-site building integrated PV, whereas Article V showed that the design of a German ZEB is a natural gas fired CHP combined with PV.

Solar thermal is not a cost-optimal choice in any of the investigated ZEB cases. Although PV and solar thermal share the same façade area, solar thermal competes with the building's heating technology and not with the PV. The only benefits for the solar thermal are saved fuel costs for heating and lower PV investment costs, which is not enough to make it economically attractive.

One of the main takeaways from the German case study is that the combination of policy instruments could give unwanted consequences. Applying both the ZEB target and the PV feed-in tariff lead to ZEBs with fossil fuelled heat technology and large PV capacity.

In Norway, the financial cost of the energy system within a *'strictly ZEB'* is 64 % higher than for a *'50 % nearly ZEB'* (50 % of the weighted consumed energy is produced on-site), caused by the additional building integrated PV (BIPV), as the heat technology remains unchanged. As BIPV can reduce the cost of façade and roof materials of the building, parts of the additional BIPV cost can be allocated to the material costs of the building, thereby reducing the building's energy system costs. In Germany, the financial cost of a *'strictly ZEB's* energy system is only 2 % higher compared to that of a *'50 % nearly ZEB',* due to the PV feed-in tariff that substantially lowers the additional PV cost for the building owner.

The grid impact of Norwegian ZEBs with bioenergy and on-site PV, shows that the hourly peak export from the building to the grid is significantly higher than the peak import value, and the self-consumption of the on-site PV is about 40 %. If heated by a heat pump, the amount of self-consumed PV increases by 10 %, but due to the larger PV size, the self-consumption share is reduced to 36 %.

The findings further show that the ZEB level has the strongest influence on the grid impact of the ZEB. Aiming for *'50 % nearly ZEB'* rather than *'strictly ZEB'*, will increase self-consumption from 40 % to almost 70 %, and reduce the total discounted cost by 39 %. This knowledge is important for policy makers that determines the ZEB definition. That is, to reduce the grid impact of ZEBs, increase the utilisation of the on-site PV production, and reduce the costs, the focus should be on the ZEB-level rather than the weighting factor for electricity.

Load aggregation (Article I, II & VII)

For countries where a large share of the existing building stock has electric heating, such as Norway, Sweden and France, it is important to include the impact of energy efficiency measures when forecasting the future aggregated electric load profile. As the temperature dependency of the heat load has non-linear characteristics, the effect of energy efficiency measures are treated with a bottom-up approach that predicts the annual electricity demand with hourly time resolution. Hence, the aggregated hourly load can be predicted for any climatic year.

Secondly, the effect of heat technology choice within buildings are quantified in this thesis. For a normal climatic year in 2030, if 50 % of the building stock in Norway is ZEBs, the annual electricity demand of the total building stock is 71 TWh, 61 TWh and 57 TWh, if ZEBs are heated by direct electric heating, heat pumps, or non-electric heating technologies, respectively.

As the heat load depends on the outdoor temperature, the aggregate electric load profiles are predicted for 30 climatic years (1980 – 2011). When comparing the reference case of no ZEB implementation (*BAU* case), to a case where 50 % of the buildings stock is replaced by ZEBs with heat pumps (*HP* case), the predicted peak load for the total building stock in 2030 is reduced by 36 % for the same cold climatic year. Comparing cold years to warmer years shows that the peak load occurs at different hours and varies from 200 % to over 300 % of the average summer load in the *BAU* case, and from 130 % to over 200 % of the average summer load in the *HP* case. Hence, the seasonal variation of the aggregated load in Norway is reduced when buildings become more energy efficient.

Power system and energy system analysis (Articles VII & VIII)

The impact of a large introduction of ZEB buildings in the Scandinavian energy system towards 2030 and 2050 is studied by two extreme cases to stress-test the system. In real life, ZEBs are likely to be introduced at lower pace, and the politically determined ZEB-level will probably be lower than the assumed '*80 % nearly ZEB'*-level. Hence, the consequences of the ZEB implementation will be less dramatic than shown here; nevertheless, the analyses show the direction of the changes.

The *power system analysis* shows the impact of ZEBs on the operation of the power system in 2030. As the power production capacities are exogenously decided, an introduction of ZEBs increases the total electricity production and reduce the electricity prices substantially. Consequently, electricity exports increase considerably, and the fossil thermal electricity production at 40 TWh in the Scandinavian countries is reduced by 1,5 TWh. The combination of solar power and flexible hydropower plants seems to be an advantage for the system, as the risk of water spillage is reduced, incentivising the power producers to reduce the reservoir levels and thereby marginally increase the annual hydropower production due to less water spillage. On a daily basis, the hydropower production adapts to the hourly variations of the PV production.

The *energy system analysis* takes into account that future investments can be altered. The results show that ZEBs reduce the investments in run-off river, wind and CHP plants, and increase the role of direct electric heating and electric boilers in buildings. The CHP reduction is mainly caused by the reduced heat demand of the ZEBs that demand less district heat from the CHP plants, whereas the on-site PV production is mainly influencing the investments in wind and flexible run-off-river hydropower plants. Together, these two effects of the ZEBs lead to reduced capacities of central electric power plants of - 7 % in 2030 and -13 % in 2050, of which 78 % is wind power and 13-15 % CHP plants. Hence, the ZEBs seem to replace renewable wind production, and the share of renewable electricity production in Scandinavia marginally increases from 78 % to 81 % with ZEBs. Future studies should investigate the optimal mix of PVs and wind plants in the system, and whether the system would benefit from local storage to increase the utilisation of on-site PV. The results of course also depend on the assumptions of future costs of these technologies (cf. discussions in Chapter 3.5.3).

As the nuclear power plant capacities and the energy demand of the industry are highly influenced by the current political landscape, they are assumed constant both in the power system analysis and the energy system analysis. However, increased power availability due to ZEBs in the Nordics might influence politicians and could be accompanied by other measures in the energy system. That is, decommissioning of nuclear power, establishment of new power intensive industry, or construction of more interconnectors to increase power export to surrounding countries.

Concluding comment

The results of the individual optimal ZEBs show that the cost-optimal technology mix for Norwegian conditions from the building owner's perspective, is building integrated PV combined with bio energy. However, the system analysis suggests to increase the use of electric heating technologies. Hence, without considering future reduction of electricity prices, the optimisation of a single building could lead to suboptimal solutions for the energy system as such. Further, if all ZEBs are to be heated by bio energy, challenges might occur regarding resource availability, and local air pollution. Moreover it might be more beneficial to use the limited amount of bio energy for emission reduction in other parts of the economy e.g. as bio fuels in transport, or as bio coal in industry.

4.2 Recommendations for future research

This thesis investigates the impact of ZEB buildings on the Nordic and Scandinavian energy system on an aggregate level. Based on the findings in Chapter 3 and the articles that this chapter builds on, and taking into account the simplifications and assumption that have been made along the way, this paragraph summarises several paths for future research.

The building optimisation model in Chapter 3.2 has a deterministic approach. The first improvement would be to apply a stochastic approach, which enables short-term operational uncertainties to be accounted for in the investment decisions. The modelling framework includes DSM mechanisms attached to the heat demand. More DSM mechanisms can be investigated if including batteries, and/or incorporating time-of-use tariffs which reflect the willingness to pay from the utility companies. Further, the building optimisation framework is developed for a single building but can be expanded to incorporate a local neighbourhood, by adjusting the cost-data and implementing local heat distributions technologies.

An obvious improvement of the econometric regression load model for buildings in Chapter 3.1, would be to expand the dataset, especially with more passive buildings. A further enhancement is to improve the modelling of the error terms by adding 24hr and/or 168hr autoregressive terms, or other seasonal factors to avoid auto-correlations. Lastly, to investigate the effect of time-invariant explanatory variables such as technical standard or construction year, the regression models can be modified towards random effects panel data models, or two-level models.

The load profile aggregation methodology is based on a bottom-up approach of average load profiles. A logic next step would therefore be to integrate the impact of rebound effects of energy efficiency and the price elasticity of the demand as seen in top-down models, with the bottom-up approach. Further, the load profile prediction methodology should incorporate the impact of DSM mechanisms, differentiating the demand response by customer type and load. Such an approach would need deep understanding of both macroeconomic relationships, including user behaviour, as well as technical knowledge on the different load characteristics and appliances.

The aggregate energy system analyses in Chapter 3.5 are challenging because of the impact of the boundary conditions of the modelling framework, i.e. the trading prices and the transmission capacities towards UK, the Netherlands, Germany, Poland, Russia and the Baltics. Further work should address not only the price profiles, but also whether the surrounding countries are able to receive the amount of power exported from Scandinavia at the given hours.

There is a contradiction between the needed flexibility from the grid and what the buildings are willing to offer with their current economic situation. As seen in Article VI, from the financial perspective of the building owner, even with high fluctuations in the electricity price or with large on-site PV production, it is not profitable to store heat longer than within 24 hours (a day). This reflects a discrepancy as the need from the electric power system is identified to 2-3 days (cf. Chapter 2.3.2). Thus, the following questions still remain: What kind of building loads can be shifted from the morning or afternoon to the middle of the night? What kind of building loads are possible to cut for up-to three consecutive days? And how are the answers to the former two questions influenced by more energy efficient buildings and/or more heat pumps in the power system?

Impact on local grid conditions is not addressed in this thesis as it focuses on unit commitment and energy balances. Further work should thus focus on analysing the grid implications in more detail, both on the regional and distributional grid level in Norway. Related work is found in (Widén, 2010) for Sweden and in (Stetz et al., 2015) for general European conditions.

The findings show that ZEBs in the Scandinavian countries lowers the peak power demand in winter due to the widespread use of electric heating in the existing building stock. This is opposite to European buildings where electricity is less used for heating purposes. Here, it is likely that the reduced heat demand of the ZEBs will affect the gas or district heat demand, but the electricity consumption might be less affected. Consequently, one could investigate how a massive introduction of ZEBs in Europe will affect the income of existing power plants, and hence the need for installed production capacity in the system.

Last, but not least, the analyses are never better than the available data at hand. Data for solar insolation and irradiation for Norwegian conditions is poor and with uncertain quality (Byrkjedal et al. 2013). Increased effort should be made on gathering real measured solar data and measured solar power production in Norway. Further, due to lack of historical data, time series of PV production could be constructed such that they correspond to the same historic years as the hydro inflow and the aggregate load profiles, i.e. 1981-2011.

In addition to these more general topics, specific remaining challenges and opportunities were identified in each of the chapters.

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Erratas

Article I, III and V contain minor errors that are listed in the following. Appendix E and G contain the corrected versions of Article I and III respectively, whereas Article V is not corrected.

Article I

The predicted heat load profile of a week in summer in Figure 11 is incorrect. The corrected graph is shown here.

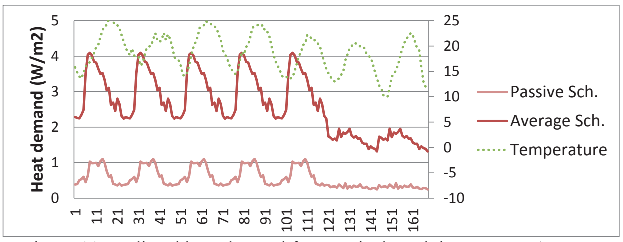

Figure 11 Predicted heat demand for a typical week in summer. Average school buildings and passive school building. (Wh/h per m^2)

The text commenting the graph is corrected to:

"Likewise Figure 11 shows that in summer, the maximum amplitude is reduced by approximately 1,1 W/m^2, equal to 60 % reduction."

The second paragraph of the conclusion is corrected to:

"The same model was applied to hourly measured heat demand for a school building with passive energy standard. Comparing predicted load profiles of the two building categories with equal outdoor temperature showed that the maximum diurnal amplitude for heat consumption is reduced by 48 % in wintertime and 60 % in summer."

Article III

Table 6, that shows the main results of all the model cases, has an error regarding the magnitude of the exported annual electricity. The table is corrected with the following numbers:

Zero-constraint	**None**	**Zero Carbon Emissions**			**Zero Primary Energy**	
Carbon factor gCO2-eq / kWh electr.	*CO_2-NOR 130*	*CO_2-NOR 130*	*CO_2-EN 350*	*CO_2-NOR 130*	*CO_2-NOR 130*	*CO_2-NOR 130*
Primary Energy factor	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN (asym)*
Grid impact						
Electricity sold [MWh/yr]	0	246	243	308	238	288

Article V

In the conclusion of Article V, the nearly ZEB level is calculated when only compensating for the electric specific demand in the case of a bio heated and a heat pump heated ZEB building. The ZEB level of the heat pump heated ZEB is 80 % and not 70 %. Hence, the fifth paragraph of the conclusion should be as follows:

"For ZEBs with HPs or BBs, it is the electric specific demand that dominates the required amount of energy generation, i.e. the PV size. First, because of the relatively low heat demand, and secondly, because the weighting factor of biomass is low and the efficiency of HP is high. In this case study, the PV size determined by the electric specific demand is 30 kW. In the case of the BB or HP, this corresponds to 91 and 80 % of the total required PV capacity, respectively. "

Appendices

A. Appendix: Further findings of optimal ZEBs

This appendix elaborates on findings gained during the work of Article V of the German case study, which were not included in the article due to space limits. As they contain important findings, they are briefly presented in the following.

A.1 Macroeconomic optimal ZEB

Calculating the costs from a macroeconomic perspective is often used when evaluating new policies. As all subsidies and taxes are removed from the calculations, the macroeconomic costs reflects the real costs for society.

The main difference of the input parameters of the macroeconomic costs compared to the financial costs lies in the electricity price, FiTPV and investment costs of the technologies as the VAT is removed. The electricity price[1] is reduced from 24 to 9,6 ct/kWh, and the PV feed-in tariff of 11 ct/kWh is replaced by the EEX price at 4 ct/kWh. The financial calculations in Article V conclude that the cost-optimal technology mix of the ZEB is a natural gas fuelled CHP combined with a large PV capacity, regardless of ZEB-level. Figure A-2 show that the macroeconomic optimal choice of the ZEB while increasing the ZEB level from 0 % (*'no ZEB'*) to 100 % (*'strictly ZEB'*).

Without any ZEB target, the heat technology choice is a gas boiler (GB). Because of the lower electricity price, the electricity produced from the CHP is not profitable (as in the financial case), and is replaced by a GB. Further, in contrast to the financial case of 'noZEB', PV is not a cost-optimal choice in a macroeconomic perspective, which indicates that the grid-parity applies for the end-customers in Germany due to high taxes on electricity.

When increasing the ZEB-level to *'40 % nearly ZEB'*, it is profitable to reduce the weighted imports by replacing the GB by a HP, and thereby reducing the PV size and the costs accordingly. Increasing the ZEB-level to 60 %, it is cost-optimal to reduce the weighted energy imports further by replacing the HP by a BB. Strengthening the ZEB level further from 60 % to 100 %, the only option is to increase the installed PV capacity, as the bio pellets boiler already is the heat technology with the lowest possible weighted energy imports. This is also illustrated in Figure A-3, which shows how the building moves in the ZEB balance scheme from *'no ZEB'* (rectangle), to *'40 % nearly ZEB'* (star), to *'strictly ZEB'* (dot).

[1] The macroeconomic electricity price shall reflect the actual cost of producing and transporting electricity to the customers. According to (Bundesverband der Energie- und Wasserwirtschaft & (BDEW) 2014), the average electricity price in Germany in 2013 for households was 29 ct/kWh, of which 4,7 ct VAT (19 %) and 10,6 ct other taxes and fees. Hence, subtracting 19 % VAT and taxes of 10,6 ct/kWh from the financial price of 24 ct/kWh, 9,6 ct/kWh represents the macroeconomic price.

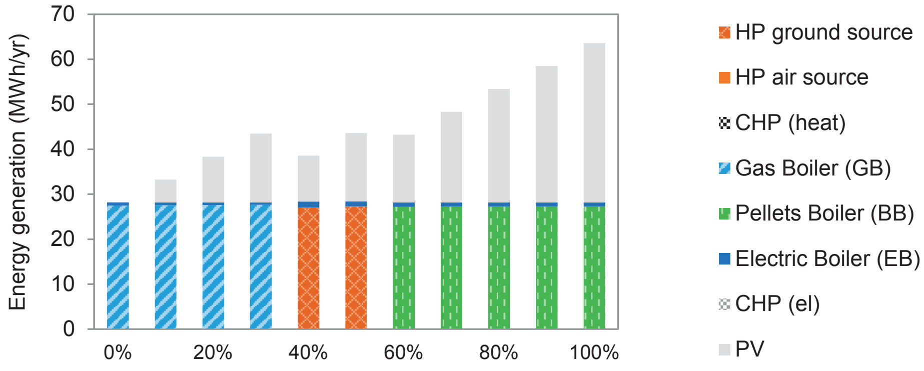

Figure A-1 Annual energy generation by technology (MWh/yr), when increasing the ZEB level of a German MFH using macroeconomic costs.

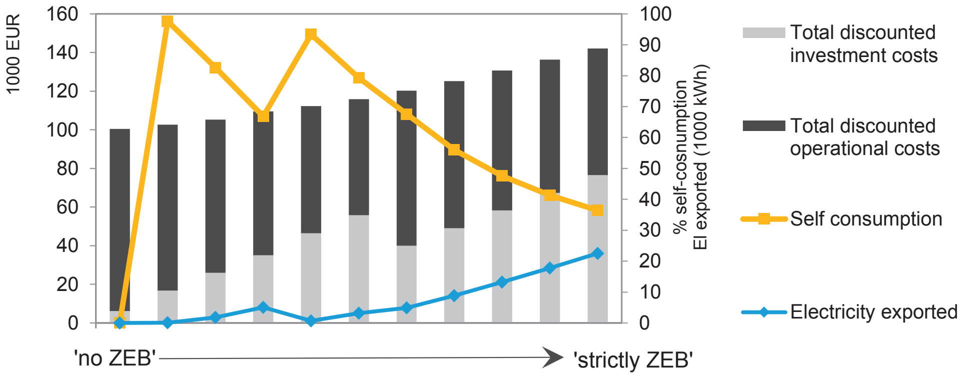

Figure A-2 Discounted investments and operational costs (MEUR), self-consumption (%) and annual electricity export (MWh/yr), when increasing the ZEB level of a German MFH using macroeconomic costs.

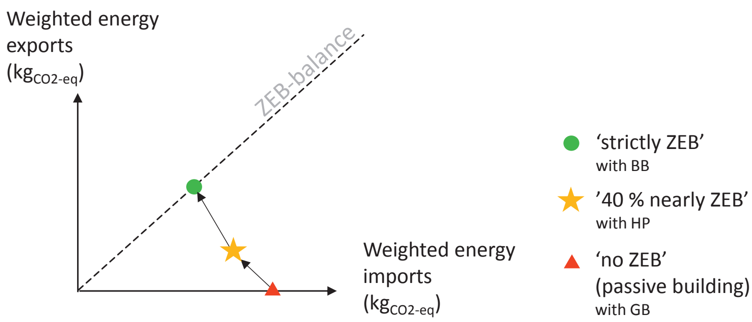

Figure A-3 Illustration of the impact of increasing the ZEB level of a German ZEB when using macroeconomic costs.

A.2 Load shifting potential for ZEBs with heat pumps

As heat pumps are said to contribute to the flexibility needs of the grid, it is of interest to study the load profiles of the German ZEB which is heated by a heat pump. Hence, this section illustrates how a heat pump and a heat storage can affect the load shifting potential of the net electric load profile of a ZEB. The illustrations are based on the work described in Article V for a German multi-family ZEB house (MFH) with optimal system sizes.

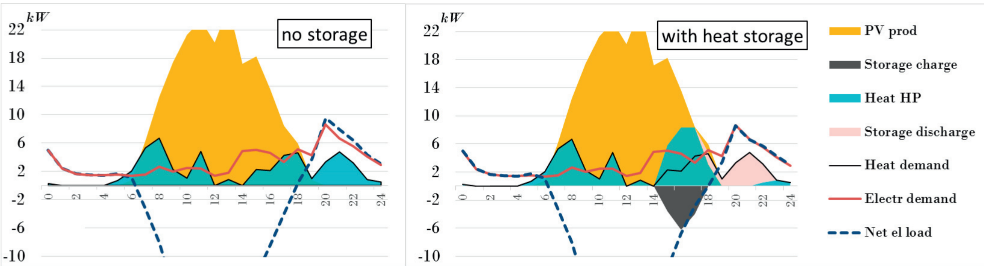

Figure A-4 Load shifting on a <u>summer</u> day within a German MFH ZEB with HP and PV. Without storage (left), with heat storage (right).

The left graph in Figure A-4 depicts the loads on a summer day without storage. The black line indicates the heat load, and the red line the electric specific load, whereas the net electric load is the dashed blue line. As the heat demand in summer is low (only for domestic hot water), the thermal electric load is almost negligible compared to the electric specific load. Thus, when adding a thermal storage (right graph), only a minor part of the net electric load is reduced in the evening, which now equals the electric specific load of the building. Hence, the load shifting potential of the net electric load (which is seen by the grid) when using HP combined with PVs is almost negligible in summer.

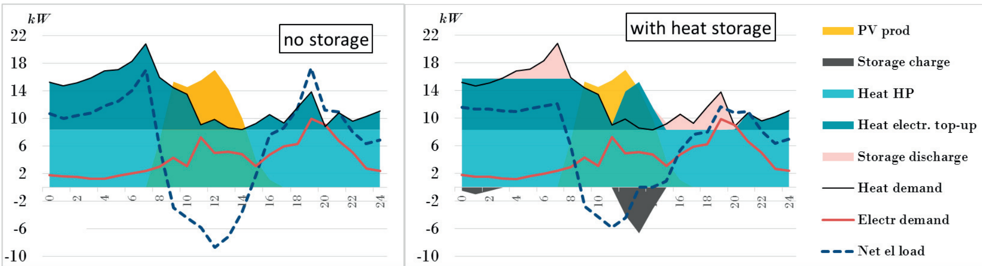

Figure A-5 Load shifting on a <u>winter</u> day within a German MFH ZEB with HP and PV. Without storage (left), with heat storage (right).

In the winter, heat demand is larger and the effect of a heat storage increases. The net electric load without storage is shown to the left in Figure A-5. As the HP is running on full capacity throughout the day, it is the electric top-up that adapts its heat generation to the hourly fluctuations. This creates a morning peak and an evening peak of the net electric load profile. Even though the PV production is lower in winter, it is still high enough to give some export in the middle of the day. When adding a thermal storage, the right graph in Figure A-5 shows, that the morning and afternoon import peaks of the net electric load are reduced.

Hence, even with a thermal storage, the net electric load in the evening is not lower than the electric specific load of the building (as discussed in Section 2.2.3). This means, that if the objective of using heat pumps is to reduce the current load peaks in the existing electricity grid (by load shifting), the findings shows that unless a battery is also included in the building, the electric load of the building will still be equal to the electric specific demand that was there initially.

Further, if the objective is to increase the electric load in hours of low electricity prices (valley filling), the findings of Article V and VI show that even with very high price peaks and price valleys, the size of the thermal storage seems to be optimised for handling daily fluctuations and not fluctuations of 2-3 consecutive days.

The findings in Figure A-4 and Figure A-5 are naturally dependent on the installed capacity of the HP, electric top-up heater, heat storage and PV, and on the applied control of the system. Which controls that are applied depends on the objective of the analysis.

B. Appendix: Profiles of all building categories

Forecasting building load profiles contain two elements that must be preserved; the hourly load profile (how the consumption varies throughout a typical working day and weekend/holiday), and the annual level of the energy consumption. The developed approach first investigates the hourly load profiles of individual buildings in order to establish the pattern of the load profiles and identify the most important characteristics, and secondly calibrating the annual energy consumption to the national energy statistics.

Previous work on load profiles of buildings in Norway for households and/or non-residential buildings are found in (Livik et al. 1999) (Pedersen 2007) (Stokke 2008) (Ericson & Halvorsen 2008) (Grinden & Feilberg 2008) (Kipping & Trømborg 2015). However, apart from (Pedersen 2007), they mostly analyse the total electricity consumption, and lacks the allocation of end use by purpose. The approach presented in this appendix estimates load profiles allocated on two purposes; heat demand, and electric specific demand (see definition on page xii).

B.1 Data sample

The data sample constitutes of hourly measurements from over 200 non-residential buildings in Norway collected for the years 2010-2012. To evaluate whether the sample is representative for the Norwegian building stock, the data sample is compared to national statistics from NVE and Enova. Figure B-1 shows relatively good concurrence between the sample and Enova's building statistics of 2011 (Enova SF 2011), and NVE's report on energy consumption of non-residential buildings in Norway based on data from 2013-2015 (Langseth 2016).

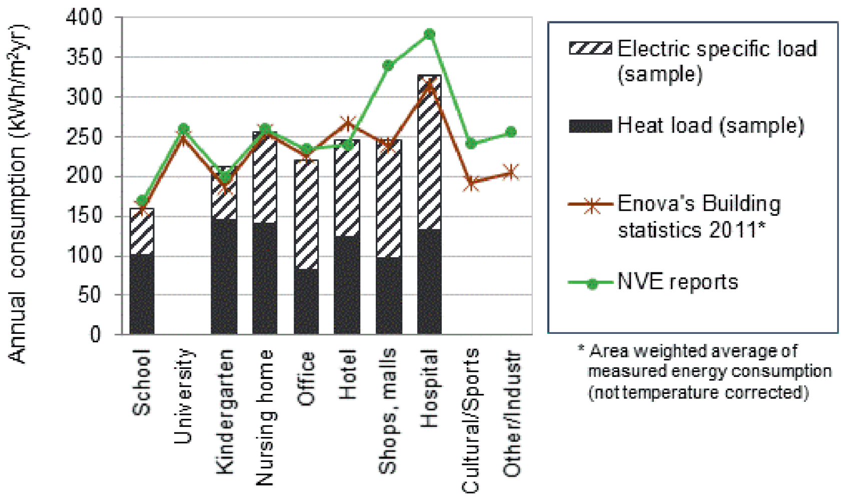

Figure B-1 Comparison of data sample to statistics from Enova (Enova SF 2011) *and NVE* (Langseth 2016).

In the national energy statistics from Statistics Norway (SSB), the energy consumption of industrial buildings is included in the industrial sector. In order to calibrate the aggregated load towards national energy statistics, industrial buildings are not included in the aggregation methodology. Load profiles for universities, cultural and sports buildings are constructed based on those of offices, nursing homes and hospitals (see Table 3-1 in Chapter 3.1), and calibrated to fit with the publications of Enova and NVE.

The following gives an overview of the developed heat and electric specific regression models of the nine non- residential building categories, which builds on material published in (Chacón, 2015), and of the two residential building categories, which builds on (Pedersen, 2007).

B.2 Heat load models

The panel data regression model framework is applied to the experimental data from stores, kindergartens, hotels, nursing homes and hospitals, in addition to the already presented load profiles for schools and offices in Article I and II. Data from each building category are fitted to separate models for each of the eight building categories. As shown in Table B-1, the significant explanatory variables are found to be similar for all the building categories. However, the value of the determined model parameters varies between the building categories, and the differences between weekdays (WD), weekends (WD) and holidays (HD) are substantial. The main characteristics of the heat models for the passive buildings is summarised in Table B-2.

Table B-1 Main characteristics of the heat load models for each building category. (WD – weekday, WE – weekend, HD – holiday, T – hourly temperature, TMA – 24 hr moving average temperature)

Building type		Heat Load Model	
		Significant explanatory variables	***Hours where temperature dependency is active***
1	Schools	Outdoor temperature; direct (T) and 24 hr moving average (TMA)	1 to 24 / WD,WE,HD
2	Offices	T + TMA	1 to 24 / WD,WE,HD
3	Stores	T + TMA + Monthly Dummies	1 to 24 / WD,ST,SN
4	Kindergartens	T + TMA	1 to 24 / WD,WE,HD
5	Hotels	T + TMA	1 to 24 / WD,HD
6	Nursing Homes	T + TMA	1 to 24 / WD,WE
7	Hospitals	T + TMA	1 to 24 / WD,WE,HD

Table B-2 Main characteristics of the heat load models for passive offices and schools.

Building type		Heat Load Model	
		Significant explanatory variables	***Hours where temperature dependency is active***
1	Passive School	T + TMA	1 to 24 / WD,WE and HD
2	Passive Offices	T + TMA	1 to 24 / WD,WE and HD

The load profiles of passive buildings for building category #3 to #11, are constructed because of lack of experimental data. First, the model parameters of the average existing schools and offices are compared to the model parameters of the passive schools and offices. Table B-3 shows that the temperature independent terms, α and γ, are reduced by 44 – 57 % for offices, whereas the temperature dependencies, β^{T} and β^{TMA}, are reduced by 40 – 61 %, dependent on day type (weekday/weekend/ holiday) and hour of the day. Secondly, as schools and offices have different characters, the average parameter reduction found for office and schools are applied to the different building categories as shown in Table B-4. Once the parameters have been determined, load profiles of all the different building categories are predicted.

Table B-3 Estimated parameter reduction for offices and schools. Comparison of existing and passive buildings.

		Parameter reduction (%)			
		α α_{wd} / α_{we} / α_{hd}	**γ** γ_{wd} / γ_{we} / γ_{hd}	**β^{T}** β^{T}_{wd} / β^{T}_{we} / β^{T}_{hd}	**β^{TMA}** β^{TMA}_{wd} / β^{TMA}_{we} / β^{TMA}_{hd}
1	Normal to passive School	70 / 80 / na	81 / 81 / na	46 / 68 / na	49 / 40 / na
2	Normal to passive Office	57 / 55 / 57	44 / 48 / 56	37 / 40 / 55	61 / 56 / 55

Table B-4 Constructed heat load models per building category for passive buildings.

		Parameter reduction % (WD / WE / HD)				Based on observed parameter reduction of:
		α	**γ**	**β^{T}**	**β^{TMA}**	
3	Shops/Malls	57 / 55 / 57	44 / 48 / 56	37 / 40 / 55	61 / 56 / 55	Offices
4	Kindergarten	70 / 80 / na	81 / 81 / na	46 / 68 / na	49 / 40 / na	Schools
5	Hotel	57 / 55 / 57	44 / 48 / 56	37 / 40 / 55	61 / 56 / 55	Schools
6	Nursing Home	57 / 55 / 57	44 / 48 / 56	37 / 40 / 55	61 / 56 / 55	Offices
7	Hospital	57 / 55 / 57	44 / 48 / 56	37 / 40 / 55	61 / 56 / 55	Offices
8	University	(as Offices)				
9	Cultural and Sport buildings	(as Hospitals)				
10	Single family house (SFH)	58 / 60 / na	44 / 50 / na	39 / 42 / na	na	Offices
11	Apartments	58 / 60 / na	20 / 20 / na	39 / 42 / na	na	Offices

B.3 Electric specific load models

The passive buildings of each building category are assumed to have similar electric specific load as the existing buildings within the same category. Hence, it is only necessary to construct electric specific load profiles for university buildings and cultural & sport buildings.

C. Appendix: Aggregate load profiles

Predictions of future aggregate electric load profiles are crucial for grid investment decisions and for energy systems planning. In order to incorporate the impact of electric heating and energy efficiency measures of buildings, heat load profiles and electric specific load profiles should be treated separately. Section C.1 presents the aggregation methodology, whereas aggregate load inputs to the energy system analysis and power system analysis, are presented in Section C.2 and C.3, respectively.

C.1 Aggregation methodology

This section describes the load aggregation methodology used for generating the load inputs for Article VII and Article VIII. Once the regression models for heat and electricity loads are established (see Appendix B), they can be used to predict future heat and electric specific demand based on the outdoor temperature of the geographical situation of the buildings. Thus, the load aggregation methodology for buildings consists of four main steps:

1. Predicting heat and electricity load for each building category *i*, for each region *r*.
2. Building stock development for each region *r*.
3. Assuming introduction of passive buildings (share of building stock)

Hourly *heat load* and *electric specific load* profiles are calculated, for each region *r*.

4. Distribution of heat technologies and their efficiencies within each region *r*.

Hourly *total electric load* is calculated, for each region *r*.

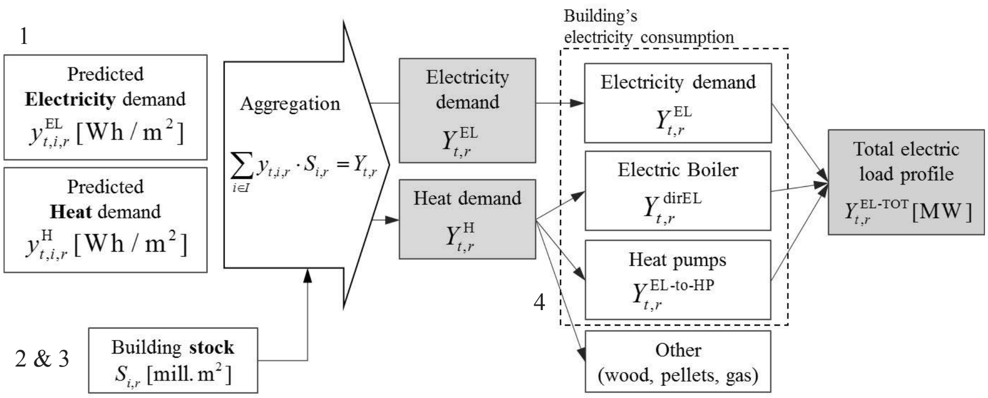

Figure C-1 Load profile aggregation, per region (r).
Load input for energy system analysis (yellow), and input for power system analysis (blue).

Figure C-1 illustrates the load aggregation methodology. The regression models described in Appendix B forms the basis of the load predictions. Together with information of the future building stock (cf. Figure C-2), and the distribution of heat technologies within the buildings (cf. Table C-1), the aggregate total electric load profile for buildings is found. Notice that the load profile at any level of the aggregation can be used to predict load profiles for each building category specific to the geographical situation of the buildings. This is important as outdoor temperatures differs between regions.

Projections of the future building stock is received from the NVE, based on a methodology described in (NVE, 2014). Here today's building stock is based on (Bøhn et al. 2012) and (Mjønes et al. 2012), which separates the national building stock per category and age class. The projections of the total building stock are made by analysing historic growth of building stock and population, and combining them with official projections of the population growth (Statistics Norway 2014a). Demolition of the buildings are based on their actual age, and an assumed average lifetime of 80 years. Hence, the new constructed buildings are the difference between the total stock projections and the remaining building stock. Finally, the stock projections are separated by region according to population (Statistics Norway 2014b).

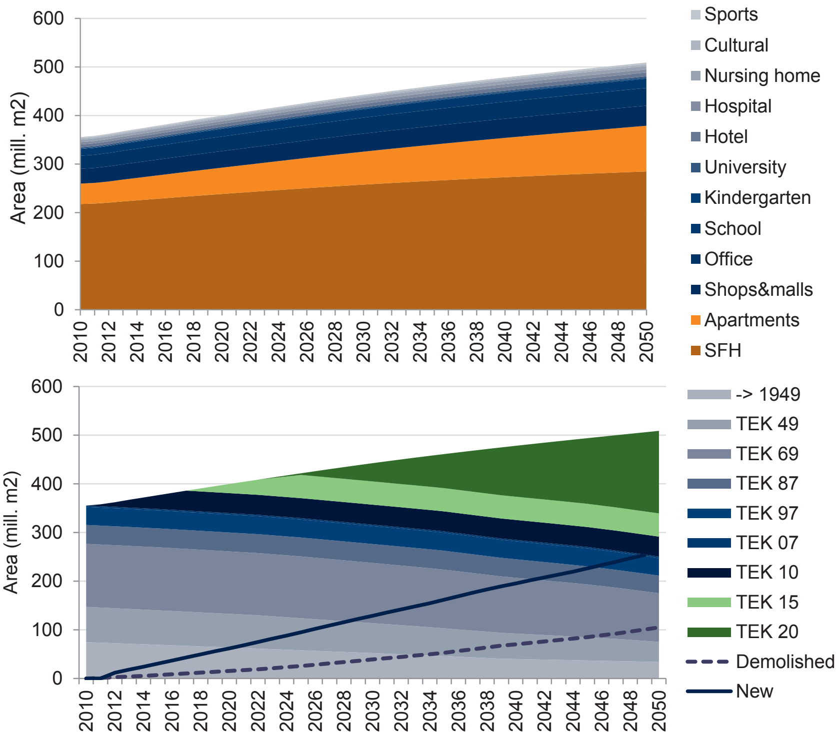

Figure C-2 Projection of the Norwegian building stock, by building category (upper graph) and technical standard (lower graph)..

Figure C-2 shows the projected buildings stock in Norway towards 2050, both in terms of building types in the upper graph, and in terms of new buildings (green) and existing buildings (blue) in the lower graph. Notice that in 2030 it is expected that almost 20 % of the building stock are built according to the newest technical standard (TEK 15 or TEK 20), and is assumed to increase to 43 % in 2050.

C.2 Aggregate heat and electric specific demand for 2030 and 2050

The load profiles are predicted per building category, and whether the building is an "average" existing building or a newly constructed "passive" building. The predictions are made with time series of outdoor temperatures for the representative region. Once the share of passive buildings are decided, the aggregate heat and electric specific load profiles are calculated (depicted as yellow rectangles in Figure C-1). This is the input required for the energy system analysis. Figure C-3 presents the annual energy demand

Norwegian building stock for normal climatic conditions with 0 %, 25 % and 50 % implementation of passive buildings in 2030 and 2050.

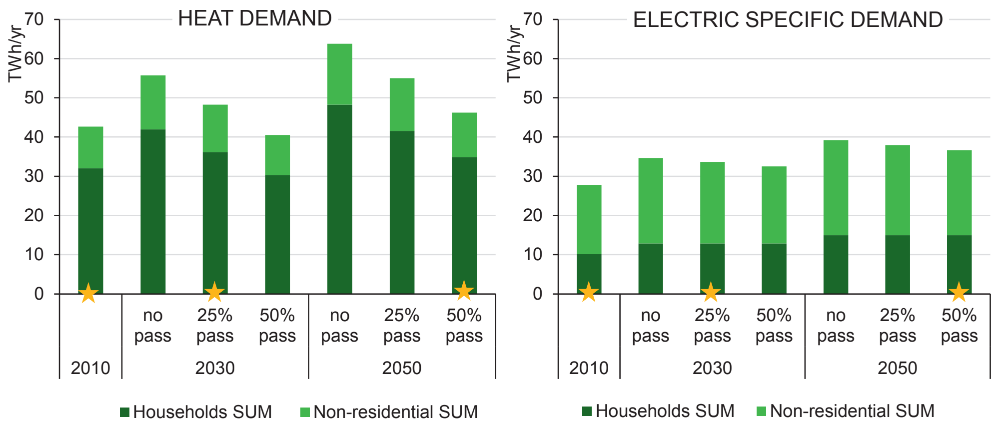

Figure C-3 Energy demand of the Norwegian building stock in 2010, and future energy demand if 0 %, 25 % or 50 % of the building stock are passive buildings in 2030 and 2050.

Comparing the to graphs in Figure C-3 the heat demand is more affected than the electric specific demand if replacing 0 %, 25 % or 50 % of the building stock with passive buildings. Notice that the households are responsible for 75 % of the total heat demand, but only 36-40 % of the electric specific demand. According to the building stock projections in Figure C-2, the share of passive buildings could reach about 25 % in 2030, and about 50 % in 2050, if some of the existing buildings are rehabilitated to passive standard in addition to the new buildings. In Figure C-3, this trend is tagged with yellow stars, which indicates that the future *heat demand* of the building stock may increase towards 2030, but decline slightly towards 2050. The *electric specific demand* however, is increasing through the whole period due to increased number of buildings.

The hourly heat load profiles are presented in Figure C-4. The seasonal variation of the profile reflects the outdoor temperature that differs for each climatic year. In summer however, the heat demand is purely hot tap water demand and does not vary with the outdoor temperature. The electric specific demand in Figure C-4 has a strong daily and weekly pattern, but the seasonal variation is almost negligible. Notice the drops in the demand around Easter, summer holiday and Christmas, which influences the electric specific load of non-residential buildings. In some hours in the middle of summer, there is a cooling effect, and as for the heat demand this depends on the climatic year.

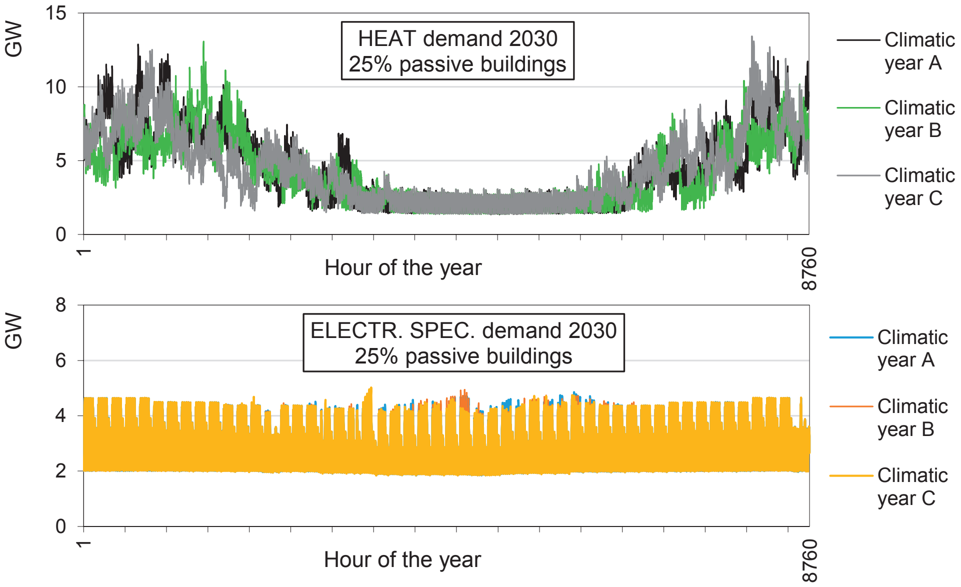

Figure C-4 Hourly load profiles for heat demand (upper) and electric specific demand (lower) of region NO1 in 2030, with a passive share of 25 %. (Predictions are made for three different climatic years).

C.3 Aggregate total electric load profile for 2030

To achieve the total electric load profile, which is used as input to the power system analysis, the fourth and last step is determining the distribution of heat technologies within the building stock. Based on the database of the Energy Labelling System of Buildings at the NVE, which contain information on heat technology and age for each building category, and Statistics Norway's information on heating technologies for households, the share is shown in Table C-1. By applying the efficiencies for each heating technology, the resulting consumption of different energy carriers are found, and the numbers are calibrated against the national statistics on energy consumption from (Statistics Norway 2013).

Table C-1 Share of heating technologies for existing building stock, by building category.

	School	**University**	**Kinder-garten**	**Nursing Home**	**Office**	**Shop**	**Hotel**	**Hospital**	**Cult & Sport**	**Average non-res.**	**SFH**	**Apartm.**
Direct electr.	61 %	36 %	71 %	53 %	63 %	68 %	63 %	36 %	59 %	**63 %**	66 %	66 %
Heat pump	10 %	5 %	16 %	12 %	9 %	11 %	6 %	6 %	11 %	**10 %**	17 %	17 %
Other	29 %	59 %	13 %	35 %	28 %	21 %	31 %	58 %	31 %	**27 %**	17 %	17 %

Regarding the new passive buildings, it is difficult to foresee which heating technology that will be installed towards 2030 and 2050. As discussed in Chapter 3.2, with the current weighting factors and ZEB definition, the cost-optimal choice of ZEBs seems to be bio energy. However, as the findings in the energy system analysis in Article VIII shows that it is cost-optimal to increase electric heating, i.e. heat pumps or even direct electric heating, from a system perspective. Hence, three cases are developed where the new passive buildings are heated by respectively direct electric heating (DIR), heat pumps (HP) or other heating technologies (OTH).

Figure C-6 shows the electricity demand input to the power system analysis in Article VII which assumes that 50 % of the building stock are passive buildings in 2030. This is an exaggeration of the projections in Figure C-2, but is made to stress-test the system. With these assumptions, the total electricity demand of the Norwegian building stock is decreased from 77 TWh in the BAU case to 57 TWh in the *OTH* case.

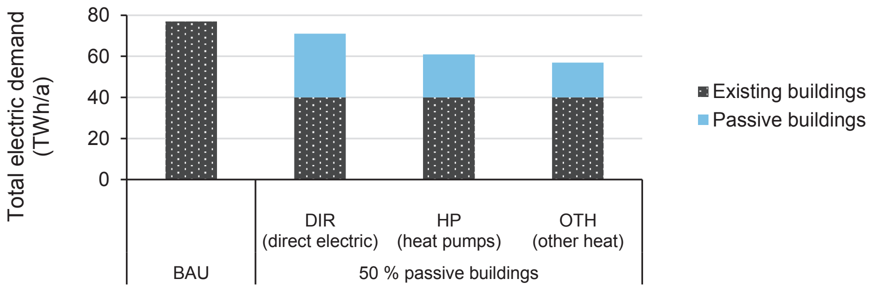

Figure C-5 Total electricity demand of the Norwegian building stock in 2030, where passive buildings contribute to 50 % of the stock. The passive buildings are either heated by direct electric heating (DIR), heat pumps (HP) or other heating technologies (OTH).

Figure C-6 shows the hourly load profile of the total electric demand, including electricity for heating purposes. The upper graph shows the *BAU* profile if no passive buildings are present in 2030 and given that the distribution of heat technologies is as today. Compared to the profile of the *HP* case (lower graph), the maximum load is reduced by 36 % from 10,1 MW to 6,5 MW for the same climatic year.

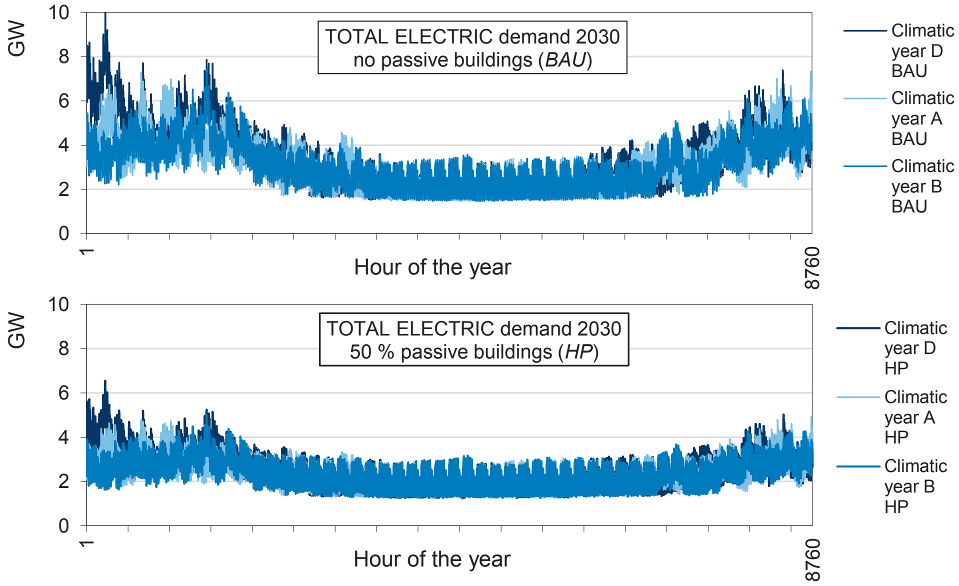

Figure C-6 Hourly load profiles of total electricity demand in region NO1 in 2030, without passive buildings (upper) and with 50 % passive buildings heated by HPs (lower). (Predictions are made for three different climatic years).

Comparing cold years to warmer years shows that the peak load occurs at different times, and that it varies between 200 % to 316 % of the average hourly summer load in the *BAU* case, and from 132 % to 208 % in the *HP* case for these three climatic years. Further, the average winter load (nov, dec, jan & feb) is about 85 % higher than the average summer load (june, july, aug, sept) in the *BAU* case. With a large introduction of ZEBs, this number is reduced to 50 % in the *HP* case. Hence, the seasonal variation of the load is significantly reduced with an introduction of ZEBs.

The results of the load modelling show that the maximum load of the building stock is highly dependent on the technical standard of the building, and on the heat technology within the buildings.

D. Appendix: Operational results in 2050 of Article VII

Due to limitations of the text in Article VIII, in the following, selected results of the operation of the Scandinavian electricity system in 2050 are presented in more detail. The two-hourly plots of the expected[2] electricity production in Figure D-1 show that the hydropower plants adjust their production according to the PV. The installed nuclear power capacity is set exogenously in both cases, but the model is still free to operate it at part load, which is observed in the summer plots. Further, the base load technologies, also called must-run technologies, reduce their production in summer with a large implementation of ZEBs.

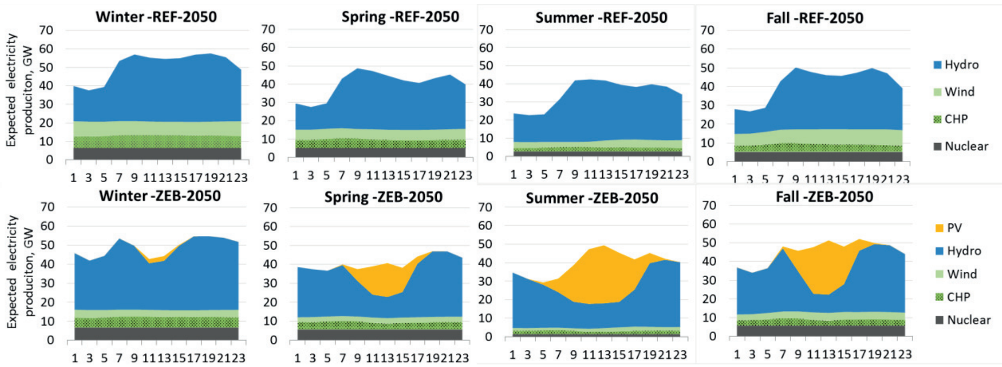

Figure D-1 Expected electricity production in 2050 on a day in winter, spring, summer and fall, by technology. Comparing the reference case (REF) in upper graphs, to the ZEB case in lower graphs.

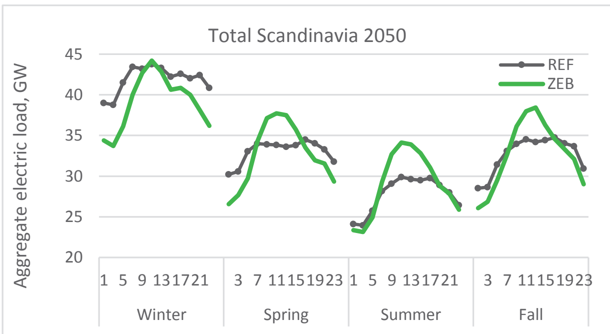

Figure D-2 Expected aggregate electric load in 2050 on a day in winter, spring, summer and fall. Comparing the reference case (REF) to the ZEB case. Total Scandinavia.

Despite that the heat demand is decreased, the expected annual electricity consumption in 2050 is hardly reduced from 319 to 315 TWh. The reason lies in the role of electricity for heating purposes.

[2] "Expected" reflects the average value of the 21 stochastic scenarios of the model operation.

Investigating the hourly heat generation, the electric heating (either direct electric heating or electric boilers) increases its production during daytime in spring, summer and fall, and thereby replaces heat generated by heat pumps, gas and bioenergy in these hours. At daytime in winter however, the electric heating is unchanged. In the hours at night, the electric heating is reduced in winter, spring and fall, but unchanged in summer. These considerations of the electric heat generation are directly reflected in the aggregate electric load in Figure D-2, where the electricity consumption is reduced at night (due to lower heat demand), but increased at day (because electric heating replaces other technologies) when ZEBs are introduced. The net effect is a relatively unaffected total electric consumption, although the shape of the profile is changed.

