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Brian Vad Mathiesen

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PhD Thesis by

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Tilegnet mine forældre
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Abstract

Efficient fuel cells and electrolysers are still at the development stage. In this dissertation, future developed fuel cells and electrolysers are analysed in future renewable energy systems. Today, most electricity, heat and transport demands are met by combustion technologies. Compared to these conventional technologies, fuel cells have the ability to significantly increase the efficiency of the system while meeting such demands. However, energy system designs can be identified in which the fuel savings achieved are lost in technologies elsewhere in the system.

This dissertation is based on the fact that the improvements obtained by implementing fuel cells depend on the specific design and regulation possibilities of the energy system in which they are used. For the same reason, some applications of fuel cells add more value to the system than others. Energy systems have been identified, both in which fuel cell applications create synergy effects with other components of the system, as well as in which the efficiency improvements achieved by using fuel cells are lost elsewhere in the system.

In order to identify suitable applications of fuel cells and electrolysers in future energy systems, the direction in which these systems develop must be considered. In this dissertation, fuel cells are analysed in the context of energy systems that are gradually changing from the current design, with large amounts of fossil fuel combustion technologies, to a future design based on 100 per cent renewable energy. The conclusions of the analyses refer to the application of fuel cells and electrolysers to such future renewable energy systems and should thus be seen in this context.

In future energy systems, there is a risk that improvements in efficiency are lost, because the system design is not equipped for utilising the full potential of fuel cells. If fuel cells replace gas turbines in combined heat and power (CHP) plants, the improvements may be lost, because a larger part of the heat demand must now be met by boilers. In integrated energy systems with large heat pumps, however, the decreased heat production from fuel cells at CHP plants can be met by heat pumps instead of by boilers using heat storages. In such applications, a synergy is created between the components of the system and the full potential of the fuel cells is utilised. Fuel cells induce higher fuel savings in integrated energy systems with large shares of intermittent renewable energy than in conventional energy systems. Thus, they are important measures on the path towards future 100 per cent renewable energy systems.

In locally distributed CHP plants with district heating grids, fuel cells are especially promising in terms of replacing conventional gas turbines. Fuel cells have higher efficiencies than these, also in part load. Fuel cells should not be developed for base load operation, but for flexible regulation in energy systems with large amounts of intermittent renewable energy and CHP plants. Base load plants are not required in such energy systems. With such abili-

ties fuel cells can replace steam turbines. Synergy can be created by using fuel cells in renewable energy systems, because the number of operation hours decreases and the lifetime of the cells becomes less significant.

Hydrogen micro-fuel cell CHPs in individual households are not suitable for renewable energy systems. This is due to the high losses associated with the conversion to hydrogen and the lower regulation abilities of such systems. In a short-term perspective, natural gas micro-fuel cell CHP may spread the CHP production more than locally distributed fuel cell CHPs are capable of doing. This can potentially increase the efficiency of the energy system and displace the production at coal-fired power plants; however, there is a risk that the production at more efficient fuel cell CHP plants is displaced. In the long term, however, it should be considered which fuels such technologies can utilise and how these fuels can be distributed. Natural gas is not an option in future renewable energy systems and the demand for gaseous fuels, such as biogas or syngas, will increase significantly. Hence, fuel cell CHP plants represent a more fuel-efficient option in terms of using such scarce resources. Heat pumps are more fuel and cost-efficient options in terms of meeting the heat demand in individual houses.

Both fuel cell and battery electric vehicles are more efficient options than conventional internal combustion engine vehicles. In terms of transport, battery electric vehicles are more suitable than hydrogen fuel cell vehicles in future energy system. Battery electric vehicles may, for a part of the transport demand, have limitations in their range. Hybrid technologies may provide a good option, which can combine the high fuel efficiency of battery electric vehicles with efficient fuel cells in order to increase the range. Such hybrid vehicles have not been investigated in this dissertation.