Article I

Hourly load modelling of non-residential building stock

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***Abstract*— Smart grid and demand side management (DSM) are expected to play a key role in facing the challenges of a nearly 100 % renewable energy system with high share of intermittent power production. Compensating for the variability in power production creates a need for flexible demand. However with the introduction of net zero energy buildings (ZEB), studies have shown that buildings' net demand may be more volatile than the existing building stock as they act as prosumers, both consuming and producing energy.**

In the ongoing work we investigate the impact of a large roll out of ZEBs in Norway, compared to today's building stock. How will the buildings' net demand profile evolve, and how will this affect the energy system?

In short one may say that the net demand profile of ZEBs consists of two components, hourly profiles of heat and electricity demand separately, and hourly profiles of onsite energy production (such as PVs). In this paper we examine the load profiles, and leave the production profiles, and subsequently the net load profiles, for later studies.

A regression model for heat demand profiles of non-residential buildings is developed and tested on Norwegian school buildings. The findings confirm that heat consumption in passive buildings is almost halved compared to normal school buildings both in terms of yearly energy demand and in terms of peak loads.

***Index Terms*-- zero energy buildings (ZEB) energy consumption, load profiles, load management, flexible demand, demand side management, smart grid, power system economics.**

I. Introduction

Zero Energy Buildings (ZEBs) have become a part of the energy policy in several countries in recent years. In the recast of the EU Directive on Energy Performance of Buildings (EPBD) it is stated that by end of 2020 all new buildings shall be "nearly zero energy buildings"[1].

A net zero energy building (ZEB) is a building which has low energy demand, with so-called "passive energy standard", and which has the capability of producing energy that corresponds to its demand on an annual basis (see e.g. [2] or [3]). The definition is in other words attached to the yearly balance, however the building still exchanges electricity with the grid on an hourly or minute basis, as the production may not always correspond with the load at these time levels [4].

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The Norwegian Water Resources and Energy Directorate (www.nve.no)
The Research Centre on Zero Emission Buildings (www.zeb.no)
The Research Centre for Sustainable Energy Studies (www.censes.no)

The building's net load (= load - export) of electricity is dependent not only on the type, size and energy standard of the building which influences demand, but also on the choice of production facility (e.g. photo voltaic, or biomass boiler). This makes the building's grid adaptability dependent on both building characteristics and production facilities.

In the ongoing work we develop a model which predicts hourly energy load profiles separated on heat and electricity demand for non-residential buildings, which makes it possible to simulate a spread of load profiles within, for instance 95% confidence interval. These load profiles will be used in an optimization model for ZEB buildings with stochastic load forecasts, electricity prices and electricity production in order to finally finding the net load profile.

In this paper a regression model for heat demand is developed and tested on school buildings. We compare predicted "normal" hourly heat load profiles based on data from 26 normal school buildings in Norway, with predicted heat load profiles for a "passive school building" in Norway. Demand profiles of other non-residential buildings such as offices, nursery homes, kindergartens and hospitals will be analyzed later.

II. Background

A. Background

Buildings in Norway account for approximately 40 % of total domestic energy consumption, hereof 40 % in non-residential buildings equivalent to 30 TWh annually [5]. Energy consumption in service buildings in Norway is available on a yearly basis (ref. [5] and [6]). However with the development of smart grids and zero energy buildings, a need for data on an hourly scale has emerged.

Previous work on load modeling of Norwegian non-residential buildings is done by Pedersen [8] and by SINTEF Energy Research through the Research Projects REMODECE [7] and ElDek. Pedersen's work explains heat load profiles by one regressor, outdoor temperature, and the electricity profiles are described by normal distributions. Pedersen suggests in further work to include additional explanatory parameters such as wind speed and solar radiation, and to expand the sample of investigation. This paper seeks to do both.

III. DATA

A. Sample data

A sample of 200 buildings was selected on the following four criteria: (1) Categories of buildings should reflect the national composition in an adequate way. (2) Availability of hourly measurements over at least three years. (3) Separate measurements for heat and electricity consumption. (4) Geographical diversification throughout the country.

Based on these criteria, 50 office buildings, 30 health buildings, and 80 educational buildings were selected, covering approximately 44 % of the non-residential building stock[2]. Measured hourly electricity and heat consumption data from 1.1.2009-31.12.2011 was collected with the help of the company Entro[1]. In this paper 26 school buildings was identified with suitable measurements and selected for the analysis. The schools are located in the following cities Bergen, Hamar, Kristiansand, Namsos, Nærøy, Porsgrunn, Skien, Sør-Odal, Trondheim, Oslo, Østre-Toten and Drammen. Together with the energy data, Entro also provided building specific data on building size. However, data on construction year and number of employees, including pupils/children in educational buildings, were not possible to obtain.

As mentioned in the introduction, the ZEB buildings are assumed to have passive house standard. Data for passive schools in Norway have been hard to collect. Only one passive school in Drammen had hourly energy measurements over a three-year period. The data was collected with the kind help of Drammen Eiendom KF.

B. Climate data

Outdoor temperature and wind speed for the geographical situation of each of the buildings were collected from The Norwegian Meteorological Institute [9]. Statistical data on solar irradiation is scarce in Norway, but in order to investigate the impact of the sun, a test was made on a school building in Kristiansand where solar data was downloaded from a climate model, STRÅNG, from Swedish Meteorological and Hydrological Institute (www.smhi.se).

IV. METHOD AND MODEL

In this paper, a heat regression model for school buildings is developed.

A. Some basic econometrics

The method used is a fixed effects regression model for panel data. Panel data is a multidimensional dataset which contains data observed over several time periods, T, for the same individuals, N.

In our case the individuals are buildings, and the time periods are hourly measurements over three consecutive years[3]. The panel dataset is denoted as “long and narrow” because T is relatively large compared to N. A possible equation for such a dataset is:

Eq.1 $$y_{it} = \alpha_i + \beta_{1t}x_{1it} + \beta_{2t}x_{2it} + \cdots + \beta_{mt}x_{mit} + \varepsilon_{it}$$

Where y_{it} is heat demand, and α_i, the constant intercept term which is included to control for building specific and time invariant characteristics such as construction year and building size. The x_{mit}-s are the {1,2,…, m} explanatory variables, such as temperature and wind, which is expected to have an effect on heat demand. The β-s reflect the estimated effect of the explanatory variables. The error term in the end is denoted by ε_{it}. Notice that the effect of the explanatory variables are assumed to be equal for all buildings *i*, but different for each hour, *t*.[12]

B. ET-curve and changing point temperature (CPT)

When analyzing energy consumption in buildings, it is useful to consider the energy-temperature curve (ET-curve). The ET-curve shows energy consumption within a building plotted against outdoor temperature. The plot is used by caretakers and building owners to register deviation of the day’s or week’s energy consumption in order to ensure efficient energy use within the building. In our work we have used the plotted the ET-curve when assessing the goodness of fit of the different model formulations.

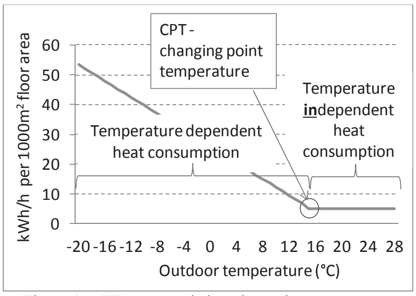

Figure 1. ET-curve and changing point temperature.

Figure 1. shows the features of the ET-curve. The changing point temperature (CPT) is found at the break of the yellow curve. For temperatures below CPT, heat demand is temperature dependent such as space heating and ventilation heat. At temperatures above CPT, heat demand is assumed to be constant and reflects the temperature independent heat demand such as hot tap water.

C. Model detection

When investigating the model formulation, school building number 12 in the sample has been used as test object. Two different model formulations was tested out on this building based on a) the work by Stokke, Doorman and Ericson [10], and b) the work of Pedersen [8]. The models were implemented and analyzed in the statistical tool, STATA [11].

As Norway is situated in a near arctic climate, the main driving force of heat demand is assumed to be outdoor temperature. Also, based on experiences in [10], a non-linear effect of temperature was expected as it exceeds the changing point temperature (no need for more heat) or reaches very low

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[1] Entro is a company which provides consulting services for energy management of non-residential buildings occupied or owned by private companies, municipalities or other entities (www.entro.no).

[2] When relying on the allocation of square meters on type of service building published by Enova [6].

[3] This means that hour t = 1, …, 8760 and building i = 1, …, N, where N=11 for schools. The total number of observations is thus 262800, which correspond to 8760 hours over three consecutive years.

temperatures (the technical heat system is not able to deliver more heat), creating an S-shaped curve. Thus a quadratic term of temperature was added. Because thermal mass embedded within the building is causing a time-delay, a 24 hr moving average of outdoor temperature is added to the model. Wind and solar minutes per hour was also tested as explanatory variables.

Model 1 has three different seasons within the year. Dependency of temperature (T, T^2, TMA), wind (W) and solar hours (SH) is determined for each season, P = {P1(nov-mar), P2 (april+oct), P3 (may-sept)}, but is equal for all hours within each season. The 24 hr profile throughout the day is captured by hourly dummies within weekday and weekend separately.

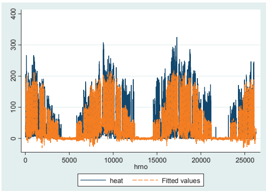

Figure 2. Model 1: Hourly measured (blue) and estimated (orange) heat consumption for school no.12 in 2009-2011.

Figure 3. Model 1: ET-curve on hour number 10 on weekdays. Measured (blue) and estimated (orange). School no.12.

Figure 2. shows the estimated hourly consumption over the three consecutive years. Figure 3. shows the ET-curve of hour number 10 on weekdays. Notice the three lines which correspond to each of the three seasons, P1 (top), P2 (middle) and P3 (bottom). As the two figures shows, the model does not satisfactory capture the peaks of heat demand. The reason seem to be that the diurnal hourly effect (the intercept term) seems to be overestimated, leaving the slope of the ET-curve less steep than what the observed data shows. Further, the squared term of the temperature gives a too large downward effect compared to the measured data. With this model formulation we also encountered problems with negative heat demand which is unlikely to happen.

Model 2 based on Pedersen [8] has no seasonal division, but rather one single equation per hour which is equal throughout the year. This means that for each hour 1-24, we have the following 4 relationships (2 for weekdays/weekends):

If $T_t < CPT_{wdh}$: $$y_{it} = \alpha_i^* + \alpha_t + \beta_t^{x1} x1_t + \cdots + \beta_t^{xM} xM_t + \varepsilon_{it}$$

If $T_t > CPT_{wdh}$: $$y_{it} = \alpha_i^* + \gamma_t + \varepsilon_{it}$$

Where x^m_t are the 1-M explanatory variables and β^{xm}_t their dependencies. When temperature is above CPT, heat demand is given by an expected value reflected in γ_t. In contrast to model 1, model 2 estimates hourly temperature dependencies regardless of season as long as the outdoor temperature is lower than CPT, e.g. that we are in the area of temperature dependent heat consumption in Figure 1.

Figure 4. and Figure 5. show that Model 2 captures the peaks in a better way. Similar as for model 1, the squared term of the temperature makes the ET-curve bend downward at very low temperatures also for Model 2. The reason why the measured data do not show the same trend could be that the heating equipment of the building is designed to handle the heat peaks, and thus the threshold that T^2 should reflect does not exist. Thus, we rule the T^2 term out.

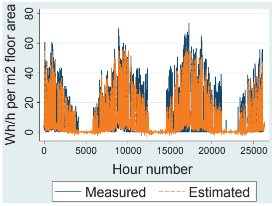

Figure 4. Model 2: Hourly measured (blue) and estimated (orange) heat consumption for school no.12 in 2009-2011.

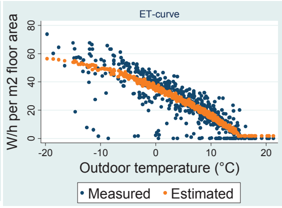

Figure 5. Model 2: ET-curve in hour number 10 on weekdays. Measured (blue) and Estimated (orange). School no.12.

TABLE I. INVESTIGATING CLIMATIC VARIABLES ON SCHOOL NO.12

Climatic variables included	***Goodness of fit***
Temperature (T)	R^2 = 75,4 %
Temperature (T), Squared temperature (T^2), 24 h moving average temperature (TMA)	R^2 = 76,6 %
T, TMA	R^2 = 76,0 %
T, Wind	R^2 = 75,8 %
T, 24h moving average wind (WMA)	R^2 = 75,6 %
T, Sunshine (S)	R^2 = 75,5 %

Investigating the significance of the different climatic variables showed only minor model improvements. When including wind and solar variables in addition to temperature, TABLE I. shows that R^2 only improved 0,4 and 0,1 % points respectively. Consequently, the main explanatory variable was detected out to be temperature. Some of the reason why the other climatic variables showed weak explanatory power could be that outdoor temperature is affected by, and thus correlated with, sunshine. TABLE II. shows that temperature is 20 % correlated with minutes of sunshine per hour. Therefore the partial effect of sunshine is less distinguishable. Another aspect may be that even though indoor temperature is affected by sunshine, heat consumption could be less affected. A third and most likely reason is the low quality of the solar data as it was retrieved from a model and not from real measurements.

Model 2 with temperature, T, and 24 hr moving average temperature, TMA, as explanatory variables, gave the best fit. Thus, this is the model that has been used for analyzing the 26 normal and 1 passive school building in the following.

D. Detecting non-operating hours

Heat demand within a school building is very sensitive to whether or not the building is being occupied. Weekends are easy to identify, however holidays such as Easter, summer holiday, Christmas and other public school holidays had to be identified for each building as they differ between regions and cities. Holidays are categorized as weekends in the model.

TABLE II. CORRELATION MATRIX FOR CLIMATIC VARIABLES

	T	***W***	***SH***
Temperature	1		
Wind	0.058	1	
Sunshine minutes per hour	0.203	0.033	1

E. Model formulation (heat demand)

The best suitable model for heat load estimation of Norwegain schools was found to be the one shown in Equation 2 (explanation of symbols in TABLE III.).

Eq.2

$$
\begin{aligned}
y_{it} = \alpha_i^* &+ \sum_{wdh=1}^{24} \alpha_{wdh} D_{wdh}^{WD} + \sum_{wdh=1}^{24} \beta_{wdh}^{T} D_{wdh}^{WD}\, T_t \\
&+ \sum_{wdh=1}^{24} \beta_{wdh}^{TMA} D_{wdh}^{WD}\, TMA_t \\
&+ \sum_{wdh=1}^{24} \gamma_{wdh} D_{wdh}^{CPT,WD} + \sum_{weh=1}^{24} \alpha_{weh} D_{weh}^{WE} \\
&+ \sum_{weh=1}^{24} \beta_{weh}^{T} D_{weh}^{WE}\, T_t \\
&+ \sum_{weh=1}^{24} \beta_{weh}^{TMA} D_{weh}^{WE}\, TMA_t \\
&+ \sum_{weh=1}^{24} \gamma_{weh} D_{weh}^{CPT,WE} + \varepsilon_{it}
\end{aligned}
$$

TABLE III. EXPLANATION OF SYMBOLS

Variable/ parameter	*Description*
t	Any hour *t* throughout the year (1-8760).
wdh	Weekday hour (1-24)
weh	Weekend or holiday hour (1-24)
y_{it}	Heat consumption in hour, *t*, for building, *i*. [W/m^2]
α_i^*	Fixed time independent effect for building, *i*, equal for all hours, *t*. [kWh/m^2]
α_{wdh}	Fixed building independent effect for weekday hour, *wdh*, as long as temperature is below the weekday-hour's changing point temperature ($T_t < CPT_{wdh}$).
D^{WD}_{wdh}	Dummy variable for weekdays. 1 if $T_t < CPT_{wdh}$, 0 otherwise.
β^{T}_{wdh}	Effect of outdoor temperature on heat demand in weekday hours, *wdh*. The effect changes for each hour of the day, but is independent of season as long as $T_t < CPT_{wdh}$. [(W/m^2)/°C]
T_t	Outdoor temperature, in hour, *t*.
β^{TMA}_{wdh}	Effect of 24h moving average of outdoor temperature on heat demand in weekday hours, *wdh*.[(W/m^2)/°C]
TMA_t	24 hr moving average of outdoor temperature, in hour, *t*. [°C]
γ_{wdh}	Fixed building independent effect for weekday hour, *wdh*, as long as temperature is **above** the changing point temperature ($T_t > CPT_{wdh}$). [W/m^2]
$D^{CPT,WD}_{wdh}$	Dummy variable for weekdays. 1 if $T_t > CPT_{wdh}$, 0 otherwise.
α_{weh}, β^{T}_{weh}, β^{TMA}_{weh}, γ_{weh}, D^{WE}_{weh}, $D^{CPT,WE}_{weh}$	Equal explanation as for the above mentioned variables with the exemption that they are connected to weekend or holiday hours, *weh*.
ε_{it}	Error term of the regression. Assumed to be independently and identically distributed over all *i* and *t*.

The first term is the (unobserved) individual specific effects, which is assumed to stay constant for a given building, *i,* over all hours, *t*. The second term reflects the fixed effects (or constant term) for each hour in weekdays. The third term is the temperature dependency for each hour (wdh = {1,..,24}) in weekdays per °C and multiplied with the outdoor temperature the corresponding hour t. The following term captures the 24h moving average of temperature dependency for each hour (wdh = {1,..,24}). The fifth term is the stationary expected heat consumption for hour 1-24 in weekdays when outdoor temperature is above CPT. Term 6 to 9 have the same explanation as term 2 to 5 for weekends and holidays.

V. RESULTS

A. Fixed effects regression model – 26 normal schools

A fixed effects regression on the panel data with 26 schools was performed and the parameter estimation is shown in TABLE V. Graphic prediction result for one normal school building using the estimated model is shown in Figure 6.

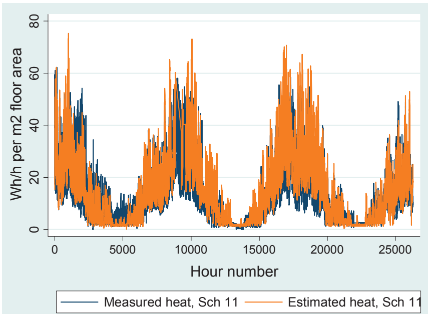

Figure 6. Hourly measured (blue) and predicted (orange) heat consumption for school no.11, based on the whole sample of normal schools in 2009-2011.

The overall R^2 for the prediction of the 26 normal school building was 68,1 % which is somewhat lower than for school building no.12 when the model detection was done on this school alone. Since the model now is calibrated to fit all 26 buildings in the best possible way (in contrast to only one building), a weaker fit is somewhat expected. R^2 = 68 % means that the model is able to explain more than 2/3rds of the heat consumption for normal schools through the explanatory variables chosen. The estimated values of the model are shown in TABLE V.

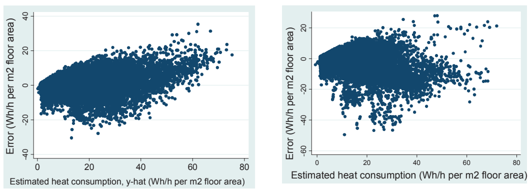

Figure 7. Plot of residuals, ε_{it},=ỹ-y, against estimated heat consumption, $\tilde{y}_{it}$, for school no.11 (left), school no.20 (right).

Regression analysis demands the error to be identically and independently distributed. A plot of the error terms against the fitted linear values for school no.11 and 20 is shown in Figure 7. The majority of the errors are located nicely and symmetrically around the zero line. However at larger heat demand in school 11, the model tends to overestimate heat demand (errors are slightly more often positive than negative). On the other hand for lower heat demand, the model seems to underestimate heat consumption in more hours. For school no.20, errors are also more negative for lower heat demand, but for higher heat demand, the error is more symmetric. The errors vary from building to building, but overall, the model seems to give a nice fit to the measured data.

B. Regression model – passive school building

The model in Equation 2 is also used for analysing one passive school building. The model for the passive school has a slightly better fit with R^2 = 68,6 %. The estimated values in the model are shown in TABLE V. Compared to the values of the normal school building both the intercept and the slope coefficients are lower for the passive school (as expected).

C. ET-curve

A plot of the ET-curve of hour number 10, for one of the normal school buildings is shown to the left in Figure 8. To the right, the ET-curve of the passive school building is shown. Comparing the two, we see that the passive school has lower peak demand, the slope of its ET-curve is less steep and the CPT is lower, indicating lower heat demand and lower temperature dependency of the passive school (as expected).

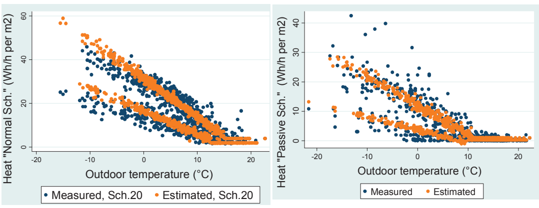

Figure 8. ET-curve of hour no 10 for normal school building no.11 (left) and passive school building (right). Measured heat consumption (blue circle), and model prediction (yellow circle). Notice the upper line as weekdays and the lower line as weekend/holidays.

In order to obtain a good fit, the CPT had to be determined for each hour (1-24). Figure 9. shows the changing point temperatures found for hour 1 to 24 of the day, separated on weekdays and weekend/holidays, both for "normal" school and passive school.

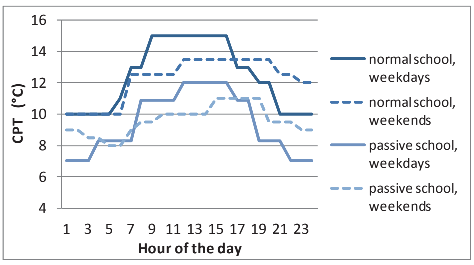

Figure 9. Estimated changig point termperature (CPT) on weekdays and weekend/holidays for normal and passive school building in Norway.

The shape of the CPT curve is similar for weekdays and weekends with higher CPT during daytime which means that heat is turned on at higher outdoor temperatures when occupied compared to evening/night. Further, the findings from Figure 8 confirm our expectations that CPT is lower for passive school buildings compared to normal school buildings. In other words, that space heating is turned on at lower temperatures in a well insulated passive school building compared to the average school building in Norway.

D. Implications for ZEB schools

An issue for the grid and grid companies is the peak load the Zero Emission Buildings may cause. Thus we have investigated the amplitude of heat consumption, or heat consumption at a given day.

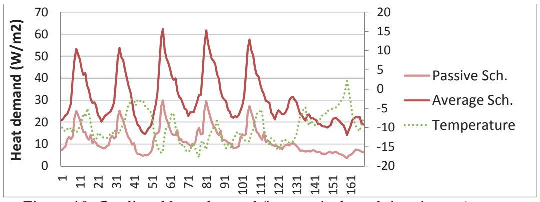

Figure 10. Predicted heat demand for a typical week in winter. Average school buildings and passive school building. (Wh/h per m^2 floor area)

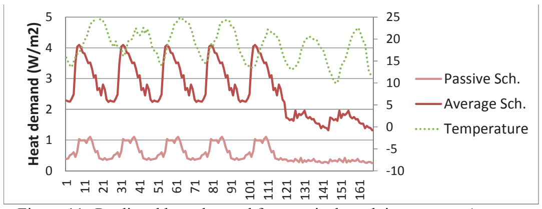

Figure 11. Predicted heat demand for a typical week in summer. Average school buildings and passive school building. (Wh/h per m^2)

Figure 10. shows predicted heat consumption in a week with very low temperatures (based on the estimated values shown in TABLE V.). We find that the maximum amplitude of heat consumption is reduced with almost 23 W/m^2, which is equal to 48 % reduction for the passive school building compared to the average school building. Likewise Figure 11. shows that in summer, the maximum amplitude is reduced by approximately 1,1 W/m^2, equal to 60 % reduction.

TABLE IV. AVERAGE ESTIMATED VARIABLES

		Normal school	*Passive school*	*Difference*	*% of normal school*
Weekdays[a]	$\alpha_i^*+\alpha$	20.66	7.09	13.57	66 %
	β^T	-0.75	-0.36	-0.38	51 %
	β^{TMA}	-0.49	-0.27	-0.22	45 %
	$\alpha_i^*+\gamma$	3.04	0.66	2.38	78 %
Weekends[a]	$\alpha_i^*+\alpha$	14.64	3.80	10.84	74 %
	β^T	-0.54	-0.17	-0.37	68 %
	β^{TMA}	-0.39	-0.23	-0.16	42 %
	$\alpha_i^*+\gamma$	1.65	0.32	1.34	81 %

a. Based on values shown in TABLE V.

TABLE IV indicates that the temperature dependency, β^T, for passive schools on average is 51 % (weekdays) and 68 % (weekends) lower compared to the normal school building. This means that when temperature drops, the gradient for heat consumption is lower for passive buildings, and thus add less stress on the electricity or district heat grid. Further, the temperature independent heat consumption, $\alpha_i^*+\gamma$, is reduced by 78% and 81% for weekdays and weekends respectively. These findings confirm that heat consumption in passive houses is drastically lower than compared to normal school buildings both in terms of yearly energy demand and in term of causing peak loads.

VI. Conclusions

In this work we have developed a prediction model for hourly heat demand for school buildings in Norway. The significant explanatory variables were found to be outdoor temperature and 24 hr moving average temperature. The model is based on hourly measured heat consumption data from 26 school buildings situated across Norway.

The same model was applied to hourly measured heat demand for a school building with passive energy standard. Comparing predicted load profiles of the two building categories with equal outdoor temperature showed that the maximum diurnal amplitude for heat consumption is reduced by 48% in wintertime and 60% in summer.

The model will be used in further work to perform quantile regression to obtain a spread of load profiles within, for instance 95% confidence interval. These load profiles will be used in a stochastic optimization model for ZEB buildings with variable load forecasts, variable electricity prices and variable electricity production from PV solar panels.

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TABLE V. Estimated model values

	Normal 26 school				***Passive 1 school***			
α_i^*	4.056				1.159			
wdh	***WD,*** $\alpha_i^*+\alpha$	***WD,*** β^T	***WD,*** β^{TMA}	***WD,*** $\alpha_i^*+\gamma$	***WD,*** $\alpha_i^*+\alpha$	***WD,*** β^T	***WD,*** β^{TMA}	***WD,*** $\alpha_i^*+\gamma$
1	12.94	-0.23	-0.57	2.29	3.03	-0.26	-0.15	0.39
2	13.10	-0.25	-0.57	2.26	3.56	-0.23	-0.21	0.40
3	13.69	-0.28	-0.58	2.25	3.94	-0.16	-0.29	0.51
4	14.36	-0.28	-0.61	2.35	6.03	-0.17	-0.42	0.54
5	15.57	-0.24	-0.71	2.49	7.05	-0.09	-0.48	0.60
6	18.05	-0.29	-0.73	3.51	6.51	-0.08	-0.48	0.45
7	23.81	-0.59	-0.78	4.04	7.33	-0.10	-0.43	0.63
8	29.25	-0.77	-0.98	4.09	12.24	-0.20	-0.69	1.03
9	31.85	-1.10	-0.80	4.02	13.29	-0.28	-0.75	0.99
10	31.50	-1.20	-0.61	3.84	12.35	-0.51	-0.51	0.99
11	31.21	-1.29	-0.49	3.82	11.89	-0.71	-0.23	0.99
12	30.01	-1.24	-0.48	3.64	11.00	-0.59	-0.26	0.90
13	30.23	-1.34	-0.41	3.50	10.52	-0.51	-0.26	1.04
14	29.71	-1.41	-0.31	3.52	10.16	-0.64	-0.08	1.10
15	28.12	-1.40	-0.25	3.33	9.31	-0.55	-0.16	0.99
16	25.21	-1.27	-0.23	3.04	8.15	-0.53	-0.08	0.77
17	19.83	-0.95	-0.23	3.11	8.44	-0.65	0.01	0.60
18	17.14	-0.80	-0.24	2.63	4.73	-0.48	-0.03	0.65
19	16.03	-0.75	-0.24	2.69	3.92	-0.50	-0.06	0.40
20	14.93	-0.64	-0.31	2.45	3.90	-0.34	-0.15	0.39
21	13.50	-0.51	-0.34	2.80	3.55	-0.31	-0.17	0.36
22	12.71	-0.43	-0.38	2.65	3.22	-0.32	-0.16	0.41
23	11.35	-0.35	-0.38	2.32	3.25	-0.25	-0.19	0.35
24	11.83	-0.30	-0.47	2.24	2.89	-0.24	-0.16	0.38
weh	***WE,*** $\alpha_i^*+\alpha$	***WE,*** β^T	***WE,*** β^{TMA}	***WE,*** $\alpha_i^*+\gamma$	***WE,*** $\alpha_i^*+\alpha$	***WE,*** β^T	***WE,*** β^{TMA}	***WE,*** $\alpha_i^*+\gamma$
1	12.63	-0.38	-0.42	1.74	3.25	-0.08	-0.26	0.37
2	12.52	-0.34	-0.45	1.70	3.41	-0.06	-0.27	0.31
3	12.66	-0.33	-0.49	1.64	3.22	-0.04	-0.29	0.33
4	12.92	-0.31	-0.52	1.68	3.80	-0.06	-0.33	0.33
5	13.28	-0.30	-0.54	1.63	4.16	-0.01	-0.40	0.30
6	14.16	-0.30	-0.58	1.96	4.09	-0.02	-0.39	0.38
7	16.17	-0.38	-0.60	1.72	3.88	-0.06	-0.34	0.34
8	16.55	-0.37	-0.68	1.85	4.11	-0.02	-0.41	0.28
9	16.67	-0.43	-0.66	1.81	4.27	-0.06	-0.39	0.42
10	16.49	-0.54	-0.54	1.86	3.79	-0.21	-0.28	0.27
11	16.51	-0.69	-0.37	1.96	3.79	-0.33	-0.12	0.34
12	16.36	-0.75	-0.29	1.76	3.92	-0.36	-0.10	0.29
13	16.40	-0.78	-0.26	1.71	3.90	-0.33	-0.11	0.35
14	16.41	-0.88	-0.17	1.75	3.94	-0.33	-0.15	0.32
15	16.29	-0.91	-0.12	1.67	4.50	-0.38	-0.08	0.32
16	15.93	-0.85	-0.15	1.69	4.63	-0.46	0.06	0.39
17	15.13	-0.77	-0.18	1.56	3.72	-0.22	-0.15	0.30
18	14.71	-0.70	-0.22	1.53	3.43	-0.15	-0.18	0.29
19	14.24	-0.65	-0.24	1.53	3.66	-0.27	-0.10	0.32
20	13.87	-0.59	-0.29	1.38	3.70	-0.22	-0.17	0.27
21	13.39	-0.49	-0.34	1.46	3.57	-0.11	-0.25	0.25
22	13.19	-0.46	-0.38	1.41	3.45	-0.06	-0.26	0.29
23	12.30	-0.43	-0.36	1.39	3.37	-0.15	-0.20	0.28
24	12.60	-0.39	-0.43	1.32	3.52	-0.14	-0.23	0.25

Article II

Hourly Electricity Load Modelling of non-residential Passive Buildings in a Nordic Climate

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***Abstract*— Detailed knowledge of electricity demand is essential for power system planning and operation. EUs 20-20-20 targets will increase the development of more energy efficient buildings as all new buildings shall be "nearly zero energy buildings" by 2020. The result from this ambition is that so-called passive buildings and nearly-net-zero-energy-buildings (nZEB), with lower energy demand, or even onsite power generation, will significantly change the way buildings are integrated in the power system. System operators must consequently prepare for changes in load profiles. However, the knowledge on the aggregated impact of nZEBs is so far limited because the actual number of such buildings is still very small. This paper contributes to this knowledge gap by estimating the aggregated effect on electricity demand profiles.**

The load modelling is based on a statistical approach deriving hourly electricity load profiles of non-residential buildings based on measurements of 100 buildings. The profiles will be used as basis in further work to study the impact of a large rollout of ZEBs on the power system.

***Index Terms*-- zero energy buildings (ZEB), load modelling, load profiles, regression, non-residential buildings, and statistics.**

I. Background

Net Zero Energy Buildings (ZEBs) have become a part of the energy policy in several countries in recent years. In the recast of the EU Directive on Energy Performance of Buildings (EPBD) it is stated that by end of 2020 all new buildings shall be "nearly zero energy buildings" [1]. A net zero energy building (ZEB) is a building which has low energy demand, with so-called "passive energy standard", and which has the capability of producing energy that corresponds to its demand on an annual basis (see e.g [2]). The definition is in other words attached to the yearly balance, yet the building still exchanges electricity with the grid on an hourly or minute basis, as the production may not always correspond with the load at these time levels [3].

In the ongoing work, we investigate the impact of a large rollout of ZEBs on the national power system in Norway. The first step of this work is to establish load profiles of today's building stock, and see how the load profile change towards energy efficient ZEB buildings.

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The Research Centre for Sustainable Energy Studies (www.censes.no)

II. Introduction

Current methods on load predictions for power system planning are based on empirical consumption data together with assumptions on future trends of population growth (see e.g. [4][5]). Such models have a top-down approach using statistical models based on real measured energy consumption data [6]. However, these methods do not take into account changes in technologies (heat pumps, PVs, CHPs) or lower energy demand (more energy efficient buildings). Another approach is to use building simulation models in order to capture the physical characteristics of the buildings and their heating technologies [6][7]. However, these models tend to deviate from the measured energy consumption because they assume perfect design and operation of the technical equipment (heating and ventilation system), and take standard values of operating hours, whereas the buildings in question often have more operating hours. Additionally, they do not capture energy used for heating of pavements, or electricity for outdoor lighting or IT-servers. In [8], measured energy consumption for office buildings was found to be up to 44 % higher compared to simulated values.

Previous studies on load modelling of residential electricity demand is vast (see e.g.[9]), however the knowledge on non-residential buildings is still limited. Our approach is to use hourly measurements of electricity demand in existing offices and school buildings, as well as for energy efficient buildings (passive or low-energy), and estimate load profiles using a fixed effects panel data model. The predicted load profiles thus reflect average operational hours, and average prevalence of additional effects such as heating of pavements and IT-servers within each building category.

In order to capture physical building changes and changes of heating technologies, the analysis is done on heat and electricity demand profiles separately. (The heat load model was previously published in [10].) The developed model creates average load profiles based on the buildings in the sample. Similar approach may be found in [11]. With our load models we are able to compare the load profiles from the existing buildings with those of energy efficient buildings (passive or low-energy), and calculate the differences in load profiles.

III. DATA

A. Sample Data

Hourly measurements of both electricity and heat consumption for 102 offices and schools were collected, of which 53 have been used due to data quality. The heat measurements were either measurements of district heat consumption, or electricity consumption for electric boilers taken from separate meters. Thus, the electricity measured is assumed to reflect consumption for electricity purposes only (such as appliances, lightning, and fans and pumps). Figure 1 shows the average annual energy consumption for each building in the sample. Black bars are "normal" buildings (i.e. buildings that are either old, or new buildings without any special energy efficiency requirements), grey is the average of these normal buildings, and light grey are buildings with low-energy or passive standard. Annual energy consumption is respectively 27 % and 55 % lower for the energy efficient offices and schools, but the reduction for electricity consumption is less obvious, 6 % and 29 %. Ideally, the statistical study of these buildings should use equal numbers of passive and low-energy buildings. Unfortunately, this was not possible as the number of passive buildings in Norway, and thereby the availability of measurements, is still limited.

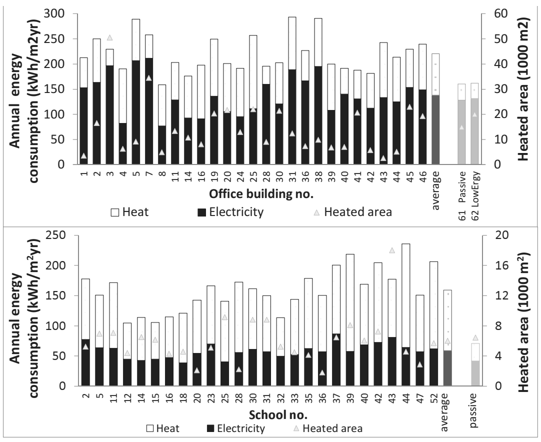

Figure 1. Average annual energy consumption (kWh/m^{2}yr) of sample of office buildings (upper) and school buildings (lower). Triangular dots denotes total heated area of each building.

B. Training and validation dataset

The observed data were collected for 3 years for each building, and divided on a training set and a validation set with the following relation 75 % / 25 %. First the parameters were determined based on the first 75 % of the observed data, and secondly, the mean absolute errors (MAE) were calculated comparing the predicted and the last 25 % observed values in the validation set.

C. Climate Data

Outdoor temperature for the geographical area of each of the buildings were collected from The Norwegian Meteorological Institute [12].

IV. METHODOLOGY

A. The Fixed Effects Model with Panel Data

Panel data is a multidimensional dataset which contains data observed over several time periods, t, for the same individuals, i. In our dataset we have hourly observations over three consecutive years for individual buildings, corresponding to a total number of observations of 262800, denoted as a "long and narrow" dataset. A general model formulation for a panel data regression model is shown in (1), where the electricity consumption of each building, y_{it}, can be influenced by variables varying by individuals, x_i, by time, x_t, and by both time and individuals, x_{it}. By investigating measurements of electricity consumption, y_{it}, and the explanatory variables, x_i, x_t and x_{it}, the model parameters (the β-s) can be determined. The α denotes the constant term independent of both individual and time, and ε_{it} is the error term.

$$y_{it} = \alpha + \beta_i x_i + \beta_t x_t + \beta_{it} x_{it} + \varepsilon_{it} \quad i = 1, \dots, N; t = 1, \dots, T \quad (1)$$

The regression model investigates the relationship between energy consumption and climatic variables taking into account that each building has individual characteristics that may influence the buildings energy demand (such as age, no of storeys and U-values). The fixed effects (FE) regression model allows us to correct for these effects, as we assume them to be constant and independent of time, by adding an individual specific effect α_i [13]. This means that in our model we have only investigated time-varying variables, x_{it}. As an example, outdoor temperature varies from hour to hour, but is also dependent on the location of the building. Therefore, temperature is dependent on both time, t, and individual, i. However, we would like the temperature effect, β_t, to be independent of individuals as we are interested in the temperature effect of the whole building stock. The general model formulation looks thus like in (2).

$$y_{it} = \alpha + \alpha_i + \beta_t x_{it} + \varepsilon_{it} \qquad i = 1, \dots, N;\ t = 1, \dots, T \quad (2)$$

Because the parameters (the β-s) are independent of the buildings, by this model formulation we obtain a general (or average) shape of the load profile for all the measured buildings. However, the level of the load profile will be different for each individual building reflected in the building specific α_i term. When predicting load profiles of the existing building stock, the average of all α_i-s, denoted as α_i*, is used.

B. Energy Signature of Buildings

The energy signature of buildings is a graphic tool used by operators of buildings in order to map its energy performance. By plotting measured energy consumption data against outdoor temperature, as seen in Figure 2. below, a temperature dependent area is identified when outdoor temperature has an influence on the energy consumption, caused by cooling needs (to the right) or heating needs (to the left). The three areas are separated by two changing point temperatures, T_{heat} and T_{cool}.

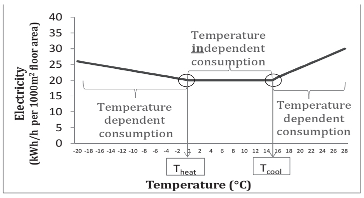

Figure 2. Energy signature curve of a building. Concept showing the changing point temperatures for heating, T_{heat}, and cooling, T_{cool}.

C. Basic Model Structure

By using the definition from the energy signature curve, the regression model is defined for three temperature ranges. When temperatures are higher than T_{cool}, the electricity consumption, y_{it}, is given by (3), where α_t^{cool} reflects the fixed building independent effect, and β_t^{cool} the temperature dependent effect. The temperature independent consumption of electricity, formed by γ_t is found in (4). For some building categories, the observed data showed a minor heating effect on the electricity consumption, and thus a heating component is added and investigated. The heating temperature dependent area is reflected in (5) through α_t^{heat}, and β_t^{heat}. The last term, ε_{it}, denotes the error term.

$$T_t > T_{cool}: \quad y_{it}^{EL} = \alpha_t^{cool} + \beta_t^{cool} T_t + \varepsilon_{it}^{EL} \tag{3}$$

$$T_{heat} < T_t < T_{cool}: \quad y_{it}^{EL} = \gamma_t + \varepsilon_{it}^{EL} \tag{4}$$

$$T_t < T_{heat}: \quad y_{it}^{EL} = \alpha_t^{heat} + \beta_t^{heat} T_t + \varepsilon_{it}^{EL} \tag{5}$$

By use of a dummy variable approach, the equations are applied for each hour of the day (1 to 24) for weekdays, weekends and holidays separately, which enables the model to capture the hourly consumption pattern throughout the day.

D. Identifying day types and T_{cool}

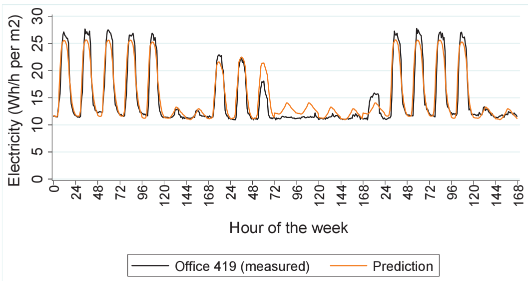

Figure 3. Tree weeks of electricity consumption for office building no.419. The second week is Easter, where Thursday-Monday are public holidays.

A large part of the work was to identify the type of each day, either working day, weekend, public holidays or other special holidays. Figure 3. shows measured electricity consumption in Easter, which illustrates the importance of the flagging of days. Further, the values of the changing point temperature for each hour was also tested and determined. The goodness of fit was used to evaluate and determine the day classification and the values of T_{cool} and T_{heat}.

V. Model

A fixed effects regression model for panel data is developed and implemented in the statistical tool, STATA.

A. Model detection for Normal Offices

Ten model formulations with various explanatory variables were investigated and tested. Mainly, the electricity consumption in buildings consists of lighting, auxiliary equipment (i.e. computers, coffee machines, projectors), fans for the ventilation system, and pumps for the hydronic heating system. The use of auxiliary equipment and fans for the ventilation system were assumed to depend on occupancy presence. The demand for lighting is dependent on the presence of occupants in the building, but may also depend on the daylight conditions outside of the building. Therefore, a daylight dummy variable was tested, which is 1 when there is sunlight, and 0 otherwise. Pumps for the hydronic heating system can depend on outdoor temperature if the system is mass regulated. Summed up, the most important explanatory variables for electricity consumption in non-residential buildings were identified to be outdoor temperature, daylight dummies, day dummies and monthly dummies.

The models that were tested were build up by the following components: cooling, daylight dummies (DLD), day dummies (DD), and monthly dummies (MD). Table 1 shows the different model formulations and their results.

TABLE I. Testing Model Types for Offices

	Model Type	***Training***		***Vali-dation***
		R^2_{total}	***R^2_{within}***	***MAE***
	NORMAL Offices			
1.1	Cool	0.532	0.806	4,352
1.2	Cool + DLD	0.532	0.806	4,352
1.3	Cool + DD	0.533	0.807	4,349
1.4	Cool + DLD + DD	0.533	0.807	4,349
1.5	Cool + MD	0.534	0.808	4,330
2.1	noCool	0.527	0.798	4,361
2.2	noCool + DLD	0.527	0.798	4,363
2.3	noCool + DD	0.528	0.799	4,358
2.4	noCool + DLD + DD	0.528	0.799	4,359
2.5	noCool + MD	0.530	0.802	4,347
	PASSIVE / LOW ENERGY Offices			
1.1	Cool	0.586	0.912	3,456
1.2	Cool + DLD	0.586	0.913	3,457
1.3	Cool + DD	0.588	0.914	3,450
1.4	Cool + DLD + DD	0.587	0.914	3,452
1.5	Cool + MD	0.589	0.918	3,462
2.1	noCool	0.585	0.909	3,464
2.2	noCool + DLD	0.585	0.909	3,465
2.3	noCool + DD	0.586	0.910	3,481
2.4	noCool + DLD + DD	0.586	0.910	3,472
2.5	noCool + MD	0.589	0.915	3,469

Model 1.1 has an R^2_{within} = 81 %, $R^2_{between}$ = 0,1 %, and R^2_{total} = 53 %. This means that the model is able to explain the electricity consumption within each building, *i*, by 81 %, however the individual differences between the buildings are very high leading to a very low correlation coefficient of 0,1%, and thus the total goodness of fit only reaches 53 %. The main conclusion is that the models with the cooling component had higher goodness of fit and lower error than those without, which indicates that normal office buildings in Norway have cooling demand. Adding daylight dummies (DLD), only gave minor improvements. This may come from the fact that the building is being operated in the same hours as there is daylight, and that this effect is captured by the basic model. When adding day dummies (DD), the estimated effect of the day dummies showed that consumption on Friday is significantly lower when compared to the other working days,although it did not have significant impact on the goodness of fit or error. As our goal is to study the aggregated load profile on a national level, we concluded to choose Model 1.3 with cooling effect and day dummies. The full model formulation is shown in (6) and the explanation of symbols in TABLE II.

$$
\begin{aligned}
y_{it} = {} & \alpha_i^* \\
& + \sum_{wdh=2}^{24} \gamma_{wdh} D_{wdh} + \sum_{wdh=7}^{18} \alpha_{wdh}^{cool} D_{wdh}^{cool} + \sum_{wdh=7}^{18} \beta_{wdh}^{cool} D_{wdh}^{cool} \quad {}_{it} \\
& + \sum_{hoh=1}^{24} \gamma_{hoh} D_{hoh} + \sum_{hoh=7}^{18} \alpha_{hoh}^{cool} D_{hoh}^{cool} + \sum_{hoh=7}^{18} \beta_{hoh}^{cool} D_{hoh}^{cool} \; T_{it} \\
& + \sum_{weh=1}^{24} \gamma_{weh} D_{weh} + \sum_{dyID=1}^{6} \beta_{dyID} D_{dyID} + \varepsilon_{it}
\end{aligned}
\tag{6}
$$

TABLE II. EXPLANATION OF SYMBOLS

Variable/ parameter	***Description***
t	Any hour t throughout the year (1-8760).
wdh	Weekday hour (1-24)
weh	Weekend hour (1-24)
hoh	Holiday hour (1-24)
y_{it}	Electricity consumption in hour, t, for building, i. [W/m^2]
α_i^*	Fixed time independent effect for building, i, equal for all hours, t. [kWh/m^2]
D_{wdh}	Dummy variable for weekdays. 1 if it is a weekday and $T_t < T_{cool,wdh}$, 0 otherwise.
γ_{wdh}	Fixed building independent effect for weekday hour, *wdh*, as long as temperature is **below** the weekday-hour's changing point temperature ($T_t < T_{cool,wdh}$). [W/m^2]
D^{cool}_{wdh}	Dummy variable for weekdays in the cooling area. 1 if it is a weekday, the hour number = {7, …,18}, and $T_t > T_{cool,wdh}$, 0 otherwise.
α^{cool}_{wdh}	Fixed building independent effect for weekday hours, *wdh*, when temperature is **above** the weekday hour's changing point temperature ($T_t > T_{cool,wdh}$).
β^{cool}_{wdh}	Effect of outdoor temperature on electricity demand in weekday hours, *wdh*. The effect changes for each hour of the day, but is independent of season as long as $T_t > T_{cool,wdh}$. [(W/m^2)/°C]
T_t	Outdoor temperature, in hour, t.
γ_{weh}, D_{weh}, γ_{hoh}, D_{hoh}, α^{cool}_{hoh}, D^{cool}_{hoh}, β^{cool}_{hoh}	Equal explanation as for the above mentioned variables with the exemption that they are connected to weekend, *weh*, or holiday hours, *hoh*. Notice that weekends do not have any cooling effect.
D_{dyID}	Dummy variable attached to the type of day – or dayID. Equal to 1 when the aqtual day occurs. (Monday, Tuesday, (…) or Sunday).
β_{dyID}	The effect on electricity consumption whether it is a Monday, Tuesday, (…) or Sunday.
ε_{it}	Error term of the regression. Assumed to be independently and identically distributed over all i and t.

B. Model detection for Passive Offices

The same model formulations were tested on the measurements from the passive buildings. The best goodness of fit and lowest MAE was also found to be Model 1.3, however, cooling is only applied for working days in the hours from 9 to 18, and not for holidays as in the model for the normal offices.

C. Model detection for Schools

Plotting the energy signature curve of the measured electricity data for normal school buildings showed a minor heating effect, but no cooling effect. Thus, the tested model formulations included heating effect, and adding either daylight, daily or monthly dummies. The results showed that the goodness of fit increased by 5 % when including the heat effect for normal schools, and the error (MAE) decreased by 6-7 %. Adding the dummy variables only gave minor changes, about 0,2 % higher goodness of fit and 0,1 % lower error. The chosen model formulation for normal schools was the model with heating effect, but without any of the additional dummy variables such as daylight, daily or monthly dummies.

Investigating the same model formulations for the passive schools concluded that adding a heat effect reduced the goodness of fit by 0,5 %, and the error increased by 6 %. Thus, the chosen model for passive schools was the model without heating effect and without any additional dummy variables.

VI. RESULTS

A. Fixed effects regression model for 27 Normal Offices

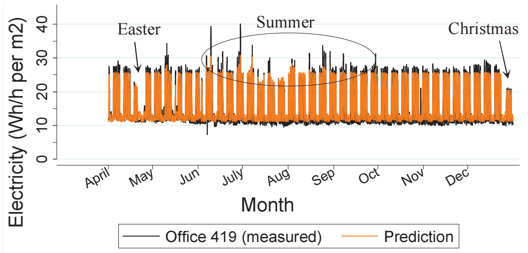

Figure 4. Electricity load (Wh/hr per m^2) for normal office building no.419. Predicted (orange) vs. measured data (black) from the validation data set.

Figure 4. shows the predicted electricity load profile for average existing office buildings compared to measured data for office building no.419. We see that the orange predicted load profile captures the cooling demand in summer quite well (peaks above 25 Wh/hr, as well as the occurrence of Easter and Christmas.

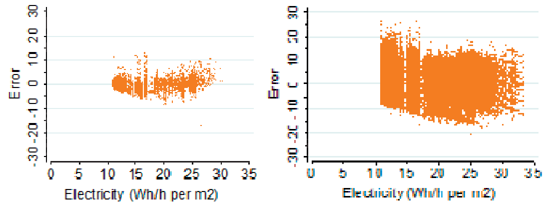

Figure 5. Plots of residuals (y-ŷ), towards measured data (y). Office building no.419 (left) and all office buildings in sample (right).

The residuals shown in Figure 5. show that the errors are evenly distributed around zero, which implies that the errors are identically and independently distributed (IDD).

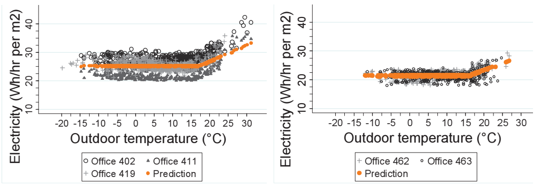

Figure 6. Electricity (Wh/hr per m^2) vs. outdoor temperature for normal offices (left) and passive offices (right) for hour no.16 (1500-1600 hrs).

Figure 6. shows the energy signature curve (energy vs. temperature) for normal offices to the left, and passive offices to the right. The orange dots in both graphs denotes the predicted electricity consumption based on Model 1.3, compared to the observed values from selected buildings in the sample. Comparing the plot for the passive office to the normal office, the cooling demand starts at a higher outdoor temperature (20 instead of 18), and the slope of the cooling demand is lower for the energy efficient office buildings (reflected in the β^{cool} value), reflecting a lower dependency on outdoor temperature.

B. Implications for the Load Profile of Offices

Figure 7. shows predicted electricity demand profiles for a week in winter (upper) and in summer (lower). In winter, the peak hour for passive offices is moved two hours earlier to hour no.10, compared to normal offices, and the value of the peak load is reduced from 26 to 22 Wh/hr·m^2, a reduction of 12 %. In summer, when cooling demand is present, the peak load occurs in the hour with the highest outdoor temperature for both passive and normal offices. In Figure 7, the reduction of the peak load on Wednesday is 4 Wh/hr·m^2, equal to 13 %. As the minimum value is unchanged, the maximum amplitude is also reduced by 3 Wh/hr·m^2 (or 23 %) in winter, and 4 Wh/hr·m^2 (13 %) in summer. This reduction may come from more energy efficient lighting, and more energy efficient ventilation and hydronic heating system due to better design and operation of these systems.

The minimum electricity demand of around 12 Wh/hr·m^2 which occurs after working hours, during night and weekends is equal for the normal and passive offices. This may come from the fact that passive offices have similar demand for equipment that is running constantly in the buildings such as IT-servers, outdoor lighting or electricity demand in the ground floor of the building which is often occupied by other services such as grocery shops and other shops.

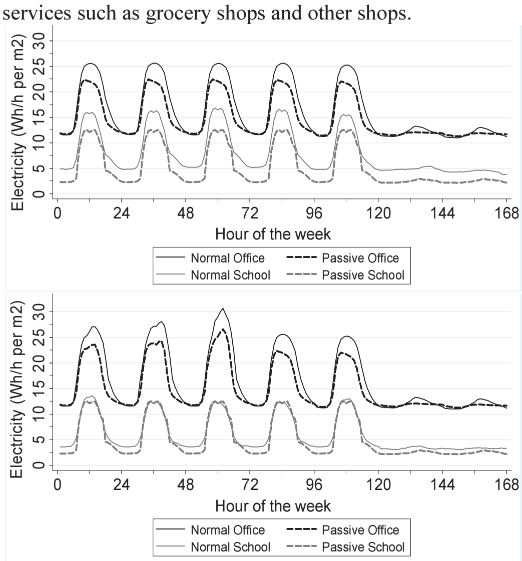

Figure 7. Weekly prediction of electricity load (Wh/hr per m^2) in winter (upper graph) and summer (lower graph) for Offices and Schools, comparing normal and passive buildings.

C. Implications for the Load Profile of Schools

Predicted load profiles for passive schools compared to normal schools show that the peak load in summer are almost identical (see lower graph in Figure 7.). In winter, however, the peak load is reduced by 4 Wh/hr·m^2 (22 %) because of the heating effect in the normal schools. The maximum amplitude in winter is also reduced by 10 %. The explanation for the higher difference in winter than in summer may lie in the ventilations system. In old schools, if the ventilation system has been installed after the construction of the building, because of practical reasons (e.g. placement of ducts and air-intake) the ventilation air is heated by electricity rather than with heat from the heat distribution system of the building. Additionally, if the heating distribution system is not sufficient, direct electric floor heating in wardrobes/showers in some schools could also occur.

D. Estimated Temperature Dependency

TABLE III. shows the estimated model parameters (average of hour no.1-24), and their change from normal to passive buildings for both offices and schools. In short, the cooling temperature dependency in passive offices is reduced by 33 %, and the heating temperature dependency in passive schools is reduced by 100 %.

TABLE III. ESTIMATED MODEL PARAMETES. COMPARING NORMAL AND PASSIVE BUILDINGS (AVERAGE OF HOUR 1-24).

				Difference	
		Normal	***Passive***		*%*
		OFFICES			
Week-days[a]	$\alpha_i^* + \gamma$	17,7	16,0	*-1,8*	*-10 %*
	$\alpha_i^* + \alpha^{cool}$	14,5	14,2	*-0,3*	*-2 %*
	β^{cool}	0,6	0,4	*-0,2*	*-33 %*
Holi-days[a]	$\alpha_i^* + \gamma$	15,9	14,8	*-1,1*	*-7 %*
	$\alpha_i^* + \alpha^{cool}$	15,0		*-0,2*	*-1 %*
	β^{cool}	0,4	*na*	*-0,4*	*-100 %*
Week-ends[a]	$\alpha_i^* + \gamma$	12,0	11,8	*-0,2*	*-2 %*
		SCHOOLS			
Week-days[a]	$\alpha_i^* + \gamma$	7,19	6,36	*-0,83*	*-12 %*
	$\alpha_i^* + \alpha^{heat}$	9,07		*-2,72*	*-30 %*
	β^{heat}	-0,12	*na*	*0,12*	*-100 %*
Holi-days[a]	$\alpha_i^* + \gamma$	3,70	3,51	*-0,19*	*-5 %*
	$\alpha_i^* + \alpha^{heat}$	5,44		*-1,92*	*-35 %*
	β^{heat}	-0,10	*na*	*0,10*	*-100 %*
Week-ends[a]	$\alpha_i^* + \gamma$	3,11	2,43	*-0,68*	*-22 %*
	$\alpha_i^* + \alpha^{heat}$	4,76		*-2,33*	*-49 %*
	β^{heat}	-0,10	*na*	*0,10*	*-100 %*

VII. CONCLUSIONS

In this paper, we have presented a regression model framework which makes it possible to predict hourly electricity demand profiles for non-residential buildings in Norway. The modelling framework have been used to estimate the changes of the electric load profiles when moving towards more energy efficient buildings.

Annual energy consumption is respectively 27 % and 55 % lower for the energy efficient offices and schools, but the reduction for electricity consumption is less obvious, 6 % and 29 % (see Figure 1). By this, we may conclude that electricity demand is less affected, compared to heat demand, when buildings become more energy efficient.

Findings for the load profiles of office buildings show that cooling demand is present in both normal and passive offices, but the temperature dependency was about 30 % lower for passive office buildings. The characteristic bell shape of the load profile is almost unchanged, however the peak load is reduced by 12-13 % even though the base load consumption is unchanged.

The electricity load model for school buildings show that the normal schools have a temperature dependency of -0,1 Wh/hr·m^2 per °C (see TABLE III), in contrast to the passive schools where this effect is not present. This means that the load profile of the passive schools are equal throughout the year, independent of outdoor temperature. In winter, the peak load was found to be 22 % lower for the passive schools. In summer though, the load profiles of the passive and normal school buildings were almost identical.

The modelled electric load profiles presented in this paper, together with the modelled heat load profiles previously published in [10], can be used to estimate the impact of more energy efficient buildings on future aggregated load profiles in the regional distribution grid. This is important for power grid analysis in order to investigate the current trend of moving towards nearly zero energy buildings, together with the deployment of heat technologies such as heat pumps and CHPs, electric cars, building integrated PVs, and smart grid technologies.

ACKNOWLEDGMENT

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Article III

OPTIMAL INVESTMENTS IN ZERO CARBON BUILDINGS

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ABSTRACT

In the ongoing work we investigate the effects of introducing Zero Carbon Buildings (ZCB) into the energy system. In order to reach the zero balance requirement several different technologies are available. With an optimisation model we investigate the preferred technology mix needed to reach the zero carbon balance in the most cost efficient way. Further, we analyse how technology choices affect the buildings interaction with the electricity grid.

A case study of a zero carbon school building is performed, taking into account investment costs, variable electricity costs, carbon emissions and grid interaction perspectives. To increase flexibility and self-consumption of on-site electricity generation, a heat storage is present. An hourly time resolution is applied to account for the variability in load and generation.

Further, we investigate the effect of restrictions on export and import of electricity to/from the grid, and how different carbon factors influence the optimal solution.

INTRODUCTION

Zero Carbon Buildings (ZCB) constitute an important step towards a holistic and integrated renewable energy system. However, the ZCB concept encompasses a new way of how we perceive the energy system as the energy flows are no longer only flowing from central energy producers to small end consumers. Each ZCB consumer is additionally an energy producer, which means that with the deployment of ZCBs the energy system is changing towards a system with many thousands of small distributed generation (DG) units, and with the energy flowing both to and from each customer. In this context, the consumers – or ZCBs – can take advantage of the possibility of managing and controlling their own energy consumption and production through smart energy management systems (EMS) within the building. Additionally, EMS is becoming more relevant with the deployment of automatic metering systems (AMS), which exposes customers to real time electricity price changing hour by hour. This concept of the energy system described can also be seen as part of the smart grids concept.

Previous studies of the grid impact of ZCBs encompass optimal operation strategies where the technical equipment (choice and size) is treated as given (Dar, Sartori, Georges, & Novakovic, 2013) . In our study we additionally seek to find the optimal investment decision taking into account an optimal operation of the energy system on an hourly basis. Investment decisions for buildings can entail many details and contradictory objective functions (Fabrizio, Filippi, & Virgone, 2009). In this study, our aim was to investigate the net electricity load profile of semi-large non-residential buildings given an optimal constitution and operation of the energy supply system of the building. For this purpose we developed a simplified model, which entails the most important aspects.

We use a dynamic deterministic optimisation model which optimises both the investment (technology choice and size), and the operation of the energy technologies. Thus, the hourly net electricity profile is given as an additional output from the model. These load profiles will be used in further work to analyse the impact of ZCBs on the Norwegian power system.

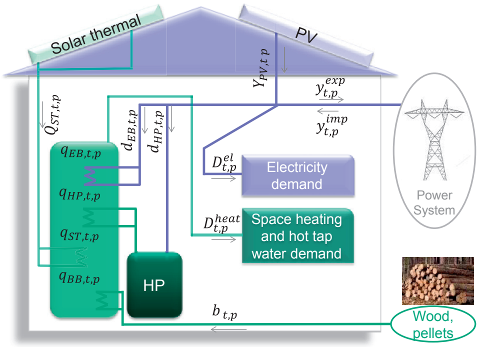


Figure 1 Energy flows in the optimisation model

METHOD

Zero Carbon Ambition Level

A Zero Carbon Building – or Zero Emission Building - is defined such that the carbon emissions the building is causing is outweighed – or compensated – by the building's renewable electricity production, under the assumption that it is exported to the electricity grid where it displaces fossil power production. The same definition may also be applied to energy, in Zero Energy Buildings (ZEB). (Marszal et al., 2011) (Sartori, Napolitano, & Voss, 2012)

There exist several ambition levels for the ZCB or ZEB definition (Dokka et al., 2013). The model is capable of adapting all levels, however in the presented case study we are including compensation of operational but excluding embodied emissions, which is in line with ambition level II in (Dokka et al., 2013).

One of the main challenges of the ZCB and ZEBs is their impact on the grid, as their electricity production tend to occur when the electricity demand is low, making the net electricity load profile become more volatile, see e.g. (Baetens, De Coninck, Helsen, & Saelens, 2010) and (Berggren, Widen, & Wall, 2012). This tendency becomes even more apparent with higher time resolution. Additionally, a seasonal discrepancy is also observed, where excess electricity production during summer is exported to the grid, and to be imported in winter.

Several dynamic grid interaction factors has been developed in order to evaluate the buildings interaction with the electricity grid, cf. (Salom, Marszal, et al., 2014). In this paper, the generation multiple (GM), defined in Equation (11), together with the absolute values for maximum import and export, are chosen as evaluation criteria.

Building energy demand (Hourly load profiles)

The heat and electricity demand of the school building is determined by a regression model which is based on measured energy consumption data combined with information on climatic parameters (Lindberg & Doorman, 2013). As there are no zero carbon school buildings built in Norway today we assume that the basis of a zero carbon building is a passive building with on-site energy production. Thus the predicted heat and electricity load is based on hourly measurements of district heat and electricity consumption data for a passive school building situated in south-eastern Norway.

Hourly time resolution

As shown in (Salom, Marszal, et al., 2014) and (Salom, Widén, Candanedo, & Lindberg, 2014) a sub-hourly time resolution is preferred when doing in-depth analysis of single building's interaction with the grid. However, due to lack of available sub-hourly measured energy consumption data for the passive building, the model could not have a higher time resolution than the input data. Model size was also an important aspect when choosing hourly in favour of sub-hourly time resolution.

Available technologies

The present technologies in the model reflect the most plausible technology options for Norwegian conditions. There are two aspects which make zero carbon buildings in Norway different from other countries. Firstly, hydro power accounts for 99 % of total electricity generation, making it almost 100 % renewable. Secondly, the historically generous access to low-cost renewable hydro power makes electricity accounting for approximately 80 % of the heat demand in Norwegian buildings (Lindberg & Magnussen, 2010). These two conditions, together with a dispersed settlement pattern, have led to relatively low distribution of district heat and natural gas grid (Skaansar, 2011). Thus, CHP units (for natural gas) and district heat connection are not included as technology options. Electricity storage (battery) is also not considered due to considerable storage capacity in the hydro reservoirs of Norway.

Available technologies in the present version of the model are thus water-to-water heat pump, air-to-water heat pump, PV panels, electric boiler, pellets boiler, and solar thermal collectors.

MATHEMATICAL DESCRIPTION

A dynamic deterministic mixed-integer linear optimisation model with hourly time resolution for a non-residential ZCB/ZEB has been developed in the Xpress-Mosel optimization modelling tool (FICO Xpress, 2013).

Objective function: Minimising total costs

The objective is to minimise total costs while complying with several constraints. Equation (1) reflects the sum of the total life time adjusted investment costs, and the total discounted operational costs. Equation (2) describes the annual operational costs in more detail, including fuel costs (equals bought energy from outside the building), and annual fixed operational costs of each technology, i.

$$min \quad \sum_{p \in P} \left(YRN \sum_{i \in I/ST} C_i^{inv} x_{i,p} + C_{ST}^{inv} \delta_{ST,p} + \frac{1}{(1+r)^{p \cdot YRN}} \sum_{yr \in YR} \frac{AC_p^{run}}{(1+r)^{yr}} \right) \quad \text{[EUR]} \tag{1}$$

where annual operational (or running) costs equal to the following:

$$AC_p^{run} = \sum_{t \in T} \left(-P_{t,p}^{sell}\, y_{t,p}^{exp} + P_{t,p}^{buy}\, y_{t,p}^{imp} + P_p^{bio} b_{t,p} \right) + GRCH + \sum_{i \in I} C_i^{run} x_{i,p} + C_{ST}^{run} + \sum_{m \in MM} PPCH\, (y_{t,p}^{imp})_{mnth\,max} \quad \text{[EUR/yr]} \tag{2}$$

The total lifetime of the building is assumed to be 60 years. In order to limit the model, annual energy costs are calculated for one average year within a period, p. The total number of periods, PN, is flexible and depends on the number of years, YRN, within each period.

Constraints

The building must comply with several requirements.

i. Zero Balance Requirements

The model is built such that all ambition levels for the ZCB/ZEB requirement can be met, including embodied carbon emissions/energy.

a. Zero Carbon Emissions

Equation (3) reflects the zero emissions requirement including embodied emissions added the annual emissions from operation of the building, times the total number of years within each period, YRN, and total number periods of the building's lifetime, PN. Note that the carbon emissions attached to the exported electricity, $y_{t,p}^{exp}$, subtracted from the balance may have a different CO_2 value than the imported electricity.

$$\begin{aligned} &Embodied\ emissions \\ &+ PN \sum_{p \in P} \Bigg(YRN \sum_{t \in T} b_{t,p} G_{bio,p} \\ &+ y_{t,p}^{imp}\ G_{el\_imp,t,p} - y_{t,p}^{exp}\quad G_{el\_exp,t,p} \Bigg) \\ &= 0 \qquad\qquad [\mathrm{g_{CO2-eq}}] \end{aligned} \tag{3}$$

b. Zero Primary Energy Consumption

As an alternative to the zero emission constraint, the model can also investigate the effect of zero primary energy consumption throughout the lifetime of the building. See Equation (4). Notice that only one of the zero constraints is active at each model run.

$$\begin{aligned} &Embodied\ energy \\ &+ PN \sum_{p \in P} \Bigg(YRN \sum_{t \in T} b_{t,p} PE_{bio,p} \\ &+ y_{t,p}^{imp}\ PE_{el\_imp,p} - y_{t,p}^{exp}\ PE_{el\_exp,p} \Bigg) \\ &= 0 \qquad\qquad [\mathrm{kWh_{PE}}] \end{aligned} \tag{4}$$

ii. Building electricity balance

The electricity balance of the building states that on-site generation by PV, $y_{PV,t,p}$, subtracted electricity used in the energy technologies, $d_{i,t,p}$, together with the electricity demand of building, $D_{t,p}^{el}$, equals electricity exported to the grid or electricity imported from the grid, see Equation (5).

$$\begin{aligned} Y_{PV,t} \cdot x_{i,p} - \sum_{i \in I} d_{i,t,p} - D_{t,p}^{el} \\ = y_{t,p}^{exp} - y_{t,p}^{imp} \quad \forall\ t,p \quad [\mathrm{kWh/hr}] \end{aligned} \tag{5}$$

As electricity import and export does not occur at the same time step, the model either runs in import or export mode.

iii. Building heat balance

Similarly for heat, Equation (6) reflects that heat within the storage $s_{t,p}$ at time step t, equals the already stored energy within the storage from the previous time step, t-1, added the heat produced, $q_{i,t,p}$, by the active technologies i (notice that ST is treated differently) and in the end substracting what is used within the building, D_t^{heat}.

$$\begin{aligned} \eta_S \cdot s_{t-1,p} + \sum_{i \in I} q_{i,t,p} + Q_{ST,t}\, \delta_{ST,p} - D_t^{heat} \\ = s_{t,p} \quad \forall\ t,p \quad [\mathrm{kWh/hr}] \end{aligned} \tag{6}$$

The heat storage has an efficiency loss of 1-η_S which reflects both charging and discharging losses.

iv. Limitations power grid

As stated earlier, one of the main challenges of the ZCB/ZEBs is the interaction with the grid. Equation (7) introduces a limitation on the import and export of electricity to the grid. By applying different values of α we are able to investigate the impact of different levels of grid limitations. Equation (8) suggests that the maximum import/export value to equal the sum of the building peak load of electricity and heat.

$$\begin{aligned} y_{im\ t,p} + y_{ex\ t,p} \leq \alpha \cdot M^{max} \\ \forall\ t,p \quad [\mathrm{kWh/hr}] \end{aligned} \tag{7}$$

where:

$$M^{max} = (D_t^{el})_{max} + (D_t^{heat})_{max} \quad [\mathrm{kWh/hr}] \tag{8}$$

v. Additional constraints

For each of the technologies, i, capacity constraints and energy balances are applied.

$$x_i - q_{i,t,p} \geq 0 \qquad \forall\ t,p \qquad [\mathrm{kW}] \tag{9}$$

In order to keep track of the energy stored in the storage, an additional requirement is set that the storage should contain the same amount of heat at the start (t = 0) and at the end (t = T) of each year. See Equation (10).

$$s_{0,p} = s_{T,p} \qquad \forall\ p \qquad [\mathrm{kWh/hr}] \tag{10}$$

INPUT DATA

The building of investigation is a school building complying to the passive house energy standard with a ground floor area of 10 000 m^2 situated in the south-eastern part of Norway.

Load profiles (hourly energy demand)

A prediction of heat demand was made on outdoor temperatures for the city of Drammen in 2012, using the statistic methodology mentioned earlier. The annual heat and electricity demand of the school building was found to be 269 and 381 MWh respectively.

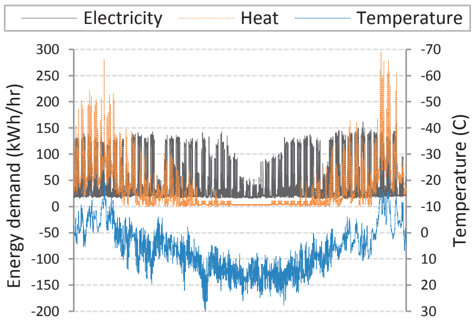


Figure 2 Energy load of the school building

Energy Technologies

Normally specific investment costs are nonlinearly related to the installed capacity, see e.g. (Fabrizio et al., 2009). This relation can be linearized in order to be included in the linear optimisation problem. However, in this first version of the model, the specific investment costs are assumed constant in EUR per kW installed capacity. The specific costs are based on medium scale technologies (~ 50-100 kW) which is applicable for the relatively large school building of 10 000 m^2. See Table 1 for details.

Table 1
Investment costs and fixed operational costs[1]

TECH-NOLOGY	INVESTMENT COST	OPER. COSTS	LIFE TIME
	(in the range of 50-200 kW)	*% of inv.cost*	*year*
PV	1 800 EUR/kWp	1 %	25
HP water-to-water	1 005 EUR/kW (incl.well drilling)	3 %	15
HP air-to-water	1170 EUR/kW[2]	3 %	15
Pellets boiler	482 EUR/kW	5 %	20
Electric boiler	145 EUR/kW	2 %	20
Heat storage	4,7 EUR/litre[3]	none	20
Solar thermal	30 860 EUR[4]	1 %	20

The technical specifications for the energy technologies are given in Table 2. The electricity production from PV panels are simulated in PVSyst with climatic conditions of a standard year in Oslo, Norway, carried out at Multiconsult (Merlet, 2013).

Heat production from the solar thermal collectors is treated similarly as for PV. Simulations in ColSim of a flat plate solar collector system were carried out at Fraunhofer ISE, with climatic conditions for Oslo and with the heat demand of the school building in question (Wittwer, 2014). The hourly heat production from the solar thermal flat plate collectors takes into account that the solar collector is shut off (yielding no heat) in summer when heat demand is low and solar irradiation is high. This is a benefit from only adding an efficiency to the solar irradiation in the optimization model. The time series of heat production from the simulations were used directly as solar thermal production, $Q_{ST,t}$, in the model.

Table 2
Technical specifications

TECH-NOLOGY	EFFICIENCY η *or COP*	REFERENCE
PV	Hourly production from simulations in PVSyst	(Merlet, 2013)
HP water-to-water	COP = 3,2	(Løtveit, 2012)
HP air-to-water	40 % * carnot eff. with T_{amb}	(Russ et al., 2010)
Pellets boiler	90 %	(Hofstad, 2011)
Electric boiler	98 %	(Hofstad, 2011)
Heat storage	99 %	(Hofstad, 2011)
Solar thermal flat plate collectors	Hourly production from simulations in ColSim	(Wittwer, 2014)

The investment decision of solar thermal is treated as a binary decision, i.e. the model can choose to invest in a 75 m^2 collector area with a collector heat production of 26,5 MWh/yr to 30 860 EUR, but it is not possible to scale it as the heat production profile of the solar thermal simulations are strictly attached to the size in question.

Electricity prices and other fuel prices

The spot price from Nordpoolspot in 2012 is used as the electricity price, with added grid taxes for Norwegian conditions. All fuel prices are without VAT as the calculations are done for a service building which gets a tax refund for the VAT expenses.

Table 3
Fuel costs

ENERGY CARRIER	PRICE $€cent/kWh$	REFERENCE
Electricity import (annual average)	5,1	(EB Nett AS, 2014) (Nordpoolspot, 2013)
Electricity export (annual average)	2,6	
Pellets	4,2	(Hofstad, 2011)

The prices vary throughout the day with the annual average price shown in Table 3. The difference in import and export price is the grid charge applied by the local grid company where the school is located. Summed up, the import price equals spot price added grid taxes, and export price equals only the spot price. The export price is always lower than the import price.

[1] Costs for Norwegian conditions using 8,3 NOK/EUR. Based on (Løtveit, 2012) if not otherwise specified.
[2] Small scale air-to-water HP (5-10 kW).
[3] Assuming $\Delta T = 45\ K$, yields 90 EUR/kWh.
[4] 75 m^2 flat plate collectors without storage, (Hofstad, 2011).

This ensures that import and export do not occur within the same hour (ref. Equation (5)).

Carbon and Primary Energy Factors

The amount of PV area required for reaching the zero balance is highly sensitive to the carbon factors applied to the different energy carriers (Noris et al., 2014), and because there are no official carbon and PE factors published for Norwegian conditions, different factors have been investigated.

Due to the high share of hydro power, the carbon factor for electricity in Norway, proposed by (Dokka et al., 2013), is lower than the EU average of 350 g/kWh (IEA, 2013), and as Norway is connected to the Nordic power system, the value is larger than zero. Table 4 shows the carbon factors used.

Table 4
Carbon factors (Dokka et al., 2013) (IEA, 2013)

	CARBON FACTOR gCO_2-eq/kWh	
	CO_2-NOR	*CO_2-EU*
Electricity import	130	350
Electricity export	130	350
Bio pellets	7	7

The draft of the overarching standard for the Directive on Energy Performance of Buildings (prEN 15603:2013), suggest new primary energy factors for various energy carriers. The new factors take into account that electricity produced onsite which is exported and reimported later, PE = 2,0, is less favoured than production that is consumed instantaneously reducing imported electricity with PE = 2,5, in order to reduce grid impact. In addition, in to investigate the impact of the asymmetric electricity factor, symmetric PE factors were also applied.

Table 5
Primary energy factors (prEN 15603:2013)

	PE FACTOR kWh_{PE}/kWh	
	PE-EN	*PE-EN (asym)*
Electricity import	2,5	2,5
Electricity export	2,5	2,0
Bio pellets	0,05	0,05

Grid Interaction Indicator

One of main the challenge of ZCBs and ZEBs is their hourly and seasonal mismatch between load and generation of electricity, and in the literature various indicators have been proposed for evaluating these effects, see (Salom, Marszal, et al., 2014).

$$GM = \frac{|ne_{max}|}{|ne_{min}|} \quad (11)$$

where $ne_t = export_t - import_t \quad \forall\ t$

The generation multiple (GM) is one of them, reflecting the ratio between the peak values for import and export of electricity to the building, shown in Equation (11). As the GM is a relative value, the actual peak values for import and export and GM relative to reference case (GM_{ref}) are given in the results table.

MAIN RESULTS

The model finds both the optimal investment decision (installed capacity) and the optimal operation (the way the technologies are being utilised at an hourly level) when minimising total costs.

Table 6 shows key figures of the passive school building situated in south-eastern Norway, when applying the zero carbon (zeroCO2) and zero primary energy (zeroPE) constraints with the factors listed in Table 4 and Table 5.

No zero constraint

The first column corresponds to minimising costs without any zero requirements to establish a reference case. Total discounted costs are 0,7 mill EUR and the preferred technology choice is a water-to-water HP, with an electric boiler and a heat storage to meet peak heat load requirements. No PV is installed and the peak electricity import value of the building is 352 kW. The annual CO2 emissions for the building are reaching 67 tonnes, and the annual primary energy consumption 1300 MWh_{PE}. The primary energy consumption is higher than the total energy demand (~ 600 MWh) because of the primary energy factor of 2,5 for electricity. Notice that the electric boiler is used as the peak load provider with an installed capacity of 192 kW, but only providing 63 MWh/yr, which is in contrast to the HP which delivers 235 MWh/yr, with 65 kW installed capacity.

Operational results

Operational results shows that different technologies are being used for base load and peak load, as expected. In the reference case without zero constraints, the use of the storage and the electric boiler varies in accordance with the variable electricity spot price. Further analysis of operational results will be discussed in future work.

Zero Balance Constraints

When applying the zeroCO_2 constraint, the investment costs are more than doubled compared to the reference case. However the annual operational costs are not changed significantly. The main reason is the PV installations that have considerable investment costs, but negligible operational costs.

Comparing the total carbon emissions and total primary energy consumption, the zeroCO2 constraint gives negative PE consumption regardless of choice of factors, thus we can conclude that the zeroPE requirement is stricter than the zeroCO2 requirement when using symmetric PE factors. However, when the asymmetric PE factors are applied (last column), it is the zeroCO2 constraint that is binding. This is also reflected through the total discounted cost where zeroPE with symmetric PE factors has the lowest cost

Table 6 Main model results

Zero-constraint	**None**	**Zero Carbon Emissions**			**Zero Primary Energy**	
Carbon factor gCO2-eq/kWh electr.	*CO_2-NOR 130*	*CO_2-NOR 130*	*CO_2-EN 350*	*CO_2-NOR 130*	*CO_2-NOR 130*	*CO_2-NOR 130*
Primary Energy factor	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN*	*PE-EN (asym)*
Total discounted cost [1000 EUR]	691	1 845	1 832	1 988	1 810	1 984
Oper. cost [1000 EUR/yr]	34	34	34	27	34	33
Emissions [kg CO2-eq/yr]	67 384	0	0	0	1 376	-6 109
Primary Energy [MWh_{PE}/yr]	1 296	-26	-16	0	0	0
Installed capacity [kW]						
PV	0	486	480	579	473	542
HP water-to-water	65	7	7	114	7	8
HP air-to-water	0	0	0	0	0	0
Pellets Boiler (BB)	0	135	136	*N.A.*	140	141
Electric Boiler (EB)	192	57	59	117	74	42
Accumulator Tank (m3)	1,5	7,3	7,0	3,6	4,7	8,7
SolarThermal (0/1)	0	0	0	0	0	0
Energy production [MWh/y]						
PV	0	407	402	484	396	454
HP water-to-water	235	18	16	283	14	22
HP air-to-water	0	0	0	0	0	0
Pellets Boiler (BB)	0	280	281	0	281	282
Electric Boiler (EB)	63	4	4	15	5	2
Losses in Storage	2	5	5	2	4	10
Grid impact						
Electricity sold [MWh/yr]	0	246	243	308	238	288
Max el import [kWh/h]	352	219	220	296	221	182
Max el export [kWh/h]	0	346	342	416	337	389
GM	0,0	1,58	1,55	1,41	1,52	2,14
GM ref	0,0	0,98	0,97	1,18	0,96	1,10

(i.e. the weakest constraint), followed by the three zeroCO2 constraints cases, leaving zeroPE with asymmetric PE factors with the highest cost. The main driver for the costs thus seems to be the PV installation needed in order to reach the different zeroCO2 or zeroPE levels. However, the preferred choice of technologies are not altered, i.e. bio pellets boiler and electric boiler for peak loads.

The grid impact at the bottom of Table 6 shows that when applying the zero balance (either zeroCO2 or zeroPE), the peak export values are higher than the peak import values, leading to GM factors between 1,5 and 2,1. This means that the maximum export from the building is 1,5 to over twice as high as the peak import from the electricity grid. However, when comparing the maximum export value to the maximum import value of the reference case, we see that the GM factors is not above 1, indicating that the grid connection capacity of the building does not need to be higher than for a passive school building without on-site production. This leads to the conclusion that zero carbon buildings in Norway do not necessarily need higher grid connection capacity than buildings without on-site production.

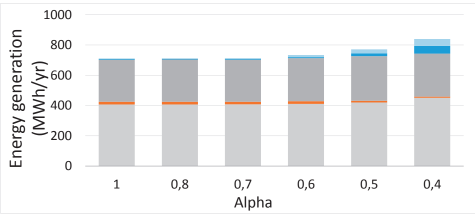
Solar thermal

Solar thermal is not chosen as a heat technology in any of the cases. The reason may lie in the heat demand profile of the school building (see Figure 2) which is close to zero during the summer holiday when solar thermal heat production is at its highest. Consequently, the building is not capable of utilizing the heat production from the ST collectors and therefore, the investment becomes too expensive. When applying the model on a different building type, e.g. an office building or hospital, the conclusion may change.

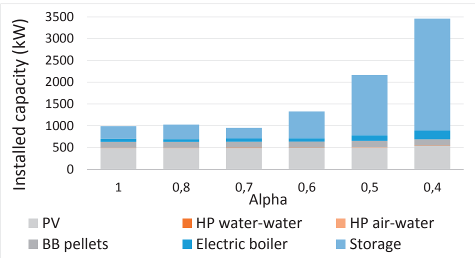
Grid restrictions

The grid impact results in Table 6 show that when the zero balance is applied, the peak export value is higher than the peak import value. As the peak export would demand a stronger grid connection capacity than the peak import alone, we applied restrictions on the maximum export value by introducing different values of alpha (see Equation (7)). When alpha decreases from 1 to 0,4, total costs increases with 37 % due to increased installed capacity in the electric boiler and heat storage. In order to reduce the export, the model invests in cheap, and less efficient technologies (electric boilers) to increase the self-consumption of PV generation and thereby limiting the maximum export. Figure 3a shows that heat generation in bio pellets boilers, which is used for base load generation, is almost unchanged, however the peak load is increasingly covered by electric boilers and larger heat storage when stronger export restrictions are applied. Due to increased use of storage, the storage losses also increase, and thereby the total energy consumption. Therefore, the on-site energy generation must also increase in order to retain the zero emission balance, leading to almost 20 % higher PV electricity generation.

This implies that, by applying a limit on export for zero carbon buildings, the costs increases, the PV installations increases, and less energy efficient technologies for heat load in summer are introduced.



a) Energy generation (MWh/yr)



b) Installed capacity (kW)

Figure 3 Investigating stronger export constraints

Sensitivity analysis

Heat pumps play an important role in a renewable energy system because they are able to utilise the on-site PV generation for heat production. In order to investigate if a heat pump would give lower grid impact, bioenergy was made unavailable. The results are shown in the grey column in Table 6. We see that the GM factor is reduced, however as the absolute value of both maximum import and maximum export is increased, the GM_{ref} is actually increasing to 1,2, which is the opposite of the initial intention. The total discounted costs are increased by 11 % because the "CO2-payments" of electricity imported from the grid is higher than that for imported bioenergy, leading to higher PV installations and thus higher costs.

In future, *PV investment costs* may be reduced even further. Thus a sensitivity analysis was performed by reducing the investment costs from 75 %, 50 % and 25 %, while applying the zeroCO2 constraint. The trend clearly shows that total discounted costs are reduced, and the technology choices alter towards increased capacity of water-to-water HP together with electric boiler, and decreased pellets boiler capacity and heat storage size. The operation of the building in winter is equally shared between the heat pump and the pellets boiler, and in summer heat demand is covered only by the HP (as desired). The GM factor decreases from 1,9 to 1,3, which indicates less grid impact, however as both max import and max export increases, the GM_{ref} increases from 0,93 to 1,09, indicating need for a higher grid connection capacity.

Investigating the impact of *changed electricity prices* we first increase both import and export prices by 18 €cent, keeping the price difference between them constant. This gave higher investments in PV, resulting in negative carbon emissions and GM_{ref} = 1,33, but with the other technological options remaining unchanged. When applying almost equal import and export price (only 0,1 €cent difference), there is less incentive to self-consume on-site PV production, but as the reference case has little self-consumption due to pellets boiler providing base load, the self-consumption cannot be reduced further, and thus the results are almost identical to column 3 in Table 6.

DISCUSSIONS

When applying the zero constraints, the solution does not seem sensitive to the different carbon or PE factors of electricity. Pellets boiler, heat storage, electric boiler and PV are still the preferred technological choices. The only difference is that PV investments tend to be higher when a stricter zero constraint applies (zeroPE with symmetric factors as the weakest, and zeroPE with asymmetric factors as the strongest), in order to provide enough export to the grid to compensate for the imported electricity. The findings are also in line with (Noris et al., 2014), which points out that the factors proposed by the EN15603 standard tend to favour bio energy as the preferred technology.

The proposed asymmetric PE factors by the prEN 15603:2013 reflect the wish to reduce unnecessary export of electricity to the grid as export (PE = 2,0) is valued less than import (PE = 2,5). This should give incentives to increase self-consumption of on-site production. However when concurrently applying the zeroPE constraint, the less valued export leads to higher investments in PV, and consequently higher total export and max export, which is the opposite of the original intention. Thus, applying both the zero constraint and asymmetric factors at the same time leads to increased costs, and higher grid impact.

CONCLUSIONS AND FURTHER WORK

A dynamic mixed integer optimisation model with hourly time resolution has been developed. A case study has been performed on a zero carbon school building of 10 000 m^2 situated in the south-eastern part of Norway. The model minimises total discounted costs and uses two major constraints: zeroCO2 and zeroPE. Cost minimization without the zeroCO2 and zeroPE constraints gives a solution with a water-to-water heat pump, an electric boiler and heat storage. When applying the zeroCO2 or zeroPE constraint, solar PV is chosen, a pellets boiler substitutes the heat pump and the heat storage is between 3 to 5 times larger. The size of the electric boiler is reduced to roughly 1/3 (depending on the constraint) compared with the cost minimizing solution, and this boiler is only used for the highest demand peaks. The total discounted cost for the zeroCO2 and zeroPE solution are 2,5 times as high as for the cost minimization solution, while the annual operational costs are almost unchanged.

When applying restrictions on the import/export of electricity from the building in order to reduce grid impact, the costs increase, PV installation increase, and less energy efficient technologies for heat load in summer are introduced.

By applying asymmetric primary energy factors together with zero primary energy constraints, the self-consumption increases, but at the same time the maximum export value also increases, which is the opposite of the original intention.

Further work includes in-depth analysis of the hourly operation of the building, investigating the net electricity load profile towards the grid. The model will also be expanded with the possibility of using district heat.

NOMENCLATURE

Indexes

i,	energy technology
t,	time step (hr);
p,	period;
g,	energy carrier;
m,	month;

Parameters

C_i^{inv},	Investment costs for energy technology *i* [EUR/kW];
C_i^{run},	Annual maintenance costs for energy technology *i*, [EUR/kW];
D_t^{el},	Electricity demand of building [kWh/hr];
D_t^{heat},	Heat demand of building [kWh/hr];
$P_{t,p}^{buy}$,	Price of electricity bought from the grid at hour *t* in period *p* [EUR/kWh];
$P_{t,p}^{sell}$,	Price of electricity sold to the grid at hour *t*, in period *p* [EUR/kWh];
P_p^{bio},	Price of pellets in period *p* [EUR/kWh];
r,	Discount rate [-]
η_S,	Storage efficiency [-]
$Y_{PV,t}$,	PV electricity generation, at hour *t* [kW/kWp];
$Q_{ST,t}$,	Solar heat generation, at hour *t* [kWh/hr];
$G_{g,t,p}$,	Carbon emissions for energy carrier *g*, at hour *t*, in period *p* [gCO2-eq/kWh];
$PE_{g,t,p}$,	Primary Energy Factor for energy carrier g, at hour *t*, in period *p* [kWh_{PE}/kWh];
$GRCH$,	Annual grid charge [EUR];
$PPCH$,	Monthly peak power grid charge [EUR/kW];

Variables

$x_{i,p}$,	Installed capacity of technology *i*, in period *p* [kW];
$y_{t,p}^{imp}$,	Electricity imported from the grid, at hour *t*, for a typical year in period *p* [kWh/hr];
$y_{t,p}^{exp}$,	Electricity exported to the grid, at hour *t*, for a typical year in period *p* [kWh/hr];
$d_{i,t,p}$,	Electricity consumed by technology *i*, at hour *t*, in period *p* [kWh/hr];
$q_{i,t,p}$,	Heat provided by technology *i*, at hour *t*, for a typical year in period *p* [kWh/hr];
$b_{t,p}$,	Bio energy consumed at hour *t*, for a typical year in period *p* [kWh/hr];
$s_{t,p}$,	Heat stored in accumulator tank at end of hour *t*, in period *p*. [kWh/hr];
$\delta_{ST,p}$,	Binary variable. Equal to 1 if investment in ST in period *p*, else 0.

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Article IV

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Methodology for optimal energy system design of Zero Energy Buildings using mixed-integer linear programming

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ABSTRACT

According to EU's Energy Performance of Buildings Directive (EPBD), all new buildings shall be nearly Zero Energy Buildings (ZEB) from 2018/2020. How the ZEB requirement is defined has large implications for the choice of energy technology when considering both cost and environmental issues. This paper presents a methodology for determining ZEB buildings' cost optimal energy system design seen from the building owner's perspective. The added value of this work is the inclusion of peak load tariffs and feed-in-tariffs, the facilitation of load shifting by use of a thermal storage, along with the integrated optimisation of the investment and operation of the energy technologies. The model allows for detailed understanding of the hourly operation of the building, and how the ZEB interacts with the electricity grid through the characteristics of its net electric load profile. The modelling framework can be adapted to fit individual countries' ZEB definitions. The findings are important for policy makers as they identify how subsidies and EPBD's regulations influence the preferred energy technology choice, which subsequently determines its grid interaction. A case study of a Norwegian school building shows that the heat technology is altered from HP to bio boiler when the ZEB requirement is applied.

1. Introduction

The recast of the EU Directive on Energy Performance of Buildings (EPBD) states that all new buildings are to be nearly Zero Energy Buildings[1] (ZEB) from 2018/2020 [1]. The definition of nearly ZEBs in the EPBD states that "*a nearly zero-energy building means a building that has a very high energy performance. The nearly zero or very low amount of energy required should be covered to a very significant extent by energy from renewable sources, including energy from renewable sources produced on-site or nearby*" [2]. Generally speaking a nearly ZEB is an energy efficient building with low energy demand that to a high extent is covered by on-site generated renewable energy [3–5]. Because ZEBs need on-site energy generation in order to compensate for their energy use, they will inevitably become an active and integrated part of the energy system.

Even though the EPBD sets a definition framework, each of the EU member states shall define their own boundary conditions, weighting factors and ambition level when calculating the zero energy balance, due to differences in climate, culture & building tradition, policy and legal frameworks. As of April 2015, about half of the member states of the EU have accomplished this, and about 5 of the 28 states have chosen to use carbon emissions as weighting factors, thus aiming at Zero *Emission* Buildings,[2] rather than Zero Energy Buildings [6]. Accordingly, a Zero Emission Building is essentially the same as a Zero Energy Building, the only difference is that the balance is calculated by using carbon emissions instead of energy units (see more in Section 1.1). Whenever using ZEB in the

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[1] The notation net ZEB, or nZEB, is also used to highlight that even though the ZEB target is on an annual or lifetime level, the balance is calculated on an hourly or monthly level. In the following of this paper, whenever using ZEB this means net ZEB.

[2] Zero Emission Buildings are also denoted as Zero Carbon Buildings.

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Nomenclature

Sets
I^{heat} Heat technologies, subset of I, I^{heat} = {ST, ASHP, GSHP, EB, BB, DH, GB, CHP}
I^{el} Power technologies, subset of I, I^{el} = {PV, CHP}
I All energy technologies $I = I^{el} \bigcup I^{heat}$
F Energy carriers, F = {el import, el export, bio pellets, natural gas, district heat}

Indexes
p Period
τ Year within period, $\tau = 1, \ldots, N$
t Time step within year, $t = 1, \ldots, T$
i Energy technology
f Energy carrier
m Month within year, $m = 1, \ldots, 12$
k Reinvestment number

Parameters
$C_i^{totspec}$ Discounted specific investment costs, including reinvestments, for technology i [EUR/kW]
$C_i^{totfixed}$ Discounted fixed investment costs, including reinvestments, for technology i [EUR]
C_i^{am} Annual maintenance costs for energy technology i [EUR/kW per year],
Φ_i Expected lifetime of energy technology i [years]
$D_{t,p}^{el}$ Electricity demand of building, at hour t within an average year in period p [kWh/h]
$D_{t,p}^{heat}$ Heat demand of building, at hour t, in period p [kWh/h]
$P_{t,p}^{buy,D}$ Price of electricity bought from the grid at hour t, in period p [EUR/kWh]
$P_{t,p}^{buy,HP}$ Price of electricity bought from the grid at hour t, in period p [EUR/kWh]
$P_{t,p}^{sell,PV}$ Feed-in-tariff of PV electricity exported to the grid at hour t, in period p [EUR/kWh];
$P_{t,p}^{sell,CHP}$ Feed-in-tariff of CHP electricity exported to the grid at hour t, in period p [EUR/kWh];
P_p^{bio} Price of bio pellets in period p [EUR/kWh];
P_p^{gas} Price of natural gas in period p [EUR/kWh];
r Discount rate [-]
η_i Efficiency of technology i [-]
$\eta_{i,t,p}$ Efficiency of technology i, at hour t, in period p [-]
$COP_{i,t,p}$ Coefficient of performance of technology i, at hour t, in period p [-]
$Y_{PV,t,p}$ Specific PV electricity generation, at hour t, in period p [kW/kWp]
$Q_{ST,t,p}$ Specific solar heat generation, at hour t, in period p [kW/m^2]
$G_{f,p}$ Carbon emissions for energy carrier f, in period p [$g_{CO2\text{-}eq}$/kWh]
$PE_{f,p}$ Primary energy factor for energy carrier f, in period p [kWh_{PE}/kWh]
$PE^{embodied}$, $G^{embodied}$ Weighted embodied energy (PE or carbon) [kWh_{PE} or $g_{CO2\text{-}eq}$]
PE^{ref}, G^{ref} Weighted energy imports (PE or carbon) without ZEB restriction [kWh_{PE} or $g_{CO2\text{-}eq}$]
GRCH Annual grid charge [EUR]
$PPCH_m$ Peak power charge, for each month m [EUR/kW]
H_m^{acc} Hour number of the last hour, for each month m [-]
$T_{t,p}^{SH}$ Temperature of water for space heating demand, at hour t, in period p [°C]
$T_{t,p}^{DHW}$ Temperature required for DHW, at hour t, in period p [°C]
$T_{t,p}^{source}$ Temperature of the heat source for HPs (ambient air temperature for ASHP, and ground temperature for GSHP) [°C]
$T_{t,p}^{collector}$ Temperature within the ST collector (assumed equal to storage temperature) [°C]

Ambient air temperature [°C]
$IRR_{t,p}^{tilt}$ Global irradiation on a tilted plane at hour t, in period p [W/m^2]
γ Factor for ZEB level [-]

Variables
x_i Installed capacity of technology i [kW]
c_p^{run} Annual operational cost, for a typical year in period p [EUR/yr]
$q_{i,t,p}$ Heat generated by technology i, at hour t, for a typical year in period p [kWh/hr]
$d_{i,t,p}$ Electricity consumed by technology i, at hour t, for a typical year in period p [kWh/hr]
$b_{t,p}$ Bio pellets consumed in BB at hour t, for a typical year in period p [kWh/hr]
$g_{t,p}^{CHP}$ Natural gas consumed in CHP at hour t, for a typical year in period p [kWh/hr]
$g_{t,p}^{GB}$ Natural gas consumed in GB at hour t, for a typical year in period p [kWh/hr]
$s_{t,p}$ Heat stored in accumulator tank (S) at end of hour t, in period p [kWh/hr]
$y_{i,t,p}$ Electricity generated by technology i, at hour t, for a typical year in period p [kWh/hr]
$y_{i,t,p}^{exp}$ Electricity exported to the grid, from technology i, at hour t, in period p [kWh/hr]
$y_{i,t,p}^{selfcD}$ Electricity consumed in the building, from technology i, at hour t, in period p [kWh/hr]
$y_{i,t,p}^{selfcHP}$ Electricity consumed in HPs, from technology i, at hour t, in period p [kWh/hr]
$y_{t,p}^{impD}$ Electricity imported from the grid, at hour t, for a typical year in period p [kWh/hr]
$y_{t,p}^{impHP}$ Electricity imported from the grid to HP, at hour t, for a typical year in period p [kWh/hr]
$\delta_{t,p}^{exp}$ Binary variable, 1 if electricity is exported from the building, 0 if import
$\delta_{t,p}^{imp}$ Binary variable, 0 if electricity is exported from the building, 1 if import
$y_{m,p}^{maximp}$ Monthly maximum electricity import value, for each month m, in period p [kWh/hr]

Definitions and terms used
FiT Feed-in tariff
Electric specific demand Demand of electricity services (lighting, fans&pumps, appliances, etc.)
Heat demand Demand of heat services (space heating and domestic hot water demand)
Electricity consumption Consumption of electricity, including electricity for heating purposes (if any)

following it embraces both Zero Energy and Zero Emission Buildings.

The balance of a ZEB is calculated as energy consumed minus energy generated over a year or over the total lifetime of the building. However, the building still exchanges electricity with the grid on an hourly or minute basis, as the instantaneous on-site generation may not always correspond with the load. As electric energy must be consumed the instant it is produced, on-site electricity generation from photo voltaic (PV) solar cells, lead to situations where the building is exporting electricity to the grid. Such electric energy generating buildings are also denoted as prosumers, which imports electricity in some hours and exports electricity in other hours.

1.1. Definition of ZEB

A significant effort was made from 2008 to 2013 to define what ZEBs are, especially through the IEA Solar Heating and Cooling Programme Task 40 "Net Zero Energy Solar Buildings" (IEA SHC Task 40) [7]. One of the issues addressed was whether export of electricity should equalise import of natural gas or bio energy, when calculating the zero energy balance. Or should they be weighted according to their energy quality? Today, all member states use weighting factors, either primary energy factors (PE), in kWh_{PE}/kWh_f, or carbon factors, in $g_{CO2\text{-}eq}/kWh_f$, which differs for each energy carrier, f, when calculating the ZEB balance. PE also has different versions; non-renewable PE and total PE, and additionally symmetric and asymmetric PE factors for electricity. As each member state is free to decide these factors, they differ slightly from country to country, however indicative values of non-renewable PE and total PE factors for European conditions are published in the EPBD [1].

Within the work of IEA SHC Task 40, several case studies of both simulated and monitored ZEBs were performed. Noris et al. [8] analyse six ZEB buildings in four European countries, investigating the possibility of reaching the ZEB target by varying the weighting factor for calculating the ZEB balance. The findings show that regardless of using carbon or PE factors, bio energy is the preferred heat technology, as it has the lowest weighting factor in almost all European countries. The only exemption is the Danish PE factors, which favours heat pumps and district heating over bio energy. The paper concludes, without considering costs, that the chosen weighting factors have a large impact on the preferred heat technology within the building, which again influences the demanded PV area and the building's interaction with the electricity grid.

1.2. Grid indicators

The initial experience from the first ZEB pilot projects showed that reaching the zero balance is possible, and in almost all cases on-site PV generation is an inevitable part of the solution [8–11]. With PV as the main way of reaching the ZEB target, the building exports electricity to the grid in summer, and imports electricity in winter. This may lead to challenges for the grid depending on the capacity and conditions of the feeders and the transformers in the local distribution grid [12]. In order to evaluate the effect of the import/export situation on the grid, various grid indicators have been proposed and investigated [10,11,13]. Salom et al. [10] conclude that a representation of net exported electricity in load duration curves is useful for showing maximum import and export values together with the amount of annual exported and imported electricity, especially when comparing different ZEBs. Further, it is stated that hourly time resolution is sufficient to capture the correlation between on-site demand and supply of energy.

1.3. Optimisation of ZEBs

When designing a ZEB, several aspects need to be taken into account, e.g. building physics, technical systems and their costs on the one hand, and the operation of the building, including energy prices and grid tariffs on the other. The complexity of this task has led to the development of several optimisation models which have;

1. Different *objectives*, such as maximising thermal comfort, or minimising costs or emissions. Mostly, multi-objective optimisation models have been developed.
2. Different constraints, such as emissions or thermal comfort
3. Different *modelling approaches*, such as simulating several different alternatives and weighting the energy performance, thermal performance and/or cost performance of the different cases in order to select the "best" cases occurring along a pareto front line, or using optimisation modelling, like LP or MILP, with one objective.
4. Different *time resolution*. The level of detail varies from minute to hourly simulations.
5. The *scope* of investigation is often either focused on optimal building design, or optimal operation.