In the short term, electrolyser hydrogen is not suitable for fuel cell applications; and in the long term, some applications of electrolysers are more suitable than others. Other energy storage technologies, such as large heat pumps in CHP plants and battery electric vehicles, should be implemented first, because these technologies are more fuel and cost-efficient. Electrolysers should only be implemented in energy systems with very high shares of intermittent renewable energy and CHP; but in a 100 per cent renewable energy system, they constitute a key part, because they displace fuels derived from biomass. In such applications, electrolysers should be developed to have the highest possible efficiency, the most flexible regulation abilities, and the lowest investment costs possible.

Dansk resumé

Effektive brændselsceller og elektrolysesystemer er stadigvæk på udviklingsstadiet. I denne Ph.d.-afhandling analyseres fremtidens brændselsceller og elektrolyseanlæg i fremtidige vedvarende energisystemer. Forbrændingsteknologier dækker i dag størstedelen af elektricitets-, varme- og transportbehovet. Sammenlignet med disse traditionelle teknologier har brændselsceller en højere nyttevirkning. Der findes dog typer af energisystemer, hvor brændselsbesparelsen går tabt i teknologier andre steder i systemet.

Udgangspunktet for denne Ph.d.-afhandling er, at de forbedringer, der opnås ved at indføre brændselsceller, afhænger af energisystemets specifikke design og reguleringsmuligheder. Af samme årsag tilfører nogle brændselsceller mere værdi til energisystemet end andre. I afhandlingen præsenteres der både energisystemer, hvor brændselsceller opnår synergieffekter med andre komponenter i energisystemet, og energisystemer, hvor brændselscellens højere nyttevirkning går tabt i andre dele af systemet.

For at kunne identificere passende anvendelsesmuligheder for brændselsceller og elektrolyseanlæg i fremtidige energisystemer, skal der tages hensyn til, i hvilken retning energisystemerne udvikler sig. I denne Ph.d.-afhandling analyseres brændselsceller i forbindelse med energisystemer, der gradvist ændres fra det nuværende design, med store mængder fossile forbrændingsteknologier, til et fremtidigt design, der er baseret på 100% vedvarende energi. Brændselsceller og elektrolyseanlæg er analyseret i disse fremtidige vedvarende energisystemer, og konklusionerne skal derfor ses i denne kontekst.

I fremtidige energisystemer er der en risiko for, at de højere nyttevirkninger, der opnås ved hjælp af brændselsceller, går tabt, fordi systemet ikke er udrustet til at udnytte brændselscellernes fulde potentiale. Hvis brændselsceller erstatter gasturbiner i kraftvarmeværker, kan disse forbedringer gå tabt, fordi en større del af varmebehovet nu skal dækkes af kedler. I integrerede energisystemer kan den lavere varmeproduktion fra brændselscellekraftvarme erstattes af varme fra varmepumper i stedet for varme fra kedler ved brug af varmelagre. Dette giver en synergi mellem brændselsceller og varmepumper, hvor det fulde potentiale af brændselscellerne kan udnyttes. I integrerede energisystemer med større mængder fluktuerende vedvarende energi giver brændselsceller større brændselsbesparelser end i traditionelle energisystemer. De er derfor vigtige skridt på vejen mod fremtidige 100% vedvarende energisystemer.

Brugen af brændselsceller i decentrale kraftvarmeværker i stedet for gasturbiner ser særligt lovende ud, fordi brændselscellerne har en højere nyttevirkning i både fuldlast og dellast. Brændselsceller bør ikke udvikles til grundlastværker men derimod til fleksible regulerbare værker i energisystemer med store mængder fluktuerende vedvarende energi og kraftvarme. Grundlastværker er ikke nødvendige i disse energisystemer. Med disse egenskaber kan

brændselscellerne erstatte kondenskraftværker. Der kan opnås en synergi ved at bruge brændselsceller i vedvarende energisystemer, fordi antallet af driftstimer mindskes og brændselscellernes levetid bliver mindre afgørende.