The initial experience with ZEB pilot projects and case studies identified a trade-off between reducing energy demand vs. generation of on-site energy, when cost is considered [14]. As a consequence, different methodologies and tools for optimisation of building design occurred. Huws et al. [15] and Hamdy et al. [16] use multi-objective optimisation by stepwise varying different design parameters. Huws finds the optimal design by comparing emission vs. cost, cost vs. discomfort, and discomfort vs. emissions, and determines the heat and renewable energy (RES) technologies within the building after the building design is concluded. Hamdy also separates the optimisation into different stages, where the first stage minimises heat demand and life cycle costs (LCC) of the building envelope. This leads to selected cases that lie on the pareto front for thermal demand vs. costs. In the second step, operation costs are calculated for each of the cases from step 1 when simulating four different heating and cooling systems. In the third and last step, ways of improving the costs and the energy consumption in step 2 are investigated by adding on-site renewable energy generation (solar thermal collectors and/or PV). In both Huws and Hamdy, the outcome depends on the weighting factors between their objectives; emissions, costs, discomfort and heat demand, and thus it may be difficult to draw clear conclusions. Lu [17] also optimises the energy system by a multi-objective function by minimising costs, emissions and grid interaction, but again the outcome depends on the weighting factors between the three. The operation of the building is simulated in both Hamdy, Huws and Lu while varying different design parameters, which might not reflect the cost-optimal operation of the building.

The optimal operation of buildings for a given design have been investigated in various studies (see e.g. Refs. [12,18–22]). Especially with the introduction of on-site energy generation different control algorithms are developed, however in these studies, the energy technologies (choice and size) and the design of the building are treated as given, which means that the system may be over or under dimensioned according to what is economically profitable.

This paper aims at finding the optimal investment decision of the energy technologies when taking into account an optimal hourly operation of the energy system. Investment decisions for buildings can entail many details and contradictory objective functions [23]. Models that both optimise investment decisions and operation, are mostly found in energy system modelling tools such as TIMES [24], Balmorel [25] and ReMod [26], which optimise the whole energy system from a macroeconomic perspective. Similar modelling approaches are also found in Korpås et al. [27] and Slungård et al. [28]. Korpås study an integrated wind-hydrogen power system with co-optimisation of investments and operation using deterministic LP, and Slungård developed a deterministic dynamic programming tool to determine the optimal choice and size of heat technologies in a district heating grid.

On a building level, to our knowledge, only Milan et al. [29] have developed a similar LP optimisation tool for a ZEB building, with hourly time resolution and which take the building energy loads as input. However, the number of technologies implemented is limited, and the size of the heat storage tank is predefined to fit the standard size of a Danish single-family home, and is not a freedom of choice. Hence, larger buildings, such as multi-family houses (MFH) or non-residential buildings, are not addressed.

1.4. The aim of this study

The focus of this work is to develop a mixed-integer linear modelling (MILP) framework to identify the cost-optimal choice and dimensioning of energy technologies for ZEBs, while simultaneously optimising the operation of the building. The framework is designed to investigate how the solution is influenced by the weighting factors (both choice and value of the factors), as well as the ZEB level and economic parameters. Moreover, it is possible to evaluate the effect of policy incentives, such as feed-in-tariffs and investment subsidies, on the building owner's choice of energy technologies for ZEB buildings. Naturally, the various energy technologies interacts with the power system in different ways, and the model facilitates the evaluation of this interaction for the optimal solution. This is done through selected grid indicators proposed in Section 3, e.g. load duration curves of the hourly net electricity load, and self-consumption of on-site electricity generation (see also Section 1.2).

Previous experience showed that when using a multi-objective approach by minimising both emissions and costs, the outcome is dependent on the weighting between them. Giving higher value to minimisation of emissions lead to unreasonable large capacity investments, because cost is of less importance, in order to avoid emissions in a few hours [30]. In the current work, it is therefore decided to use a single objective function, minimising the total discounted costs while posing restrictions on the weighted energy consumed by the building. This approach leads to a clear outcome of the results and is consistent with the optimal operation of the building with the given energy prices. The design of the building is predetermined, and thereby treating the energy loads as input. In contrast to already existing literature, the model developed also determines the optimal sizing of the heat storage tank and contains mixed-integer variables.

This paper gives a thorough description of the developed mixed-integer linear deterministic optimisation model, while leaving in-depth case studies for coming papers. The model structure captures the whole lifetime of the building, and incorporates effect of parameters[3] that might change in future by dividing the lifetime into periods. The integrated optimisation of the investment and operation strongly connects the investment decision with the operational outcome as well as the influence of support schemes, which can be included in the model. Thus, it is possible to analyse how different assumptions on e.g. various subsidies, feed-in tariffs, market prices, energy indicators and ZEB ambition level (nearly or strictly ZEB?) change the optimal energy solutions of the building.

The hourly time resolution of the operation of the building's energy system ensures an optimal utilisation of the heat storage and the on-site renewable energy generation. Optimal utilisation of the heat storage indirectly facilitates demand side management (DSM) as it enables the optimal way to shift the heat loads according to market conditions. The hourly time resolution also enables investigation of the building's grid interaction in detail for the different cases.

This paper is structured as follows. In Section 2, the methodology of the model is presented. The sub-models of the energy technologies are presented in Section 2.2, and the objective function is described in Section 2.3. Section 2.4 explains the main restrictions, including the hourly heat and electricity balances, and the lifetime ZEB balance. Section 3 presents the criteria selected for assessing the ZEB building's interaction with the power grid. Examples of model results are given in Section 4 based on a case study of a Norwegian school building. The most important assumptions of the model framework are discussed in Section 5, before making concluding remarks in Section 6.

2. Optimisation model

This paper investigates cost-optimal solutions for ZEBs for different energy indicators with a financial perspective. For this purpose, a dynamic deterministic mixed-integer linear optimisation model (MILP) is developed which optimises both the investments (technology choice and size), and the operation of the energy technologies simultaneously. This model is presented in the following.

2.1. System description

Fig. 1 illustrates the energy technologies and energy flows that are implemented in the model, where solid and minor dashed arrows indicate the hourly flows of respectively electricity and heat within the building. The ZEB balance is achieved on the life cycle as embodied energy is included (see Section 2.4.4).

The energy technologies available are a micro combined heat and power unit (CHP), gas boiler (GB), district heat exchanger (DH), bio pellets boiler (BB), air source heat pump (ASHP), ground source heat pump (GSHP), electric top-up coil (EB), solar thermal collectors (ST), photovoltaic modules (PV) and a heat storage (S). The availability of a heat storage makes the system capable of shifting the heat generation to when it is economically profitable, while still being able to cover the heat demand at a later or earlier stage.

The selection of energy technologies to be implemented in the model is made on grounds of common available energy sources and energy technologies in European countries, and is inspired by the first experiences from the ZEB pilot projects in the IEA SHC Task 40 [7,8,10]. It is assumed that the building is attached to the electricity grid, and depending on the geographical situation, a natural gas grid and district heating grid may also be present. Even though natural gas is a fossil energy carrier, CHP and gas boilers was installed in some of the ZEB pilot projects [8], and it is of interest to study the effect of using natural gas on the ZEB balance of the building. Bio energy and heat pumps are seen as key technologies to lower Europe's climate emissions, especially as the electricity grid is expected to become greener in future [31,32]. In general, energy systems require a technology for providing base load capacity and peak load capacity. Both the electric top-up coil and the gas boiler may serve as peak load technologies. For the building to become a ZEB, it needs onsite renewable energy generation. ST collectors and PV panels are the two technologies that may provide the building with this.

2.2. Modelling of energy technologies

The installed capacity of the heat pumps (HP), pellets boiler, gas boiler and the micro CHP unit are semi-continuous variables. Hence, the technology is either invested, or not, and if invested, a

[3] As the lifetime of a building can be up to 60 years, it is possible to divide the lifetime into three periods, each containing 20 years. Thus, e.g. the weighting factor for electricity can be set lower with more renewable electricity, and the FiTPV can be reduced or even removed in the second and third period.

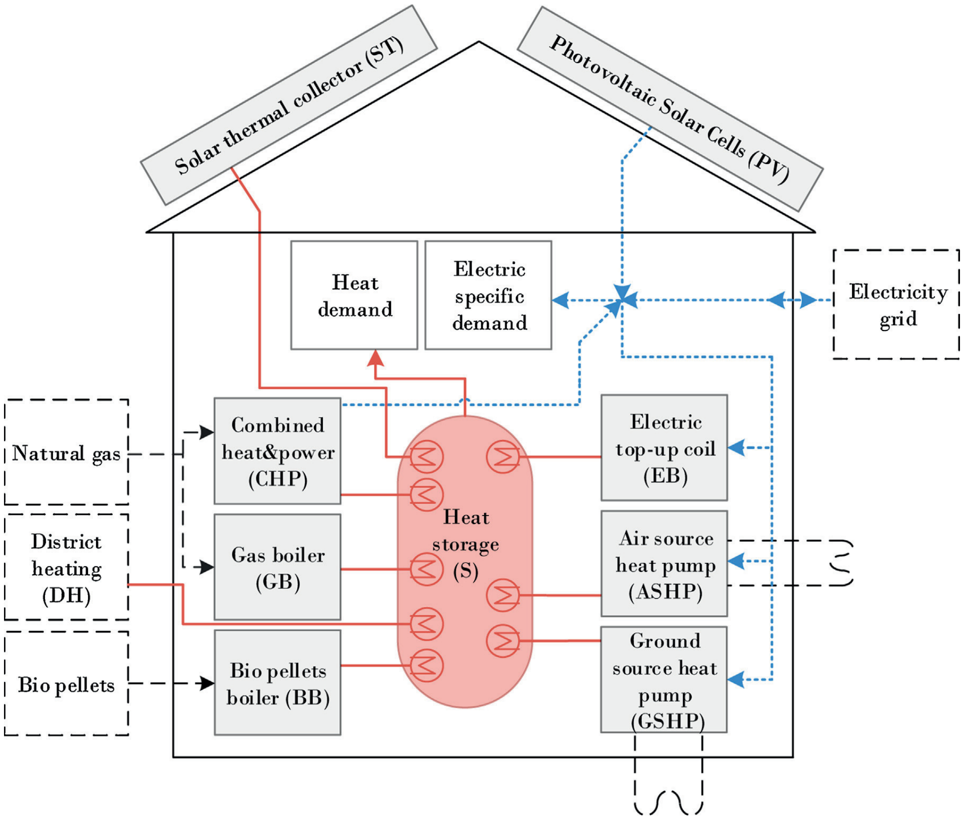

Fig. 1. System scheme and energy flows of the building; heat flows (red solid lines) and electricity flows (dotted blue lines). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

minimum required capacity has to be installed. In real life, technology costs are dependent on size, as larger units often have lower specific costs (EUR/kW) than smaller units. The integer formulation of minimum installed capacity is important when specific technology costs are assumed constant (EUR/kW). Without it, the model would choose to install in several different technologies, some with a very small capacity. As end-users tend to invest in one base load technology and one peak load, and not a variety of technologies, we are able to correct for this. The operation of the heat technologies, is also semi-continuous, this explains it can either be shut down, and if operating they must generate heat above a minimum capacity level (approximately 30% of minimum installed capacity). The only exception is the solar thermal system, which naturally operates whenever the sun shines. The model is implemented in the optimisation modelling tool MOSEL Xpress provided by FICO systems [33].

2.2.1. Building's energy loads

Hourly heat and electricity demand of the building are given as input to the model as time series of heat, $D^{heat}_{t,p}$, and electricity, $D^{el}_{t,p}$, varying by hour, t, and period, p. The heat demand is the sum of domestic hot water demand (DHW) and space heating demand (SH), whereas electric specific demand includes electricity for electric appliances, lighting, fans & pumps and for cooling machines. The energy loads can be provided from either building simulation models, or from statistical models based on energy measurements of buildings (see e.g. Refs. [34–36]).

2.2.2. Constant efficiency for boilers and CHP

The CHP, and the gas, electric and bio boilers are modelled with a constant efficiency. Because the efficiency varies with the load, this is a simplification to keep the model linear. In order to compensate for this, the minimum operating capacity is set to 30% of the installed capacity. This means, that the heat generated from the heat technologies, $q_{i,t,p}$, is modelled as a semi-continuous variable being either 0 or going from 30% of the installed capacity, x_i. The exemption is the electric boiler, which mostly have the same efficiency regardless of part load, and is thus assumed to have a continuous heat generation variable, $q_{EB,t,p}$.

Eq. (1) reflects the energy balances for each of the boilers: gas boiler, bio boiler and electric boiler.

$$q_{GB,t,p} = g^{GB}_{t,p} \times \eta_{GB},\ q_{BB,t,p} = b_{t,p} \times \eta_{BB},$$
$$q_{EB,t,p} = d_{EB,t,p} \times \eta_{EB} \qquad \forall t, p\,[kWh] \tag{1}$$

The CHP is modelled with two efficiencies, one for heat generation and one for electricity generation, similar to the approach in [26] and [37]. This means that when the model decides to generate one unit of electricity from the CHP, $\eta_{CHPheat}/\eta_{CHPel}$ units of heat are simultaneously generated. Similarly, if the model decides to generate one unit of heat, $\eta_{CHPel}/\eta_{CHPheat}$ units of electricity are generated.

$$q_{CHP,t,p} = g^{CHP}_{t,p} \times \eta_{CHPheat},\ y_{CHP,t,p} = g^{CHP}_{t,p} \times \eta_{CHPel} \qquad \forall t, p\,[kWh] \tag{2}$$

2.2.3. Variable efficiency for air source and ground source heat pumps

The conversion efficiency of electricity into heat (COP) of a heat pump is dependent on the heat source temperature, in this case air or ground temperature, and the supply temperature, which is the temperature of the accumulator tank. The latter is approximated by weighing the required energy demand with its set-point temperature. In the model, the heat demand of the building is treated as the sum of the domestic hot water demand (DHW) and the space heating demand (SH), on the assumption that they are supplied by a stratified storage tank. The supply temperature for the domestic hot water is assumed constant throughout the year. The supply temperature of the space heating, however, is dependent on the outdoor temperature and determined according to a heating curve, which is dependent on the heat distribution technology used (see examples in Fig. 2).

The COP of the heat pump is represented by a polynomial based on a fit of manufacturer's data presented in [38]. The coefficients k_0 to k_3 are dependent on the technology used, and thereby respecting the characteristics of either the ground source heat pump (GSHP), where $T^{\text{source}}_{t,p}$ is the ground temperature, or the air source heat pump (ASHP), where $T^{\text{source}}_{t,p}$ is the same outdoor temperature used for creating the building's heat demand, $D^{\text{heat}}_{t,p}$ (see Section 2.2.1).

$$\begin{aligned} &\text{COP}_{t,p} = k_0 - k_1\left(T^{\text{supply}}_{t,p} - T^{\text{source}}_{t,p}\right) + k_2\left(T^{\text{supply}}_{t,p} - T^{\text{source}}_{t,p}\right)^2 \qquad \forall t,p \quad [-] \\ &\quad \text{where} \quad T^{\text{supply}}_{t,p} = T^{\text{DHW}} \quad \text{for} \quad \text{DHW} \\ &\qquad\qquad T^{\text{supply}}_{t,p} = T^{\text{SH}}_{t,p} \quad \text{for} \quad \text{SH} \end{aligned} \tag{3}$$

The heat storage is modelled as a single node, serving both DHW and SH demand. Thus, the average COP of the heat pump when delivering to the whole tank is assumed to be a weighted average of the COP for DHW and for SH as described in Eq. (4), where $D^{\text{DHW}}_{t,p}$ is the demand of hot water, and $D^{\text{SH}}_{t,p}$ the demand for space heating.

$$\text{COP}_{t,p} = \frac{D^{\text{DHW}}_{t,p}\text{COP}^{\text{DHW}}_{t,p} + D^{\text{SH}}_{t,p}\text{COP}^{\text{SH}}_{t,p}}{D^{\text{heat}}_{t,p}} \qquad \forall t,p\ [-] \tag{4}$$

Eq. (5) reflects that the heat generated from the ASHP, $q_{\text{ASHP},t,p}$, equals the electricity consumed,$d_{\text{ASHP},t,p}$, multiplied by the COP. Similarly, the energy balance for the GSHP is given in Eq. (5). Notice that the COP changes by hour as the supply temperature and temperature of the source also varies by hour.

$$\begin{aligned} &q_{\text{ASHP},t,p} = d_{\text{ASHP},t,p} \times \text{COP}^{\text{ASHP}}_{t,p}, \\ &q_{\text{GSHP},t,p} = d_{\text{GSHP},t,p} \times \text{COP}^{\text{GSHP}}_{t,p} \qquad \forall \text{t, p}\ [kWh] \end{aligned} \tag{5}$$

2.2.4. District heating

District heating is modelled with a constant efficiency, reflected in Eq. (6).

$$q_{\text{DH},t,p} = \text{DH}_{t,p} \times \eta_{\text{DH}} \qquad \forall t,p\ \ [kWh] \tag{6}$$

2.2.5. Storage

The energy balance of the storage is equal to the heat balance of the total heat system of the building shown in Eq. (17), which incorporates the heat losses of the storage.

In order to make the optimal solution independent of the final storage content, the storage is required to contain the same amount of heat at the start ($t = 0$) and at the end ($t = T$) of the year. See Eq. (7).

$$s_{0,p} = s_{T,p} \qquad \forall p\ \ [\text{kWh/hr}] \tag{7}$$

2.2.6. Solar energy—PV and solar thermal collectors

The efficiency of the flat plate solar thermal collector (ST) is represented by a polynomial (see Eq. (8)) where the constants are determined by laboratory experiments in [39]. The total irradiation on the tilted plane, IRR^{tilt}, varies hourly and is calculated according to Quaschning [40] with the same climatic conditions as when calculating the building's energy loads in Section 2.2.1. The temperature within the solar thermal collector, $T^{\text{collector}}_{t,p}$, must be determined exogenously. As Eq. (8) shows, a higher value of the temperature from the collector decreases the module efficiency. Thus, an assumption of e.g. 30 °C of the collector temperature will give an optimistic value for the efficiency of the ST.

$$\eta_{\text{ST},t,p} = c_0 - c_1\frac{T^{\text{collector}}_{t,p} - T^{\text{amb}}_{t,p}}{\text{IRR}^{\text{tilt}}_{t,p}} - c_2\frac{\left(T^{\text{collector}}_{t,p} - T^{\text{amb}}_{t,p}\right)^2}{\text{IRR}^{\text{tilt}}_{t,p}} \ \forall \text{t, p}\,[-] \tag{8}$$

The input time series of ST heat generation,$Q_{\text{ST},t,p}$, in Eq. (9) is equal to the total irradiation on the tilted plane, $\text{IRR}^{\text{tilt}}_{t,p}$, multiplied with the collector efficiency, $\eta_{\text{ST},t,p}$. The utilised ST heat, $q_{\text{ST},t,p}$, within the building can be either equal to or lower than the actual ST heat generation, which is necessary if heat demand is low and the storage tank is full at the time of ST heat generation.

$$Q_{\text{ST},t,p} = \text{IRR}^{\text{tilt}}_{t,p} \times \eta_{\text{ST},t,p} \qquad \forall t,p\ \ [kWh/m^2_{\text{collector}}] \tag{9}$$

$$q_{\text{ST},t,p} \le Q_{\text{ST},t,p} \times x_{\text{ST}} \qquad \forall t,p\ \ [kWh] \tag{10}$$

The PV electricity generation, $Y_{\text{PV},t,p}$, in Eq. (11), is found by using the same irradiation on the tilted surface as described above for ST. The efficiency of the PV module and the inverter is calculated based on a methodology proposed by Huld et al. [41] which takes cell temperature and module type into account, in addition to solar irradiation and outdoor temperature.

$$Y_{\text{PV},t,p} = \text{IRR}^{\text{tilt}}_{t,p} \times \eta(\text{IRR}^{\text{tilt}}_{t,p}, T^{\text{amb}}_{t,p})_{\text{PV},t,p} \qquad \forall t,p\ \ [kWh/kWp] \tag{11}$$

$$y_{\text{PV},t,p} = Y_{\text{PV},t,p} \times x_{\text{PV}} \qquad \forall t,p \quad [kWh] \tag{12}$$

2.3. Objective function

This section presents the objective function which minimises total costs, while posing restrictions on the emissions or primary energy consumed.

A single objective function is used, which minimises discounted investment and operational costs over the total lifetime of the building. The lifetime of the building may be divided into periods, p, where the model is run for a representative year within each period. Hence, the total lifetime of the building equals the total number of periods,P, multiplied by the number of years within each period,N.

Eq. (13) shows the objective function which sums the discounted investment costs (fixed [EUR] and specific [EUR/kW]), for each technology, i, and the total discounted annual operational costs. Starting from the right in Eq. (13), the annual operational costs, c^{totrun}_p, for a representative year in a period, p, are discounted and summed for all years, τ, within the period. Next, the operational costs for each period are discounted for all periods.

$$\begin{aligned} \min\pi = &\sum_{i\in I}\left(C^{\text{totspec}}_i x_i + C^{\text{totfixed}}_i\right) \\ &+\sum_{p=1}^{P}\frac{1}{(1+r)^{(p-1)\cdot N(p)}} \times \sum_{\tau=1}^{N}\frac{c^{\text{totrun}}_p}{(1+r)^{\tau}}\ [EUR] \end{aligned} \tag{13}$$

The lifetime adjusted specific investment costs, C^{totspec}_i, are found for each technology, i, on the basis of its expected life-

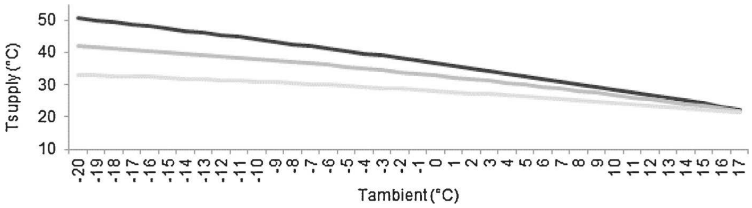

Fig. 2. Heating curve. (supply temperature for space heating vs. outdoor temperature).

time, Φ_i, as shown in Eq. (14), where C_i^{spec} is the investment cost [EUR/kW], and $\left(\frac{P\times N(p)}{\Phi_i}-1\right)$ is the number of reinvestments, k, needed throughout the lifetime of the building. As an example, if the total lifetime of the building is 40, the number of reinvestments of an ASHP with an expected lifetime of 20 years equals $\frac{40}{20}-1=1$, and the salvage value is zero.

$$C_i^{\text{totspec}} = \sum_{k=0}^{\left(\frac{P\cdot N(p)}{\Phi_i}-1\right)} \frac{C_i^{\text{spec}}}{(1+r)^{k\times\Phi_i}} - Z^{\text{salvage}} \qquad [EUR/kW] \qquad (14)$$

$$C_i^{\text{totfixed}} = \sum_{k=0}^{\left(\frac{P\cdot N(p)}{\Phi_i}-1\right)} \frac{C_i^{\text{fixed}}}{(1+r)^{k\times\Phi_i}} - Z^{\text{salvage}} \qquad [EUR] \qquad (15)$$

Eq. (16) reflects that the annual operational costs for a representative year within each period, c_p^{totrun}, equals the cost of energy imports in all hours, t, which is the price for each energy carrier, $P_{t,p}^{f}$, multiplied by the amount of electricity, $y_{t,p}^{\text{imp}}$, bio pellets, $b_{t,p}$, or natural gas,$g_{t,p}$, consumed. Notice that in some countries, electricity used for heat pumps, $y_{t,p}^{\text{impHP}}$, has a lower tariff than normal electricity consumption, and is thus specified separately. In the second line, the cost of self-consumption of on-site electricity generation $\left(P_{t,p}^{\text{selfc}}\times y_{t,p}^{\text{selfc}}\right)$ is added, and in the third line, the income of electricity sold to the grid is subtracted $\left(P_{t,p}^{\text{sell}}\times y_{t,p}^{\text{exp}}\right)$. The last line presents the fixed annual maintenance cost for each technology, $C_i^{\text{am}}\times x_i$, and two special taxes of the electricity grid, where PPCH_m reflects the monthly peak power charge (see more in Section 2.4.3) and GRT the annual grid charge.

$$c_p^{\text{totrun}} = \sum_{t\in T}\left(\begin{array}{l} P_{t,p}^{\text{buy,D}}y_{t,p}^{\text{impD}} + P_{t,p}^{\text{buy,HP}}y_{t,p}^{\text{impHP}} + P_p^{\text{bio}}b_{t,p} + P_p^{\text{gas}}\left(g_{t,p}^{\text{GB}}+g_{t,p}^{\text{CHP}}\right) \\ +P_{t,p}^{\text{selfc}}\left(\left(y_{t,p}^{\text{PVselfc\_D}}+y_{t,p}^{\text{PVselfc\_HP}}\right)+y_{t,p}^{\text{CHPselfc}}\right) \\ -\left(P_{t,p}^{\text{sell,PV}}y_{t,p}^{\text{PVexp}}+P_{t,p}^{\text{sell,CHP}}y_{t,p}^{\text{CHPexp}}\right) \end{array}\right) + \sum_{i\in I} C_i^{\text{am}}x_i + \sum_{m\in M}\text{PPCH}_m y_{m,p}^{\text{maximp}} + \text{GRCH} \quad \forall p \; [EUR/year] \qquad (16)$$

The model can easily be adapted to investigate conditions in countries where there is no peak power charge, or fee for self-consumption by letting them be zero. Further, if no feed-in-tariffs are present, the $P_{t,p}^{\text{sell,PV}}$ and $P_{t,p}^{\text{sell,CHP}}$ are replaced with the spot price in the electricity market.

This means that both the investment problem and the operation problem are solved at the same time. In other words, the least cost solution for the operation of the building with the optimal technologies and their sizing is found.

2.4. Restrictions

The optimal solution is found according to a set of constraints that cannot be violated. The technology restrictions were elaborated on in Section 2.2. This section presents the constraints reflecting the hourly heat and electricity balance and the lifetime ZEB balance of the building. Additional restrictions, such as grid tariffs and maximum available façade area, are also explained.

2.4.1. Heat balance

For each hour, the heat demand of the building has to be met. Eq. (17) reflects the heat balance where the sum of heat generated from all heat technologies, $q_{i,t,p}$, added the content of the storage at the beginning of hour t, must equal the heat demand of the building, $D_{t,p}^{\text{heat}}$, plus the energy content of the storage at the end of hour t, $s_{t,p}$. Notice that the content of the storage at the beginning of the hour equals the content of the storage at the end of the previous hour, $s_{t-1,p}$, multiplied with an efficiency factor, η_S.

$$\sum_{i\in I^{\text{heat}}} q_{i,t,p} + \eta_S\times s_{t-1,p} = D_{t,p}^{\text{heat}} + s_{t,p} \qquad \forall t,p \quad [kWh] \qquad (17)$$

2.4.2. Electricity balance

Similar as for heat, the electricity demand of the building, $D_{t,p}^{\text{el}}$, must be met every hour. Fig. 3 illustrates the four electricity balance equations, where Node I reflects that the electricity demand of the building, $D_{t,p}^{\text{el}}$, and the electric top-up coil $d_{EB,t,p}$, must be met by electricity bought from the grid, $y_{t,p}^{\text{impD}}$, and/or on-site generated electricity from PV, $y_{PV,t,p}^{\text{selfcD}}$, and/or CHP, $y_{CHP,t,p}^{\text{selfcD}}$(see Eq. (18)). As explained in Section 2.3, electricity used for heat pumps may have a separate tariff, and is thus treated separately as seen in Node II in Fig. 3. Eq. (19) reflects the electricity balance of the heat pumps, where the electricity demanded by the heat pumps, $d_{ASHP,t,p}+d_{GSHP,t,p}$, is covered by import from the grid, $y_{t,p}^{\text{impHP}}$, and/or on-site generated electricity from PV, $y_{PV,t,p}^{\text{selfcHP}}$. It is assumed that if a CHP is installed, a HP will not be installed additionally, and accordingly, the option of CHP providing electricity to the HP is left out. Node III and IV, reflects the electricity balances for the PV and the CHP (given in Eqs. (20) and (21)) respectively, where generated electricity, $y_{i,t,p}$, can be exported to the grid,$y_{i,t,p}^{\text{exp}}$, and/or self-consumed within the building.

$$\text{I} \quad D_{t,p}^{\text{el}} + d_{EB,t,p} = y_{PV,t,p}^{\text{selfcD}} + y_{CHP,t,p}^{\text{selfcD}} + y_{t,p}^{\text{impD}} \qquad \forall t,p \qquad (18)$$

$$\text{II} \quad d_{ASHP,t,p} + d_{GSHP,t,p} = y_{PV,t,p}^{\text{selfcHP}} + y_{t,p}^{\text{impHP}} \qquad \forall t,p \qquad (19)$$

$$\text{III} \quad y_{PV,t,p} = y_{PV,t,p}^{\text{exp}} + \left(y_{PV,t,p}^{\text{selfcD}} + y_{PV,t,p}^{\text{selfcHP}}\right) \qquad \forall t,p \qquad (20)$$

$$\text{IV} \quad y_{CHP,t,p} = y_{CHP,t,p}^{\text{exp}} + y_{CHP,t,p}^{\text{selfcD}} \qquad \forall t,p \qquad (21)$$

Eqs. (18)–(21) must be separate, if not, the export from the CHP will "turn to" PV export because the payment is often higher for PV export. Further, because the feed-in tariff (FiT) for CHP export is lower than the FiT for PV export, the model will always choose to export electricity from PV in favour of CHP, and thus, there is no need for additional restrictions for the import-export situation.

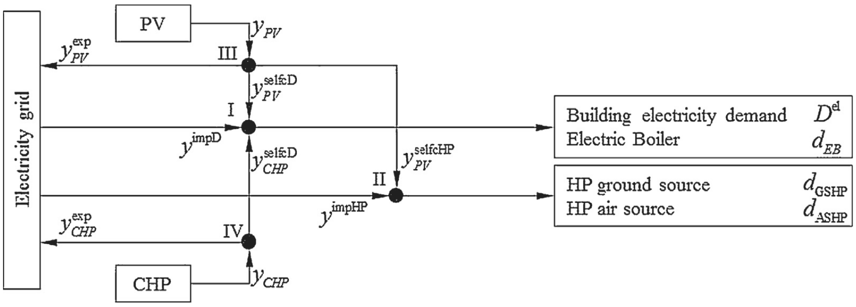

Fig. 3. Graphical description of the hourly electricity balance.

2.4.3. Grid constraints

To avoid import and export of electricity within the same hour, the following three constraints are applied in order to force the model to either import or export. This is done by use of binary variables (0 or 1), $\delta^{exp}_{t,p}$ and $\delta^{imp}_{t,p}$, that get the value one if respectively export or import is positive. M^{grid} is an exogenously determined parameter that has to be large enough for the equations to hold.

$$\text{If import}: \left(y^{impD}_{t,p} + y^{impHP}_{t,p}\right) \leq \delta^{imp}_{t,p} \times M^{grid} \qquad \forall t, p \tag{22}$$

$$\text{If export}: \left(y^{PVexp}_{t,p} + y^{CHPexp}_{t,p}\right) \leq \delta^{exp}_{t,p} \times M^{grid} \qquad \forall t, p \tag{23}$$

$$\text{Either import or export}: \delta^{exp}_{t,p} + \delta^{imp}_{t,p} \leq 1 \qquad \forall t, p \tag{24}$$

Grid companies may operate with a monthly peak power charge. To include this, the monthly peak power needs to be found. Eq. (25) determines the highest monthly peak value of electricity import, where H_m is a vector containing the time step number of the last hour of the last day in the month, $\theta(m)$, for every month throughout the year.

$$\text{if} \quad t \leq H_m = H_{m-1} + 24 \times \theta(m) \quad \rightarrow \quad y^{maximp}_{m,p} \geq (y^{impD}_{t,p} + y^{impHP}_{t,p}) \tag{25}$$

The value of the first month (January) is $H_1 = 744$, while the last month (December), is $H_{12} = 8760$. For every month, the peak electricity import value will be stored in the variable $y^{maximp}_{m,p}$. The monthly peak power charge thus equals $\left(\text{PPCH}_m \times y^{maximp}_{m,p} \forall m, p\right)$, as seen in Eq. (16).

$$\sum_{p \in P} \left(N(p) \sum_{t \in T} \sum_{f \in F} \left(\left(y^{impD}_{t,p} + y^{impHP}_{t,p}\right)_f - \left(y^{PVexp}_{t,p} + y^{CHPexp}_{t,p}\right)_f + (b_{t,p})_f + \left(g^{GB}_{t,p} + g^{CHP}_{t,p}\right)_f \right) \times \text{PE}_{f,p} \right) + \text{PE}^{embodied} = (1-\gamma) \times \text{PE}^{ref} \ [\text{kWH}_{PE}] \tag{26}$$

$$\sum_{p \in P} \left(N(p) \sum_{t \in T} \sum_{f \in F} \left(\left(y^{impD}_{t,p} + y^{impHP}_{t,p}\right)_f - \left(y^{PVexp}_{t,p} + y^{CHPexp}_{t,p}\right)_f + (b_{t,p})_f + \left(g^{GB}_{t,p} + g^{CHP}_{t,p}\right)_f \right) \times G_{f,p} \right) + G^{embodied} = (1-\gamma) \times G^{ref} \left[\text{g CO2}_{-eq}\right] \tag{27}$$

2.4.4. ZEB constraints

The modelling framework developed allows for modification of boundary conditions, weighting factors and ZEB ambition level in order to fit individual countries' ZEB definitions. Here, the boundary condition is set at the building's physical walls, and the ZEB ambition level includes energy used for constructing the building (embodied energy) and all energy consumed within the building. In line with the EPBD [1] the balance of the ZEB building is calculated as weighted energy imported minus weighted energy exported over the total lifetime of the building.

Eqs. (26) and (27) reflect the zero primary energy and zero emission constraint, respectively. In Eq. (26) the total primary energy imports over the entire lifetime of the building equals the sum of operational and embodied energy, $G^{embodied}$. The operational energy import is found by multiplying the import of each energy carrier, f, with its primary energy factor, $\text{PE}_{f,p}$, for each time step, t, summed over a representative year within each period, p, multiplied by the number of years within each period, N, and lastly summed over all periods, P. Notice that the balance only includes energy carriers either exported from or imported to the building. As an example, solar thermal generation is not explicitly accounted for, however its heat indirectly contributes to reduced energy imports for heat generation.

In order to investigate a relaxation of the ZEB constraints, γ is introduced which can take the values $\{0, \ldots, 1\}$. PE^{ref} represents the building's primary energy consumption when only minimising costs without enabling the ZEB constraint, and is afterwards set as an exogenous parameter when activating the ZEB constraint. Imposing $\gamma = 1$ means that the building is a strictly ZEB, and the restriction in Eq. (26) equals zero. When $\gamma = 0$, there is no ZEB requirement, and the cost-optimal solution without considering primary energy consumption is found. Imposing $\gamma = 0,6$ means that the primary energy consumption, PE^{totref}, must be reduced by 60%, reflecting a 60% nearly ZEB. As the environmental impact for the energy carriers might change in the future, especially for electricity, the primary energy factors, $\text{PE}_{f,p}$ [kWh $_{PE}$/kWh $_f$], can be changed according to the period.

The zero emission constraint in Eq. (27) has a similar layout as the zero primary energy constraint, where the primary energy factors, $\text{PE}_{f,p}$, are replaced with carbon factors, $G_{f,p}$[g $_{CO2\text{-}eq}$/kWh $_f$].

2.4.5. Technology capacity constraints

For each technology, i, capacity constraints and energy balances are applied, which states that the heat, Eq. (28), or electricity, Eq. (29), generated cannot surpass the installed capacity, x_i, of each technology. Constraints for ST and PV are given in Eq. (10) and Eq. (12), respectively.

$$x_i \geq q_{i,t,p} \qquad \forall i \in I^{heat} \backslash ST, t, p \,[\text{kW}] \tag{28}$$

$$x_i \geq y_{i,t,p} \qquad \forall i \in I^{el} \backslash PV, t, p \,[\text{kW}] \tag{29}$$

Maximum available façade and roof area for mounting PVs and ST modules is shown in Eq. (30). Notice that the installed ST is given in m^2, and the installed PV in kWp. Thus a factor of Ω m^2/kWp is multiplied to the latter. With a relatively high module performance of e.g. 300 W, a factor of 5,3 m^2/kW may be reasonable.

$$x_{ST} + \Omega \times x_{PV} \leq A^{max} \qquad [m^2] \tag{30}$$

3. Assessment criteria: grid interaction indicators

A thorough presentation of assessment criteria for ZEBs is given in the report of Salom et al. [13], and further elaborated on in [10]. In this work, five grid interaction indicators are chosen for assessing the building's interaction with the power grid (see Table 1).

The self-consumption evaluates the share of on-site electricity generation that is consumed within the building. A graphic illustration of the hourly net electricity load is useful for showing maximum import and export values together with the annual exported and imported amount of electricity. The generation multiple (GM) relates the maximum export value to the maximum import value, and gives an indicative value on how much stronger the grid connection capacity needs to be if the maximum export value exceeds the maximum import value. As the choice of energy technology impacts the net electricity load profile, the reference generation multiple (GM_{ref}) can be used to compare the different cases on the same grounds, i.e. in relation to a reference peak import value.

4. Results

This section presents selected results in order to illustrate how the modelling framework can be used as a tool to optimize the energy system of ZEBs. The modeling framework can also be used to study the impact of different incentives and governmental support schemes for energy efficiency and local energy generation, which will be presented in papers to come.

The techno-economic optimization model described in this paper requires an extensive amount of input data. In order to avoid a detailed description of the input parameters, they are taken from a case study conducted on a simplified version of the model in [42]. The case study is a relatively large school building of 10,000 m^2 with an assumed lifetime of 60 years, situated in Norway. The technology costs and efficiency data, the energy market conditions and climatic conditions are adapted to the country specific conditions.

It is assumed that a ZEB is a building with passive energy standard, but with on-site energy generation. The load inputs are given by regression models based on hourly measurements of electricity and district heat consumption of a passive school building in Norway [35,36]. Fig. 4 shows that the building's heat demand is correlated with the ambient temperature. When the temperature hits −15° C, the hourly heat demand is between 270 and 290 kWh, however at temperatures above 10–15° C the heat demand reflects only the hot tap water demand. The number of months with a heating strategy for the school building is thus about 7 months. The electricity demand on the other hand, is related to the school holidays when lights are switched off and the operation of the ventilation system is reduced. Further, there is no cooling demand in summer as the school is closed.

As mentioned in the introduction, every EU member state is obliged to define its own ZEB definition and ambition level. The ambition level reflects how "nearly" ZEB, or how close to zero the ZEB target, is set to be. With the additional features of the γ presented in Section 2.4.4, the relaxation of the ZEB constraint can be investigated. The following thus investigates the relaxation of the ZEB constraint when using carbon factors.

Fig. 5 shows how the technology choice is influenced by the ZEB ambition level; here varying from no-ZEB (0%-ZEB) to strictly ZEB (100%-ZEB). The energy technology choice shifts from heat pump (HP) to bio pellets boiler and PV when strengthening the ZEB target from 0% to 100%. The most cost efficient way to reduce the carbon emissions is first to reduce the operational emissions. In this case, electricity used for heat pumps is replaced by bio pellets used in a bio boiler, which emits less carbon per heat unit. When the heat pump is fully replaced by the bio pellets boiler, the next option is to compensate the emissions by onsite renewable energy generation, where the installed PV capacity starts at 26 kWp for 20%-ZEB, and reaches 483 kWp for 100%-ZEB.

Fig. 6 shows the impact on the energy system costs, the annual electricity export and the self-consumption rate. The total discounted investment cost increases from 0.65 mill EUR (no-ZEB) to 2.04 mill EUR (100%-ZEB), which is mainly caused by the increased PV investments. The total discounted operational costs increases by 11% at 20%-ZEB, due to the more expensive operation & fuel cost of the bio boiler compared to the heat pump. From 30%-ZEB and onwards, the operational costs declines due to the increased income from sold electricity to the grid. Because Norway do not have a feed-in tariff for PV, the income of the exported PV electricity is limited, and the total discounted operational cost reaches 0.57 mill EUR at 100%-ZEB, which is only 3% lower compared to the 0%-ZEB case.

Table 1
Indicators chosen to evaluate the building's grid interaction.

Grid Indicator	Description	Formula	
Self-consumption	Share of on-site electricity generation used by the building. First introduced by [12]. (Also called "supply cover factor")	$\gamma_S = \dfrac{\sum_{t \in T} \left(y_t^{PVselfc} + y_t^{CHPselfc} \right)}{\sum_{t \in T} \left(y_t^{PVexp} + y_t^{CHPexp} \right)}$	(31)
Annual Export	Yearly electricity exported.	$EX = \sum_{t \in T} \left(y_t^{PVexp} + y_t^{CHPexp} \right)$	(32)
Net electricity load	Annual duration curves of hourly net electricity import (+ import, − export). (This is the opposite of the definition in [11] which defines duration curves for net electricity export (- import, + export), however as buildings normally pose a load on the grid, import is given a positive sign.)	$ne_t = \left(y_{t,p}^{impD} + y_{t,p}^{impHP} \right) - \left(y_t^{PVexp} + y_t^{CHPexp} \right)$	(33)
GM factor	Generation Multiple relates the maximum export value to the maximum import value of electricity.	$GM = \dfrac{\max_{t \in T, p \in P} \left\{ y_{t,p}^{PVexp} + y_{t,p}^{CHPexp} \right\}}{\max_{t \in T, p \in P} \left\{ y_{t,p}^{impD} + y_{t,p}^{impHP} \right\}}$	(34)
GM_{ref} factor	GM_{ref} relates the maximum export value to the maximum import value of electricity in a reference case.	$GM_{ref} = \dfrac{\max_{t \in T, p \in P} \left\{ y_{t,p}^{PVexp} + y_{t,p}^{CHPexp} \right\}}{\left(\max_{t \in T, p \in P} \left\{ y_{t,p}^{impD} + y_{t,p}^{impHP} \right\} \right)_{ref}}$	(35)

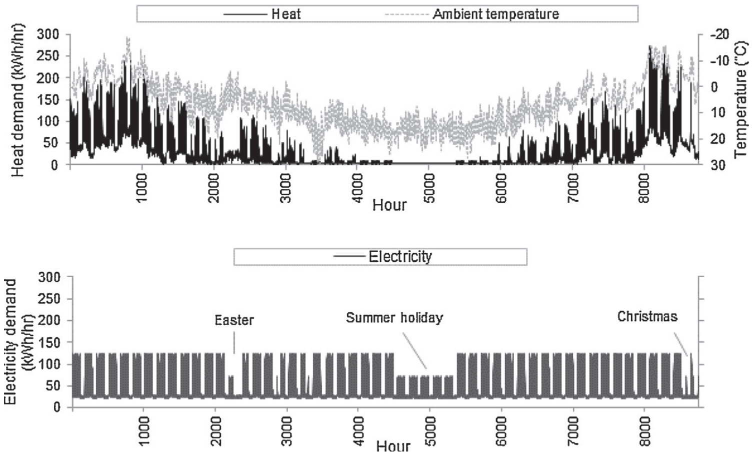

Fig. 4. Hourly heat (upper) and electricity (lower) demand for a passive school building situated in southern Norway.

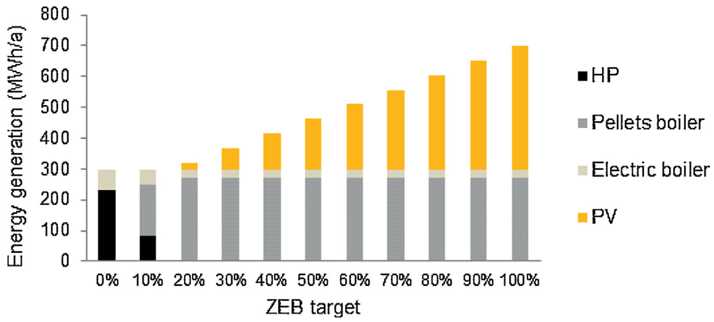

Fig. 5. Relaxation of the zero emission constraint. Impact on annual heat and electricity generation (MWh/yr) within the building, by technology.

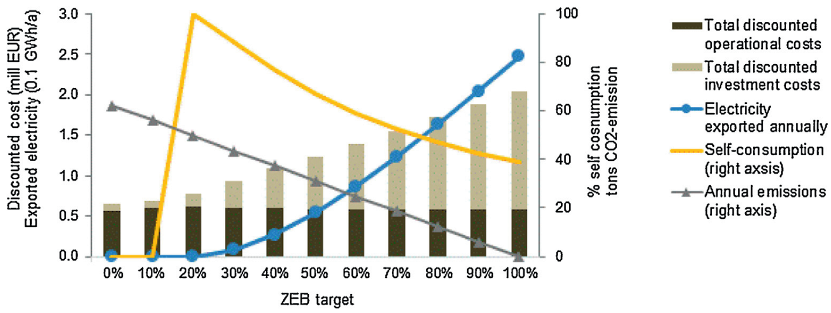

Fig. 6. Relaxation of the zero emission constraint. Impact on total discounted investment and operational costs (1000 EUR), annual electricity exported (100 kWh/yr) and self-consumption rate (%).

The self-consumption rate is the amount of on-site PV generation that is consumed within the building calculated on an hourly level (see definition in Eq. (31)). When there is no PV present, the self-consumption is not defined and is seen as 0% in the graph. As the PV is introduced at 20%-ZEB, the amount of PV is so small that almost all the generation is consumed within the building and the self-consumption is 100%. As the ZEB target becomes more ambitious, the PV installation increases, and the generation thus becomes larger than the building's electricity consumption in the hours when there is sunshine. Consequently, the self-consumption decreases to 40% in the 100%-ZEB case.

Fig. 6 underlines the challenges of ZEBs because as the stronger the target is, the more PV needs to be installed, but the less of the actual on-site generated electricity can be self-consumed. Consequently, the building imports electricity in winter, and exports electricity in summer, using the electricity grid as a virtual seasonal storage. This is emphasized in Fig. 7 which shows that the 100%-ZEB building is exporting electricity in 26% of the hours, and

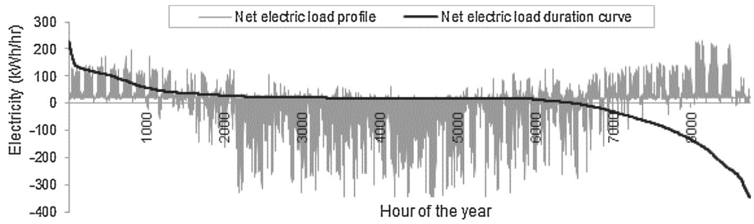

Fig. 7. Hourly net electricity load profile and the sorted load duration curve for the strictly ZEB (100%).

the peak export value at 345 kW is higher than the peak import value at 229 kW, leading to a GM-value of 1,5.

Summed up, the modelling framework can be used for evaluating at which level it is reasonable to set the ZEB-target. Should it be at 20%, when self-consumption is at its highest, or at 50% when both emissions and electricity exports are within reasonable values, or will the grid handle everything and the cost of PVs drop further so that the 100% target will be applicable?

5. Discussion of the modelling framework

The time resolution of the presented work is on hourly level. To capture all variations of load and generation, especially from PV, the time resolution would benefit from being closer to 15 or even 1 min. This can be seen in for example de Baetens et al. [12], who use a 1-min time resolution to investigate the impact on grid-feeder level of the operation of a ZEB, but where investment decisions are taken as input. Salom et al. [11] investigate measurements of three ZEBs, showing that using sub-hourly data is preferred to hourly data when evaluating grid impact of a household, as the stochasticity of the load leads to high fluctuation for the imported electricity values which is not captured in the hourly data. However, on a building or cluster level, hourly values are adequate to make reliable conclusions on the correlation between import and export of electricity [10]. This assumption is also confirmed by [43] where a smoothening effect on the short-term variability of PV power output was identified at an aggregated level.

In the present work, when investigating investment decisions in ZEBs, a more detailed time resolution of 15 min would increase the number of binary variables from 8760 to 35 040 multiplied by the number of available technologies within the model. Thus, it seems adequate to make the investment decision based on an hourly time resolution, however when investigating the real operation of one single building, sub-hourly values would be preferred.

As temperatures of the heat distribution within the building is not considered in the modelling framework, the feedback of the ST and heat pumps on the heat storage are not considered explicitly. In previous studies of energy investment analysis, the energy storage is often also treated as a single node, see e.g. Refs. [25,44] or [45]. This formulation may however lead to too efficient components in some hours, thus slightly too optimistic, or small, sizes of the considered technologies. A dynamic simulation of operation of a building would definitely need temperatures, but again, as the focus of this work is on the investment decision, it is considered adequate to treat the heat as energy flows and the heat storage tank as a single node.

6. Summary and conclusions

The introduction of the concept nearly ZEB buildings has changed the view on buildings from being passive receivers of power, i.e. consumers, towards becoming active players in the electricity system by both consuming and producing electricity, i.e. prosumers. This development has opened new perceptions on building's energy systems e.g. for combining heat and electricity systems such as PV coupled with heat pumps in a thermal-electric system. When the operation of such buildings is evaluated, the investment decision considering dimensioning and choice of energy technologies should be optimised accordingly. This part has received little attention over the past years.

This paper presents a modelling framework for assessing the cost optimal dimensioning of the energy technology system for a zero energy, or zero emission, building (ZEB) from the building owner's perspective. The framework builds on the definition in the EPBD, and can study any country's specific ZEB definition by adapting e.g. the weighting factors, the ZEB level, and/or the energy market conditions such as feed-in tariffs, investment subsidies, peak load tariffs or other grid tariffs.

The model structure captures the whole lifetime of the building, and is able to take into account altered conditions in future by dividing the lifetime into periods. This is important especially for the weighting factor for electricity (with more renewable energy in the electricity production mix), and for future energy market conditions (such as feed-in-tariffs for PV electricity). The interaction between the different components of the building is optimised each hour throughout a representative year within each period, and the primary energy consumption and carbon emissions throughout the lifetime of the building is calculated.

With semi-continuous variables on investment decisions and hourly operation of the heat technologies, the linear optimisation formulation is able to reflect the dynamics of the building's energy system in a sufficient way. The heat storage is modelled as a single node, thus treated as an energy bucket where heat may be stored or taken out. The hourly loads of heat and electricity are treated as given input. Heat demand includes demand for space heating (both radiators or floor heating system and ventilation heat) and hot tap water, including distribution losses. Electricity demand includes electricity for covering e.g. lighting and electric appliances. This means that the building design, including U-values and dimensioning of ventilation ducts, are treated as given.

The strength of this model is the combined optimisation of investments and operation costs, together with a high level of detail for the component models compared to general energy system models like TIMES, MARKAL and Balmorel. Because of the hourly time resolution, results of electricity import and export from the building are given as hourly time series, which enables investigation of the buildings grid impact. Hourly optimal operation of both heat and electricity system within the building, and the resulting net electricity load profile, will be analysed in detail in coming papers.

The influence of altered weighting factors (carbon emissions, and primary energy indicators), and policy incentives will be investigated in coming papers. For example, how the combination of a ZEB target and a feed-in tariff for PV electricity may lead to unintended outcomes. Thus, the modelling framework facilitates a holistic approach, which enables us to analyse how policies, technology data, ZEB targets and weighting factors affect the energy system design within ZEBs, and consequently their impact on the electricity grid.

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Cost-optimal energy system design in Zero Energy Buildings with resulting grid impact: A case study of a German multi-family house

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ABSTRACT

Zero Energy Buildings (ZEBs) are considered as one of the key elements to meet the Energy Strategy of the European Union. This paper investigates cost-optimal solutions for the energy system design in a ZEB and the subsequent grid impact. We use a Mixed Integer Linear (MILP) optimisation model that simultaneously optimises the building's energy system design and the hourly operation. As a ZEB have onsite energy generation to compensate for the energy consumption, it is both importing and exporting electricity. The hourly time resolution identifies the factors that influence this import/export situation, also known as the building's grid impact. An extensive case study of a multi-family house in Germany is performed. The findings show that the energy system design and the grid impact greatly depend on the ZEB definition, the existing policy instruments and on the current energy market conditions. The results indicate that due to the feed-in-tariff for PV, the cost-optimal energy design is fossil fuelled CHP combined with a large PV capacity, which causes large grid impacts. Further, we find that heat pumps are not a cost-optimal choice, even with lower electricity prices or with increased renewables in the electric power system.

1. Introduction

In the European Union, buildings are responsible for nearly 40% of final energy consumption and 36% of the greenhouse gas emissions [1]. The emissions reflect both *direct emissions,* from the use of gas or oil for heating purposes, and *indirect emissions* through the use of electricity and district heat. The concept of Zero Energy Buildings (ZEB) was introduced in the recast of the Energy Performance of Building's Directive (EPBD) in 2010, to make the buildings a part of the solution to combat GHG emissions and increase security of supply, by incentivising local energy production as well as energy efficiency.

A'nearly ZEB' is an energy efficient building with low energy demand that to a high extent is covered by on-site generated renewable energy [1]. Because ZEBs need on-site energy generation in order to compensate for their energy use, they will inevitably become an active and integrated part of the energy system. This paper, aims to identify which factors that determines the grid impact of ZEB buildings, i.e. how they interact with the electricity grid.

1.1. Definition of ZEB buildings

According to the EPBD each member state must develop a definition of the 'nearly zero energy building', including a ZEB methodology, and how 'near' zero the ZEB target should be. Even though the definition can be set individually, the framework of how to calculate the energy balance is given by the EPBD [2] as follows (see Eq. (1)): the weighted annual energy imports to the building,

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subtracted the annual weighted energy exports from the building, summed over all energy carriers, *i*. The weighting is done by use of weighting factors *f*, which are unique for each energy carrier. Using primary energy factors, lead to a Zero *Energy* Building (ZEB), whereas using CO_2 factors lead to a Zero *Emission* Building or Zero *Carbon* Building (ZCB). However, in the following, whenever using ZEB, it embraces both ZEB and ZCB.

$$\sum_i f_i \times \text{imported}_i - \sum_i f_i \times \text{exported}_i = G \quad (1)$$

When the balance is strictly zero ($G = 0$), the building is a 'strictly' ZEB. To fulfil the target of a strictly ZEB can be challenging as the weighted on-site energy generation must equalize the weighted energy consumption of the building.[1] The target is fulfilled by reducing the consumption through energy efficiency measures, and/or applying on-site electricity generation [3]. However, it is also possible to relax the strictly zero target by letting $G > 0$, heading for a 'nearly' ZEB. Thus, maybe the most important element of the ZEB definition is determining the level of ZEB.

Another element of the ZEB definition is what energy consumption to include in the energy balance. For example, some claim that energy used for elevators or equipment, such as computers or IT-servers, are dependent on the user and should not be a part of the energy balance of the building [4]. While others claim that not only all the energy consumed by the building, but also embodied energy of the materials and construction of the building should be included [5].

Summed up, the definition of ZEB that each member state is free to decide, has the following elements:

- the *metric* of the weighting factor (primary energy or CO_2)
- the *value* of the weighting factors (see examples in Table 4)
- the *level* of ZEB ('strictly' or 'nearly' ZEB)
- what *energy consumption* is included (partly operational, all operational, or all operational & embodied)

Previous work in Lindberg et al. [6] show that when applying the ZEB target on a Norwegian building it mainly affects the energy imports for heat because the electric specific demand of the building (i.e. electric equipment and lighting), cannot be replaced by other energy carriers than electricity. This is confirmed in Noris et al. [7] which shows that the weighting factors influence the preferred heat technology choice. In many European countries, bio energy has the lowest weighting factor because of its renewable status, thus making a bio boiler the preferred heat technology choice [7]. As an example, when using the European primary energy factors [2], the weighted energy imports for heating is reduced by a ratio[2] of 13 if using a bio boiler rather than a heat pump.

1.2. ZEB's grid impact

The on-site energy generation in ZEBs often tend to be large PV installations, which is confirmed by several case studies in e.g. [7–12], even though the technology choices may also comprise solar thermal (ST) modules, micro-wind turbines or micro-CHPs. However, building integrated micro wind turbines have challenges with noise and vibrations [13], and a ZEB with CHP still needs to compensate for the gas imports. Solar thermal can provide heat in summer time, but cannot contribute to the energy exports from the building unless it is attached to a district heating grid.

One of the challenges of ZEBs in northern European countries is that heat demand occurs in winter when PV generation is low, thereby making the building importing energy in winter both for heat and electricity demand. To fulfil the zero energy balance of the ZEB building, the electric power system must serve as a seasonal storage that is 'charged' in summer and 'depleted' in winter. This is also known as the seasonal 'mismatch' problem [14]. As electricity needs to be consumed the instance it is produced, there has to be enough electricity demand in the rest of the power system, which can utilize the exported electricity from ZEBs in summer. Likewise, the power system must be able to provide the ZEB buildings with electricity in winter.

Hourly or instantaneous 'mismatch' is another challenge of the ZEBs. Due to the often large PV installations of ZEB buildings, grid challenges, such as over-voltages, may occur in summer when many ZEBs are located within a geographically small area [15]. To ease the mismatch problems of the individual ZEB buildings, research on local energy systems for small areas are emerging (see e.g. [16–18]). The idea is to exploit the characteristics of different energy sources and technologies, e.g. PVs, micro-CHPs and micro-wind, with the different energy demand profiles, e.g. service buildings and residential buildings, and additionally applying smart control on top of it all. Having a local energy system perspective rather than a building perspective [17], showed that the seasonal mismatch problems of the local area can be reduced, even though the mismatch problems of the buildings are unchanged.

As the focus in this paper is on a building level, the identified grid challenges of ZEBs are attached to both the seasonal and hourly mismatch problems. It is of vital importance to communicate where policy makers can contribute to ease the grid challenges, but still being able to fulfil the ZEB target given by the EPBD. This paper identifies how the definition of ZEBs and the current energy market conditions and taxes impact the grid challenges of ZEBs. In the literature, the grid challenges are analysed by using several grid indicators (see Salom et al. [8] for a thorough explanation). In this paper, we focus on the graphical presentation of the *net electricity load profiles*, as they show the building's maximum import and export values and annual electricity exports in an informative way. The self-consumption rate and additional grid connection capacity (GM values) are also presented.

1.3. The aim of this study

The aim of this study is to identify the most important factors that affect the ZEB's grid impact. A case study of a German multi-family house (MFH) is performed, where several input parameters are varied, regarding both energy market conditions and the definition of ZEB. We use a mixed-integer optimisation model, which is introduced and described in Lindberg et al. [6], hence only a brief introduction of the model concept is given in this paper. To the authors' knowledge, only Milan et al. [9] presents a similar model on a building scale. The model introduced in Lindberg et al. improves Milan's model in two ways; (1) by applying binary variables on the investment decision and hourly heat generation, making it a mixed-integer linear optimization problem (MILP), and (2) expanding the implemented number of energy technologies, including the sizing of the heat storage. Ten different energy technologies are implemented, and the model finds the optimal mix and size that minimises total discounted costs over the lifetime of the building. Through the model's hourly time-resolution, the cost-optimal hourly operation is also undertaken, enabling investigation of the hourly electricity import and export from the building.

[1] It can be shown that calculating the balance by weighted energy consumed and generated rather than weighted imported and exported from the building, gives the same answer for the energy balance, *G*.

[2] With values from Table 2 and Table 4: (heat from HP)/(heat from BB) = $(PE_{electricity}/COP_{HP})/(PE_{bio}/\eta_{BB})$ = 12,6.

Based on the case study, we show that the most important factors that influence the building's net electric load profile are: (1) how 'near' zero the ZEB target is, and (2) the choice of heat technology, which is influenced by the value of the weighting factors, technology costs, energy prices, and policy instruments (investment support schemes, feed-in-tariffs, taxes).

1.4. Paper structure

Section 2 introduces the case study and presents the cost-optimisation model and input parameters. Section 3 shows the results of the German MFH while applying a 'nearly' ZEB target, a 'strictly' ZEB target, and for comparison, a case without any ZEB target. In Section 4, sensitivity analyses are performed, investigating how future market conditions may influence the energy system design and the grid impact. Section 5 provides general discussion of selected results, before making final conclusions in Section 6.

2. Case study: Multi-family house

A case study of a simulated multi-family-house (MFH) located within the area of Berlin in Germany is performed. The building is a representative new MFH according to German statistics and is assumed to have 10 apartments and a total heated area of 1000 m^2. The architectural design and building physics are treated as given, and fulfils the passive standard. The energy technologies implemented in the model are chosen according to the available energy carriers in the region. The total system scheme, including the implemented energy technologies, is shown in Fig. 1.

The ZEB target is in this case study defined to include operational energy consumption, i.e. embodied energy is not taken into account. Even though the target is set on an annual basis, the energy consumed and generated are calculated each hour, making the building importing electricity in some hours, and exporting electricity in other hours.

The inputs to the model described in Section 2.2 are fitted to the climatic conditions and energy market conditions for the region of Berlin. This especially affects the heat demand of the building, the hourly COP of the heat pumps, the energy generation from ST and PV panels, and the feed-in-tariffs of electricity from PV and CHP. The lifetime of the building is set to 40 years, and the calculations are done with a discount rate of 4%.

2.1. Cost optimisation model

This section briefly describes the cost optimisation model which is implemented in MOSEL Xpress [19]. For an in-depth description, see Lindberg et al. [6].

Fig. 2 illustrates the basic idea of the model, where total costs are minimised, based on inputs of technology costs, prices and the building's energy demand. Hence, the optimal investments and operation of the building are decided simultaneously. The main outputs are capacity sizes of the chosen energy technologies, together with their hourly fuel consumption. Accordingly, the building's hourly net electric load profile is found, which forms the basis for analysing the grid impact.

The objective function π represents the net present value of the total costs of the energy system within the building, which depends on the installed capacity, x, of each energy technology i. The discounted investment costs, C^{inv}, consist of reinvestments throughout the entire lifetime of the building, N, minus its salvage value at the end of the lifetime. C^{run} is the sum of fixed maintenance costs and variable fuel costs. The discounted net present value of the total operational costs equals the annual operational costs multiplied by the net present factor, ρ. The annual fuel costs are calculated each hour throughout one representative year within

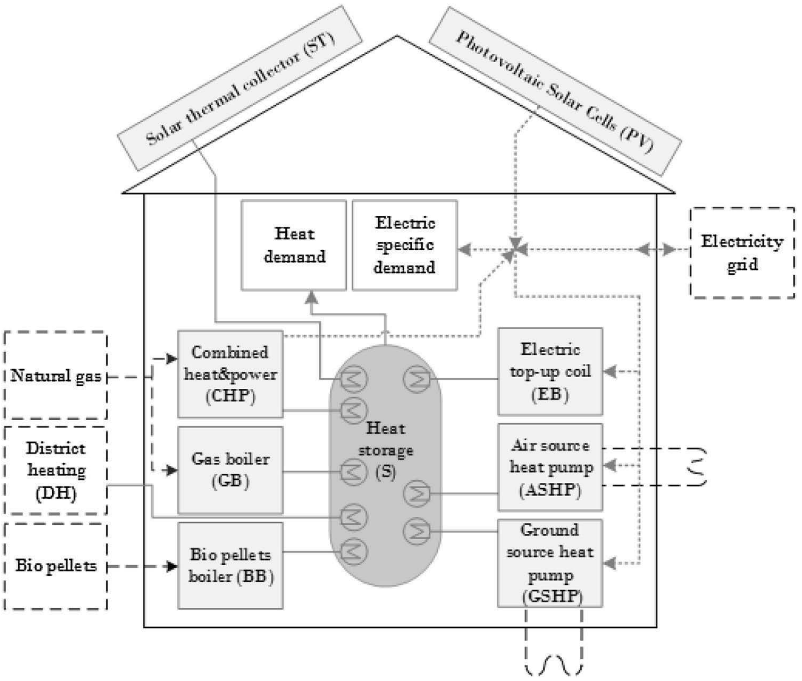


Fig. 1. System scheme and energy flows of the building.

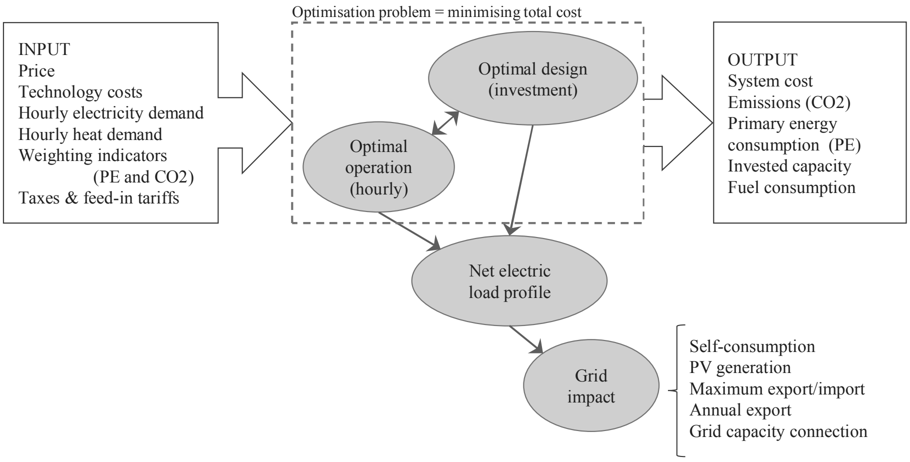


Fig. 2. Model description with main inputs and outputs. Grid impacts are consequences of the optimal design and operation.

each period. The building's energy system must fulfil equality h(x), and inequality g(x), constraints dependent on the installed capacity for all the energy technologies, forming the vector x.

$$\begin{aligned} \min\pi &= \sum_{i \in I} C_i^{\text{inv}}(x_i) + \rho \times C_i^{\text{run}}(x_i), \\ s.t.\ & \boldsymbol{h}(\boldsymbol{x}) = 0 \\ & \mathbf{g}(\boldsymbol{x}) \le 0 \end{aligned} \tag{2}$$

$$\text{where, } \rho = \sum_{\tau=1}^{N} \frac{1}{(1+r)^{\tau-1}}$$

The electricity balances of the building, given in Eq. (3)–(6), are influenced by the special electricity tariffs in Germany (see Section 2.3.2). As described graphically in Fig. 3, the tariff structure makes it necessary to keep the flows of self-consumed electricity $\left(y_{i,t}^{\text{selfcD}},\ y_{i,t}^{\text{selfcHP}}\right)$, exported electricity $\left(y_{i,t}^{\text{exp}}\right)$ and imported electricity $\left(y_{i,t}^{\text{impD}},\ y_{i,t}^{\text{impHP}}\right)$ separate. Notice that the building's electricity consumption includes both the electric specific demand of the building, D_t^{el}, and the electricity consumed by the electric boiler, $d_{\text{EB},t}$, and the heat pumps, $d_{\text{ASHP},t}$, $d_{\text{GSHP},t}$.

$$\text{Building :} \quad D_t^{\text{el}} + d_{\text{EB},t} = y_{\text{PV},t}^{\text{selfcD}} + y_{\text{CHP},t}^{\text{selfcD}} + y_t^{\text{impD}} \quad \forall t \tag{3}$$

$$\text{Heatpump:} \quad d_{\text{ASHP},t} + d_{\text{GSHP},t} = y_{\text{PV},t}^{\text{selfcHP}} + y_t^{\text{impHP}} \quad \forall t \tag{4}$$

$$\text{PV :} \quad y_{\text{PV},t} = y_{\text{PV},t}^{\text{exp}} + \left(y_{\text{PV},t}^{\text{selfcD}} + y_{\text{PV},t}^{\text{selfcHP}}\right) \quad \forall t \tag{5}$$

$$\text{CHP :} \quad y_{\text{CHP},t} = y_{\text{CHP},t}^{\text{exp}} + y_{\text{CHP},t}^{\text{selfcD}} \quad \forall t \tag{6}$$

The net electric load profile of the building, ne_t, is equal to the electricity imported subtracted the electricity exported from the building to the grid, as presented in Eq. (7), and illustrated in Fig. 3.

$$\begin{aligned} \text{ne}_t &= \text{electricity import }(t) - \text{electricity export }(t) \\ &= \left(y_t^{\text{impD}} + y_t^{\text{impHP}}\right) - \left(y_t^{\text{PVexp}} + y_t^{\text{CHPexp}}\right) \end{aligned} \tag{7}$$

2.2. Input parameters of the energy technology models

This section presents the input parameters of the energy technologies, and for determining the load profiles of heat and electricity demand.

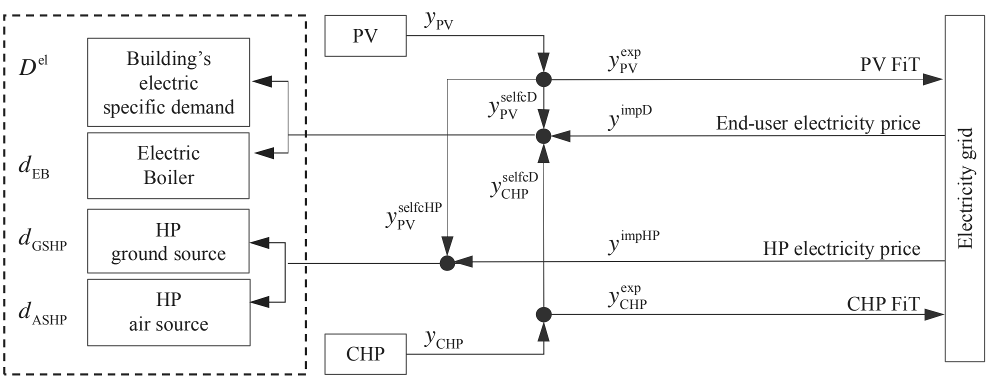


Fig. 3. Detailed graphical explanation of the electricity flows in Fig. 1, together with their electricity price or export value.

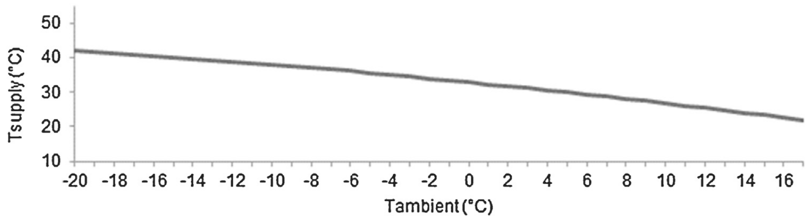


Fig. 4. Heating curve. Supply temperature for space heating vs. outdoor temperature.

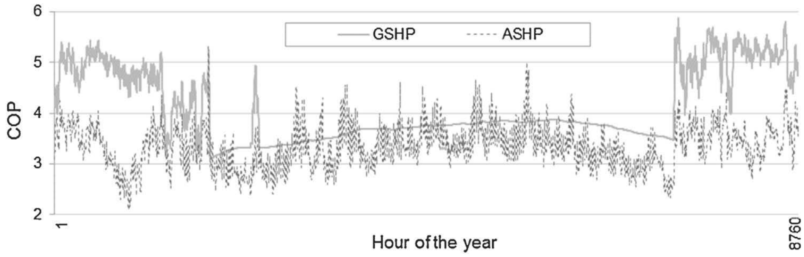


Fig. 5. Hourly COP of ground source heat pump (GSHP) and air source heat pump (ASHP) with climatic data for Berlin, Germany in 2012.

2.2.1. Building's energy demand

Hourly energy loads are constructed using SynPro, a bottom-up model where stochastic behaviour of the occupants is linked to the stock of electric appliances [20]. First the electricity load and domestic hot water load (DHW) is determined based on stochastic behaviour of the residents sampled from the German time-of-use-survey [21], and secondly, the electricity load is set as internal gains when determining the space heat demand calculated for climatic conditions of Potsdam for 2012 [22]. The U-values of the building envelope are set according to the German passive building standard. The resulting annual heat demand (sum of space heating and DHW) and electric specific demand are respectively 28 MWh/yr and 33 MWh/yr. The maximum hourly peak demand is 23 kW and 13 kW, for heat and electricity respectively.

2.2.2. Hourly COP for air source and ground source heat pumps

The heat pump models for air source heat pump (ASHP) and ground source heat pump (GSHP) take the supply temperature into account. The heating curve used to determine the supply temperature for space heating is shown in Fig. 4, and the average supply temperature of the DHW is assumed to be 55 °C. Together with the COP models presented in [6], and the heat demand determined in Section 2.2.1, the hourly COPs for 2012 for Potsdam are found (see Fig. 5).

2.2.3. Investment cost of heat storage

The heat storage is formulated as a single node, serving both DHW and SH demand. As the cost of the accumulator tank is determined by the volume, given in EUR/liter, the temperatures in the storage is needed to obtain the cost per heat capacity in EUR/kWh. The conversion factor ε is found by multiplying the ΔT of the storage tank by the specific volume, ν, density ρ_{water}, and heat capacity Cp, of water as shown in Eq. (8).

$$\varepsilon = \nu \times \rho_{\text{water}} \times \text{Cp} \times \Delta T \qquad [\text{kWh/ltr}] \tag{8}$$

Hedegaard and Balyk [23], uses a ΔT of 15 °C, and argues that this does not reflect the real ΔT of the storage, but rather how much energy that is available for being utilised by the model. In this case study, we assume the ΔT to be 30 °C, reflecting an average maximum temperature of 60 °C, and an average minimum temperature of 30 °C.

2.2.4. Solar thermal efficiency

The model of the solar thermal collector (ST) presented in [6], takes the temperature of the water from the collector, $T^{\text{collector}}$, into account. The ST heat is often supplied to the bottom of the

Table 1
Specific investment costs (EUR/kW), annual operation and maintenance cost (%) and fixed investment costs (EUR) for technology sizes of 5–10 kW.

	Specific investment cost		Fixed annual O&M costs	Fixed investment cost		Reference
	EUR/kW$_{th}$	Description	(% of inv.costs)	EUR	Description	
PV	1800	Module cost (per kWp)	1.0%	1000	Mounting and installation	[24]
ST—Solar thermal collector	570	Module cost (per m^2)	1.0%	4000	Mounting and installation	[25]
GSHP—Heat pump (liq-water)	770	Unit cost	2.0%	17000	Drilling of well, installation and engineering costs	[25]
ASHP—Heat pump (air-water)	1 150	Unit cost	2.0%	3000	Mounting and installation	[25,26]
BB—Bio pellets boiler	610	Unit cost	3.0%	4000	Storage/Silo with automatic feeder	[25]
EB—Electric top-up coil	60	Unit cost	2.0%			[25]
DH—District heating	80	Grid connection	0%	4000	Connection to district heating grid	[25,26]
GB—Gas boiler	600	Unit cost	1.5%	1600	Connection to gas grid	[26]
CHP—Combined Heat & Power	3 400	Unit cost (per kW$_{el}$)	3.0%	1600	Connection to gas grid (not active if GB already invested)	[25,26]
AT—Hot water storage	90	Unit cost (per kWh)	0%			[25]

Table 2
Technology efficiencies.

	Efficiency [–]	Comment	Reference
ASHP—Heat pump (air-water)	3.28	Simulated SCOP	
GSHP—Heat pump (liq-water)	4.45	Simulated SCOP	
BB—Bio pellets boiler	0.90		[27]
EB—Electric top-up	0.98		[28]
DH—District heating	0.98		
GB—Gas boiler	0.96		[29]
CHP—Electric Efficiency	0.33		[29,30]
CHP—Heat Efficiency	0.52		[29]
AT—Hot water storage	0.99		

storage tank, and thus the collector temperature is assumed equal to the lower temperature of the storage, 30 °C. In real life, dependent on the control of the system, the temperature from the ST will vary every hour and might reach up to 90 °C in summer. However, a higher value of $T^{collector}$ decreases module efficiency, and the assumption of 30 °C gives an optimistic value for the efficiency of the ST collector. When investigating the results in Section 3, ST is not found as an economic optimal technology choice, even with the higher efficiency, indicating that the 30 °C collector temperature is not a limiting factor of the model.

2.2.5. Available roof and façade area

The findings of the case studies in Noris et al. [7] show that the available façade and roof area for installation of ST or PV might be a limiting factor in order to reach the ZEB balance. However, as the main intention of this paper is to analyse the ZEBs if everything is possible, it is decided to let the available façade and roof area be without limitations.

2.3. Technology costs and energy prices

This section presents the costs and efficiencies of the energy technologies implemented. The energy market conditions for Germany is presented through fuel prices, and special electricity tariffs.

2.3.1. Technology costs and efficiencies

A newly built house needs to install energy technologies at the time of construction which fits to its demand. As the specific technology costs (EUR/kW) are assumed constant, they must be collected for the appropriate size of the building in question [6]. In this paper, investment costs are collected for heat technology sizes of 5–10 kW to fit the heat demand found in Section 2.2.1. Table 1 shows the details of the collected technology cost data. The minimum capacity of the boilers, if invested, is set to 5 kW_{th}, which equals 3.2 kW_{el} for the CHP.

The efficiencies of the energy technologies are given in Table 2, where the calculated seasonal average COP is based on the hourly COP in Fig. 5. The CHP has a constant relationship between the electricity and heat efficiency, so if 1 kWh heat is needed, the unit simultaneously generates 0.63 kWh electricity. The last row of the table shows the hour-by-hour dispersion factor of the heat storage which is not the same as the seasonal average efficiency of the storage.

2.3.2. Electricity tariffs

In Germany, the feed-in tariff (FiT) for roof mounted PV up to 500 kW is about 11 ct/kWh [31], and the FiT for highly energy efficient CHPs, regardless of fuel, is 5.4 ct/kWh [32]. Currently, the FiT for PV is being replaced by a market premium model, depending on the actual price of electricity in the EEX-market each hour instead of a fixed feed-in. Even though the income varies from hour to hour, the overall income for the building owner should be more or less unchanged [33]. Therefore, for simplicity reasons, the selling price of PV electricity, is set equal to the FiTPV which is constant for all hours. Due to the current resistance to the EEG-tax in Germany, on-site electricity generation directly self-consumed by the building must pay 30% of the EEG-tax, which equals 1.85 ct/kWh [33].

2.3.3. Fuel prices

Representative fuel prices are based on current offered contracts in Germany. The contracts for fuels attached to a distribution grid have a fixed annual charge and a specific energy charge, as shown in Table 3. Notice that the price for electricity used for heat pumps is 5 ct/kWh lower compared to the general electricity price [34].

2.4. Weighting factors – PE and CO_2

Table 4 shows weighting factors used for calculating the ZEB balance. The CO_2 factors are according to IEA [39], and primary energy factors are according to the EPBD. The *non-renewable* primary energy factors (PEnr) reflect the amount of non-renewable energy required to attain 1 kWh of the respective energy carrier, whereas the *total* primary energy factors (PEtot) reflect the total use of energy, both renewable, fossil and nuclear, per kWh. Comparing PEnr and PEtot, the major difference occur for bioenergy which increases by 1. Another alternative of the PE factor is to apply asymmetric factors to electricity, which value exported electricity less than imported electricity, in order to increase the incentive for self-consuming on-site generated electricity.

3. Results

In the Introduction, four elements of the ZEB definition was identified. As it is already defined that all consumed energy is included in the ZEB balance, the first three of these four elements are investigated in the following; i.e. (1) the metric of the weighting factors, (2) the value of the weighting factors, and (3) the level of ZEB. The first sub-section investigates the impact on the energy system design of the building, and the second sub-section analyses the corresponding grid impact.

3.1. Energy system design

3.1.1. Baseline – no ZEB target

For comparison, we first investigate which solution people would choose if only minimising costs without posing the ZEB restriction. Fig. 6 shows that the most economic way to serve the passive building with energy, is to install a micro CHP unit of 3.5 kW_{el} which provides both heat and electricity. To cover peak heat demand, a gas boiler, an electric top-up coil and a heat storage are installed. In addition, it is profitable to invest in 14 kWp of PV, both because of the FiTPV of 11 ct/kWh, and the saved costs of imported electricity due to self-consumed PV. Since the roof area of the building is not restricted, this is an inner optimum. Even without the FiTPV, it is profitable to invest in 7 kWp PV. This supports the claim that PVs have reached grid-parity in Germany.

3.1.2. 'Strictly' ZEB

When the building is to be strictly ZEB, all energy consumed by the building has to be compensated by on-site energy generation. Fig. 6 shows the investment decision when using the CO_2 factors given in Table 4. CHP is still the most economic way of serving the building with heat and electricity, despite its high investment

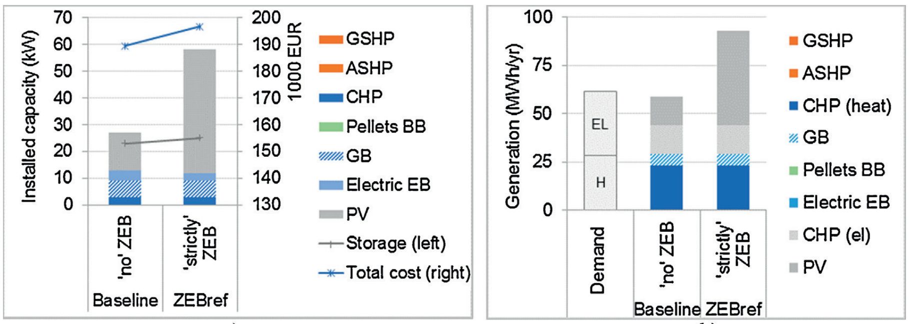
[5] European Energy Exchange AG, www.eex.com/en/

Table 3
Fuel prices for end-users. Energy prices [EURcent/kWh] and fixed annual grid charges [EUR/yr].

Energy carrier	Category	Energy price cent/kWh	Fixed annual charge EUR/yr	Reference
Bio pellets		6.0		[35]
GAS	Gas distribution grid	5.5	170	[36]
DH	District heating grid	7.2	327	[37]
EL	Import price from electricity grid	24.1	140	[34,38]
EL	Import price HP electricity	19.0		[34]
EL	Export price PV electricity (FiTPV)	10.8		[31,34]
EL	Export price CHP electricity (FiTCHP)	5.4		[32,34]
EL	Self-consumption (30% of EEG-tax)	1.9		[33]

Table 4
Weighting factors (Primary Energy [2], and CO_2 [39]).

	CO2	Primary Energy Factor (PE)			
		Non-renewable PE		Total PE	
	$g_{CO2\text{-}eq.}$/kWh	PEnr-sym $kWh_{PEn.r.}$/kWh	*PEnr-asym* $kWh_{PEn.r.}/kWh$	PEtot-sym kWh_{PEtot}/kWh	*PEtot-asym* kWh_{PEtot}/kWh
Power grid, import	350	2.3	2.3	2.5	2.5
Power grid, export	350	2.3	2.0	2.5	2.0
Wood, pellets	14	0.05	0.05	1.05	1.05
District heat	270[5]	1.3	1.3	1.3	1.3
Natural gas	210	1.05	1.05	1.05	1.05



a) b)

Fig. 6. Installed capacity (kW) (a) and annual energy generation (MWh/yr) (b) of a 'strictly' ZEB compared to a Baseline case without any ZEB target.

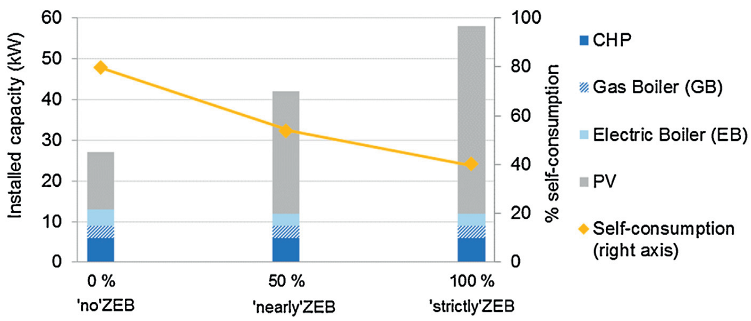


Fig. 7. Installed capacity (kW) of a 'nearly' ZEB case. Relaxing the ZEB constraint.

cost. There are two reasons for this. First, the alternative cost of electricity for the building owner at 24 ct/kWh, is far above the gas price at 5.5 ct/kWh. As the CHP unit generates both 0.55 units of heat and 0.33 units of electricity from the same gas unit, the self-generated electricity from the CHP is highly valued. Secondly, the feed-in tariff for PV compensates for much of the investment cost of the PV, and thus, reaching the annual net zero balance is met by adding more PV as it constitutes little additional cost for the building owner. This is confirmed in Fig. 6a where the total cost of the 'strictly' ZEB only increases by 2–4% compared to *Baseline*. This means that it is profitable to invest in more PV (46 kWp) to compensate for the weighted energy imports from using natural gas, rather than reducing the weighted imports to the heat generation itself.

The annual energy generated from each of the technologies is shown in Fig. 6b, where the CHP unit provides 79% of the heat demand and the gas boiler 20%. The electric top-up coil only contributes with 1% to cover peak heat demand and is hardly visible in the graph. The installed capacity of the PV is 46 kWp for *'strictly'ZEB* case which equals an area of approximately 250 m^2 if using a conversion factor of 5.3 m^2/kWp.[3] Compared to the size of the multi-family house of 1000 m^2, this could be physically possible with an adapted architectural design.

If using the primary energy factors given in Table 4, instead of the CO_2 weighting factors, the energy system design remains the same. The only difference when changing the weighting factors is the PV size, which is determined by the relationship between the weighting factor of electricity export and natural gas import, given in Table 8. Readers who are interested in the details of these findings, please see Appendix. Hence, we can conclude that whether the ZEB is a Zero Emission or a Zero Energy Building does not impact the heat technology choice.

When the FiTPV is applied together with the ZEB target, it makes the fossil based heat technology choice remain unchanged. Due to the FiTPV the ZEB target is met by adding more PV to the building, rather than reducing the weighted energy imports for heating purposes, by switching to renewable heating, and this is done without increasing the cost for the building owner significantly.

3.1.3. 'Nearly' ZEB

The ambition level of the ZEB reflects how 'near' to zero the ZEB target is set. Fig. 7 shows the investment results of a 50% nearly ZEB target when using CO_2 factors. Compared to *Baseline*, the only difference is found in the size of the PV which is doubled from 14 to 30 kWp. Notice also that the self-consumption starts at 80% in *Baseline* and decreases towards 40% in the *'strictly'ZEB* case. This logically reflects that the more PV that is installed, the smaller amount of the generated PV electricity the building is able to consume itself.

As a conclusion, when relaxing the ZEB target aiming at a 'nearly' ZEB, the size of the weighted energy imports remains unchanged, meaning that the building is still very energy efficient. However, a 'nearly' ZEB will claim a smaller amount of weighted energy exports, leading to a smaller PV size, which is important for the grid impact (see Section 4.2).

3.2. Grid impact

The hourly operation of the building is necessary for understanding its net electric load profile. This section first investigates the hourly optimal operation of the energy system of the *'strictly'ZEB*, which lies the basis for understanding the net electric load characteristics of the building.

3.2.1. Hourly load characteristics of the 'strictly' ZEB

The hourly operation of the building is best seen by investigating the heat and electricity balances in parallel. In the following, three consecutive days in summer are analysed. Figs. 8 and 9 show the hourly operation of the building of heat and electricity balances respectively. The black solid lines indicate the hourly heat or electricity demand of the building, which are inputs to the model.

[3] Based on a conversion factor of 200 g_{CO2}/kWh_{PE} for district heating obtained from [46].

The heat generation in Fig. 8 shows that during daytime, the CHP is only run if the heat storage is empty, and never such that CHP electricity is exported to the grid. This is because the marginal cost of operating the CHP and the heat storage is higher than the income of selling CHP electricity for export. When the sun sets and the PV no longer generates electricity (see Fig. 9), the CHP unit is run such that it covers the heat demand and fills up the heat storage, provided that its electricity generation does not exceed the electricity consumption of the building.

The net electric load of the building is the blue dashed line in Fig. 9, which shows that electricity is exported during daytime, reaching maximum values of up to 31.3 kW. In the evening, even though the CHP is run at its maximum, it is not able to cover the evening peak electricity demands, and thus the building imports electricity in the late hours from 19h–24h.

On the coldest winter day, when heat demand is high, the CHP is operated at maximum load all 24 h. The gas boiler (GB) is also run throughout the day, while the electric top-up coil and heat storage is contributing at peak heat hours. As the CHP unit also runs during daytime, its electricity generation is added to the PV generation. On a sunny day in February, this may result in export values up to 30.7 kW because of the relatively low electricity demand of the household during daytime. Consequently, the maximum electricity export from the building in winter is not very different from the one in summer (see also Fig. 10).

3.2.2. Comparing grid impact of 'no', 'nearly' and 'strictly' ZEB

When plotted for a whole year, the hourly net electric load profiles for *'strictly'ZEB* (equal to the blue dashed line in Fig. 9) becomes like shown in Fig. 10. For comparison, the *Baseline* with *'no'ZEB* is also plotted. The positive values indicate electricity imports to the building, and negative values export.

When sorting the hourly net electric load, we obtain load duration curves as shown in Fig. 11. In *'no'ZEB*, the installed PV size is 14 kWp, which is doubled to 30 kWp in *'nearly'ZEB*, and more than tripled to 46 kWp in *'strictly'ZEB*. Thus, the largest difference in their net electric load duration curves occurs in the peak export hours, from 9 kW, to 20 kW and 31 kW. The import values, however, are unchanged as the operation of the CHP is not altered. As seen in Table 6, the annual export of electricity is five times higher for the 'strictly' ZEB reference case compared to the Baseline case. Notice that in both cases, the peak export values are lower than the installed PV capacity due to some self-consumption, and to the fact that the PV generation seldom reaches its installed capacity due to inverter efficiency and clouds.

4. Sensitivity analysis

The first findings show that the optimal technology choice is fossil based, regardless of whether the ZEB target is Zero Emission or Zero Energy, and whether the ZEB level is 'nearly' or 'strictly'. Section 4.1 investigates how changes of future energy market parameters might alter the optimal energy system design towards renewable heating choices of a 'strictly' ZEB. Whereas Section 4.2 analyses how the energy system design affects the building's grid impact. The *'strictly'ZEB* case from Section 3 is in the following denoted as *ZEBref*.

4.1. How robust is the choice of CHP?

When looking into the future, several parameters may change from today's conditions. According to EU's energy and climate policy, EU shall have 80% renewable energy in their electricity production mix within 2050, which will lower the weighting factor for electricity. Further, the electricity price in the power market is also

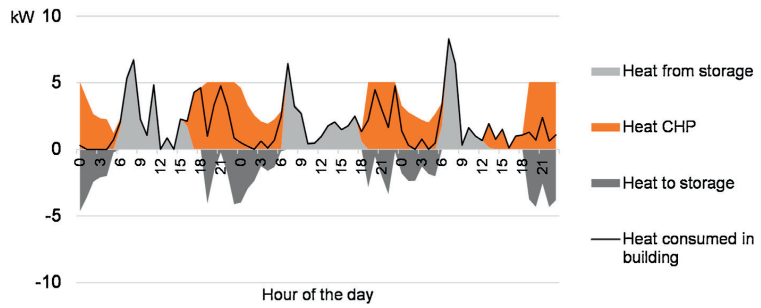


Fig. 8. Hourly heat generation (kWh/hr) for the *'strictly'ZEB* with CHP, for three days in August (Tuesday – Thursday).

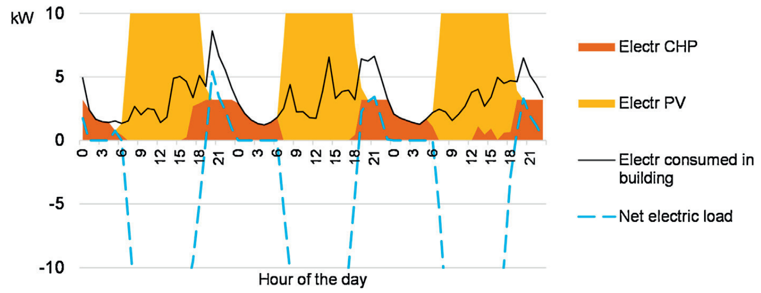


Fig. 9. Hourly electricity generation (kWh/hr) for the *'strictly'ZEB* with CHP, for three days in August (Tuesday – Thursday). (Notice that the peak values of PV electricity generation and net electric load exceed the borders of the graph).

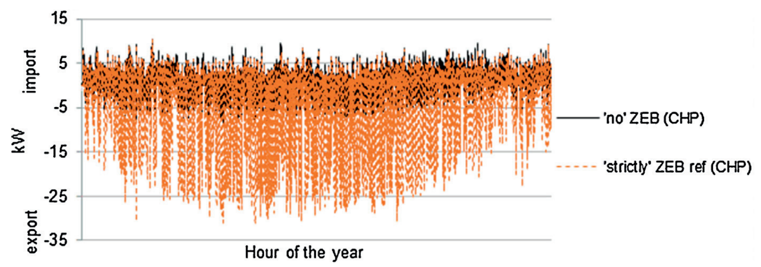


Fig. 10. Net electric load profile for baseline ('no' ZEB) and 'strictly' ZEB case, both with CHP serving the base heat load (kWh/hr).

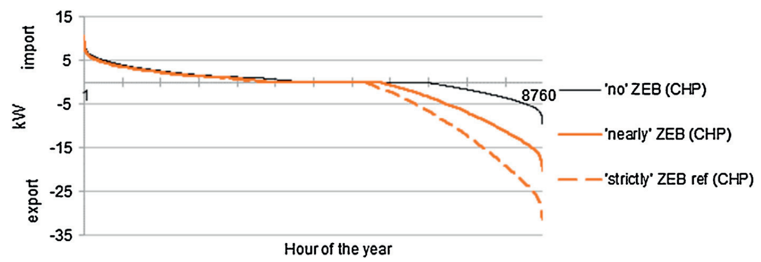


Fig. 11. Impact of 'nearly' ZEB on the load duration curves. Comparing Baseline ('no' ZEB) to, 50% ZEB and 'strictly' ZEB, all with CHP serving the base heat load (kWh/hr).

expected to decrease as the marginal cost of renewable electricity production is close to zero. Further, the political landscape in Europe could change, and if gas imports are restricted, and/or gas demand increases, the gas price might increase. The investigated sensitivities are shown in Table 5.

Table 5
Inputs to the sensitivity analyses. Investigated possible future gas prices, electricity prices and electricity weighting factors.

	Unit	Value	Comment
End-user gas price	ct/kWh	6.6	+20% Increasing the price 1,2 times
	ct/kWh	8.25	+50% Increasing the price 1,5 times
End-user electricity price	ct/kWh	19	−21% Equal to HP tariff
	ct/kWh	12	−50% Halving the price
	ct/kWh	9.6	−60% Similar to end-user prices in Scandinavia.
Feed-in-tariff for PV	ct/kWh	11	Today's FiT for PV
	ct/kWh	5.4	Equal to FiT for CHP electricity
	ct/kWh	3.5	No FiT for PV. Export price equal to average EEX power price (2013–2015)
Electricity weighting factor	gCO2/kWh	210	Equal to natural gas
	gCO2/kWh	170	Halving today's factor
	gCO2/kWh	130	Average carbon factor of European electricity for the next 60 years, if the target of 90% reduction within 2050 is reached [4].
	gCO2/kWh	70	80% reduction of today's factor

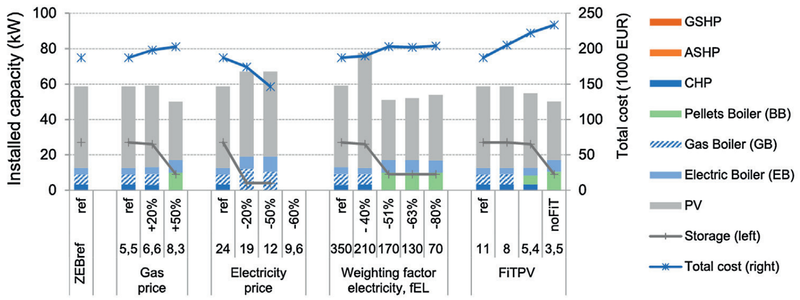


Fig. 12. Results of the sensitivity analysis. Influence of higher gas price (ct/kWh), lower electricity price (ct/kWh), reduced weighting factors for electricity (gCO2/kWh) and lower FiT for PV (ct/kWh), on installed capacity (kW) and total discounted cost (1000 EUR).

4.1.1. Higher natural gas price

Fig. 12 shows that when the gas price increases by 20%, the CHP is still a cost optimal choice. Increasing the gas price further, the gas boiler is replaced by a bio pellets boiler. Notice that the PV size is reduced by 31% because bio energy has a lower weighting factor compared to natural gas, leading to smaller amount of required weighted energy export.

4.1.2. Lower electricity price, P_{EL}

Today's electricity price on the EEX[4] electricity market is about 3–4 ct/kWh, so the main part of the end-user price of 24 ct/kWh consists of taxes. Even though the market price of electricity might decrease, it is still unclear how the end-user price will evolve because it is mainly influenced by policy makers – it might stay constant, or it could decrease towards levels as in Norway and Sweden. Regardless of the actual development, it is of interest to see how the energy system design would be affected by a lower electricity price.

Fig. 12 shows that reducing the electricity price from 24 to 19 ct, the electricity generated from the CHP becomes less valuable as the alternative price for electricity from the grid decreases, and thus, the gas boiler is chosen instead of the CHP. Reducing the electricity price further to 12 ct/kWh (also for the HPs), a gas boiler is still the preferred option, but the electric boiler for peak load increases slightly. Reducing the electricity price below the FiTPV to 9.6 cent/kWh, the building gets more paid for PV electricity sold to the grid than what it buys, which is not a realistic option.

The electricity price thus only affects the cost-competitiveness of the CHP. Higher electricity price, the more cost-optimal is the CHP. Lower electricity price leads to the next best heat technology choice, which is GB. Notice that the heat pump is still not a viable option due to its relatively high investment costs, even though the fuel costs are low.

4.1.3. Lower electricity weighting factor, f_{EL}

Reduced CO_2 factor for electricity would intuitively lead to less need of installed on-site energy generation (PVs) as the imported electricity is "greener". However, as the findings in Fig. 12 show, the opposite effect occurs. The reason lies in the strictly zero restriction, because not only is the imported electricity less polluted, but the exported electricity also displaces less pollution in the grid. In order to compensate for the unchanged amount of imported natural gas, the amount of exported PV electricity increases as the weighting factor for electricity decreases. Because of the FiTPV, the increased PV size influences total cost little, and the preferred heat technology remains unchanged. However at 130 g/kWh$_{el}$, it is necessary to change towards more renewable heat generation, but the heat pump is still not chosen due to its higher investment and fuel costs compared to the bio boiler.

4.1.4. Reduced FiTPV

If the FiT for PV is reduced, Fig. 12 shows that the CHP is still the favoured heat technology however, the peak heat load is covered by a BB instead of a GB. Also notice that the total cost has increased as expected, because of the lower income from the exported PV. When removing the FiT for PV, the building owners may sell their PV electricity in the electricity market, which was about 3–4 ct/kWh in 2012–2015 [40]. Without the FiTPV, the PV installation becomes

[4] www.eex.com/en/ This reflects a relatively high module capacity of 300 Wp, which normally has an area of 1.6 m^2.

more expensive and it is necessary to reduce the emissions from the heat generation, and a BB is chosen for both peak and base load heat demand.

The FiT is introduced to give incentives for the end-user to invest in local energy generation. However, when applied together with the ZEB requirement that demands PV in the first place, the FiTPV leads to lowering the total cost for the building owner. This makes it profitable to use fossil fuels for covering heat demand, at the cost of higher installed PV and consequently higher electricity exports from the building. When reducing or removing the FiTPV, the building's possibility of reaching the zero balance becomes more expensive, and the fossil fuelled heat generation is replaced by a greener alternative, the bio pellets boiler (Fig. 13).

4.1.5. Increased RES in the grid – combining lower f_{EL} and FiTPV

When more renewable energy sources (RES) are introduced in the electric power system, most likely the FiTPV will decrease along with the weighting factor for electricity (f_{EL}). Hence, three model cases *30%RES*, *50%RES* and *80%RES* are developed by combining the two. Fig. 14 shows the results.

As found in Section 4.1.3, when the weighting factor, f_{EL}, is reduced (from *ZEBref* to *30%RES*) while everything else stays constant, this leads to increased PV area, but the heat technology unaffected. As the FiTPV is unchanged at 11 ct/kWh, the total cost increases with only 3% even though the PV size is 30% larger. In *50%RES*, the f_{EL} is reduced further, which contribute to larger PV size and higher costs if not changing the heat technology. Hence, the heat technology is changed to a BB, and even though the PV size is reduced, the halved FiTPV and the more expensive BB makes the total cost increase with 22%, when compared to *ZEBref*.

When the FiT is removed in *80%RES*, together with further decreased weighting factor for electricity, a HP is installed. Even though the electricity price is unchanged and the technology costs are unchanged, lowering the weighting factor for electricity to 70 g/kWh and removing the FiTPV makes the heat pump a cost-optimal choice. The reason is as follows. When the electricity weighting factor is decreased, a ZEB with BB will need to increase its amount of PV exports. When reducing the FiTPV, the increased PV size will become more expensive. Reducing one at a time, Fig. 12 showed that BB was chosen in both cases. However, when reducing both the FiTPV and the electricity weighting factor simultaneously, the choice finally becomes HP. Another option is to increase the weighting factor for bio energy, however this is not investigated in the current work.

4.1.6. Concluding comment on investment decision

Because the price of electricity is high compared to the other energy carriers (see Table 3), the benefit of generating your own electricity makes CHP the favoured heat technology choice.

The choice of CHP seems to be very robust when changing each input parameter separately. A lower electricity price was the only thing that could make the CHP less profitable, as the cost of the electricity generated from the CHP becomes higher than the price of electricity from the grid.

When reducing the FiT and the weighting factor for electricity simultaneously have a larger effect than lowering the electricity price alone. The sensitivity analysis also shows that the opportunity window for HP is narrow (see more in Section 5.3).

Comparing the technology choices in Fig. 12 shows that whenever BB, or CHP, is chosen as main heat technology, the composition of the other heat technologies in the ZEB building is the same. That is, in the cases that lead to investment in BB (e.g. higher gas price or lower electricity price), the composition of installed capacity of the BB, electric boiler, and storage are identical, regardless on what grounds the choice was made. When the installed capacity is the same, the annual energy consumption is the same, and the optimal hourly operation is also identical.

The findings in Section 3, together with the sensitivity analysis in this section, show two main trends that are important for the grid impact. (1) once the main heating technology is determined, the hourly heat operation is identical; and (2) the ZEB level only affects the PV size, which is critical for the grid impact.

4.2. How does the energy system design affect the ZEB's grid impact?

Another finding of the sensitivity analysis in Section 4.1 is that the PV area changes with the choice of heat technology. From Section 3.2, we know that the PV size is decisive for the grid impact of the ZEB. Thus, it is interesting to see how the grid impact is affected by the main heat technology choice, while keeping all other input variables unchanged. Thus, this section analyses the grid impact of a 'strictly' ZEB with four different main heating technologies; BB, HP, GB and CHP. Their grid impact is further compared to the grid impact of *'no'ZEB* and *'nearly'ZEB* from Section 3.1. Table 6 summarises the findings elaborated on in the following.