Brintbaserede mikrokraftvarmeanlæg med brændselsceller i individuelle husstande er ikke egnede til vedvarende energisystemer på grund af store tab i omdannelsen til hydrogen samt lavere reguleringsmuligheder i sådanne systemer. På kort sigt kan naturgasbaserede brændselsceller i mikrokraftvarmeanlæg udbrede kraftvarmeproduktionen, udover hvad der kan lade sig gøre med decentrale brændselscellekraftvarmeværker. Dette kan potentielt set øge effektiviteten af energisystemet og erstatte produktionen på kulkraftværker, men der er en risiko for, at produktionen på mere effektive brændselscellekraftvarmeværker dermed bliver fortrængt. På lang sigt bør det dog overvejes, hvilke brændselstyper mikrokraftvarmeanlæg kan anvende, og hvordan brændslet kan distribueres. Naturgas vil kun i begrænset omfang være til stede i fremtidige vedvarende energisystemer og efterspørgslen på brændstof i gasform, såsom biogas og syngas, vil stige betydeligt. Brændselscellekraftvarmeværker udgør derfor en mere brændselseffektiv mulighed for at udnytte disse knappe ressourcer. Varmepumper er en bedre opvarmningsform i individuelle husstande, da de er mere brændselseffektive og er forbundet med lavere omkostninger.

Både brændselscellebiler og batteridrevne elbiler har en højere nyttevirkning end køretøjer med traditionelle forbrændingsmotorer. I et fremtidigt vedvarende energisystem er elbiler mere egnede til transport end brændselscellebiler. Rækkevidden for elbiler kan dog være et problem i forhold til en del af transportbehovet. Her kan hybridbiler med både brændselsceller og batterier kombinere de to teknologiers høje nyttevirkning og øge rækkevidden. Hybridbiler er ikke analyseret i denne afhandling.

På kort sigt er brint fra elektrolyseanlæg en unødvendig løsning, og på lang sigt er visse anvendelser mere egnede end andre. Andre energilagringsteknologier, som f.eks. store varmepumper på kraftvarmeværker samt elbiler, bør indføres som de første, fordi disse teknologier er mere brændselseffektive og har væsentlig lavere omkostninger. Elektrolyseanlæg bør kun implementeres i energisystemer med store mængder fluktuerende vedvarende energi og kraftvarme. De udgør dog en vigtig del af 100% vedvarende energisystemer, fordi de kan erstatte biobrændsler. I disse systemer bør elektrolyseanlæg udvikles til at have størst mulige nyttevirkning, mest fleksible reguleringsmuligheder og lavest mulige omkostninger.

Contents

Appendices

Preface

In the spring of 2001, in my 6th semester, I wrote a report about life cycle assessments of marine waste products with my fellow students Rasmus Olsen, Niels Døssing Overheu, Frederik Gudi Sommer-Gleerup and Thomas Norman Thomsen. We found that the energy supply had a profound effect on the results of this cradle-to-grave environmental assessment. One and a half years later, life cycle assessment was back in focus. I participated in conducting an analysis of organic waste for the Danish Environmental Protection Agency. Again, the outcome was very sensitive to the surrounding energy supply system. This made me wonder about this energy supply system. I found that whichever issue I studied or touched upon in my own work or in other analyses of environmental impacts, the energy supply system involved played a crucial role. I thought that, if this system is so important, it should be investigated how the composition of energy supply technologies could be changed! In the following semester, I decided to conduct further analyses of the energy system in order to find out, how changes in the energy system could be constructed. Since then, this has been on my mind. And it is my initial motivation for conducting this research of fuel cells and electrolysers in future energy systems.

In September 2005, two years after finishing my Master's degree programme, I came back to the University to start my work on the PhD dissertation. At the same time, Danish petrol prices had increased and, for the first time, crossed the limit of 10 DKK per litre (1.33€/litre). This was a local sign of a global development which made me realise that the future energy supply should not only have lower environmental impacts, but should also provide affordable energy for the people who depend upon it. Affordable energy does not only require affordable technologies but also well-functioning markets and security for new investors.