4.2.1. Net electric load duration curve

Fig. 14 shows how the net electric load duration curve is influenced by the main heat technology choice, i.e. GSHP, BB, GB and CHP, for a 'strictly' ZEB. The positive part of the load duration curve, i.e. the electricity import, is identical for ZEBs with BB or GB as the operation of the boiler do not influence the electricity imports. A ZEB with CHP has the lowest duration curve for electricity imports. As found in Section 3.2.1, this is because all electricity generated from the CHP is self-consumed, and hence, the net electric import curve is shifted downwards 2–3 kWh/hr compared to a ZEB with a boiler (GB or BB). When using a heat pump, the electricity imports increase, as electricity is also used for heating purposes. However, the net imports of the ZEB with HP in Fig. 14 is only 0,5–1 kW higher compared to the boilers. There are two reasons for this; (1) the low heat demand of the building, and (2) the high seasonal COP at 4,5. The largest difference occurs in the peak import value of 18 kW for the HP, which is caused by the electric top-up coil in peak heat hours. As shown in Table 6, the peak import value with HP is about 40% and 70% higher when compared to a ZEB with a boiler or CHP, respectively.

The load duration curve for electricity export is heavily influenced by the size of the PV. Table 6 shows that the fossil fuelled heat technologies require the largest PV size, which is reflected in the peak export values reaching 31 and 33 kW for CHP and GB, respectively. The shape of the duration curve of electricity export is also very similar for these two. The BB has a similar shape, though the export values are smaller. The shape of the HP electricity export differs from all the other heat technologies as it has the least amount of hours with export, but as soon as it starts exporting, the curve becomes steeper, and finally reaching a maximum export value of 25 kW.

Lastly, we observe for ZEB with HP, that import values between 50 and 100% of the peak import only occurs in 3% of the hours. This is due to the price structure of electricity in this case study, which do not have a component for maximum load from the grid. This may cause problems for electricity grids with transmission capacity limitations, or for electric power systems with capacity limitations for flexible generation, which hence must provide capacity payment in so-called capacity markets.

4.2.2. Self-consumption

For a ZEB with either GB or BB, the boilers are operated to cover heat demand only, and consequently do not influence the way the building is utilising the electricity grid. Therefore, the self-

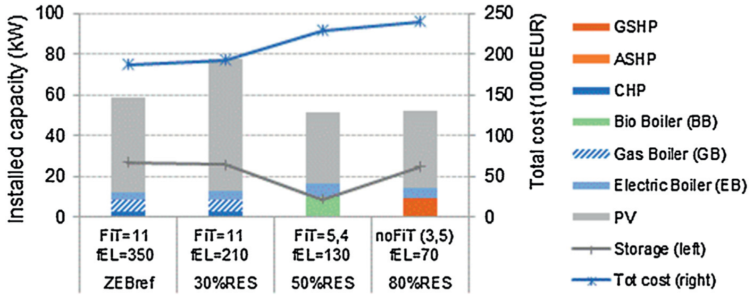


Fig. 13. Results of greener electricity production mix. Influence of reduced weighting factors for electricity (gCO2/kWh), combined with lower FiT for PV (ct/kWh), on installed capacity (kW) and total discounted cost (1000 EUR).

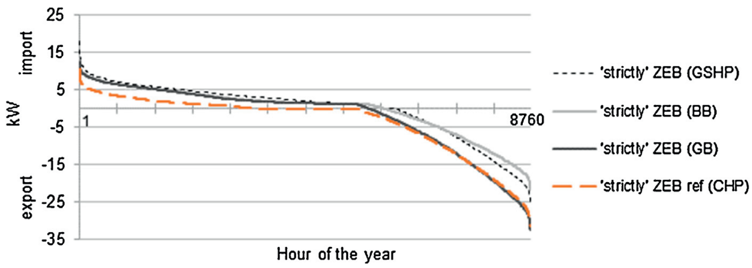


Fig. 14. Duration curves of the net electric load for 'strictly' ZEBs (kWh/hr). Comparing cases with HP, BB, GB or CHP serving the base heat load, respectively.

Table 6
Key performance indicators and grid indicators of investigated ZEB cases.

ZEB level		'no' ZEB	'nearly' ZEB	'strictly' ZEB			
Main heating Technology		CHP (Baseline)	CHP (50%ZEB)	CHP (ZEBref)	Gas Boiler	Bio Boiler	GSHP
Electricity imported (MWh/yr)		8	8	8	20	21	25
Electricity exported	PV	6	22	38	37	22	25
(MWh/yr)	CHP	0	0	0	–	–	–
Electricity generated	PV	15	32	49	51	35	41
(MWh/yr)	CHP	15	15	15	–	–	–
PV installed (kWp)		14	30	46	48	33	38
Self-consumption (MWh/yr)		24	25	26	14	13	16
Self-consumption, total (%)		80%	54%	40%	27%	37%	40%
Self-consumption, PV (%)		60%	31%	22%	27%	37%	40%
Max export value (kWh/hr)		9	20	31	33	22	25
Max import value (kWh/hr)		11	11	11	13	13	18
GM		0.8	1.8	3.0	2.6	1.6	1.4
GMref (ref = 12,6 kW)		0.7	1.6	2.5	2.6	1.7	2.0

Table 7
Storage size of strictly ZEBs by main heating technology.

ZEB level	'strictly' ZEB			
Main heating technology	CHP	Gas boiler (GB)	Bio boiler (BB)	Heat pump (GSHP)
Storage size (kWh)	25	4	9	14

consumption is only related to how much of the PV that can be utilised for the building's electric specific demand (i.e. appliances, lighting, fans&pumps). Because of the larger PV size of the GB compared to the BB, the self-consumption rate is 27% with GB and 37% with BB, even though the amount of self-consumed PV is the same, at 13–14 MWh/yr.

A HP on the other hand, can shift its operation to consume PV generated electricity by utilising the heat storage. However, the self-consumption only increases by 3 MWh/yr compared to the BB because the heat demand is low when the sun shines. Even though the amount of self-consumed electricity is higher for the HP case, the share is only 3%-points higher compared to the BB due to the larger PV generation (41 vs. 36 MWh/yr).

The highest amount of self-consumed on-site electricity generation, and thus the lowest amount of annual electricity imports of 8 MWh/yr, is found when CHP is the main heating technology. In Section 3.2.1, the CHP was found to be operated such that all the on-site CHP generated electricity is self-consumed. This is confirmed in Table 6 where no CHP electricity is exported to the grid, and the self-consumption at 26 MWh/yr is twice as high compared to the ZEB with a boiler.

4.2.3. Additional grid connection capacity

The GM-ref is the relation between the peak export and a reference peak import value, and reflects the need for additional grid connection capacity for the building compared to a reference building without on-site electricity generation. Table 6 shows that the GB and the CHP in theory demands 2.5 higher grid connection capacity, whereas the BB demands 70% more.

4.2.4. Concluding comment on grid impact

From the findings above, we may conclude that the CHP and GB have the highest peak export value, the HP somewhat lower, and the BB the lowest export value. It is surprising that even though the CHP has the highest self-consumption, the peak export value is still one of the highest. The reason lies in the use of natural gas which demands a large PV area. The maximum export value occurs in summer when heat demand is low, and therefore, is determined by the PV size alone. If bio gas had been used in the CHP, the PV size would have been smaller, and thus, the CHP case would have had the lowest export value and the highest self-consumption rate, i.e. the lowest grid-impact.

5. Discussions

The results of this study are dependent on the assumptions made, especially regarding the level of ZEB, the value of the weighting factors, fuel prices and cost of the available technologies. However, there are some general characteristics of ZEBs that become evident from the investigated cases in this paper.

5.1. PV size

The findings in this paper reveals three elements of the PV size in ZEB buildings: (1) A minimum PV size is determined by the electricity specific demand, regardless of the electricity weighting factor, and (2) The total PV size is determined by (a) the ZEB-level and (b) the weighting factor of the electricity grid.

Electric specific demand of the building is present 24 h a day, also when the sun is not shining, and thus a minimum amount of imported electricity to the building is always required. This means that the building needs to export at least the equal amount of electricity, regardless of the weighting factor, as long as it is >0. Therefore, a ZEB needs a minimum PV size, only determined by the electric specific demand, regardless of PV cost nor the weighting factor of electricity. In this case study, this minimum PV size is about 30 kWp. When compared to the four 'strictly' ZEB cases in Table 6, the additional heat determined PV size ranges from 3 to 18 kWp, dependent on fuel. Thus, it is evident that the electric specific demand dominates the determination of the PV size.

Whether the building is a 'nearly' or 'strictly' ZEB, is directly reflected in the PV size. Here, the *'nearly'ZEB* has 35% smaller PV size compared to the *'strictly'ZEB* (see Fig. 6 and Table 6).

The sensitivity analysis of the weighting factor of electricity revealed another aspect of the PV size. If the heat technology is a CHP, a greener electricity grid (i.e. lower factor of electricity) claims a larger PV size. As the exported PV must compensate for the amount of weighted gas imports (which is unchanged), a lower weighting factor of electricity reduces the value of the weighted exported electricity. Hence, the amount of electricity export has to increase in order to reach the zero target. The same applies for ZEBs with other heating technologies. The exemption is HPs, where the weighting factor does not influence the PV size at all as it is an all-electric building.

5.2. Storage size dependent on heat technology

Investigations of the hourly operation reveals that the storage size of the boilers (GB and BB), depends on the peak heat load in winter, and the cost of the base load technology. The gas boiler has a relatively low investment cost, thus the size of the GB is high, whereas the storage size is small. The bio boiler have higher investment cost, leading to larger peak load unit and larger storage size. However, when heat pumps or CHP is chosen, the storage size is larger as the storage is sized for summer conditions. In the case of CHP the storage is sized to store heat generated at night time, to cover the morning peak heat demand. The heat pump on the other hand operates during daytime when PV electricity is available, and the storage is dimensioned to cover the heat demand at night. As discussed in Section 2.2.3, the size of the heat storage should be used with care, as they rely on an assumption of $\Delta T = 30\,^{\circ}C$ (Table 7).

It can also be mentioned that a seasonal heat storage was never an economically beneficial decision, regardless of storage efficiency. A seasonal storage would enable PV electricity being stored as heat in summer and used for heat demand in winter. However, as the building must export electricity to reach its annual zero requirement, there is no benefit of storing heat seasonally.

5.3. Heat pump opportunity in ZEBs

When the electricity grid becomes greener in near future, many studies expect that heat pumps will replace fossil fuelled heating [23], [41–44]. A lower electricity weighting factor should intuitively lead to HP investments. However, because the investment cost and operational cost of the HP is more expensive than the BB, the sensitivity analysis shows that both the FiTPV and the weighting factor for electricity must be reduced substantially to make the HP a cost-optimal choice over a BB.

When moving from fossil fuelled to renewable heat for the ZEB building, the BB is a more cost-efficient choice compared to the HP. Even reducing the electricity price did not affect this solution. The reason lies in the weighting factor of bio energy which demands a smaller PV size compared to the HP. The choice of whether to install HP or BB is thus influenced by (1) the investment and fuel cost of the heat technologies on the one hand, and (2) on the FiTPV and PV installation cost on the other hand, which determines the cost of compensating the weighted energy imports to the building.

5.4. Solar thermal never chosen

For none of the cases investigated, solar thermal (ST) was profitable. In general, using solar thermal (ST) collectors reduces the need for alternative heat generation, which subsequently reduces the weighted energy imports and therefore lowers the required PV investment to balance them off. Thus, the choice of investing in ST is determined by the trade-off of saved fuel costs for alternative heat generation, together with lower investment costs of PV panels, versus the investment costs of ST. As the heating technologies are dimensioned to cover the peak heat load in winter, they are very well capable of also covering the heat demand in summer. Hence, installing ST does not reduce the installed capacity of the heating technologies, but only saves the fuel costs. In order for the ST to be chosen, the specific cost had to be reduced by 75% to 200 EUR/m^2, with a size of 14 m^2. When studying the hourly operation, it is seen that this size fits well with the domestic hot water demand in summer. This confirms the findings in [45] which investigated ways of finding the optimal size of a ST system, and found that cost minimization would lead to no investments in ST at all, and consequently developed an alternative algorithm for sizing of the system. Further, our findings are also in line with [7] which concluded that if available roof area is limited, then it is more beneficial to use it for PV panels compared to ST collectors, despite the higher efficiency of the ST.

5.5. Aspects not considered

The analysis is performed on a single building containing 10 apartments, thus the possible benefits of utilising different energy sources in a local energy system for several buildings is not a part of the present work. Sensitivity analysis of future development of the technology costs is not performed in this paper, even though the modelling framework allows for this. Bio gas is not included in the analysis. If this had been done, dependent on price, the optimal technology might be CHP fuelled by bio gas rather than natural gas. The weighting factor of district heating is quite high for the present European conditions as it is linked to the thermal power plants. As for the weighting factor of electricity, this may change in future. Electric storage can be a viable option with the present support system of batteries in Germany, which will be implemented in future work.

6. Conclusion

This paper identifies the most important factors that influence the grid impact of a ZEB situated in Germany. The analyses are performed using a MILP model which finds the cost-optimal energy system design within the ZEB.

We find that whether the building is a ‘nearly’ or ‘strictly’ ZEB building impacts the import/export situation of the building, but it does not affect the choice of energy technologies. The cost-optimal technology mix is thus the same, however the PV size increases by 53% when going from ‘nearly’ to ‘strictly’ ZEB. This directly affects the grid impact, and the peak export value is increased by 55% from 20 to 31 kW.

Whether the ZEB balance is calculated using CO_2 factors (Zero Emission Building) or primary energy factors (Zero Energy Building), the choice and size of energy technologies are not altered. In this case study, a CHP combined with a GB, EB and PV is the cost-optimal technology choice independently of whether the building is a Zero Emission or a Zero Energy Building. The only exemption is the size of the PV, which is determined by the relation between the weighting factor of electricity export and the factor of the other energy carriers. The closer the weighting factor of electricity is to the weighting factor of the other energy carriers, the larger PV size is required to reach the ZEB balance.

The choice of whether to use a CHP, GB, BB or HP to cover the base load of the heat demand, is a trade-off between the investment & fuel cost, and the cost of the PV which generates the weighted energy exports. On the one hand, CHP or GB has the lowest costs, but also the highest weighted energy imports, which requires the largest PV size. On the other hand, BB or HP has higher costs, but lower weighted energy imports, leading to smaller PV size (see Table 6). The present FiT of PV in Germany, makes the additional cost of a larger PV size negligible compared to the saved fuel and investment costs by using natural gas for heating. In other words, the choice of heat technologies of a ZEB is dependent on the trade-off between higher costs for renewable heat generation vs. saved costs of smaller required PV size.

For ZEBs with HPs or BBs, it is the electric specific demand that dominates the required amount of energy generation, i.e. the PV size. First, because of the relatively low heat demand, and secondly, because the weighting factor of biomass is low and the efficiency of HP is high. In this case study, the PV size determined by the electric specific demand is 30 kW. In the case of the BB or HP, this corresponds to 91 and 70% of the total required PV capacity, respectively.

Solar thermal (ST) is not a cost-optimal choice in any of the investigated cases. ST competes with the fuel cost of alternative heating technologies and not with the PV. The only benefits for the ST are the saved fuel costs for heating and the lower PV investment costs, which are not enough to make it economically attractive.

Onsite PV installation leads to challenges for the grid in peak hours when the generation exceeds the electricity consumption within the building, creating large export values. A ZEB with fossil fuelled heating technologies requires the largest PV installation, and has consequently higher grid impact. When compared to a ZEB which uses bio fuel, the annual export of electricity to the grid is 73% higher, the maximum export value is 41% higher, and the self-consumed PV is reduced to about 25%.

In future, the FiT of PV is most likely to be reduced or even removed. When removing the FiTPV, the findings from the sensitivity analysis show that BB is the preferred heat technology. A HP is not a cost-optimal choice until the weighting factor of electricity is reduced by 80% (equal to 70 g/kWh). Thus, using bio energy for heating purposes seems like a robust technology choice for ZEBs in the future. However, is there enough resources available to cover this demand if all Germany is to be heated by bio energy? Thus, for future policy development, it might be an option to assess a direct investment subsidy, not only for CHPs, but also for heat pumps.

One of the main takeaways from this paper is that applying both the ZEB target and the FiTPV lead to fossil fuelled based heating technologies with a large PV area. This contradiction should be addressed when the political definition of ZEB buildings is determined. A mayor concern is also the design of the ZEB definition. There are certain reasons for wanting specific heating technology choices in some countries, and the value of the weighting factors can affect this decision.

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Appendix A.

When applying non-renewable primary energy factors (PEnr-sym), Fig. 15 shows that the installed capacity of the CHP, GB, EB and heat storage is the same as when using CO_2 factors. The only difference is seen in the PV size which is 7 kWp lower. When using the total primary energy factors (PEtot-sym), where the factor for bio energy is increased from 0.05 to 1.05, there is still no change, as bioenergy is not a part of the ZEB solution, only that the PV size is 9 kWp smaller.

When applying asymmetric factors for electricity, where export (2.0) is valued less than import (2.3 or 2.5), the incentive for self-consuming on-site PV generation increases. The findings from Fig. 6 shows that the only change from symmetric to asymmetric factors is increased PV area. Due to the optimal operation strategy of the model, the self-consumption is already maximised, and the imported electricity is already minimised. By applying the asymmetric factors for electricity, the exported generation is less valued when calculating the balance, and thus the building needs to export more kWh's in order to reach the zero balance.

Summed up, the only difference when using either CO_2 or primary energy factors, is the size of the PV system. The PV size is determined by the relationship between the factors of electricity exports and natural gas imports, given in Table 8. The lower weighting factor of the electricity export is, compared to the weighting factor of the gas import, the larger amount of annual electricity export is required to compensate for the energy imports. In Table 8, the CO_2 factors have the smallest difference between the weighting factor for electricity export and gas import and requires thus the largest PV size, which is confirmed by the findings in Fig. 15.

The annual energy generated from each of the technologies is shown in Fig. 16, where the CHP unit provides 79% of the heat demand and the gas boiler 20% regardless of weighting factor. The electric top-up coil only contributes with 1% to cover peak heat demand and is hardly visible in the graph.

Table 8
Relationship between weighting factors for electricity and natural gas, and between electricity and bio pellets.

Weighting factor	Description	Natural gas vs. Electricity	Bio pellets vs. Electricity
CO2	Zero Emission (using CO_2 factors)	(210: 350) Relation 1: 1,7	(14: 350) Relation 1: 25
PEnr-sym	Zero Primary Energy (using symmetric non-renewable PE factors)	(1,05: 2,3) Relation 1: 2,2	(0,05: 2,3) Relation 1: 46
PEtot-sym	Zero Primary Energy (using symmetric total PE factors).	(1,05: 2,5) Relation 1: 2,4	(1,05: 2,5) Relation 1: 2,4

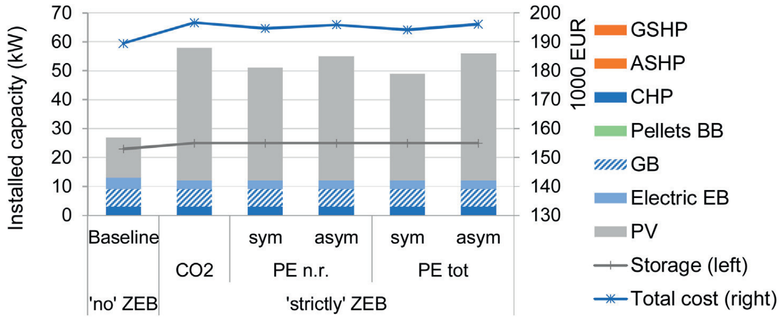

Fig. 15. Installed capacity (kW) of ZEBs using different weighting factors; Baseline ('no' ZEB) is compared to a zero emission, zero non-renewable primary energy (symmetric and asymmetric), and zero total primary energy (symmetric and asymmetric) building.

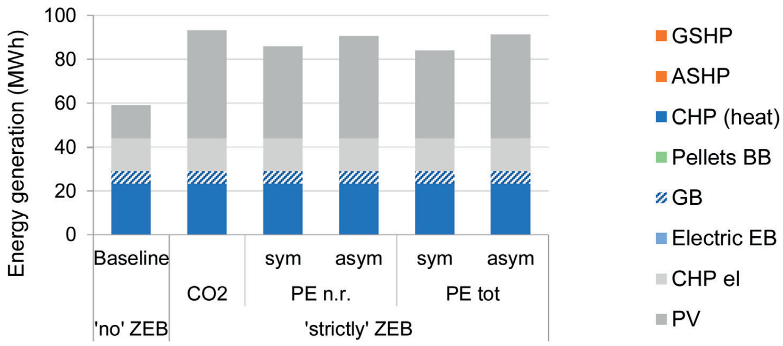

Fig. 16. Annual energy generation (MWh/yr) in the baseline case (noZero), compared to when applying five different ZEB targets: zero emission, zero non-renewable primary energy (symmetric and asymmetric), and zero total primary energy (symmetric and asymmetric).

Article VI

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Impact of PV and variable prices on optimal system sizing for heat pumps and thermal storage

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PV self-consumption

ABSTRACT

Heat pump (HP) units coupled to thermal storage offer flexibility in operation and hence the possibility to shift electric load. This can be used to increase PV self-consumption or optimise operation under variable electricity prices. A key question is if new sizing procedures for heat pumps, electric boilers and thermal storages are needed when heat pumps operate in a more dynamic environment, or if sizing is still determined by the thermal demand and thus sizing procedures are already well known. This is answered using structural optimisation based on mixed integer linear programming. The optimal system size of a HP, an electric back-up heater and thermal storage are calculated for 37 scenarios to investigate the impact of on-site PV, variable electricity price, space heat demand and domestic hot water demand. The results are compared to today's established sizing procedures for Germany. Results show that the thermal load profile has the strongest influence on system sizing. In most of the scenarios investigated, the established sizing procedures are sufficient. Only large PV sizes, or highly fluctuating electricity prices, create a need for lager storage. However, allowing the storage to be overheated by 10 K, the need for a larger storage only occurs in the extreme scenarios.

1. Introduction

Increased generation of electricity from intermittent renewable energy sources increases the need for flexibility on the demand side. This is needed to allow stable operation of the power system [1,2]. It has been widely accepted that heat pumps coupled to thermal storage can provide flexibility to the power system [3–5]. For such a case variable electricity prices can be used as a way to influence heat pump operation [6–8]. Further, heat pumps (HP) can be used to increase the use of electricity from photovoltaic plants (PV) on a building level [9–11]. In many countries the cost for on-site generated PV electricity is below the electricity price, and self-consumption of PV electricity is economically attractive. Today, most HP manufacturers offer control schemes to align heat generation with available PV electricity.

Thus variable electricity prices and PV self-consumption will change the way HPs are used. As a consequence, the sizing procedures of the heat pump unit, the electric back-up heater and thermal storage might need to be adjusted. The aim of this study is to find the optimal system configuration and operation which minimizes the costs over a lifetime of 20 years, using structural optimisation.

A central question of this study is whether operation under variable electricity prices or PV requires different system sizing compared to what is seen today? This essentially boils down to the question if larger storages for heat pump systems are required in the future. Further, the role of the electric back-up heater is questioned. If there is no need for changed sizing procedures it can be concluded that the current system sizing procedures and hence, what is installed in the field today, is already prepared to a large extend for the increased flexibility demanded by the changes in the electric energy system.

It is assumed that thermal energy storage will play a central role for the heat pump's ability to respond to the needs of the power system [3]. This is good news as at least in Germany installing thermal storage is common practice. As a consequence the focus of this study is on storage tanks. The use of the building's thermal inertia is not part of this study, but is reflected in the storage sizing recommendations used. According to scientific literature [12–15], engineering guidelines and manufacturers recommendations [16–23] the reasons to install thermal storage can

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be summarized to three points: (1) Reduced investment costs for the system, as need for peak capacity is reduced (2) Ensure feasible operation so that minimum unit run times can be kept, (3) Allow flexible operation e.g. to self-consume PV or benefit from varying electricity prices. Further, in Germany most heat pumps are offered a reduced grid fee when the grid operator is allowed to block heat pump operation up to 3×2 h a day. If blocking is activated, a thermal storage or high building thermal inertia is needed to keep the indoor temperature within the comfort limits during blocking hours.

For system sizing in the field the established procedures are based on thermal loads of the building and for hot water. For operation under variable electricity prices or on-site PV, sizing procedures are not yet established. In this study, the optimal sizing and operation of an air-source heat pump system are calculated using mixed integer linear optimisation. The case study is performed on a multi-family house situated in Germany with an air-source heat pump, as they are gaining increasing market share [24]. The heat pump is coupled with an electric back-up heater and a water tank used as thermal storage, which is current practice in Germany.

The most important factors that influence the system sizing are identified by varying the building's space heating load, domestic hot water (DHW) load, size of the on-site PV and variability of the electricity price. Optimal sizing and operation is determined by solving a mixed integer linear optimisation problem (MILP), which is briefly explained in Section 3. The problem is solved for 37 scenarios explained in Section 4 to identify the most important factors that determines the system sizing. Studying the optimisation results (presented in Section 5) and comparing them with today's sizing procedures (explained in Section 2), leads to a better understanding of the dominant effects and helps developing sizing recommendations for future heat pump systems (presented in Sections 6 and 7).

2. Sizing procedures according to manufacturers

A heat pump system that provides space heating and domestic hot water (DWH), typically consists of the following components: A heat pump, a back-up heater and a thermal energy storage. Today, sizing of the individual components is based on manufacturers guidelines and textbooks [16–23]. This section presents a summary of sizing recommendations for a variable speed air-source heat pump (ASHP) system with water storage tanks, as this is the focus of this study.

2.1. Sizing of heat pump and back-up heater

The sizing of the ASHP is determined by the heat load, the heat distribution system of the building, and the presence and type of the back-up heater. The latter determines whether the system is monovalent, mono energetic, or bivalent. In the case of monovalent HP systems, the building's space heating and DHW demand is entirely served by the heat pump at all times of the year. In case of a mono-energetic HP system, an electric back-up heater supports the heat pump during thermal peak hours, and the HP unit is sized to cover approximately 95% of the total annual heat demand [20,21]. In case of a bivalent system a non-electric back-up heater is used, which, in Germany, typically is a gas fired boiler. Here, the sizing of the HP is such that it covers about 60% of the annual heat demand.

A sorted annual duration curve of heat demand over ambient temperature is used to determine the exact share of heat covered by the heat pump. The bivalence temperature T_{biv} is the outdoor temperature below which the back-up technology is used to support the heat pump. At that point, the HP size is determined as the sum of the instantaneous space heating load $\dot{Q}_{\mathrm{sh}}$ and an added capacity $\dot{Q}_{\mathrm{DHW}}$ for DHW. The additional heat pump capacity $\dot{Q}_{\mathrm{DHW}}$ for DHW decreases with the number of people in the building due to the smoothing of peaks with increasing number of occupants. Values between 0.88 and 0.17 kW extra capacity per person are recommended for dwellings with 4 up to 10 occupants. Lastly the calculated thermal peak demand for space heating and DHW is multiplied by a safety factor f_{block} for blocking hours:

$$\dot{Q}_{\mathrm{HP}} = f_{\mathrm{block}}(\dot{Q}_{\mathrm{sh}}(T_{\mathrm{biv}}) + \dot{Q}_{\mathrm{DHW}}) \quad [\mathrm{W}] \tag{1}$$

The calculated extra capacity to be added, is the ratio of maximum hours per day to maximum allowed operational hours per day:

$$f_{\mathrm{block}} = \frac{24}{24 - t_{\mathrm{block}}} \quad [-] \tag{2}$$

Although in practice, the additional capacity added for blocking hours according to manufacturers recommendations, is approximately 10% below the calculated value [20–23].

The gap between the maximum HP capacity at minimum ambient temperatures and the thermal peak demand, determines the size of the back-up heater.

The explained sizing procedure can be summarized as follows:

1. Determine heat load and DHW demand of the building
2. Determine space heating supply temperature curve for a given ambient temperature
3. Decide on the operation of the HP – (Monovalent, mono-energetic, bivalent)
4. Size the heat pump for the bivalence temperature, and if needed, add capacity for DHW
5. Size the back-up heater for the minimum ambient temperature
6. Increase sizing for blocking hours

2.2. Sizing of storage for DHW demand

Sizing of the domestic hot water storage is determined by the DHW load profile and the allowed temperature difference ΔT in the storage. As the DHW load profile is dependent on the number of persons and their occupancy behaviour, it is difficult to predict the exact demand, and hence sizing heuristics are applied. In the following, two sizing heuristics are presented.

According to [16] and manufacturers recommendation, the following procedure is applied. First, the annual DHW demand and the peak demand is determined according to DIN 4708 [25] depending on the number of "standard" flats in the house. From this, a characteristic storage parameter depending on the peak demand and the duration of the peak demand is derived. Most manufacturers offer an already prepared look-up table where the needed storage can be directly selected when the characteristic storage parameter is known with respect to allowed temperatures in the storage.

An alternative heuristic is found in [16] where the needed DHW storage capacity is directly determined by the number of persons, as shown in Eq. (3). The formula is valid for the range up to 300 persons, and S is a safety margin between 125% for low numbers of persons, and 105%, for more than 200 persons.

$$V_{\mathrm{DHW}} \simeq S \cdot 65.0 \cdot n_{\mathrm{persons}}^{0.7} \quad [\mathrm{l}] \tag{3}$$

2.3. Sizing of space heating storage

For HP systems only providing space heating demand, the sizing of the buffer storage depends on the type of heat pump, (air- or ground-source), compressor (fixed or variable speed), the minimum runtime of the heat pump unit (usually about 6–20 min), blocking hours and on the thermal inertia of the heat distribution system and the building. In case of variable speed air-source heat pumps, no or only a small storage of about 10–20 l per kW HP is recommended for defrosting and smooth operation.

The minimum recommended buffer tank size is based on the installed heat pump size and calculated to:

$$V_{\mathrm{min,SH}} \simeq 10.0 \cdot \dot{Q}_{\mathrm{HP}} \qquad [\mathrm{l}] \tag{4}$$

However, to overcome blocking hours, the buffer tank needs to be sized such that the maximum heat load of the year $\Phi_{\max}$ can be supplied to the building for 2 h. Using the specific heat capacity C_{water} of water and the allowed temperature difference ΔT in the storage, the needed storage size when allowing for blocking hours can be calculated according to Eq. (5). Given an allowed ΔT of 10 K this leads to a theoretical storage size of 172 l per kW nominal heat load.

$$V_{\mathrm{theory,SH}} = \frac{\Phi_{\max} \cdot 7200s}{C_{\mathrm{water}} \Delta T} \qquad [\mathrm{l}] \tag{5}$$

In practice however, the building's thermal inertia and relaxation of the indoor comfort temperature requirements, may lead to smaller storage size recommendations. Hence, the manufacturer recommendations for heavy buildings and/or floor heating ranges from approximately 20–60 l per kW maximum heat load, and 50–80 l/kW for lighter buildings and/or radiator heating.

Eqs. (6) and (7) show fits of manufacturer's recommended values for storage size accounting for blocking hours. The coefficients depend on the maximum heat load $\Phi_{\max}$ and on the thermal inertia of the system [17]. The fits are valid for heat loads up to 108 kW. For smaller units with peak demand below 4.5 kW, no storage is recommended.

For floor heating systems (high inertia, HI), the recommended storage size is:

$$V_{\mathrm{HI,SH}} \simeq 19.4 + 28.1 \cdot \Phi_{\max} \quad [\mathrm{l}] \tag{6}$$

For radiator heating systems (low inertia, LI), the recommended storage size is:

$$V_{\mathrm{LI,SH}} \simeq 81.54 + 53.8 \cdot \Phi_{\max} \quad [\mathrm{l}] \tag{7}$$

2.4. Methods used for optimal energy system sizing in academic literature

In academic literature, various methods for determining the optimal size of energy system components are found. They are either based on parameter variation and simulation, i.e. incrementally changing the parameters of interest and rerunning the simulation, or on structural optimisation.

Parameter variation is presented in [26] for optimised solar thermal and storage sizing. In [27] a scenario based analysis to determine the optimal size of CHP and storage system according to time of use tariffs (TOU) is presented and stated that variable electricity prices lead to increased storage size.

A second approach is to use a simulation model in combination with optimisation techniques. First, the optimal system sizing is found, and secondly, a simulation model is used to calculate annual operation and performance figures. This usually results in a non-linear or even black box formulation of an optimisation problem as in [28], where Tabu Search is used for optimising thermal storage size to increase the use of wind power in an interlinked thermal-electric scenario.

The third approach is to fully formulate the investment and the control problem into one optimisation problem. This approach was applied in [15] showing the impact of optimal heat pump use on the Danish system in 2030. The HP systems including thermal storage, were optimised in size and operation to reduce peak loads and fluctuations created by introducing wind energy into the power system. The problem was formulated and solved as a linear problem, and the HP's coefficient of performance was assumed constant.

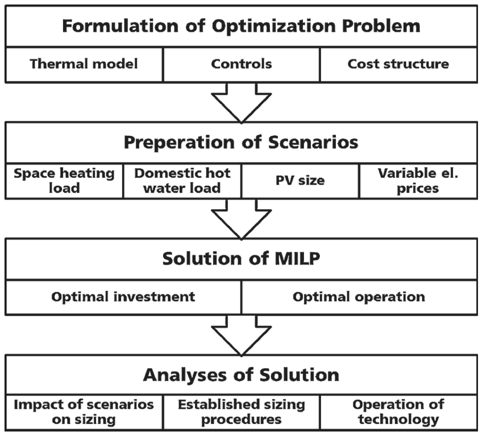


Fig. 1. Description of the general methodology.

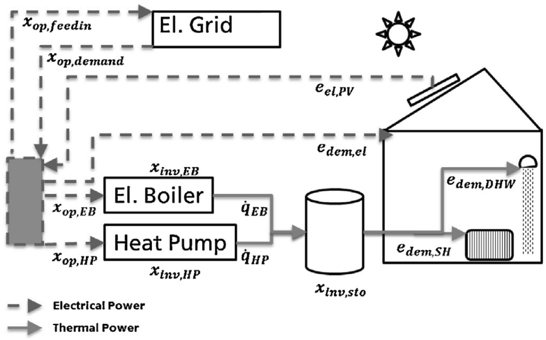


Fig. 2. Description of the system.

In [29] the effects of electricity tariffs on optimal battery sizing, when applied in a residential PV setting are studied and formulated as a mixed integer linear problem.

A framework for optimal investment and operation of building energy systems in the context of zero energy buildings is presented in [30]. A mixed integer linear program is formulated and solved for investment and operation for each hour of the year. The target for optimisation is flexible as to account for minimum cost or minimum CO_2 emissions. This work lays the foundation of the optimisation approach chosen in the presented paper.

3. Method

This section describes the general methodology for investigating the influence of selected factors on sizing of an air-source heat pump system (see Fig. 1).

The ASHP is coupled to an electric back-up heater and thermal storage tank, and is hence a mono-energetic system. A mixed integer linear optimisation model is used to find the optimal system sizing and operation for each scenario. A detailed description of the optimisation framework is provided in [30].

3.1. System description and assumptions

Fig. 2 shows the system under consideration. It is a residential building, with radiator heating system, stratified thermal storage and PV on the roof. The storage tank is used for both domestic hot water and space heating. The heat is supplied to the storage by a variable speed air source heat pump (ASHP) and an electric boiler (EB). The variable speed ASHP is capable of changing its thermal output in the range from 30% to 100% of the capacity. HP efficiency is dependent on the ambient temperature, and the temperature set point needed for DHW or space heating. The storage temperature is kept between the set point and a 10 K offset. Electricity generated from the PV plant is used for serving the electric load in the house and the surplus can be used by the HP unit, or exported to the grid at a price equal to the feed-in-tariff of 0.11 €/kWh paid to the building owner. The HP tariff in Germany at 0.19 €/kWh is set as the buying price for electricity to the heat pump, whereas the electricity price for the electric demand of the building, equals the end-user price in Germany at 0.24 €/kWh [31].

3.2. Formulation of optimisation problem

The aim of this study is to find the system configuration and operation which minimizes the total discounted costs over a lifetime of 20 years. The total costs J are the sum of total investment costs and total operation costs which depend on the chosen sizes $x_{\text{inv},i}$ for technology i and its operation $x_{\text{op},i,t}$ on each time step of the year t. Annual operation costs are discounted by $1/(1+r)^a$ for each year a using the nominal interest rate r. This leads to the following objective function:

$$\min_{x_{\text{inv}},x_{\text{op}}\in\mathbb{R}} J=\sum_{i=0}^{I}\left[c_{\text{inv},i}x_{\text{inv},i}+\sum_{a=1}^{20}\sum_{t=0}^{T}\frac{c_{\text{op},i,t}x_{\text{op},i,t}\Delta t}{(1+r)^a}\right] \tag{8}$$

where $c_{\text{inv},i}$ are the specific investment costs and $c_{\text{op},i,t}$ are the operational costs of each technology i at each time step t. The operational decision variables $x_{\text{op},i,t}$ and the demands e_i are visualized in Fig. 2.

To guarantee a physical reasonable operation, the optimisation problem is constrained for all points in time T and all available technologies I by the following set of equations:

No negative invest:

$$0\le x_{\text{inv},i}\quad \forall i\in I \tag{9}$$

Electric energy balance holds:

$$0=\sum_{i=0}^{I}x_{\text{op},i,t}+e_{\text{dem,el}}-e_{\text{el,PV}}\quad \forall t\in T \tag{10}$$

Thermal storage content s_t within allowed limits:

$$s_t=\sum_{t=0}^{t}\eta_{\text{sto}}^{t}\left(\sum_{i=0}^{I}\eta_{\text{op},i,t}\cdot x_{\text{op},i,t}-e_{\text{dem,SH},t}-e_{\text{dem,DHW},t}\right)\Delta t$$

$$0\le s_t\le x_{\text{inv,sto}}\quad \forall t\in T \tag{11}$$

HP thermal capacity within allowed limits:

$$\eta_{\text{op,HP},t}\cdot x_{\text{op,HP},t}\in[0,(0.3,\gamma_{\text{max,HP},t})\cdot x_{\text{inv},HP}]\quad \forall t\in T \tag{12}$$

EB within allowed limits:

$$0\le x_{\text{op,EB},t}\le x_{\text{max,EB},t}=x_{\text{inv,EB}}\quad \forall t\in T \tag{13}$$

Storage losses in Eq. (11) are accounted for by means of a storage efficiency η_{sto}, which is the share of storage energy that is available from the previous time step.

3.2.1. Heat technology models

The conversion efficiency of electricity to heat $\eta_{\text{op},EB,t}$ at each time t for the electric boiler is as follows:

$$\eta_{\text{op,EB},t}=0.99\quad \forall t\in T\quad [-] \tag{14}$$

For the ASHP, the coefficient of performance COP, is dependent on the temperature lift between the hot and the cold side, which is a function of the ambient temperature $T_{\text{amb},t}$ and the set point temperature $T_{\text{set},t}$.

$$COP_t(T_{\text{amb},t},T_{\text{set},t})=a_0+a_1\Delta T_t+a_2\Delta T_t^2\,[-] \tag{15}$$

The coefficients a are obtained using a least square fit on HP data from manufacturers [17], where ΔT_t is as follows:

$$\Delta T_t=T_{\text{set},t}-T_{\text{amb},t}\quad [\text{K}] \tag{16}$$

Since the heat pump is modelled as one unit, but operated at two operation points, namely DHW preparation and space heating, the average efficiency $\eta_{\text{op},HP,t}$ at each time t, is calculated as the energy weighted COP of both operation points, weighted by the respective heat demands $\dot{Q}$.

$$\eta_{\text{op,HP},t}=[\dot{Q}_{DHW,t}COP(T_{\text{amb},t},T_{DHW,t})+\dot{Q}_{sh,t}COP(T_{\text{amb},t},T_{sh,t})]\cdot\frac{1}{\dot{Q}_{DHW,t}+\dot{Q}_{sh,t}}\forall t\in T\quad [-] \tag{17}$$

The set temperature for space heating T_{sh} is derived from the heat curve for a given building and heat distribution system using the ambient temperature T_{amb}.

The maximal thermal capacity of the heat pump changes with ambient temperature. This is accounted for by introducing a normalized maximum heat pump capacity $\gamma_{\text{hp,max,t}}$ in Eq. (12), which is linearly dependent on the ambient temperature $T_{\text{amb},t}$.

$$\gamma_{\text{max,HP},t}=b_0+b_1\cdot T_{\text{amb},t}\quad \forall t\in T\quad [-] \tag{18}$$

The coefficients b are obtained using a least square fit on HP data from manufacturers [17].

3.2.2. Investment, lifetime and interest rate

The investment costs for each technology are separated in fixed costs, and specific costs depending on the unit size. The fixed costs are independent of the unit size and specific costs are modelled linearly in the given range. Costs for wear and tear are accounted for by fixed annual operational costs. The used cost data is listed in Table 1.

The specific investment cost per litre storage is transformed into cost per kWh using the specific heat capacity of water in kWh/(l K) and the maximum allowed storage temperature range ΔT, which is set to 10 K. The specific cost per litre is 1.4 €. The interest rate is set to 4% and the lifetime used for calculation is 20 years.

4. Scenarios

The introduction (Section 1), identified that changed operation of the HP systems, due to variable prices or PV self-consumption, might lead to adjustments of today's sizing procedures, presented in Section 2.4. This work investigates the impact of the following four input parameters on the system sizing: (1) building physics,

Table 1
Cost assumptions including VAT.

	Fixed	Specific	
Installation costs:			
ASHP	2000 €	1500	€/kW
Electric boiler		60	€/kW
Thermal storage		60/120	€/kWh[1]
Annual operation &maintenance costs:			
ASHP		1.1	% of invest
Electric boiler		1.4	% of invest
Thermal storage		0	% of invest

[1] Allowing ΔT = 10 K/ΔT = 20 K in storage.

Table 2
Investigated scenarios, reference scenario underlined.

Building	DWH [n persons]	PV [kWp]	El. price Variability	Storage ΔT [K]
Unrefurbished	12	0	Constant	10
<u>Refurbished</u>	6,<u>12</u>,18	<u>0</u>–160	<u>0</u>–100%	<u>10</u>,20
New	12	0	Constant	10

(2) number of persons for DHW consumption, (3) PV electricity generation, and (4) variability of the electricity price. The resulting scenarios are listed in Table 2 and are explained in detail in the following section.

4.1. Reference scenario

The reference scenario is a refurbished German multi family house, with six flats each containing two occupants [32] and without on-site PV generation. A constant electricity price at 24 ct/kWh for the electric demand is applied, and 19 ct/kWh for electricity consumed by the HP system. Potsdam is taken as the reference climate location and measured climate data for 2012 for the given station is used as input.

To investigate the system sizing if either covering the DHW or the space heating demand alone, two additional scenarios are applied, which contains the space heating and DHW demand of the reference scenario separately (see "Single operation" in Fig. 10).

4.2. Building physics

To analyse the impact of different heat load profiles an unrefurbished, a refurbished and a new building are simulated, based on the building parameters provided in [32]. The specific annual heat demand is 188 kWh/m^2, 69 kWh/m^2 and 36 kWh/m^2, respectively.

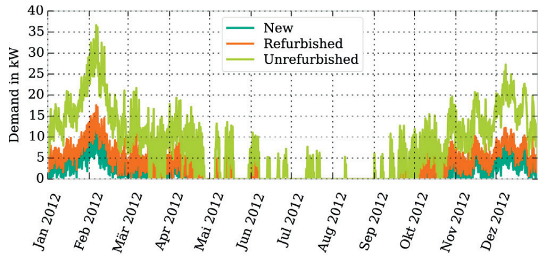
The space heating load is calculated using a 5R1C building model. The model is based on the simplified hourly method according to DIN EN 13790 [33] for calculating heating and cooling demands. The heat load model is presented and validated in [34]. Inputs to the model are irradiation, building physics and internal gains. Internal gains are calculated based on building occupancy and the use of electric devices, obtained from the synPRO behavioural model [35].

Fig. 3 shows the 15 min heat demand and the sorted annual duration curves for the three scenarios. The figure shows that increased energy efficiency of the building, decreases the load peaks and the number of days where the heating system is activated. Particularly during summer and changing season, increased building efficiency leads to fewer heating days.

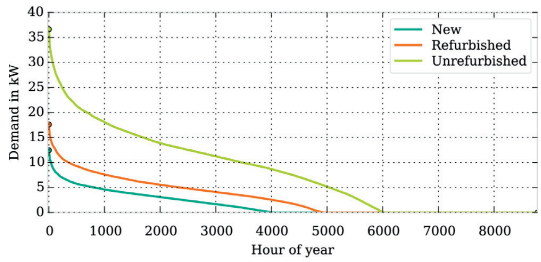
4.3. DHW loads

The influence of increased DHW loads is investigated by changing the number of inhabitants in the reference case, to 8 and 16 people. The domestic hot water consumption is obtained using a stochastic bottom-up model (synPRO), which links user behaviour to the number of tappings, dependent on time of the day. The energy demand for each tapping is calculated based on the volume flow rate, and on the hot and cold water temperatures, taken from VDI 2067 [36]. Detailed information and validation of the DHW load profiles are given in [34].

Fig. 4(b) shows the DHW annual duration curves. It can be seen that the yearly peak increases non-linearly with increasing amount of people, and a smoothing of the load curve can be observed. Further, the shape of the duration curve is less steep in the hours of high demand when adding more people.

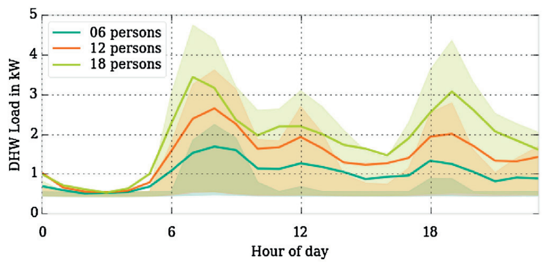


(a) Space heating demand for each 15 min.

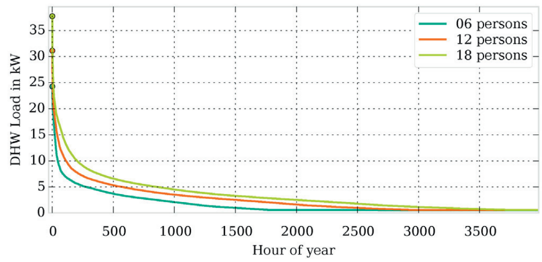


(b) Annual duration curve for each 15 min.

Fig. 3. Scenarios for space heating for different building physics.



(a) Hourly mean daily profile over the year and 0.25/0.75 quantiles.



(b) Annual duration curve for each 15 min.

Fig. 4. Scenarios for DHW consumption with 6, 12 (reference) and 18 persons in the house.

4.4. On-site PV electricity generation

The effect of on-site PV generation is investigated by increasing the size of the installed PV capacity incrementally from 0 to 160 kWp. The PV plant is oriented southward and 35° inclined. A feed-in tariff of 0.11 €/kWh is used, together with a constant electricity price. The generated PV electricity is first consumed by the electric building loads, and the remaining is provided to the heat pump.

PV electricity generation is obtained using a PV model based on the work of Huld [37], which itself is based on the work of King [38] and is widely used in academic literature (e.g. [39]). It is a linear regression model with logarithmic and squared predictor variables, such as ambient temperature and in-plane global irradiation. Electricity losses due to high module temperatures are accounted for by approximating the module temperature T_{mod}, according to the ambient temperature T_{amb} and the in-plane global irradiation E^{glob}_{poa}:

$$T_{\mathrm{mod}}(E_{poa}, T_{amb}) = T_{amb} + \rho \cdot \frac{E^{glob}_{poa}}{E^{glob,STC}_{poa}} \quad [\mathrm{C}] \tag{19}$$

$E^{glob,STC}_{poa}$ denotes the in-plane global irradiation at standard conditions (1000 W/m^2, 25 °C), and the factor ρ corrects for different types of PV installation and arrangements according to [40].

4.5. Variable electricity price

To investigate the influence of variable electricity prices on the system sizing, a variable electricity price is constructed by dividing the electricity price into a fixed and a variable part. For all scenarios, the yearly mean electricity price is kept constant at 19 € ct/kWh, which corresponds to the heat pump tariff in Germany. The hourly price for electricity of the German day-ahead market is used as a signal for the price variability. Both climate and electricity price time series are taken for the year 2012 to keep the correlation between the price signal and climate conditions. The price of electricity p at time t is calculated for each scenario k according to:

$$p_{\mathrm{demand},t,k} = 19.0 \cdot (1 - v_k) + 19.0 \cdot v_k \cdot \hat{p}_{\mathrm{EEX},t} \quad [\mathrm{ct/kWh}] \tag{20}$$

where v_k is the price variability in percent and $\hat{p}_{\mathrm{EEX},t}$ is the normalized price signal.

$$\hat{p}_{\mathrm{EEX},t} = \frac{p_{\mathrm{EEX},t}}{\bar{p}_{\mathrm{EEX}}} \quad [-] \tag{21}$$

The normalized price is the hourly day ahead price for electricity at the European Energy Exchange $p_{\mathrm{EEX},t}$, divided by the annual mean electricity price $\bar{p}_{\mathrm{EEX}}$. The variable share of the price is increased stepwise up to 100%, while the mean value is kept constant. Fig. 5 shows the daily mean electricity price curve averaged for one year, for the different price variability scenarios of 0–100%. It can be seen that fluctuations increase with increasing variability, while the shape of the price signal is conserved.

Fig. 6 shows the annual duration curve of the variable electricity price scenarios. Here, the absolute value of and the number of peak hours of both positive and negative prices, increase with increased variability. Notice that part of the scenario space is unrealistic to be applied to the end customer and is used to study the impact of extreme prices.

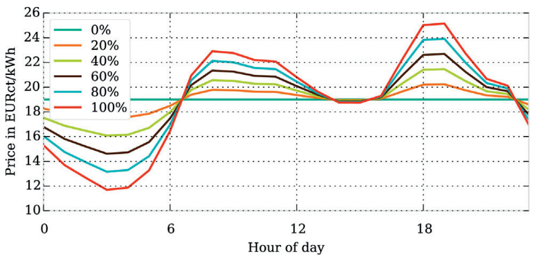


Fig. 5. Daily mean profiles for the electricity price with a variability from 0% to 100%.

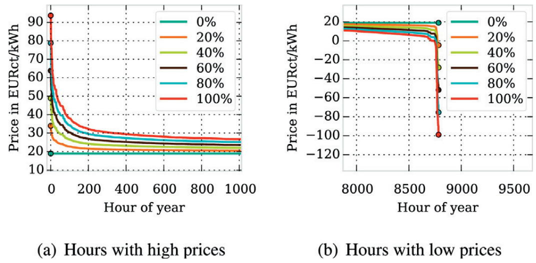


Fig. 6. Selected parts of the annual duration curve for the variable price scenarios.

4.6. Operation strategy of the storage

The thermal storage temperature is controlled to be within a tolerance band of maximum 10 K above the set point, which is the minimum temperature required for adequate thermal comfort. The tolerance band is limited to 10 K to avoid high storage temperatures, as this increases the storage losses and lowers the heat pump efficiency. However, in some cases it could be beneficial to allow for higher storage temperatures, which is also technically possible. For instance, when electricity is cheap, or if PV self-consumption should be increased. By increasing the maximum allowed storage temperature additional storage capacity can be enabled [10].

The effect of an operation strategy which allows for over heating of the storage, is analysed for the PV and the variable electricity price scenarios. Hence, these scenarios are both run with 10 K (reference) and a 20 K allowed temperature tolerance band in the storage. For the 20 K scenarios, the minimum storage capacity resulting from the reference scenario is set as lower bound, to avoid a reduction of storage size due to the now eased limitation.

5. Results

The scenarios described in Section 4 are applied to the optimisation model presented in Section 3 to investigate the influence of space heating load, DHW load, PV generation and variable electricity prices on the operation and system sizing. A total of 37 optimisation runs are performed, using a 15 min time resolution.

5.1. Operation

The cost-optimal operation of the heat pump and the electric back-up heater (EB) is obtained at every time step for the cost-optimal system size. Hence, this reflects the best possible control using perfect foresight and no mismatch between the optimisation model and the real world. As the operation costs for each technology are minimized, the control makes a technology to be operated when prices are low and efficiency is high, and the storage will be used when gains exceed the losses.

5.1.1. Operation over time

Fig. 7 shows a carpet plot of the HP operation in the reference scenario, for each hour of the year. It can be seen that during the cold periods (from hour 30 to 50 and 330 to 350) the heat pump is constantly operating at its maximum and not modulating its capacity. The impact of the reduced maximum heat pump capacity with falling ambient temperature, is visible when comparing the peaks of summer and winter operation in the presented graph. When the heat demand is reduced e.g. during changing season, the heat pump is operated at part load, which is also the case during night and early

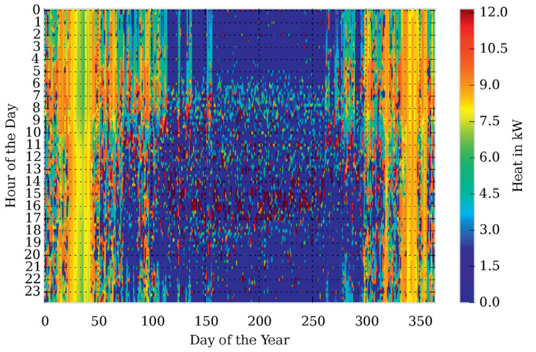


Fig. 7. Operation of the heat pump in the reference scenario.

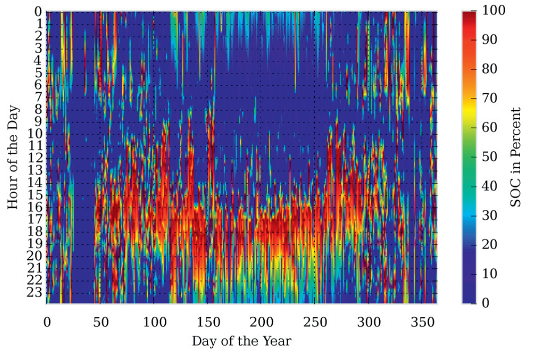


Fig. 8. Storage state of charge (SOC) in the reference scenario.

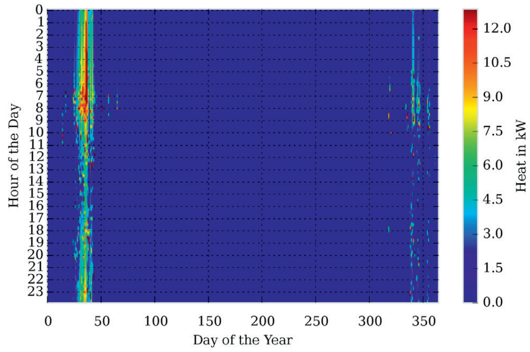


Fig. 9. Operation of the electric back-up heater (EB) in the reference scenario.

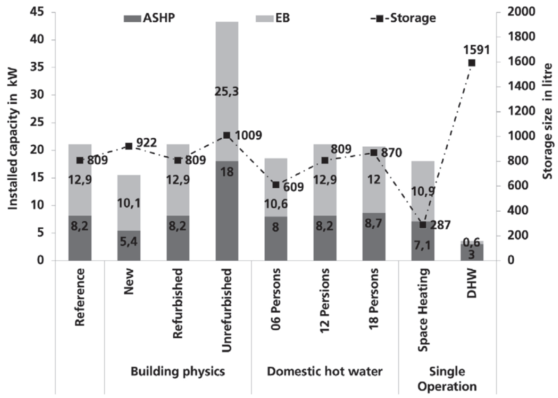


Fig. 10. Optimal system sizing with changed thermal demand.

morning hours. In the summer months, the heat pump is operated mostly during hours with high ambient temperature where heat pump efficiency is high and operational costs are low. During these times, the heat pump is often operated at its maximum capacity to charge the storage.

The storage content for each hour of the year is shown as state of charge (SOC) in Fig. 8. The storage is charged at hours with low operational costs which occurs during daytime when the ambient temperature, and thus the COP of the HP, is high. Especially in summer, the storage is charged at the latest possible time of the day, to preserve heat only as long as needed (until the next morning), in order to limit storage losses. During the coldest days of the year, storage is mostly unused and contributes only to cover short term peak loads. During this part of the year the heat pump capacity is fully used to cover the space heating demand, and there is no extra capacity available for charging the storage. Hence, during the coldest days, the electric back-up heater is used to support the heat pump operation, which is clearly seen in Fig. 9.

The operational characteristics of the reference scenario described above holds for the other scenarios investigated, although the hours of operation change according to the cost. That is, with high electricity prices during daytime, the HP is operated at night, and with high PV generation, the HP is operated during daytime. In general, the characteristics of the system operation is as follows: (1) the possibility to charge the storage in favourable times is utilized when the system is not operated at its limit, and (2) the hours when the storage is charged are dependent on the economic incentive which varies between the scenarios.

5.1.2. Heat generation by source

Investigating the annual thermal energy generation, the heat pump provides approximately 93% of the needed annual heat demand for most scenarios. The exemptions are commented in the following. In the "100%" variable price scenario, the HP covers 91% of the annual heat demand, as the EB is used more often to profit from negative prices. In the pure (or "single operation") space heating scenario, the storage size is reduced and compensated with increased use of the electric back-up heater, resulting in a share of 91% HP heat. In the pure DHW scenario, the heat pump together with a larger storage, covers 100% of the heat production.

5.2. Technology sizing

This section analyses the cost-optimal design of the HP, the electric back-up heater and the thermal storage, for each of the investigated scenarios.

5.2.1. Influence of building physics and DHW loads

Fig. 10 shows the installed capacity of the heat pump, electric back-up heater and storage when the thermal loads are changed. The reference scenario has a 8.1 kW_{th} heat pump and a 12.9 kW_{th} electric back-up heater, which results in a ratio of back-up-to-HP-capacity of 1.59. The storage size is 808 l, which equals 99 l per kW_{th} installed heat pump capacity.

When the space heat demand is increased in the unrefurbished scenario, the total installed capacity of HP and electric back-up heater increases to 43.3 kW_{th}. However, the ratio of back-up-to-HP-capacity decreases to 1.41, and the specific storage volume also decreases to 55.5 l per kW_{th}.

When the space heat demand is reduced in the new building, the total heat generation capacity is decreased to 15.5 kW_{th}, however the ratio of EB-to-HP-capacity is increased to 1.87. Surprisingly the storage volume increases although thermal load is reduced, and the specific storage volume per installed capacity of HP increases to 169.5 l per kW_{th} HP. As the load duration curve of the space heat demand, shown in Fig. 3, flattens with increased energy efficiency of the building, a larger share of the heat load can be covered with a smaller heat pump unit. To cover the peaks larger back-up heater and storage capacity is needed though. Since the DHW is becoming more dominant in the total heat demand in well insulated buildings, the results indicate that for new buildings, it is more cost efficient to invest in a large storage and cheap electric back-up technology, rather than in a large HP capacity.

In the pure space heat demand scenario, where DHW is neglected, the ratio of EB-to-HP-capacity is only slightly decreased to 1.53, whereas the specific installed storage capacity is decreased considerably to 39 l per kW_{th} HP. Compared to the storage size of the reference case which includes the DHW load, this affirms that the storage is mainly needed for covering DHW peaks.

Compared to changed building physics, changed domestic hot water consumption has less impact on the system sizing. Increasing the number of persons from 6, 12 to 18, heat pump capacity is hardly affected going from 8, 8.2 to 8.7 kW_{th}. The electric back-up heater capacity is increased from 6 to 12 persons, but slightly decreased from 10 to 18 people. The storage capacity is always increased with in increased number of persons, however the incremental increase flattens out with higher number of people, from 33 l per person (from 6 to 12 persons) to 10 l per person (from 12 to 18 persons). This is explained by the lower relative peak loads of the annual DHW load with increased number of persons (see Fig. 4). With a flatter demand curve the heat pump, showing higher investment costs but also lower operation costs, becomes an increasingly attractive option compared to the electric back-up heater. This leads to reduced specific storage and electric back-up heater capacity per person, with increased number of people.

In the pure DHW scenario, where space heating is neglected, the size of the electric back-up heater is reduced to only 20% of the heat pump capacity, and specific storage size is increased to 529 l per kW_{th} HP. Indicating that storage is used for peak coverage and charged over a longer time period.

5.2.2. Influence of PV size

Fig. 11 shows technology sizing for the PV scenarios with an allowed storage ΔT of 10 K and Fig. 12 shows the results for a ΔT of 20 K.

In general, the results show that increased PV size does not influence the size of the heat technologies, but the need for storage increases moderately, especially for PV sizes up to 50 kWp.

With increasing PV and a ΔT of 10 K, the heat pump capacity remains almost unchanged, the electric back-up heater size is slightly decreased, and the storage is slightly increased. This indicates that the thermal demand is the determining factor for sizing of the HP and back-up heater, whereas the storage is affected by the available PV.

When PV size is increased from 0 up to 5 kWp, the storage size remains approximately unchanged. From 5 kWp to 10 kWp, the storage is increased by 13.5 l/kWp and stagnating from 10 kWp up to 20 kWp. Further PV increase up to 60 kWp, and 100 kWp, leads to a storage growth of 4.5 l/kWp and 3 l/kWp, respectively. From 100 to 160 kWp, the storage is increased by 1.5 l/kWp. This clearly indicates diminishing returns of increased storage after 20 kWp.

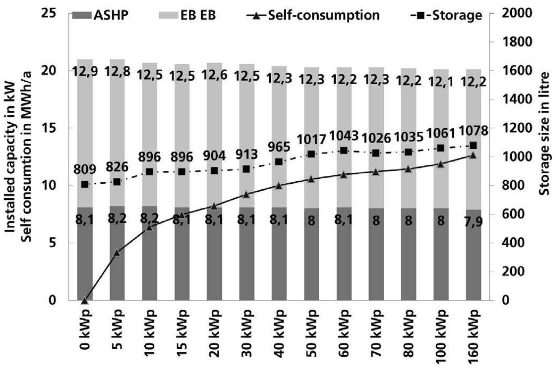


Fig. 11. Optimal system sizing with increased PV installation and an allowed storage hysteresis of 10 K.

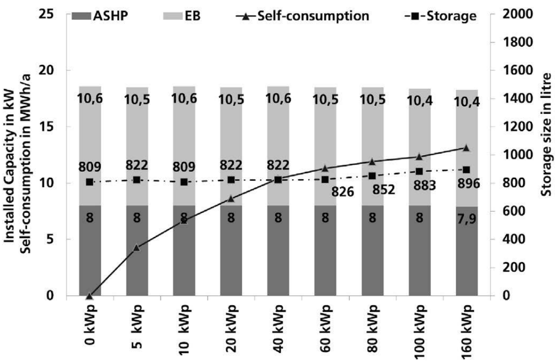


Fig. 12. Optimal system sizing with increased PV installation and an allowed storage hysteresis of 20 K.

Fig. 11 shows that the storage size does not increase for PV sizes from 10 to 30 kWp. The reason is explained in the following. If left as free variable, the cost-optimal size of the PV is 9.3 kWp. In this case, the electricity surplus in the morning and evening hours is now frequently above the minimum required for heat pump operation and is directly used in the HP. As a consequence, the need to store heat for the late afternoon hours decreases. Beginning at 9.3 kWp, the objective function hence enters a flat minimum up to 30 kWp. A further reason that the storage is not increasing is that PV generation appears mainly in summer where thermal demand is mostly for DHW. As a result already for small PV sizes the storage is sufficient to cover DHW demand until the next day. Hence increasing the storage offers only limited additional benefits. This corresponds well with the findings of more detailed studies on PV self-consumption with heat pumps reported in [10,14,6].

When the maximum allowed ΔT of the storage is increased to 20 K (see Fig. 12), a change in storage capacity is hardly observed up to 60 kWp installed PV capacity. From that point onwards, an almost negligible growth of 0.5–0.84 l/kWp is observed. Thus, the option of allowing higher storage temperatures in situations with PV production removes the need for larger storage from an investment point of view. However, increasing the storage temperature comes with a loss of efficiency, which should be examined in detailed simulations.

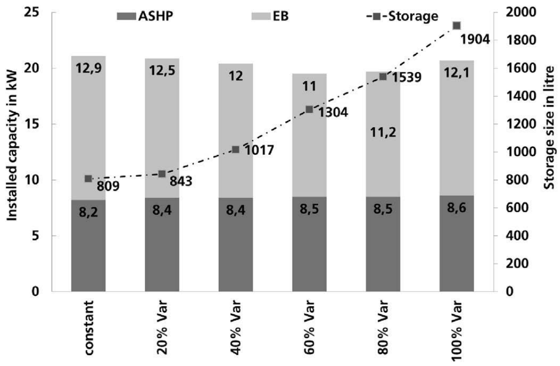


Fig. 13. Optimal system sizing with increased price variability and an allowed storage hysteresis of 10 K.

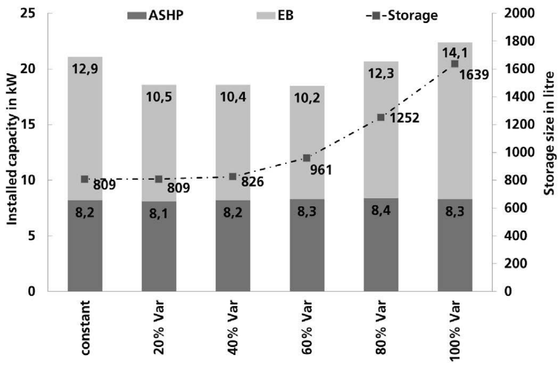


Fig. 14. Optimal system sizing with increased price variability and an allowed storage hysteresis of 20 K.

5.2.3. Influence of variable electricity price

Fig. 13 shows the system sizing with increasing variable electricity prices with an allowed storage ΔT of 10 K, and Fig. 14 shows the results for a ΔT of 20 K. Generally, increasing price variability leads to slightly larger heat pump sizes, increased storage capacity and changed sizing of the electric back-up heater.

Up to 40% price variability, the storage size increases non-linearly, the size of the heat pump remains almost unchanged (increased by 2.5%) and the size of the electric back-up heater is decreased by 8%. From 40% onwards, the storage size increases linearly up to 1903.5 l at 100% price variability, where it is charged in hours of low electricity prices. From 60% price variability, the installed heating capacity of the electric back-up heater starts to slightly rise again, which is due to the increased occurrence of negative electricity prices.

Allowing the storage to be overheated, increases the capacity of the heat storage even though its volume is unchanged. As shown in Fig. 14, the electric back-up heater's capacity is immediately reduced due to the increased storage capacity. The storage size remains unchanged up to a variability of 40% and then increases up to 1638 l, while the electric back-up heater capacity is increased by 40%.

Comparing the variable price scenario to the PV scenario, it can be seen that variable prices lead to a stronger increase in storage size than PV. The reason is that price variability occurs during the whole year and thus also in times with high thermal demand when there is sufficient load to be shifted. Whereas in the case of on-site PV, shifting mainly occurs in summer and during changing season when space heating demand is comparably low. Hence, larger storage size with PV does not offer the same benefits as with variable electricity prices.

Table 3
Comparison of optimised storage sizing results with recommended values.

	Base-line	New	Un-ref.	6 Pers.	18 Pers.
Number of persons	12	12	12	6	18
DHW demand [MWh/a]	12.6	12.6	12.6	8.8	16.7
Heating demand [kWh/a]	25.8	13.1	70.6	25.8	25.8
Heat covered by HP [%]	93	92	93	93	93
Storage optimized [l]	809	922	1009	609	870
Storage lower value [l]	635	577	816	454	791
Storage middle value [l]	1420	1101	2431	1239	1576
Storage upper value [l]	1903	1423	3423	1722	2059

6. Discussion

In this section, the findings are further analysed and compared to recommended sizing procedures. Additionally, the influence of selected model assumptions is discussed.

6.1. Comparing the results to recommended sizing procedures

The main question of this study is whether HP system sizing procedures need to be adjusted when variable prices and PV will be increasingly introduced in the residential sector. In the following, the findings of this study are compared to the manufacturers recommendations for sizing described in Section 2. The main numbers are listed in Table 3.

As shown in Section 5.1.1, the share of heat covered by the heat pump, resulting from the optimisation results, is around 93%, whereas the recommended value according to [20] is above 95%. Hence, the model chooses a slightly smaller HP size than recommended. However, the numbers are so close that it can be concluded that today's recommendations lead to almost optimal heat pump and electric back-up heater sizes.

Regarding the optimised storage size when compared with the results of current sizing recommendations (see Section 2), three different storage sizes are calculated:

(a) A lower storage size without blocking hours, where the minimum needed storage size for safe HP operation is ensured, see Eq. (4)
(b) A middle storage size, accounting for blocking hours and assuming a building with high thermal inertia, see Eq. (6).
(c) An upper storage size, accounting for blocking hours and assuming a building with low thermal inertia, see Eq. (7).

The needed storage size for DHW is calculated using Eq. (3), and added to the buffer tank for all three storage cases.

The results in Table 3 show that the optimised storage values lie 9–37% above the lower size of the manufacturers recommendations. This indicates that for the given scenarios, even for a variable speed heat pump, a small storage is economically interesting.

When the storage sizing accounts for blocking hours and high thermal inertia of the building and the hydronic system, the recommended storage size is approximately 1.2–2.4 times the optimised values. Sizing according to the middle and upper storage values, leads to storage sizes that are 1.5–3.4 times the optimal solution. Hence, sizing respecting blocking hours leads to suboptimal big storage sizes from an investment point of view. On the other hand, blocking-hours have not been included in the optimisation model, if done so, larger storages might have been experienced.

Comparing the sizing recommendations with the results obtained by varying electricity price and PV size, shows that the currently recommended storage sizes are sufficient to cover most of the scenarios. Thus, most heat pump systems found in the field today can be seen as smart grid ready, although controls need to be adjusted. For the scenarios allowing overheating of the storage (ΔT = 20 K), the need for larger storage is almost eliminated, even when compared to the lower value of the sizing recommendations.

6.2. Assessing model assumptions

One reason that optimisation results are favouring smaller storage sizes is due to the optimal control, which utilises the installed storage capacity in the best possible way. Another reason is the perfect foresight, which eliminates the need for safety margins for storage and unit sizing, since there is no such thing as an unexpected event in the calculations. Further, since the storage is modelled as a mixing tank serving both space heating and DHW demand, the volume can be used for both purposes and thus more efficiently than in a real system – even if stratified. Nevertheless, the calculated results are close and consistent with current recommendations.

For variable speed heat pumps, the efficiency decreases with increasing the thermal output from part load towards full load conditions. In the current MILP model formulation, to avoid non-linearity, heat pump efficiency is set independent of the part load ratio. Hence heat pump operation at full load conditions is not penalized in the objective function. This probably leads to smaller heat pump sizes and a more aggressive operation of the heat pump and the storage.

7. Conclusion

Variable end-use prices for electricity and increased penetration of PV in the residential sector, offer new possibilities and challenges for heat pump operation. In this work, the optimal investment and operation strategy for an ASHP system is analysed using MILP. The sizing results are compared to currently applied sizing procedures. The findings show that today's heat pump and back-up heater sizing is close to the optimisation results and does hardly change if PV and variable electricity prices are introduced. However storage size changes depending on the scenario.

In the scenarios where installed PV capacity is below 30 kWp (corresponding to 2.5 kWp per person) and where the variable share of the electricity price is below 40% (±3.8 € ct/kWh), a storage increase of maximum 30% compared to the reference scenario is sufficient. However, if the storage is allowed to be overheated, even in these scenarios, no change in sizing is necessary. Even though this might come at a cost of increased storage losses and decreased heat pump efficiency.

Hence, based on the given system and price assumptions, the following statements concerning future sizing procedures are made:

1. Thermal demand determines and will determine the sizing of the heat pump and the electric back-up heater.
2. With on-site PV, additional storage capacity of 4.5–9 l/kWp is beneficial. However, if overheating of the thermal storage is allowed, investing in larger storage is not economically viable under current conditions.
3. The optimal PV size for the given case study is between 9.3 and 20 kWp, which corresponds to a range of 0.8–1.6 kWp PV capacity per person.
4. With variable electricity prices, the need for storage capacity rises. Also if overheating of the storage is allowed, additional storage capacity is economically viable. However, up to a price variability of 40%, no or only modest storage increase is needed. This need could be further reduced when actively using the building's thermal mass.
5. Current system sizing procedures correspond well with the findings of the optimisation, and if sizing recommendations are applied in a conservative way (see middle range in Table 3), this will result in sufficiently large storage capacity for the majority of the scenarios. Thus, control might be of more importance than sizing for enabling flexibility from heat pumps.

As a conclusion, the current system sizing as applied in the German residential sector today, does not need radical changes if PV or dynamic prices are introduced. They can thus be seen smart grid ready, given the prior that optimal or close to optimal control schemes are applied. Storage sizing for blocking hours as applied in Germany already leads to sufficient or even too large storage capacity. The storage capacity could be used in a more optimal way than done today, by changing controls and allowing higher storage temperature, providing flexibility for the power system and end customers.

If increased storage and HP capacity is politically wanted or needed to increase flexibility, strong economic incentives or reduced specific investment costs have to applied to motivate heat pump users to invest.

8. Outlook

The findings of this study will be further tested in detailed simulations to investigate the effect of imperfect controls, decreasing part load efficiency of the heat pump and storage stratification on the presented results. The role of actively using building's thermal mass will be investigated in future studies.

Acknowledgements

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Article VII

Large scale introduction of Zero Energy Buildings in the Nordic Power System

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***Abstract*— The objective of this paper is to investigate the effects of a large deployment of Zero Energy Buildings (ZEB) in Norway on utilization of hydropower in 2030. A ZEB is a building with low energy demand, which produces on an annual basis, as much renewable energy as its energy consumption, and is considered as one of the key elements to reach EUs 20-20-20 goals. The simulations are conducted using a detailed power market model of the Nordic countries, i.e. Denmark, Norway, Sweden and Finland. The findings show that ZEBs mainly influence the optimal operation of the power system in two ways, 1) through their lower electricity demand, and 2) through their on-site PV production. Hydro power contributes to 50 % of the total power generation in the Nordic countries. Because PV generates power before the spring flooding occurs, the power producers go lower in the hydro reservoirs, thus lowering the spillage of water, which increases the hydro power production with 0,5 %. Further, the introduction of ZEBs leads to 4-6 TWh lower coal power production, reduced power price, and 17-26 TWh increased export from the Nordic countries.**

***Index Terms*— Distributed power generation, Energy efficiency, Load profiles, Optimal generation mix, Policy implications, Power Market Simulation, Solar Power, Zero Energy Building.**

I. Introduction

According to EU's Energy Performance of Buildings Directive (EPBD), all new buildings in Europe shall be nearly ZEB by 2020 [1]. A zero energy building (ZEB) is an energy efficient building, which has the capability of generating energy that corresponds to its demand on an annual basis [2]. A large introduction of ZEBs will significantly change the way buildings are integrated in the power system, and system operators must consequently prepare for changes in load profiles. However, the knowledge on the aggregated impact of ZEBs is so far limited because the actual number of such buildings is still very small. This paper contributes to fill this knowledge gap by estimating the effect on the aggregated national load profile of a large deployment of ZEBs in Norway. The novelty of the presented work is that it links the impact of binding legislations on building's energy consumption with power market analysis on an aggregated level.

This paper is structured as follows. Section II shortly highlights the motivation of the present work, while Section III describes the power market simulation model and the six model cases. Section IV presents the methodology of the load profiles of ZEBs. The results are analysed in Section V, and discussed in Section VI. Conclusions are made in Section VII.

II. Motivation

When studying the grid load on a short term, often different statistical models such as regression models, time-series models (AR, ARIMA, SARIMA), distribution models (normal, log-normal or log-logistic) [3], or intelligent models (ANN or machine learning techniques) [4], are used. Such models use information of the load of the previous day in addition to climate data and seasonal and daily patterns [5].

For long term analysis, the load must be predicted for a whole year or several years, but still with hourly or sub-hourly time resolution. Current practice on load predictions for power system analysis mostly uses hourly consumption data combined with historic growth of annual demand. Thus, the load prediction is based on snap shots of today's building stock, and is not able to account for lower energy demand (more energy efficient buildings), or increased electric heating through heat pumps (HP). There are some studies which aim to include changes of the building stock. Henning & Palzer [6] treat the heat and electricity demand separately, and evaluates when to use electricity for heating and/or transport by minimizing the national energy consumption, but do not take into account the behaviour of actors in the power market. Veldman et al.[7] and Boβman et al.[8] take today's aggregated electricity load profile and add changes on top of this according to assumed future development of population, electric vehicles (EVs) and HPs. Veldman capture the impact

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Acronyms	
BAU	Model case: Business as usual
COP	Coefficient of performance (HP efficiency)
DHW	Domestic Hot Water
DIR	Model case: all ZEBs have direct electric heating
EMPS	Power system modelling tool
EPBD	EU's Energy Performance of Building's Directive
EV	Electric Vehicles
HP	Heat Pump
HP	Model case: all ZEBs have HPs
OTH	Model case: all ZEBs have non-electric heating (i.e. they are heated by other energy carriers)
PAS	Model case: all ZEBs have HPs, but without PV
PV	Photovoltaics, i.e. solar power
SUN	Model case: no ZEBs, but with 17 TWh PV
ZEB	Zero Energy Building

of households on a local grid level, whereas Boβman studies the national load. However, the impact of more energy efficient buildings on the national electric load is yet to be investigated. This work captures the reduced temperature dependency of heat demand of energy efficient buildings compared to existing buildings, and links this to electric heating technologies when predicting the total load profile.

III. METHODOLOGY

We investigate the operation of the Nordic power system in 2030 while replacing 50 % of the building stock in Norway with ZEBs. The analysis is performed by use of a stochastic multi-area power-market model that is divided into 12 regions reflecting the price areas of the Nord Pool Spot market.

A. EFI's Multi-area Power-market Simulator (EMPS)

EMPS [9] is a model for stochastic optimisation and simulation of hydro-thermal power markets, with focus on economic optimisation. It has a detailed description of the generation system and uses an algorithm based on Stochastic Dynamic Programming to first find the shadow cost ("water value") of the hydro stored in reservoirs, and subsequently simulates the market based on these costs as well as the costs and characteristics of renewable and thermal generation. EMPS is the most widely used model for medium and long term power market analysis and price forecasts in the Nordic power market. In this study, historic years from 1981-2011 are used when constructing stochastic scenarios of the hydrological inflow, and of the temperature dependent electricity demand (see Section IV.A). A model version with 3-hourly consecutive time resolution is used.

B. The Nordic power system in 2030

The EMPS model simulates the operation of a given power system. Thus, assumptions are made on the development of the Nordic power system towards 2030, e.g. interconnections, production capacities and demand in the various countries. In addition to today's power lines, the following cables are assumed built within 2030: "Viking Link" between Denmark and UK, "North Sea Link" between Norway and UK, "NordLink" between Norway and Germany, and "COBRA" between Denmark and Holland. Production capacities and demand are based on official national projections for the respective Nordic countries. TABLE II. shows that the Nordic region in 2030 expects a positive power balance of 36 TWh in the "business as usual" (*BAU*) case. Based on [10], the prices of oil, gas and coal in 2030 are respectively set to 41, 25 and 11 EUR/MWh, and the cost of CO_2 at 19 EUR/ton.

C. Model cases

The *BAU* case assumes a 'normal' development of the building stock, reflecting some energy efficiency measures due to existing policies. Three ZEB cases are established, where it is assumed that 50 % of the building stock are ZEBs. This reduces the total heat demand of buildings in Norway by 20 % compared to the *BAU* case. Since electricity can be used for heating purposes, the total electricity demand of ZEBs depends on the choice of heat technology. The "Direct Electric" (*DIR*) case assumes that ZEB's heat demand is met by direct electric heating, whereas heat pumps are used in the *HP* case, and other energy carriers, such as gas or bio fuel, are used in the *OTH* case (see TABLE I).

On-site power production in the ZEBs is assumed to be PV, as previous work shows that this is the most realistically available on-site energy generating technology in ZEBs [11]. Further, we assume that PV compensates for the ZEB building's electric specific demand in 2030, which results in 17 TWh PV produced annually, equal to a required installed capacity of 20 GW in Norwegian buildings. In order to investigate the two effects of ZEBs separately, i.e. reduced power demand and on-site PV production, two additional model cases are applied. *SUN* investigates the effect of 20 GW installed PV while keeping electricity demand unchanged, and *PAS* which investigates the *HP* case without solar power.

TABLE I. MODEL CASES. ELECTRICITY DEMAND AND PV GENERATION IN NORWAY IN 2030 (TWH/YR).

Model cases	***BAU***	***SUN***	***PAS***	**ZEB cases**		
				DIR	***HP***	***OTH***
Electricity demand	**137**	**137**	**121**	**131**	**121**	**117**
ZEB buildings	-	-	21	31	21	17
Existing buildings	77	77	40	40	40	40
Industry & EVs	59	59	59	59	59	59
PV generation	-	17	-	17	17	17
Net electric demand	137	120	120	114	104	99
change from *BAU*		**-17**	**-16**	**-23**	**-33**	**-37**

IV. INPUTS

This section describes the sub-models that calculate the inputs of load profiles for electricity demand in buildings and transport, and production profiles for PV electricity.

A. Load profiles for ZEBs and existing buildings

Based on previous work in [12]–[14], aggregated hourly electricity load profiles of the building stock in Norway are developed. The load profiles take into account different development paths for ZEBs and their heating technologies.

The electric specific demand, i.e. electricity demand for lighting and other electric equipment, for 11 different building categories are calculated by use of regression models, based on a methodologies developed in [13][14]. The findings from [13] showed no clear trend of lower electric specific demand for energy efficient buildings, and thus it is here assumed that the electric specific demand in ZEBs is equal to that in existing buildings.

The heat demand of buildings, i.e. space heating and domestic hot water (DHW) demand, on the other hand, is dependent on outdoor temperature and on the technical standard of the building. The EMPS model requires scenarios of electricity demand that are linked to the historic years of water inflow. To generate the scenarios for heat demand, we use the hourly outdoor temperatures for representative locations in five regions of Norway for the scenario years a = 1981–2011. Based on regression models in [12], the temperature dependent heat demand is predicted for each of the building categories i, in each model region r. The findings from [12] showed a clear trend of the heat load profiles of ZEB buildings being lower, both regarding peak load, and annual heat demand, when compared to existing buildings.

Next, as shown in Figure 1, the electricity consumption for heating is found by choice of heat technology (direct electric heating, heat pumps or other non-electric technologies such as bio or district heat) to cover the building's heat demand, multiplied by the respective efficiency.

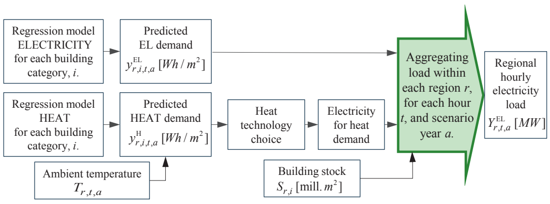

Figure 1. Methodology for the building's total electricity load profile. The approach is applied to both existing buildings and ZEBs.

In the last step, the building loads y (r, i, t) in Wh/m^2 are multiplied by the regional building stock, S (r, i) in mill.m^2. The regional building stock of 2030 is found by the following methodology. The current stock, distributed by building type, is based on [15], [16] and distributed by region according to population [17]. With assumption on future population [18], and demolition of buildings that takes into account the actual age of the building stock, the total building stock is expected to increase from 355 mill. m^2 in 2010 to 448 mill. m^2 in 2030.

B. *Heat pump model*

In this work, it is assumed that HPs in residential buildings are air-sourced, and HPs in non-residential buildings are ground-sourced. The COP of the two are described in [11], and depends on the outdoor temperature.

C. *Load profile for Electric Vehicles (EV)*

The electric load profiles for vehicle charging are dependent on future deployment of electric vehicles, main charging technology and charging habits. By 2030, it is assumed that 50 % of a total of 3 million personal cars are electric. It is assumed that each car drives on average 12 000 km [19], with an electricity use of 0,2 kWh/km [20]. The share between home, work and fast charging are assumed to be 65 %, 25 % and 10 %, respectively, based on user surveys in [19] [21]. With these assumptions, the electric demand for EVs in Norway is 3,5 TWh, with a load profile as shown in Figure 2.

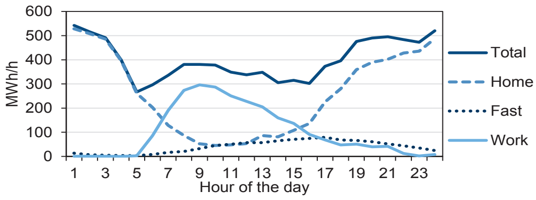

Figure 2. Daily profile of electric demand for EVs, total in Norway 2030.

D. *Profiles for PV generation*

The electricity production from PV panels are simulated in PVSyst [22]. Hourly production profiles where generated using the climatic conditions of a standard year, for each of the model regions. As an example, Figure 3 shows the PV production profile of region NO2.

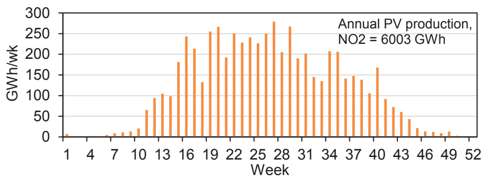

Figure 3. PV production, region NO2 in Southern Norway. GWh/week.

E. *Aggregated national load profile*

Through the regional outdoor temperatures from 1981–2011, 30 load profile scenarios within each region are now directly correlated to the hydrological scenario years.

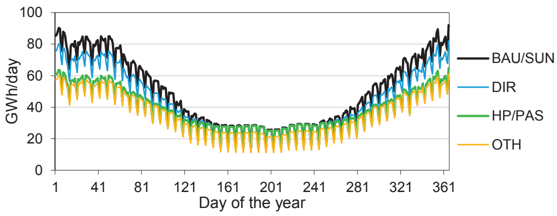

Figure 4. Power demand in region NO2 in Southern Norway in 2030, by model case (GWh/day). (Average of all 30 scenario years).

Figure 4 shows the average (of the 30 scenarios) aggregated total load, and underlines the importance of taking into account the temperature dependency of the load and the heat technology choice. The figure shows daily mean values, where weekends have lower power demand than weekdays. (The model input is however on an hourly basis.) As expected, the highest power demand is in the *BAU* case where no additional energy efficiency measures are taken. The three ZEB cases, *DIR*, *HP* and *OTH*, each show lower demand in winter. *DIR* has the highest demand as it reflects all heat demand is covered by direct electric heating, and *OTH* the lowest because it is only the electric specific demand of the

ZEBs that is included in the total electric load. Notice that the demand in summer is similar for all model cases as the electric specific demand and DHW demand is independent of temperature and building standard.

V. Results

The impact on the power system of a large roll out of ZEB buildings in Norway in 2030 is presented in the following.

A. Power balance

The actual power generation and consumption are a result of the generation capacity, the power demand and the endogenous power prices. TABLE II shows that when adding PV in *SUN*, or improving energy efficiency in *PAS*, the already considerable power export of 36 TWh increases to 49 TWh, whereas introducing ZEB buildings increases the export up to 62 TWh. As seen in the coming sub-sections, increased power surplus leads to lower power prices, and thereby also increased power consumption and lower thermal production (see also TABLE III).

TABLE II. Power Balance of the Nordic Region (TWh/yr)

	BAU	***SUN***	***PAS***	**ZEB cases**		
				DIR	***HP***	***OTH***
Production	453	469	451	467	465	464
Thermal	170	168	168	166	164	164
Wind	53	53	53	53	53	53
Hydro	231	232	231	232	232	232
Consumption	417	419	402	414	405	402
Balance	36	49	49	53	60	62
Change from *BAU*		+13	+13	+17	+23	+25

B. Reservoir levels of the hydro power

Figure 5 shows the weekly levels of the hydro power reservoirs in Norway throughout the year. Due to the 30 scenarios years, the possible outcome is wide, and for simplicity only the maximum and minimum levels, together with the average (solid lines) are shown for each model case in Figure 5. When compared to *BAU*, increasing the power generation by 17 TWh, in the *SUN*, *DIR*, *HP* and *OTH* cases, the reservoir level is shifted downwards about 10 % throughout the year, but the amplitude of the curves are similar. If nothing else changes, an increased production (PV) will increase the risk of water spillage when the spring

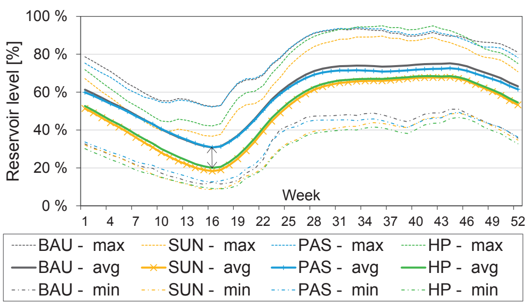

Figure 5. Hydro reservoir level, by model case, Norway total. (Weekly values of max, average and min reservoir level of 30 scenario years).

flooding occurs around week 17. The hydro power producers thus adapts by reducing their reservoir levels in order to maintain the relationship between the risk for flooding in spring, and rationing during winter.

Even though the PV production varies on an hourly level, there is little fluctuations in the monthly or annual production. Thus, when PV increases its power generation from the beginning of April (around week 15), it does so every year, and the hydro power producers are incentivized to empty their reservoirs further (to approx. 20 %) and hold back water when the flooding occurs. As seen in TABLE III, the reduced reservoir level decreases the spillage of water, and increases the annual hydropower production with 1.2 TWh.

C. Power prices

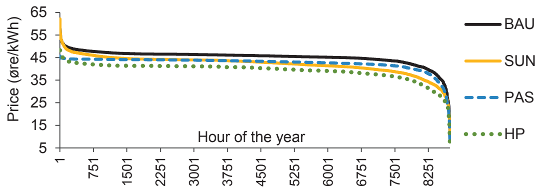

Figure 6. Power price duration curve for Southern Norway (NO2), by model case. (average of 30 scenario years).

Figure 6 indicates that the power prices are reduced by the introduction of ZEBs. As the prices from each case to another show similar trends in all regions, only the prices of region NO2 in Norway are elaborated here. NO2 is the area with the strongest interconnections to the European continent. On an annual basis, the power price declines from 45 øre/kWh in *BAU* to 42 øre/kWh in *SUN&PAS*, and respectively 41, 39 and 38 øre/kWh in the three ZEB cases *DIR*, *HP* and *OTH*.

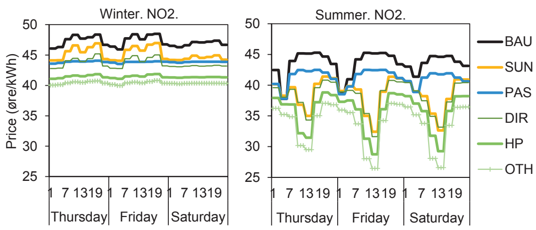

Figure 7. Power prices for Southern Norway (NO2) in winter (*left*) and summer (*right*), by model case. (average of 30 scenario years).

Figure 7 shows that the profile of the power price is less changed in winter compared to summer. In winter, the introduction of solar power only reduces the price, but does not change the shape of the profile, whereas lower power demand in *PAS* has a smoothening effect on the profile. In summer however, the power price profile changes dramatically when introducing solar power in Norway, both in the *SUN* case and in all three ZEB cases. From having high prices at day and low at night, the prices are lowest at mid-day and highest in the evening when demand is high and no solar power is available.

D. Production mix and net export

As seen from the power balance in TABLE II most of the excess power from ZEBs, is being exported out of the Nordic region. Because of the solar power generation in summer, more water is available for the winter, leading to more hours of net export from Norway. In *BAU*, Norway is a net exporter 66 % of the time, which is increased to 90 % in the *HP* case. In summer, the export values lie close to the maximum export capacity from Norway, and thus in years with large inflow of water, the risk of water spillage is high.

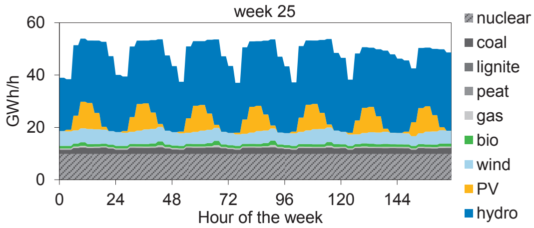

Figure 8. Production mix in a summer week, Nordic Total, in *HP* case.

Figure 8 shows that the solar power represents a significant share of the Nordic power generation in summer. According to TABLE III, the annual thermal production is reduced by 2 to 7 TWh, which is mostly coal power plants in Finland (75 %) and Denmark (25 %).

TABLE III. CHANGED PRODUCTION AND CONSUMPTION (TWH/A)

	SUN	*PAS*	*DIR*	*HP*	*OTH*
Hydro production (change from *BAU*)	+1.3	+0.1	+1.2	+1.2	+1.2
Thermal production (change from *BAU*)	-2.6	-1.9	-4.0	-6.1	-6.5
of which is coal	100%	96%	100%	99%	99%
Increased electricity consumption due to lower prices	+2.5	+1.8	+3.3	+4.7	+5.9

VI. DISCUSSION

There are three main ways of creating a market balance with an increased power availability. The initial effect is a drop in power prices, which reduces the thermal production and incentivises increased consumption (dependent on the demand elasticity). The third possibility is to increase the export out of the region. As always, the results depend on the inputs and the boundary conditions, especially on the assumed export price to the surrounding countries, e.g. UK, Germany and Russia. Lower export prices, will lower the electricity prices in the Nordics, but the thermal production is already reduced substantially (ref. TABLE III) and will probably not be reduced further. As PV production occurs in summer when heat demand is low, increased consumption in summer when prices are low might not be sufficient. Thus, the only possibility left is to export the available power almost regardless of the export price.

VII. CONCLUSION AND OUTLOOK

This paper presents the initial results of investigating the implications of ZEB on the power system. The assumption of 50 % of the building stock being ZEBs in 2030 is highly unrealistic, but is made in order to test how the power system reacts to increased power availability with limited grid connections to the countries outside the Nordics. The work is based on extensive research on load profiles of future and existing buildings. The load methodology covers reduced temperature dependency of heat demand in energy efficient buildings, and accounts for heat pumps and direct electric heating when predicting the total electric load.

Introduction of ZEBs in Norway decreases electricity demand in winter, and increases on-site PV production in summer, which both leads to more available power. The findings indicate that the Nordic power system is capable of handling 17-27 % reduced net power demand in Norway, both regarding the Nordic energy balance and the operation of the grid on a central grid level. As could be expected, this results in lower power prices and reduced thermal generation. The expected Nordic power export of 36 TWh in *BAU* increases up to 62 TWh by the introduction of ZEBs. The hydro power producers are able to adapt to the changes, which leads to decreased spillage of water and increased power production of 1.2 TWh. The reduced power prices represents a benefit for the consumers and can be accommodated by larger and new industry, further electrification of transport, more exchange capacity towards Europe or reducing the nuclear power production in Sweden or Finland.

About 70-80 % of the increased available electricity is exported out of the Nordic region, and thus, the results rely on the assumption that it can be received by the surrounding countries at the given time. Further work should thus address the implications of increased deployment of PV electricity in Europe, which might reduce the possibility of receiving the exported power. Because of the EMPS model's superficial grid description, internal grid congestion within the model regions are not considered. Further work should focus on analysing the grid implications in more detail, both on the regional and distributional grid level.

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Article VIII

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The impact of Zero Energy Buildings on the Scandinavian energy system

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Energy system model

ABSTRACT

This paper investigates how an extensive implementation of net Zero Energy Buildings (ZEBs) affects cost-optimal investments in the Scandinavian energy system towards 2050. Analyses are done by a stochastic TIMES model with an explicit representation of the short-term uncertainty related to electricity supply and heat demand in buildings. We define a nearly ZEB to be a highly efficient building with on-site PV production. To evaluate the flexibility requirement of the surrounding energy system, we consider no use of energy storage within the ZEBs. The results show that ZEBs reduce the investments in non-flexible hydropower, wind power and Combined Heat and Power, and increase the use of direct electric heating and electric boilers. With building integrated PV production of 53 TWh in 2050, ZEBs increase the Scandinavian electricity generation by 16 TWh and increase the net electricity export by 19 TWh. Although the increased production reduces the electricity prices, the low heat demand in ZEBs gives a drop in the electricity consumption by 4 TWh in 2050. Finally, the results demonstrate that the Scandinavian energy system is capable of integrating a large amount of ZEBs with intermittent PV production due to the flexible hydropower in Norway and Sweden.

1. Introduction

A net Zero Energy Building (ZEB) is a building with low energy demand that produces, on an annual basis, as much renewable energy as its energy consumption [1,2]. This paper presents the cost-optimal adaption of an extensive introduction of ZEBs in the Scandinavian energy system towards 2050. To study this, we have developed a stochastic TIMES (The Integrated MARKAL-EFOM System) model [3–7], with an explicit modelling of the short term-uncertainty related to electricity generation and heat demand in buildings.

1.1. Research motivation

Implementation of ZEBs is identified as one of the remedies to meet the Energy Strategy of the European Union, and according to the Energy Performance of Buildings Directive (EPBD), all new buildings shall be 'nearly' ZEBs from 2020 [8]. The initial experiences with ZEBs show that Photovoltaic electricity (PV), integrated in the façade and roof of the building, has been a propitious solution to produce energy in ZEBs [9,10]. This leads to challenges for the surrounding energy system since ZEBs may export electricity in periods of high PV production and import electricity when the solar radiation is low. In Scandinavia the electricity consumption in buildings is highest in winter when the solar conditions are poor. Hence, the electricity sector will serve as a seasonal storage for the ZEBs, where excess electricity from a ZEB is supplied to the electricity grid in summer, and electricity is provided from the grid to the ZEBs in winter.

The energy system needs to consider the reduced heat demand and the on-site electricity generation with an integration of ZEBs.

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Abbreviations

CHP	Combined Heat and Power
DH	District Heat
EPBD	Energy Performance of Buildings Directive
HP	Heat Pump
PV	Photovoltaic electricity (solar power)
PE	Primary Energy
TIMES	The Integrated MARKAL-EFOM System
ZEB	net Zero Energy Building

This implies that the existing energy system needs to adapt with respect to both operation and future investments. Although the net energy demand of the ZEBs is low, the existing electricity capacity might need to be maintained, as the ZEBs do not necessarily lower the peak electricity demand. However, if heated by electricity, the low heat demand in ZEBs, caused by energy efficiency measures, can reduce the peak electricity demand.

The electricity mix in Scandinavia is unique. Denmark is the EU nation with the largest share of electricity generation from Combined Heat and Power (CHP) and wind power at 65% and 35% respectively in 2013 [11]. The electricity generation in Norway and Sweden is also distinctive, as the two countries have the largest hydro production among the EU countries, with 129 TWh and 61 TWh in 2013 [11], and have about 70% of the European hydro storage capacity with 82 TWh and 34 TWh respectively [12]. Due to flexible CHP plants, hydro reservoirs and an integrated electricity grid, the Scandinavian countries are well suited to integrate a larger share of intermittent PV production caused by ZEBs. Hence, it is interesting to study how, and to what extent, hydro production and other renewable energy technologies adapts to an extensive introduction of ZEBs. With a low energy demand and on-site energy production, ZEBs might impact the cost-optimal investments in the overall energy system and change the operation pattern of the flexible production technologies. In order to quantify these changes, an extensive analysis on the aggregated system level is needed. It is assumed that a large share of ZEBs influences the electricity price, and thereby affects both investments in the electricity sector and in heating technologies within buildings, including ZEBs. Consequently, it is important to evaluate the cost-optimal heating design in buildings together with its interaction with the remaining energy system.

1.2. Recent studies and scope of study

This section presents literature that is related to the scope of this paper. The first part focus on the energy system with ZEBs and the second part motivates for the applied stochastic methodology.

1.2.1. Energy systems with ZEBs

The literature concerning ZEBs is mostly related to a single building, investigating e.g. the architecture and building envelope, and/or the energy technologies within the building. Congedo [13] and Evola [14] investigate cost-effective building design alternatives for nearly ZEBs, considering different materials and thickness for the respective building elements, but has no integrated optimisation approach. Milan [15] and Lindberg [16,17] treat the building envelope as given, and investigate the energy system design of the ZEB using linear optimisation. Hamdy [18], Lu [19] and Zhang [20] have developed different kinds of multi-objective or multi-stage optimisation approaches, first finding the cost-efficient building envelope and secondly the energy system design within the ZEB.

Literature that investigates ZEBs in the national or regional energy system is scarce. The presented literature above do not consider that the energy related decisions in a ZEB can have an impact on the surrounding energy system, as for example changing the electricity price. This can be a reasonable assumption with a limited share of ZEBs in the building sector, but is less valid with an extensive implementation of ZEBs. To capture such feed-back effects, this paper uses a methodology that optimises the interaction between the building sector and the surrounding energy system including endogenous investment decisions in the building, electricity and district heat sector. There are however related studies, such as Henning [21] and Palzer [22], that evaluate the cost-optimal evolvement of the energy system with significant renewable electricity generation and increased energy efficiency measures in the building sector, reaching a target of 50% reduction of a country's primary energy consumption.

1.2.2. Stochastic modelling approach

The existing literature using long-term energy system models of Scandinavia, including [23–29], apply a deterministic modelling of short-term uncertainty. Unlike our stochastic approach, a simplified deterministic model includes only one operational situation and provides investment decisions that do not directly take into account a range of operational situations which can occur. It is therefore unclear whether the results from deterministic models are valid with the presence of short-term uncertainty. This is supported by Seljom [30] that concludes that the method used to represent the unpredictable characteristics of wind power in investment models can significantly affect the model results. A stochastic approach to incorporate short-term uncertainty in TIMES was first introduced in Loulou [31] and is used to represent intermittent wind capacity in Seljom [30]. This approach provides cost-optimal investment decisions, which are valid for a range of representative operational situations. For a realistic representation of the grid interaction of a ZEB and the surrounding energy system, we apply a stochastic representation of short-term uncertainty of electricity supply and heat demand in buildings.

There are studies, focusing only on the electricity sector, that have incorporated a stochastic modelling of the short-term uncertainty of intermittent renewables in investment models. For example, Nagl [32] apply stochastic modelling of wind power and PV in a combined investment and dispatch optimisation model of the European electricity market. Their results demonstrate that intermittent renewables are significantly overvalued, flexible energy technologies are underestimated and that the total system cost is significantly underestimated in deterministic electricity models. Other work includes [33–37]. As this literature does not include investments in the building sector, they do not include a stochastic representation of heat demand in buildings. It is however appropriate to consider the uncertainty of heat demand, when analysing the interaction of ZEBs with the surrounding energy system, as the heat demand is highly dependent on the outdoor temperature.