Once started, my own analyses and calculations confirmed what I had only previously read about. The design of the energy system has a profound effect on the national economy and the emission of green house gasses. In the summer of 2006, I found myself deeply involved in constructing and analysing future 100 per cent renewable energy systems, which documented that Danish society could achieve large economic savings by taking the first step including a renewable energy share of 50 per cent as well as 60 per cent reductions in greenhouse gas emissions. High temperature fuel cells and electrolysers were used in these systems in order to increase the efficiency and lower the dependence on other fuels.

I never analysed the environmental effects of marine waste products in this context; however, I am sure that they would have lower environmental effects and that the analyses of organic waste would now be in favour of bio gasification instead of incineration.

In this dissertation, fuel cells and electrolysers in future energy systems are analysed, considering the perspective that they can have different effects in different energy system contexts.

This dissertation is part of the research project "Efficient Conversion of Renewable Energy using Solid Oxide Cells", which in total includes eight subprojects and is conducted in collaboration between The Fuel Cells and Solid State Chemistry Department at Risø-DTU, the Department of Physics and Astronomy at Aarhus University, the Department of Chemistry at the Technical University of Denmark, Ørsted Laboratory at the University of Copenhagen, the Department of Chemistry at the University of Southern Denmark, and the Department of Building Technology & Structural Engineering and the Department of Development and Planning, both at Aalborg University. The research project is financed by the Danish Ministry of Science, Technology and Innovation.

In the chapters of this dissertation, I summarise and conclude on the research conducted in the PhD project, including the analyses of the potential applications of fuel cells and electrolysers in future energy systems. More details and assumptions as well as more results are available in the appendices.

During these last three years, I have been fortunate to meet a lot of very inspiring and supportive people. I know that I cannot remember them all (and do not have room to mention everybody anyway). I would, however, like to thank Henrik Lund and Frede Hvelplund for inspiring and fruitful conversations as well as my other colleagues from the Sustainable Energy Planning Research Group, from the LCA Team, and others at the Department of Development and Planning at Aalborg University.

Special thanks are due to Georges Salgi and Decharut Sukkumnoed, with whom I have shared office, for very good company; and to Mette Reiche Sørensen for providing excellent proofreading and helpful comments to improve the understanding of the text. Special thanks are also extended to Jens Adler Christensen and Astrid Viskum for helping me out in the final stages of the project.

I would also like to thank my colleague Marie Münster and the employees at the Systems Analysis Department at Risø-DTU for giving me new inspiration and putting up with me for a few months in the fall of 2006, as well as Søren Linderoth from the Fuel Cells and Solid State Chemistry Department at Risø-DTU and Thilde Fruergaard from the Department of Environmental Engineering at the Technical University of Denmark for a fruitful collaboration.

I would also like to thank Mads Pagh Nielsen from the Institute of Energy Technology at Aalborg University; Henrik Wenzel from the Institute of Chemical Engineering, Biotechnology and Environmental Technology at the University of Southern Denmark for inspiring

conversions on life cycle assessment methodology, as well as others involved in the CEESA project.

To the people involved in the Danish Engineering Association's Energy Year I am especially grateful; thank you for inviting me and Henrik Lund to conduct the technical and economic analyses for the IDA Energy Plan 2030. I would like to thank everybody who participated and gave inputs at meetings and seminars, as well as Bjarke Fonnesbech, Kasper Dam Mikkelsen, Michael Søgaard Jørgensen, and the members of the steering group, Søren Skibstrup Eriksen, Hans Jørgen Brodersen, Per Nørgaard, Kurt Emil Eriksen, Charles Nielsen, John Schiøler Andersen, Mogens Weel Hansen, and Thomas W. Sødring.

Thanks to my friends and family for believing in me and for supporting me through the rough patches that turn up on the road once and a while.

The dissertation was completed on September 15th, 2008 and was successfully defended on December 11th, 2008 at Aalborg University. The Evaluation Committee was composed of Associate Professor Bernd Möller, Aalborg University (Chairman), Senior Scientist Kenneth Karlsson, Risø National Laboratory, DTU, and Professor Dr.Sc. Neven Duić, University of Zagreb.