1.3. Outline

The remainder of this paper is structured as follows; Section 2 gives an overview of the methodology and Section 3 is devoted to the model cases that are used in the analyses. Finally, the results are presented in Section 4 and the conclusions are given in Section 5.

2. Methodology

First, this section gives an overview of the model structure and assumptions of the TIMES model. Thereafter, we present the applied definition and assumptions of ZEBs. Finally, we provide an overview of the applied stochastic methodology, including the scenario generation of the uncertain parameters.

2.1. Model structure and assumptions

TIMES is a bottom-up optimisation modelling framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. It is mainly used for medium- and long-term analysis on global, national and regional levels, including the Energy Technology Perspectives published by the International Energy Agency [38]. The model minimizes the total discounted cost of the energy system to meet the demand for energy services. The model decisions are made with full knowledge of future events and suppose free competition with no market imperfections. To provide the macroeconomic cost-optimal solution, we exclude current policy instruments, including taxes and subsidies. The annual discount rate is set to 4%.

To represent the current structure of the electricity market, the model is regionally divided into the Nord Pool price areas, as shown in Fig. 1. To analyse the long-term impact of ZEBs, we use a time-horizon from 2010 to 2050, with investment and operational decisions in each five-year model period of the time-horizon. To consider seasonal and daily variations in energy supply and demand, each model period is represented by 12 2-h steps for a representative day of four seasons: winter (December, January and February), spring (March, April and May), summer (June, July and August) and autumn (September, October and November), giving 48 time-slices in total. While investments are made for each model period, the operational decisions are optimised on the two-hourly daily level to satisfy the energy demand at least cost.

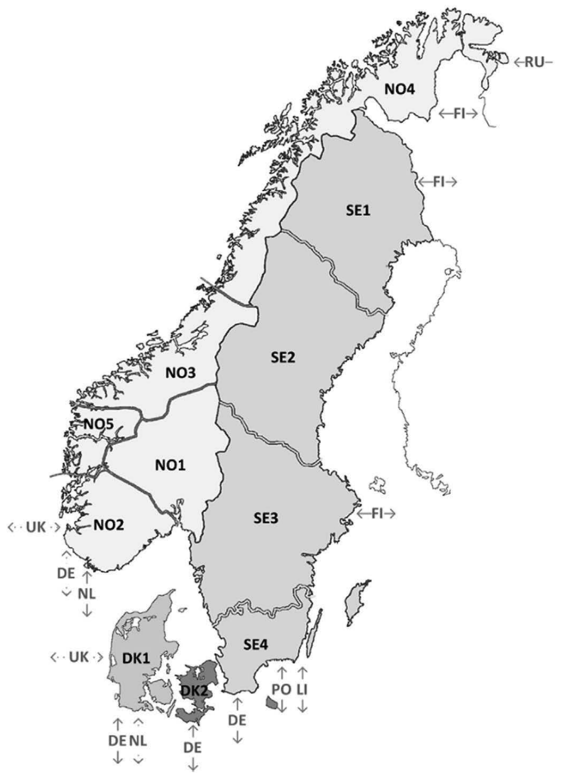


Fig. 1. Illustration of the Scandinavian Nord Pool price areas, with indication of existing and proposed transmission capacities to surrounding countries; Finland (FI), Poland (PO), Lithuania (LI), Germany (DE), the Netherlands (NL) and the United Kingdom (UK).

The model includes a set of technologies to transform energy sources to final demand, including conversion processes such as electricity and heat generation technologies and demand technologies as for example boilers and vehicles. The characterisation of the energy technologies, as cost data and efficiencies, are exogenous input to the model and are inter alia based on [39,40].

Future energy demand of heat, transport and non-substitutable electricity are exogenous input to the model and are based on reference energy projections for Denmark [41], Norway [42] and Sweden [43,44]. Due to different data availability, the heat demand is divided differently for the Scandinavian countries. The heat demand is split into three categories for Denmark; central district heat, de-central district heat and individual buildings, in six categories for Norway; commercial buildings, single family house, multifamily house, metal industry, pulp and paper and other industry, and into four categories for Sweden; buildings, district heat, forest industry and other industry. With the explicit modelling of the DH demand in Denmark and Sweden, we do not capture the competition between district heat and other heating options, e.g. if it is profitable to expand the DH grid to replace the natural gas grid. The electricity consumption, beyond the non-substitutable electricity demand, is an endogenous model decision since it is an option to use electricity to produce heat in the district heat and building sector.

Projected energy prices for biomass, fossil fuels and electricity in European countries are based on [45], and are summarised in Appendix A. Note that the electricity prices within the Scandinavian regions are endogenous, as they are the dual values of the electricity balance equation. However, the electricity prices in the countries with trading capacity to Scandinavia are exogenous, and it is assumed that these electricity trade prices are independent of the quantities traded to Scandinavia.

Fig. 1 shows the existing and proposed transmission capacity to the countries outside Scandinavia. The transmission capacity within and outside the model regions reflects the current capacity. The model can choose to invest in new capacity expansions to Europe, but the capacities within the Scandinavian model regions are fixed. The on-going project from Sweden to Lithuania, “NordBalt” [46], is included as model input, while investments in the projects, “VikingLink” between Denmark and the United Kingdom [47], “NSN” between Norway and the United Kingdom [48] and “NordLink“ between Norway and Germany [49] are endogenous options. Note that the electricity trade is modelled in a simplified manner, without considering Kirchhoff's laws, and the electricity loss is set as a given percentage of the electricity consumption; 3% on a high voltage level and 7% on a lower voltage level.

Two types of hydropower plants are included; flexible plants and non-flexible plants. The non-flexible plants have a seasonal availability factor that reflects the average seasonal production over the installed generation capacity. The non-flexible electricity production is set identical for all days within a season, assigning these plants no flexibility. The flexible hydropower plants have an annual availability factor, reflecting the annual production over the installed capacity, and are flexible to distribute their production over the sub-annual time-slices of the model. Finally, the seasonal production of the flexible hydropower plants, are limited to a maximum and minimum level according to historical production data.

2.2. Modelling of ZEBs

A ZEB is a highly energy efficient building with on-site renewable energy generation. Hence, a ZEB is characterised by low energy demand due to e.g. high airtightness and considerable insulation, which is also the case for passive buildings. According to the Norwegian definition, the annual space heat demand of a residential passive building is limited to 29 kWh/(m^2y) when located close to Oslo [50]. For a non-residential building in Norway, as an office building, the maximum allowable net heat demand for space heating is about 30 kWh/(m^2y), but varies with building category and geographical location.

The energy balance of a ZEB is typically calculated as the energy consumed minus the energy generated over a year [51]. The annual energy balance reflects the difference between the weighted sum of the imported energy carriers consumed in the building, and the weighted sum of energy carriers exported from the building, as denoted in Equation (1). The amount of imported or exported energy y_i, are multiplied with a Primary Energy (PE) factor, f_i, for each of the respective energy carriers, i. As an example, the PE factor for electricity is 2.5 for average European conditions [1], but each member state can define its own PE factors. Further, the EPBD states that the buildings shall be 'nearly' zero, meaning the balance, D, may be positive. The value of D is a member state decision.

$$\underbrace{\sum_{i\in I} f_i \cdot y_i^{\text{import}}}_{\text{weighted energy import}} - \underbrace{\sum_{i\in I} f_i \cdot y_i^{\text{export}}}_{\text{weighted energy export}} = \underbrace{D}_{\text{balance}} \tag{1}$$

A consistent handling of PE factors for all Scandinavia is a challenging task since Denmark has decided on different PE factors than Sweden while Norway has not defined any factors [10]. In addition, if the PE factors represent the environmental impact of the use of an energy carrier, the factor should be a model decision rather than a model input. For example, the PE factor of electricity depends on the share of renewables in the electricity generation mix, which is a model output. Findings from Ref. [17] shows that the electric specific demand of a multi-family ZEB accounts for 80% of its total primary energy consumption if heated by a heat pump. For this case, a ZEB definition which only includes the electric specific demand, gives an energy generation which accounts for 80% of the total energy consumption of the building. For comparison, using the Danish ZEB definition, which only includes heat demand and lighting, on the same case, requires on-site energy generation which accounts for 28% of the total energy consumption of the building. This indicates that a ZEB definition that accounts for the electric specific demand only, is stricter than the Danish ZEB definition.

For a manageable definition of ZEBs, we assume the energy requirement of a 'nearly ZEB' only includes the electric specific demand of the building. With this assumption, both the import and export of the ZEB balance, as shown in Eq. (1), is electric, and the use of PE factors is avoided. Consequently, the annual energy generation equals the annual electric specific demand in a ZEB.

Further, we assume a ZEB to be a passive building, according to the Norwegian definition [50,52] with on-site PV production. In order to evaluate the maximum flexibility required by the surrounding energy system, we consider no use of energy storage within the buildings. Hence, the difference between electricity supply and demand in a ZEB is handled by trade with the electricity grid.

2.3. Model input on energy demand in buildings and PV capacity

The model input on energy demand in buildings is separated into heat demand and electric specific demand. The electric specific demand includes electricity that is non-substitutable with other energy carriers, such as electricity for lighting and equipment. Based on findings in Refs. [53,54], and the fact that the electric specific demand of Swedish households, according to the Swedish Energy Agency, has been relatively stable since 1990, we conclude that it is mainly the heat demand that is reduced when introducing ZEBs and the electric specific demand is unaffected.

Considering current rehabilitation rates, new construction rates and demolition rates, if all new buildings and some of the rehabilitated buildings towards 2050 become ZEBs, ZEBs contributes to 25% in 2030 and 50% in 2050 of the total building stock. Table 1 shows the corresponding impact of ZEBs on the annual heat demand for each of the Scandinavian countries in 2015, 2030 and 2050. Since the heat demand is temperature dependent, the figure includes both the expected heat demand, based on average temperatures, together with the minimum and maximum outcome of heat demand.

Compared to no implementation of ZEBs, the heat demand is reduced by 8% in 2030 and by 18% in 2050 with ZEBs. In 2050, the annual heat demand with ZEBs ranges from 145 TWh to 183 TWh, dependent on realisation of the outdoor temperature. Please note that the indicated model cases in the tables below are defined in Section 3.

Table 2 shows the model input for electric specific demand in 2030 and 2050, with the corresponding model input on PV capacity. In Scandinavia, the electric specific demand in buildings is 100 TWh in 2030 and 106 TWh in 2050. The PV capacity is derived from our ZEB definition, where the PV capacity is set such that the annual PV production equals the annual electric specific demand within each region. With a 50% share of ZEBs in the building sector in 2050, the electricity specific demand and the annual PV production in ZEBs is 53 TW h, corresponding to 63 GW installed PV capacity.

As TIMES optimises all parts of the energy system simultaneously with a macro-economic perspective, the model is indifferent to whether the electricity generated from PV is supplied within the building or centrally. To reduce the computational complexity, we model the PV production in ZEBs as electricity supply to the electricity grid. The disadvantage with this approach is that it overestimates the electricity losses and trade costs related to the electricity generation in ZEBs.

2.4. Stochastic modelling approach

We apply a two-stage stochastic model [55,56] to provide cost-optimal investments that explicit consider the short-term uncertainty of the following stochastic parameters: PV production, wind production, hydro production, heat demand in buildings and the electricity prices outside Scandinavia. The electricity prices represent the short-term uncertainty of the market equilibrium in the countries with interconnection to Scandinavia. The listed parameters are selected to give an appropriate representation of the grid interaction of ZEBs, which depend on intermittent electricity supply and a climate dependent heat demand. Each uncertain parameter is represented by 21 possible realisations, called scenarios, with equal probability to occur. The scenarios are generated by random sampling, with adjustments to ensure selected statistics properties, as described in Section 2.4.1–2.4.5. The number of

Table 1
Heat demand in buildings in 2015, 2030 and 2050 dependent on ZEB implementation.

	Minimum/**Average**/Maximum Heat demand, TWh/y				
ZEBs		No		Yes	
Model period	2015	2030	2050	2030	2050
Model case	REF	REF, SUN		PBU, ZEB, ZEB*	
Denmark	49/**53**/61	47/**51**/58	43/**46**/53	43/**47**/53	35/**38**/44
Norway	41/**45**/51	47/**51**/58	51/**54**/63	43/**47**/53	41/**44**/51
Sweden	84/**92**/107	83/**92**/106	85/**92**/108	76/**84**/97	69/**75**/88
Scandinavia	174/**189**/219	177/**194**/222	179/**192**/224	162/**178**/203	145/**157**/183

Table 2
The electric specific demand in buildings, with corresponding on-site PV capacity, for 2015, 2030 and 2050.

	Electric specific demand, TWh/y			**PV capacity, GW**	
Model period	2015	2030	2050	2030	2050
Model case	REF, ZEB, PBU, SUN, ZEB*			ZEB, SUN, ZEB*	
Denmark	19	19	19	4.6	9.2
Norway	30	33	37	9.5	21.2
Sweden	48	48	50	15.3	32.2
Scandinavia	98	100	106	29.4	62.6

scenarios is primarily chosen for a manageable computational time, although a higher number of scenarios can increase the quality of the results [57].

Fig. 2 illustrates a scenario tree with the information structure of the two-stage stochastic model. At the first stage, the realisation of the operational scenarios is unknown and investments in new capacity for the entire model horizon, from 2010 to 2050, are made. At the second stage, starting at the branching point of the scenario tree, the outcomes of the different scenarios are known, and operational decisions are made for each of the scenarios for all model periods. Consequently, the investments are identical for all scenarios, whereas operational decisions are scenario dependent. To consider the different operational situations in the optimisation, the model minimise the investment costs and the average of the operational costs for all scenarios. This gives investment decisions that recognize the expected operational cost, and that are feasible for all the model specified realisations of the uncertain parameters. Note that the investment and operational model decisions are made simultaneously, and we apply a multi-horizon model structure [58], with no dependency of the operational decisions between the model periods. Unlike a stochastic approach, a simplified deterministic model has only one operational scenario. Consequently, the investment decisions in a deterministic model do not take into account a range of operational situations that can occur.

As this is a long-term investment model, the scenarios are designed to represent realistic operational situations and not to forecast the future. Therefore, the construction of the scenarios is based on historical data instead of using a prediction model. The hydro production and heat demand scenarios are modelled as dependent since climatic conditions affect both the inflow to the hydro reservoirs and the heat demand in buildings. The other uncertain parameters are modelled as independent due to limited data availability. Consequently, we do not capture the correlation between hydro production, PV production and wind production in Scandinavia with the European electricity prices. However, as the Scandinavian energy system is relatively small, compared to the rest of Europe, the electricity generation in these countries has limited influence on the European electricity prices. Another model adjustment, caused by limited data availability, is that the uncertain parameters are independent between the model periods. This implies that there are no dependency between the wind conditions in 2030 and the wind conditions in 2035. Nevertheless, the scenario generation method is designed to explicit capture the regional and time-slice correlation of the uncertain parameters. This is elaborated in the sections below, which describes the scenario generation methodology of each of the uncertain parameters.

2.4.1. PV production

The PV scenarios consist of hourly availability factors, which equal hourly PV production over installed capacity, for each model region. First, historical, availability factors from 2014 are derived by dividing hourly production data by the installed capacity. Second, every second hour from the data set is selected to adjust to the time-slice structure of the model with 12 2-h daily steps. In Denmark and Sweden, the grid operator provides data on PV production on an hourly level [59,60], whereas PV production data for Norway is scarce [61]. To handle this, we have generated artificial Norwegian PV data based on the Swedish availability factors and simulated availability factors for Norway and Sweden from Ref. [62]. As Norway and Sweden are roughly located at the same latitude, we assume that the PV characteristics of the Norwegian

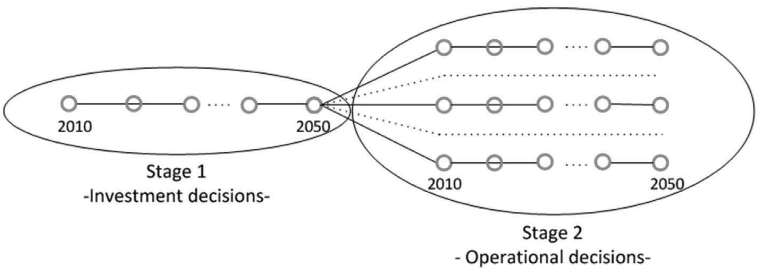


Fig. 2. Illustration of the two-stage scenario tree.

regions are similar to the PV characteristic of the closest located Swedish region.

For each model period, the scenarios are generated by a random sample of 21 days within each season. Thereafter, the corresponding 12 two-hourly availability factors of the sampled day are used. To ensure that the scenarios have the same mean value as the historical data, the availability factors are adjusted such that the average annual availability factor, within each region, is identical the observed annual availability factor of 2014. Consequently, for each model period, region and season, the PV scenarios consist of 21 different daily realisations of the PV production. Note that this approach ensures a consistent daily correlation, since each scenario consists of 12 two-hourly chronological values. Further, because the same sampled days are used for all model regions, we explicitly capture the correlations between the model regions.

Although the number of scenarios is limited, we consider the 21 scenarios as representative to indicate a range of daily PV production profiles. Fig. 3 illustrate the characteristics of the model input on PV availability factors in the Swedish region with highest population, SE3, for summer in 2030, by showing the 25/75 quantile, minimum, maximum and median of the daily realisations in the 21 stochastic scenarios The figure shows clearly that the availability factors vary significantly between the scenarios and time of the day. For example at 12:00, when the PV production peaks for most scenarios, the availability factor ranges from 0.03 to 0.20. Here, the difference in availability factors is mostly due to different cloud covers.

2.4.2. Wind production

The wind scenarios consist of hourly availability factors, which equal the hourly wind production over the installed wind power capacity, for all model regions. The scenarios are based on historical production data from 2012 to 2014 [59,60,63]. Besides a larger data set, with three years of data instead of one, the scenario generation method for wind production is identical to the generation of the PV scenarios that are described in Section 2.4.1.

2.4.3. Hydropower production

The hydro scenarios contain seasonal availability factors in all regions, which reflect the seasonal hydropower production over the installed hydro capacity, and are based on historical data from 2001 to 2014 [64,65]. For each model period, a scenario is generated by random selection of a year among the 14 historical years. In each region, the corresponding seasonal availability factor is used in all seasons for the non-flexible plants, and the corresponding annual availability factor is used as a model input for the flexible plants. This approach is designed to ensure the correlation of hydro production between model regions, seasons and hydro plant types. To ensure that the hydro scenarios are representative with respect to the statistical mean, we have controlled that the average availability factor of all scenarios, over all model periods, is in accordance with the historical data.

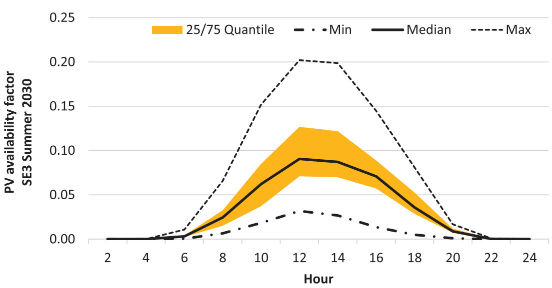


Fig. 3. PV scenario characteristics for SE3 Summer 2030; 25/75 Quantile, Minimum, Median and Maximum daily PV availability factor.

2.4.4. Heat demand

The heat demand scenarios contain hourly load profiles that are based on simulated hourly heat demand for 14 historical climatic years. The simulations are done by use of regression models and historical outdoor temperatures from 2001 to 2014 for a representative location within each model region. The methodology used to develop the regression models for non-residential buildings is described in Ref. [54], which detects the temperature dependency of the heat demand by using hourly measurements of heat consumption and outdoor temperature. A similar regression model, based on [66], is developed for residential buildings. The regression methodology is also applied to measurements of passive buildings, which enable us to adjust the regional hourly heat demand to different deployment of passive buildings in the building stock. Although the parameters of the regression models are based on Norwegian conditions, we assume they are valid to derive hourly heat demand for all the Scandinavian model regions.

The scenarios of the annual heat demand are constructed by selecting the heat demand simulated for the same 21 historic years that were sampled for the hydro scenarios. This is to capture the correlation between the climate dependent hydro inflow and the outdoor temperature. To represent the heat demand variations within each season and time of day, one day within each season is randomly selected for each scenario. Finally, for each model period, the scenarios are adjusted such that the expected value of all scenarios equals the annual expected heat demand as specified in Table 1.

To illustrate the model input, Fig. 4 shows the characteristics of the heat load profiles for non-residential buildings for NO1 in 2050, with 0% and 50% of the building stock being ZEBs, by showing the 25/75 quantile, minimum, maximum and median of the 21 different daily realisations.

The plot demonstrates that the heat demand varies significantly by time of day, by scenario and by the share of ZEBs. For example at 10:00, the heat demand ranges from 168 GWh to 381 GWh with 0% ZEBs, and from 135 GWh to 308 GWh with 50% ZEBs.

2.4.5. Electricity prices outside Scandinavia

The scenarios for the electricity prices outside Scandinavia are based on hourly electricity prices from 2014 in Germany, Netherlands, Finland, Lithuania, Poland and United Kingdom. We use the same sampling method as applied to generate the PV scenarios in Section 2.4.1 to generate the electricity price scenarios. After the scenarios are sampled, the model input is adjusted to the hourly prices in each trading region, such that the average of the scenarios is consistent with the assumed annual electricity price, as specified in Appendix A, for all model periods.

Further, it is likely that there will be an implementation of ZEBs with PV not only in Scandinavia but also in Europe, and that their PV production affects the traded electricity prices towards Scandinavia. Several studies, including [67–69], indicate that more intermittent electricity generation, as PV, can increase both the average electricity price and the price volatility. However, others, as [70,71], states that the annual electricity price can be reduced with more intermittent electricity production. In this study, we assume that a large introduction of ZEBs with PV, increases the volatility of the hourly European electricity prices, but leave the average price unaffected. We propose a methodology that changes the price profile proportional to the solar radiation in the different European countries. This approach implies fitting a cubic equation such that

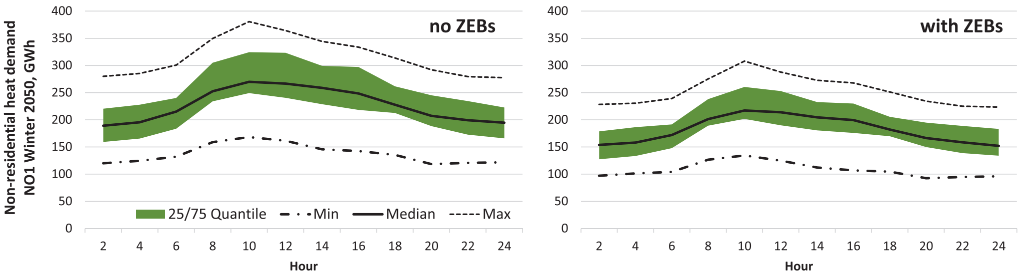


Fig. 4. Heat demand scenario characteristics for NO1 Winter 2050; 25/75 Quantile, Minimum, Median and Maximum daily non-residential heat demand, with and without ZEBs.

the electricity trade price is unaffected when there is no PV production, and reduces the price to zero in the scenario with the highest PV production in 2050. The scenarios for the solar radiation in all trading countries are based on national hourly solar radiation simulations from Ref. [62].

The resulting 25/75 quantile, minimum, maximum and median of the 21 stochastic price scenarios for Germany in summer 2050 are plotted in Fig. 5, with and without influence of ZEBs with PV in Europe. ZEBs decrease the prices in the hours with solar radiation, increase the price at night and thus cause larger price variability. For example, the average price at 02:00 is 49 EUR/MWh without ZEBs, and 85 EUR/MWh with ZEBs. Since the solar radiation is scenario dependent, the price impact of ZEBs varies greatly within each hour of the day. For example with ZEBs, the electricity price ranges from 5 EUR/MWh to 73 EUR/MWh at 12:00.

3. Model cases

In this study, we analyse five model cases with different model input on the heat demand, PV production and European electricity prices, representing different long-term trends in the Scandinavian building sector and the European energy system. We emphasise that the model cases and stochastic scenarios are two different types of model input. Each model case apply the same stochastic scenarios, that are described in Section 2.4, to explicitly capture the stochastic nature of i.e solar radiation, wind speed and outdoor temperature. As shown in Fig. 2, there is one investment decision for each model case, based on 21 possible outcomes of the uncertain parameters. However, the investment decisions can differ with the various the model cases, as shown in Section 4.

The main characteristics of the model cases are summarised in Table 3. The first case is a reference case, denoted *REF*, with no implementation of ZEBs. For this case, we assume a gradual increase of energy efficient buildings with 10% in 2030 and 20% in 2050 to take into account that an increasing share of the building stock has the current building standard in the future. These numbers are derived by the methodology described in Ref. [72] and are provided by the Norwegian Water Resources and Energy Directorate. In the *ZEB* case, all new buildings and some of the rehabilitated buildings have a passive building standard and on-site PV installed, corresponding to 50% of the Scandinavian building stock being ZEBs in 2050. In this model case, we assume that ZEBs are introduced in the same order of magnitude in the rest of Europe as in Scandinavia, and influence the European electricity prices as presented in Section 2.4.5. To differentiate the impact of the two characteristics of a ZEB; reduced heat demand and increased on-site PV production, we include two additional model cases. The *PBU* case includes the passive building standard of the ZEBs but has no on-site PV production. Opposite, the *SUN* case includes the on-site PV capacity of the ZEBs without the implementation of the passive building standard. Finally, to differentiate the influence between the Scandinavian ZEBs and the change in European electricity prices, we evaluate the impact of ZEBs with no change in the European electricity prices in a separate case, *ZEB**. Consequently, this case represents a situation with a large implementation of ZEBs in Scandinavia and no implementation of ZEBs in the rest of Europe.

The model input on heat demand and PV capacity for the various model cases are given in Section 2.3. For all model cases except *REF* and *PBU*, the PV capacity is according to Table 2. The heat demand is shown in Table 1, with a lower heat demand for *PBU, ZEB, and ZEB** compared to *REF* and *SUN*, due to the implementation of the passive building standard. The model assumptions for the electricity prices outside Scandinavia are presented in Section 2.4.5. Note that since the heat demand and PV capacity are exogenous model input, we do not consider the additional cost related to a passive building standard and on-site PV production.

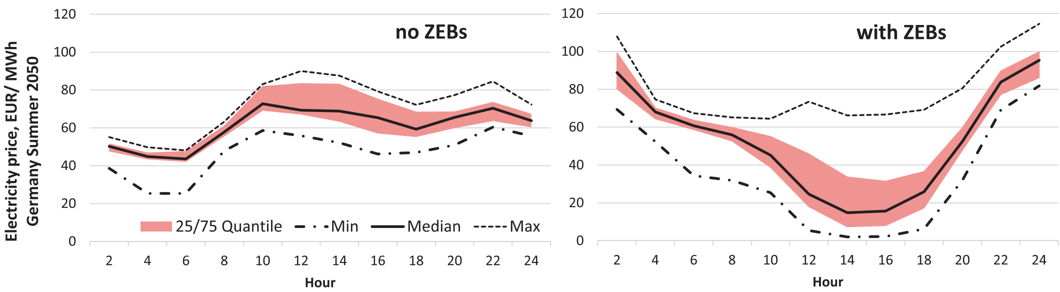


Fig. 5. Electricity price scenario characteristics for German Summer 2050, 25/75 Quantile, Minimum, Median and Maximum daily prices, with and without ZEBs.

Table 3
Main characteristics of the model cases.

Case	Passive building standard in Scandinavia	On-site PV production in Scandinavian buildings	ZEB deployment in Europe
REF	No	No	No
ZEB	Yes	Yes	Yes
PBU	Yes	No	Yes
SUN	No	Yes	Yes
ZEB*	Yes	Yes	No

4. Results and discussions

This section presents and discusses the results of the model cases to evaluate the effects of a large introduction of ZEBs in the Scandinavian energy system. First, the effects on the electricity and building sector are explained in Section 4.1 and Section 4.2, respectively. Second, the system integration of ZEBs in Scandinavia is discussed; the system adaption of PV production in Section 4.3, and the impact on system costs in Section 4.4. Third, the impact of using a stochastic modelling approach is presented in Section 4.5. Finally, in Section 5 we give our conclusions. If not otherwise specified, the results report the expected value of the operational decisions, i.e. the average of the operational decision of the 21 stochastic scenarios.

4.1. The electricity sector

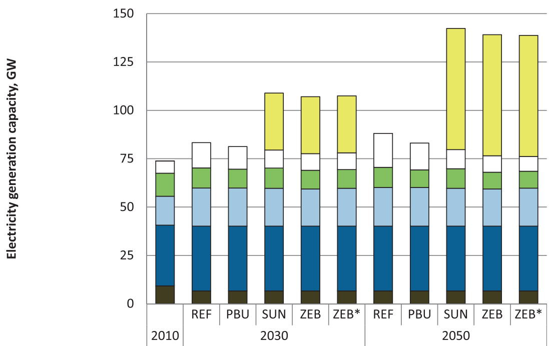
ZEBs increase the total electricity generation in Scandinavia, giving a drop in the electricity prices. This lowers the incentives for investments in new generation capacity. In Norway and Sweden, the price drop is significant, due to limited transmission capacity to the neighboring regions together with the long lifetime of the hydropower and nuclear power, with low reinvestment needs. Whereas in Denmark, the price drop is lower and more temporarily, as the existing electricity plants are phased out towards 2050. Nevertheless, given our model assumptions on the European electricity prices, Denmark find it cost-optimal to investments in new electricity generation capacity, also with an extensive implementation of ZEBs.

Table 4 provides the national electricity balances in 2050 for all model cases. On a Scandinavian level, an introduction of ZEBs increases both the annual electricity generation and the electricity export to Europe, but has a minor impact on the electricity consumption. The effect on the electricity consumption is two-sided. On the one hand, the passive building standard reduces the heat demand and thus electricity used for heating. On the other hand, the PV production decreases the electricity price, which incentivises substitution towards electric heating. In total, the electricity consumption is 4 TWh lower with ZEBs in 2050, corresponding to a 1% lower heat demand for *ZEB* compared to *REF*. Comparing *REF* to *ZEB* on a Scandinavian level, the electricity generation increases by 16 TWh, giving an increase in the net export by 19 TWh.

Fig. 6 depicts the installed electricity generation capacity by technology, in 2010, 2030 and 2050 for all model cases. Note that the nuclear capacity in all cases and the PV capacity for *SUN*, *ZEB* and *ZEB**, is a model input and not a model decision. The total capacity is significantly increased with an implementation of ZEBs due to the on-site PV. Nevertheless, the electricity capacity in CHP, wind power and non-flexible hydropower are lowered, whereas investments in flexible hydropower capacity are unaffected. Comparing *REF* and *ZEB*, the investments in non-flexible hydropower are reduced with 13% in 2030 and 16% in 2050. Note that this is given our assumption that current hydro capacity remains available towards 2050. The lower investments in CHP plants are mainly caused by the passive building standard as it decreases the district heat demand. For example compared to *REF* in 2050, the CHP capacity is 1.2 GW and 1.5 GW lower in *PBU* and *ZEB* respectively. Further, we conclude that the PV production has a greater influence than the passive building standard on the wind investments. Compared to *REF* in 2050, the wind capacity is reduced

Table 4
National electricity balance in Scandinavia in 2050 for all model cases.

Model case	TWh	Denmark	Norway	Sweden	Scandinavia
REF	Generation	37	182	148	367
	Consumption	34	140	145	319
	Net export	1	35	−5	30
	Loss	2	7	8	17
PBU	Generation	33	175	143	351
	Consumption	33	135	138	307
	Net export	−2	33	−3	29
	Loss	2	7	7	16
SUN	Generation	40	190	162	392
	Consumption	35	147	138	321
	Net export	3	36	7	45
	Loss	2	8	17	27
ZEB	Generation	39	186	158	382
	Consumption	34	141	139	315
	Net export	2	38	10	49
	Loss	2	7	9	18
ZEB*	Generation	37	188	157	383
	Consumption	33	140	139	313
	Net export	2	41	10	52
	Loss	2	7	8	18



	2010	2030 REF	2030 PBU	2030 SUN	2030 ZEB	2030 ZEB*	2050 REF	2050 PBU	2050 SUN	2050 ZEB	2050 ZEB*
Total	73.8	83.3	81.3	109.0	107.0	107.5	88.0	83.1	142.3	139.1	138.7
PV	0.0	0.0	0.0	29.4	29.4	29.4	0.0	0.0	62.6	62.6	62.6
Wind	6.3	13.0	11.7	9.3	8.6	8.7	17.5	13.8	9.9	8.6	7.6
CHP	11.9	10.4	9.7	10.4	9.6	9.7	10.4	9.1	10.1	8.6	8.7
Non flexible hydro	15.0	19.8	19.7	19.6	19.2	19.6	20.0	20.0	19.6	19.2	19.7
Flexible hydro	31.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4	33.4
Nuclear	9.3	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7

Fig. 6. Installed electric generation capacity in total Scandinavia, by technology, for all model cases in 2010, 2030 and 2050.

with 3.7 GW in *PBU*, 7.6 GW in *SUN* and 9.0 GW in *ZEB*. Although PV constitutes a large part of the installed capacity, it has a smaller share of the electricity production mix. For *ZEB*, PV corresponds to 45% of the installed capacity, but only 14% of the electricity generation in 2050.

There are large regional differences in wind investments. This is illustrated in Fig. 7 that shows the national wind power capacity in 2015, 2030 and 2050 for all model cases. For *ZEB*, the wind capacity is considerably larger in Denmark with 6.0 GW, compared to Norway and Sweden, with 1.1 GW and 1.5 GW respectively in 2050. This is a consequence of the regional differences in reinvestment needs towards 2050. Even though the wind capacities are reduced with ZEBs, the share of renewable electricity generation, including hydro, PV and wind, increases from 78% in *REF* to 81% in *ZEB*.

The results show that PV is not a competitive technology in *REF* and *PBU*, with an investment cost at 2.1 EUR/W in 2015 declining to 1.5 EUR/W in 2050. For these model cases, a substantially cost reduction is needed for investments in PV. The regional differences in the electricity sector and the transmission capacity give regional differences in cost-competitive investment of PV. For *REF*, this investment cost ranges from 0.3 EUR/W in NO4 to 1.0 EUR/W in DK2 in 2050.

An implementation of ZEBs changes the operation of the flexible electricity generation and gives a different electricity trade pattern with Europe. This is illustrated in Fig. 8 where the net electricity export from Scandinavia in spring for 2050 is plotted for *ZEB* and *ZEB**. For *ZEB**, with European electricity prices according to the current price profiles, Scandinavia exports at daytime when prices are high and imports at night when prices are low. In contrast, for *ZEB*, with low electricity prices in periods of high PV production, Scandinavia exports at night and imports electricity from Europe at day. Nevertheless, as the annual electricity price is the same for all model cases, the total net export is in a similar range at 52 TWh in *ZEB** and 49 TWh in *ZEB*. This demonstrates that the Scandinavian energy system, with a considerable amount of flexible hydro production capacity, can adapt to substantial changes in the European electricity prices.

4.2. Heating technologies in buildings

The passive standard, the on-site PV production and the development of the European electricity prices influence the heat technologies and heat supply in buildings. Fig. 9 illustrates the installed heat capacity for all model cases. Here, the connection capacity to district heat is not included as the district heat demand is exogenous, and the technology group named *Electricity* includes both electric boilers and direct electric heating. As the heat demand is reduced with ZEBs, the heat capacity is lowered by 9.0 GW in *PBU* and 7.0 GW in *ZEB* when compared to *REF* in 2050. For *SUN*, the heat capacity is 2.3 GW higher in 2050 when compared to *REF*, despite that these model cases have the same heat demand. The increased capacity is caused by the altered variability of the European electricity prices, giving more investments in low-cost electric heating. Note that these results are based on an aggregated representation of the building stock by model region, and further work needs to address the effects on installed heat capacities on a local level.

Fig. 10 shows the annual heat supply to buildings in 2030 and

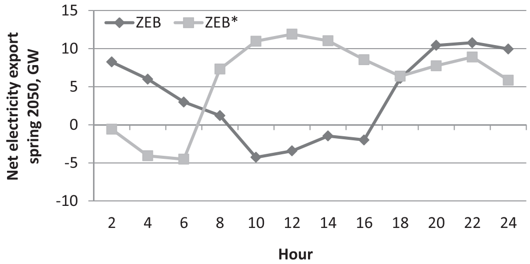
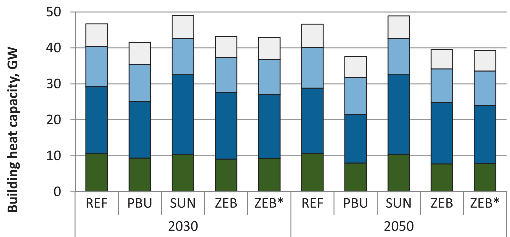
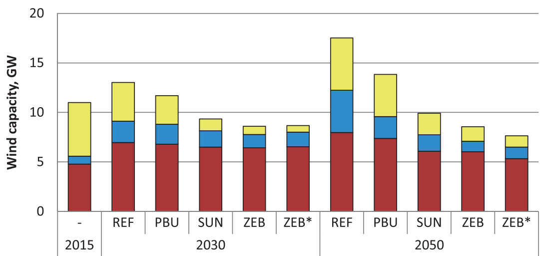


Fig. 8. Expected net electricity export from Scandinavia in spring 2050 for ZEB and ZEB*.



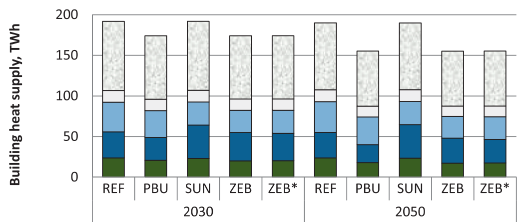
	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
	2030					2050				
Total	46.7	41.6	49.0	43.2	42.9	46.6	37.6	48.9	39.6	39.3
Gas	6.3	6.1	6.3	5.9	6.1	6.5	5.8	6.3	5.4	5.7
Heat Pump	11.1	10.3	10.1	9.7	9.8	11.3	10.2	10.1	9.4	9.5
Electricity	18.7	15.8	22.2	18.6	17.9	18.2	13.5	22.2	17.0	16.2
Biomass	10.6	9.4	10.3	9.1	9.2	10.6	8.0	10.4	7.8	7.8

Fig. 9. Heat technologies installed in buildings, for all model cases in 2030 and 2050.



	-	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
	2015	2030					2050				
Total	11.0	13.0	11.7	9.3	8.6	8.7	17.5	13.8	9.9	8.6	7.6
SE	5.4	3.9	2.9	1.2	0.8	0.7	5.3	4.3	2.2	1.5	1.1
NO	0.8	2.2	2.0	1.6	1.4	1.5	4.3	2.2	1.7	1.1	1.2
DK	4.8	7.0	6.8	6.5	6.4	6.5	8.0	7.4	6.1	6.0	5.3

Fig. 7. Wind power capacity in Denmark, Norway and Sweden for all model cases in 2015, 2030 and 2050.



	REF	PBU	SUN	ZEB	ZEB*	REF	PBU	SUN	ZEB	ZEB*
	2030					2050				
Total	192	174	192	174	174	190	155	190	155	155
District heat	85	78	85	78	78	82	68	82	68	68
Gas	14	14	14	14	14	15	13	15	13	13
Heat Pump	36	33	28	27	28	38	34	28	27	28
Electricity	32	28	41	35	34	31	22	41	31	29
Biomass	24	21	23	20	20	24	18	23	17	17

Fig. 10. Heat supplied to buildings, by technology, for all model cases in 2030 and 2050.

2050 for all model cases. The majority of heat supplied by natural gas occurs in Denmark and Sweden, and biomass used for heating consists primarily of wood used in the cold winter season. The main differences, when comparing *REF* to *ZEB*, is that heat supplied by heat pumps (HP), gas and biomass boilers and wood stoves, is reduced, whereas the low-capital electricity heat generation is unchanged. However, as the total heat demand is lower in a ZEB, the share of direct electric heating increases from 16% in *REF* to 20% in *ZEB* in 2050. The results also indicate that the use of low-capital electricity heat increases with more variability of the European electricity prices, as the installed capacity of *Electricity* in 2050 is 0.8 GW higher in *ZEB* compared to *ZEB**.

4.3. System integration of PV production

With PV contributing to 14% of the total electricity generation in Scandinavia in 2050, situations when it is not feasible to utilise all PV production or other non-flexible electricity generation may occur. This is due to grid constraints between the model regions in hours with high PV production, and a relative low electricity demand. This situation is illustrated in Fig. 11, which shows the electricity balance for region SE3 for a random summer day in 2050 for *ZEB*. The difference between supply (regional production plus import into the region) and demand (regional consumption plus export out of the region) peaks in the middle of the day when the solar radiation is at its highest, with 7.5 GW at 14:00. For this hour, PV contributes to 90% of the regional electricity generation where the remaining electricity generation consists of non-flexible hydropower, nuclear power and industrial CHP plants. Accumulated for this specific day, 20% of the non-flexible electricity generation is unutilised, that is mainly caused by the PV production between 10:00–14:00.

Note that Fig. 11 shows a summer day with an extreme high share of unutilised PV. On an annual level, only 0.4% of the total electricity consumption or 2.4% of the PV production, in 2050 is unutilised due to limitations in the transmission grid for *ZEB*, corresponding to 1.3 TWh. The unutilised PV occurs in 2.6% of the 1008 operational time slices (12 daily periods *4 seasons *21 scenarios) in 2050, mostly in summer with a few instances in fall. There are however regional differences in the occurrence of unutilised electricity, ranging from 0.0% in NO2 to 1.6% in NO5.

These results indicate that the Scandinavian energy system is capable of integrating significant amounts of ZEBs with PV on an aggregated level, also with no local storage within the buildings. However, our study captures only the limitations of the electricity grid between the model regions and does not consider the local grid conditions within each model regions. Nevertheless, there exist technical solutions to the local grid challenges. This is supported by Ref. [73] that provides technical solutions for three PV penetration levels; including PV curtailment, voltage adjustment in trafos, local storage and advanced short-term PV forecasting methods.

4.4. Energy system cost

Fig. 12 shows the energy system cost for the model cases, relative to the energy system cost of *REF*. The discounted energy system cost is the minimum investment and operational costs, accumulated over the total time-horizon, to meet the Scandinavian energy demand. This includes investments in both supply and demand technologies, expenses related to operation of capacity, fuel costs, income of electricity export and costs of electricity import from countries outside Scandinavia.

The deployment of passive building standard in the model cases *PBU, ZEB* and *ZEB**, and the building-integrated PV production in *SUN, PBU, ZEB* and *ZEB**, are model inputs and their related costs are not reflected in the energy system cost. Thus, the difference between *REF* and *PBU*, of 28 billion EUR, represents the energy system savings due to the reduced heat demand, and the difference between *REF* and *SUN*, of EUR 26 billion, reflects the savings caused by the added PV production. The system saving of ZEBs, is derived by comparing *REF* and *ZEB*, and is EUR 47 billion. Note that this is less than the sum of the cost savings due to passive standard and building integrated PV separately. It is also beneficial for Scandinavia with more variable European electricity prices. This is because the flexible electricity generation in Scandinavia enables electricity export when the prices are high and electricity import

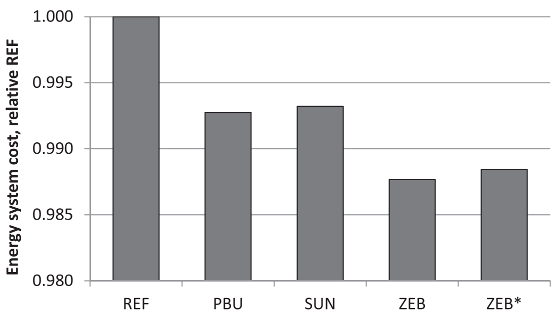


Fig. 12. Energy system cost for all model cases, relative to REF.

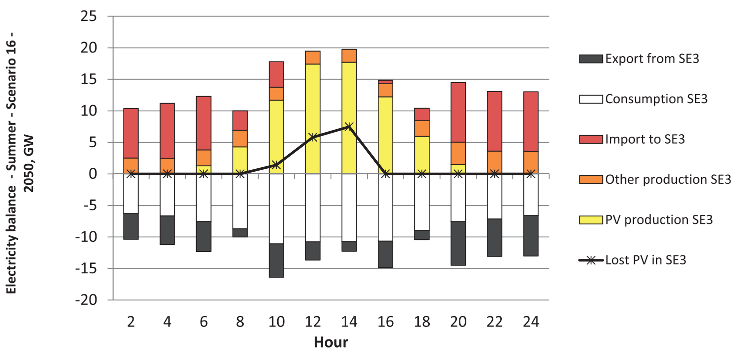


Fig. 11. The electricity balance of a random summer day in 2050 for *ZEB* in region SE3.

when the prices are low. With ZEBs in Europe, that increase the price variability, the energy system cost is reduced with EUR 3 billion when comparing *ZEB* and *ZEB**,

4.5. Benefit of stochastic model approach

The applied stochastic approach gives investment decisions that differ from the corresponding deterministic models, as the stochastic approach base investment decisions on a range of possible realisations of operational situations. The difference in investment decisions in electricity- and heating-technologies between a deterministic and our stochastic approach is evaluated in Appendix B. The main conclusion from this analysis is that a simplified deterministic approach, where the expected values of the uncertain parameters are used as model input, overestimates the competiveness of intermittent electricity generation and underestimates the investments in heat capacity in buildings compared to the stochastic approach.

5. Conclusions

This paper investigates the impact of a large introduction of ZEBs on the Scandinavian energy system towards 2050 with a stochastic TIMES model. When assuming that all new buildings and parts of the rehabilitated buildings are nearly ZEBs, 50% of the Scandinavian building stock is expected to be nearly ZEBs by 2050. A nearly ZEB is defined to be a passive building with on-site PV production that equals the building's annual electricity specific demand. Further, we assume no use of energy storage within the buildings, and hence the difference between electricity supply and demand of ZEBs is handled by electricity trade.

An implementation of ZEBs affects the cost-optimal investments and operation of the energy system in two ways; through the lower heat demand and the increased PV production. In the electricity sector, the investments in CHP, non-flexible hydropower and wind power are reduced, with the largest reduction on the wind capacity. As ZEBs lowers the electricity price throughout Scandinavia, the wind capacity is reduced with over 50% in 2050, where most of the reductions occur in Sweden and Norway. Although Norway has more favourable wind conditions than Denmark, the wind capacity is highest in Denmark due to their absence of hydropower with a long lifetime, and due to the grid interconnections to Europe.

In the building sector, where deployment of ZEBs reduces the heat demand by 35 TWh in 2050, the capacities of all types of heating technologies are decreased, but the share of heat supply from electric boilers and direct electric heating increases. Jointly, this gives a marginal decrease in the electricity use in buildings, contributing to a 4 TWh reduction of the Scandinavian electricity consumption in 2050.

The results illustrate that the Scandinavian energy system is well suited to integrate a large amount of ZEBs with PV on an aggregated level due to its flexible hydropower plants. With 63 GW of PV in 2050, the energy system cannot utilise all the non-flexible electricity generation in 3% of the time, corresponding to 2% unutilised PV production. Further work should address whether the Scandinavian energy system will benefit from local energy storage within buildings or if curtailing the PV production is more cost-efficient. Although additional energy storage in buildings can increase the trading flexibility to Europe, the existing hydropower plants provides substantial flexibility to the electricity market, and is able to adapt the electricity trade pattern between Scandinavia and Europe with an implementation of ZEBs.

Acknowledgement

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Appendix A. Model input on energy prices

Table A1
Model input on energy prices in 2020, 2030, 2040 and 2050

EUR/MWh	2020	2030	2040	2050
Fossil fuels				
Coal	13	13	14	14
Natural gas	32	35	36	36
Oil	64	69	72	72
Biomass				
Pellets	29–44	31–46	31–47	31–47
Straw	24	26	27	27
Chips	22–33	24–37	25–38	25–38
Biogas	30–46	31–47	33–49	33–49
Electricity				
Germany	56	62	64	64
Lithuania	56	62	64	64
Poland	56	62	64	64
United Kingdom	84	75	72	72
The Netherlands	66	65	65	65
Finland	54	57	58	58

Appendix B. The value of a stochastic model approach

This appendix evaluates the difference in investment decisions in electricity and heat capacity of using a deterministic and a stochastic approach. Both approaches have the same model input except for the representation of the uncertain parameters. In the deterministic approach, the expected values of the uncertain parameters are used as model input.

Fig. B1 depicts the difference in electricity capacity between a deterministic and a stochastic approach for all cases in 2030 and 2050. For all model cases, the deterministic methodology has higher investments in electricity capacity, with primarily an increase in intermittent electricity generation. In 2050, the increased wind capacity ranges from 1.4 GW for *ZEB** to 2.2 GW for *PBU*, corresponding to 18% and 12% higher capacity respectively compared to the stochastic approach. The flexible hydro capacity is indifferent to the representation of the uncertain parameters, whereas the profitability of non-flexible hydro plants is overestimated with a deterministic approach. For *ZEB* in 2050, the investments in new non-flexible capacity is 4.4 GW with a deterministic and 4.3 GW with a stochastic approach. The impact of modelling approach on CHP investments varies with model case, where the CHP capacity is higher for the stochastic approach for most instances.

Further, the results indicate that the deterministic approach underestimates the optimal investments of heating technologies in buildings. Fig. B2 illustrates the difference in heat capacity between the deterministic and stochastic approach in 2030 and 2050 for all cases. Here, the heat capacity excludes district heat plants, and the technology group named *Electricity* includes both electric boilers and direct electric heating. For all instances, the deterministic methodology finds it optimal to invest in less capacity in electricity and gas technologies compared to a stochastic approach whereas the influence on HPs and bio fuelled heating depends on case and period. It is especially the installed capacity for direct electric heating that is affected by the representation of the uncertain parameters. For *REF* in 2050, the electricity capacity is 71% higher for a stochastic compared to a deterministic approach.

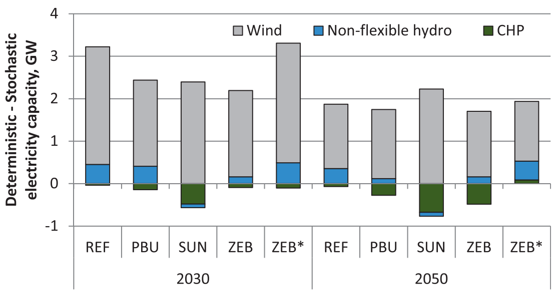

Fig. B1. Deterministic minus Stochastic electricity capacity in 2030 and 2050 for all model cases.

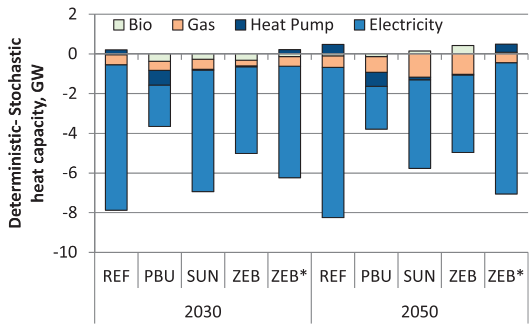

Fig. B2. Deterministic minus Stochastic heat capacity in 2030 and 2050 for all model cases.

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