I hope you enjoy reading my report.

Nomenclature

Power generation and renewable energy etc.

AC	Alternating current
CCGT	Combines cycle gas and steam turbines
CHP	Combined heat and power
COP	Co-efficient of performance
DC	Direct current
EB	Electric boilers
ELT/CHP	Electrolysers with CHP plants
ELT/micro	Electrolysers with micro fuel cell micro combined heat and power
FC-CHP	Fuel cell combined heat and power
FLEX	Flexible electricity demand
GT	Gas and steam turbines
HP	Heat pumps
Micro-CHP	Micro combined heat and power
PES	Primary energy supply
PP	Power plant
RES	Intermittent renewable energy sources
SCGT	Single cycle gas turbines

Transport

BEV	Battery electric vehicles
HFCV	Hydrogen fuel cell vehicles
V2G	Vehicle to grid

Energy units etc.

MJ	Mega joule
PJ	Peta joule (1 billion MJ)
kWh	Kilo watt hour (3.6 MJ)
MWh	Mega watt hour (1,000 kWh)
GWh	Giga watt hour (1,000 MWh)
TWh	Tera watt hour (1,000 GWh)
TWh_e	Tera watt hour electricity
TWh_{th}	Tera watt hour heat
TWh_{fuel}	Tera watt hour fuel
MW	Mega watt capacity (1,000 kW)
MW_e	Mega watt electrical capacity
Bbl oil	Barrel of oil (159 litre standard oil)
Mt	Million ton

Fuel cells and electrolysers

AFC	Alkaline fuel cell
DMFC	Direct methanol fuel cell
HT-PEMFC	High temperature polymer exchange fuel cell
MCFC	Molten carbonate fuel cell
PAFC	Phosphoric acid fuel cell
PEMFC	Polymer exchange membrane fuel cell
RMFC	Reformed Methanol Fuel Cell
SOFC	Solid oxide fuel cell
SOEC	Solid oxide electrolyser cell

Economy

DKK	Danish kroner
€	Euro
$	US Dollar
O&M	Operation and maintenance costs

Materials, substances and fuels

CH_3OH	Methanol
CO	Carbon monoxide
CO_2	Carbon dioxide
DME	Dimethyl-ether (CH_3OCH_3)
H+	Hydrogen ion
H_2	Hydrogen
H_2O	Water
LPG	Liquefied petroleum gas
Ngas	Natural gas
NH_3	Ammonia
NMVOC	Non-methane volatile organic compounds
NO_x	Nitrogen oxides
O^{2-}	Oxide ion
O_2	Oxygen
S	Sulphur
SO_x	Sulphur Oxides

1 Introduction

The purpose of this dissertation is to identify suitable applications of fuel cells and electrolysers in future renewable energy systems. In this chapter, the research subject is introduced by elaborating the design of future energy systems and the applications of fuel cells and electrolysers to such systems.

1.1 Advantages of fuel cells and electrolysers

Two main reasons can be defined for increasing the focus on fuel cells in terms of replacing conventional conversion technologies; they have potentially better efficiencies and they have no or very low local environmental effects [1;2]. Fuel cells are developed for applications to power plants, large and small-scale combined heat and power (CHP), micro-CHP and transport. Although fuel cells have the advantage of providing better electricity efficiencies, the efficiency and costs are dependent on the size of the system; i.e. the smaller the system, the balance of plant equipment requires relatively more energy and investment in relation to the size of the cells [1]. Fuel cells may also have some disadvantages in comparison with combustion steam turbines in conventional power plants, as fuel cells require higher quality fuels. Conventional combustion technologies can use a large variety of fuels, while fuel cells must be combined with fuel processing systems increasing the fuel quality. The applications of fuel cells to future energy systems depend on their ability to utilise fuels derived from biomass resources or the identification of paths of fuels from electrolysers to fuel cells. Solid oxide fuel cells (SOFC) CHP plants are the subject of analysis of this dissertation; however, other types of fuel cells, such as polymer exchange membrane fuel cells (PEMFC), are also included in some analyses of micro-CHP and transport technologies.

Electrolysers are often mentioned as an important part of energy systems with high shares of intermittent renewable energy. By using fuel cells and hydrogen or hydrogen carrier fuels from electrolysers, more renewable energy can be integrated into the transport sector or used for replacing fuel in CHP plants. Thus, electrolysers enable the utilisation of electricity replacing fossil fuels. While electrolyses may seem to be the obvious solution to the integration of intermittent resources in the long term, other technologies, such as large heat pumps, flexible demand or electrical transport are more efficient options [3;4]. The expansion of intermittent resources combined with energy savings will often lead to a critical excess electricity production and thus increase the demand for strategies for integrating these resources. In this situation, electrolysers will be competing with other technologies. The notion of “free” excess electricity production from wind turbines is widespread; however, this will hardly be the situation in future energy systems, as long as options exist in which such production can be utilised. In this case, electrolysers provide a potential good solution in terms of integrating intermittent resources replacing other fuels.

Fuel cells and electrolysers have the potential for supplying three main energy services to the end-users: electricity, heat and transport; and can replace existing less efficient or more polluting technologies. The challenge is to identify in which applications these technologies should be used in future energy systems.

1.2 Future energy systems

Worldwide, local and regional energy supplies face three key challenges: The displacement of imported fuels and better fuel efficiency to improve security of supply; the reduction of emissions of climate gases and the mitigation of climate change; and finally, the reduction of local atmospheric pollution and improvement of public health. These challenges are hardly new; however, two other developments have added to these challenges: Internationally, the prices of natural gas, oil and coal have increased significantly within a few years because of an increase in demand, and the price of food products has followed.

The focus on intermittent renewable energy sources and biomass for energy purposes has increased. Intermittent renewable energy resources are increasingly used for the displacement of fossil fuels for heat and power. Biomass is increasingly used for heating purposes as well as for transport, because of the total dependence on oil of this sector, the focus on greenhouse gasses, and the high oil costs [5;6]. In terms of transport, the most obvious available solution has been to produce liquid biofuels because these, to a large extent, can be used in existing vehicles.

In future energy systems, intermittent resources, such as wind turbines, photovoltaic power, wave power and solar thermal power, in addition to efficient energy conversion technologies and savings in demand are key technologies. They contribute to reducing the dependence on fossil fuels, increasing the security of supply and also minimising the pressure on biomass resources and land use. This has also increased the focus on CHP technologies, which can improve the utilisation of fuels.

New legislation supports intermittent renewable resources, CHP and savings in end demand. In the EU, the cogeneration of power and heat for heating and cooling purposes is promoted due to its potential for increasing total fuel efficiency [7]. The aim is to raise the share of electricity from CHP[1] from approx. 9 per cent now to 18 per cent in 2010 in the EU-15 countries [8].

In the agreement from January 2007, the EU committed to reaching the target of 20 per cent renewable energy supply of the primary energy demand, 20 per cent energy efficiency, and 20-30 per cent reduction in greenhouse gas emissions by 2020. The level of the

[1] Combined heat and power (CHP) production covers energy for heat and cooling purposes and thus the analyses regarding CHP described in this dissertation are also applicable to locations where cooling is required.

goal for reductions in greenhouse gas emissions is dependent on the commitment of other developed countries. In July 2008, some of the world's most powerful nations in the G-8 announced a goal of halving greenhouse gas emissions worldwide by year 2050, if China and India are also committed to an international agreement. The international focus on greenhouse gas reduction commitments is increasing as we approach the United Nations' Climate Change Conference 2009, the COP15 in Copenhagen in November and December 2009.

With an increased focus on intermittent renewable resources, CHP, and energy savings, the European energy systems can integrate considerably more distributed generation from local CHP and intermittent resources in the future [9]. Worldwide, similar policies can be expected for CHP due to high fuel prices and reductions in greenhouse gases, and many initiatives have already been taken in promoting intermittent renewable resources. Future energy systems may look very different from the systems we know today; thus, when identifying the suitable applications of fuel cells and electrolysers, it is insufficient to analyse these in the current energy system designs.

1.3 On the path towards future energy systems – the Danish case

The Danish energy system is a practical example of one configuration of such a future energy system. Approx. 20 per cent of the electricity demand is supplied from wind turbines, and 50 per cent is produced at CHP plants. Energy savings, especially in the heating sector, combined with the large penetration of CHP and wind power production have kept the primary energy supply at a stable level since the early 1970s. The Danish case reflects many of the challenges faced by the international community in the energy supply sector. Until now, the changes in the Danish energy supply represent a transition from a situation with total dependence on oil and separate heat and power supplies in the 1970s to an integrated system, currently involving large shares of CHP and intermittent renewable resources and utilising a variety of fuels [10].

Within 20 years, the energy supply has changed from a classical centralised system with very few and big power plants to a decentralised system. With 1.223 MW additional wind power capacity planned by 2012, this development can be expected to continue [9]. The future challenges of combining energy savings with intermittent renewable resources and CHP were emphasised in October 2006, when the Danish Prime Minister announced the long-term target of 100 per cent independence of fossil fuels and nuclear power. This target poses two additional challenges: 1) as the shares of intermittent resources and CHP increase and energy savings are implemented, the energy system must be adapted to this situation in order to maintain fuel efficiency and avoid excess electricity production; and 2) the challenge of integrating the transport sector.

In December 2006, a plan for how and when to achieve the goal of a 100 per cent renewable energy system was proposed by the Danish Association of Engineers in the IDA Energy Plan 2030 [5;11-13]. This energy plan involved three main transformations from the current Danish energy system; i.e. increased savings in demand, increased energy conversion efficiency with fuel cells and large heat pumps, and renewable energy replacing fossil fuels, also involving the use of electrolysers.

The Danish energy system represents a good case for the identification of possible applications of fuel cells and electrolysers. It represents both a historical and a future development, reflecting the transition which is likely to occur in the design of other energy systems at the international level.

1.4 Identifying suitable applications of fuel cells and electrolysers

The advantages of using fuel cells as power plants in energy systems with separate electricity and heat supplies can be identified rather simply, i.e. by comparing the efficiencies of traditional steam turbine power plants to the potential developments of fuel cells, as illustrated in Fig. 1.

However, while this identification may seem simple in the current energy systems; it becomes more complex in integrated energy systems with intermittent resources and CHP, etc. In Fig. 2 to Fig. 4, schemas of different energy systems are presented, illustrating the different phases from current energy system designs to future integrated energy systems designs, all supplying the same services. The figures illustrate the effects of replacing state-of-the-art conventional technologies with more efficient fuel cell technologies.

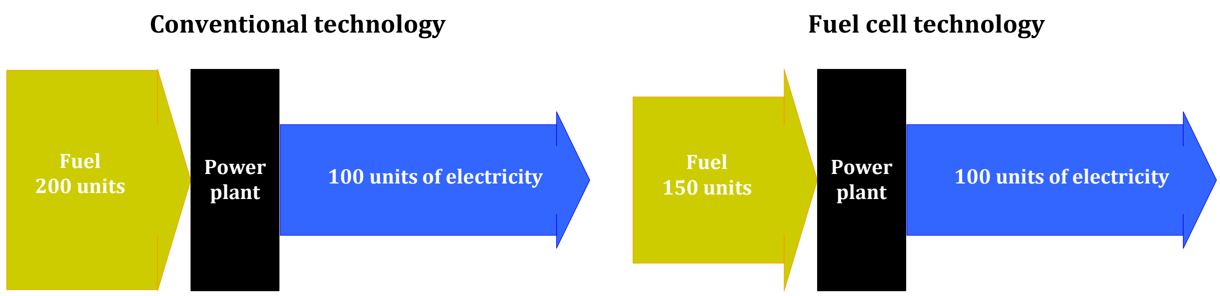

Fig. 1, Schema of the electricity supply in conventional power plants and fuel cell power plants.

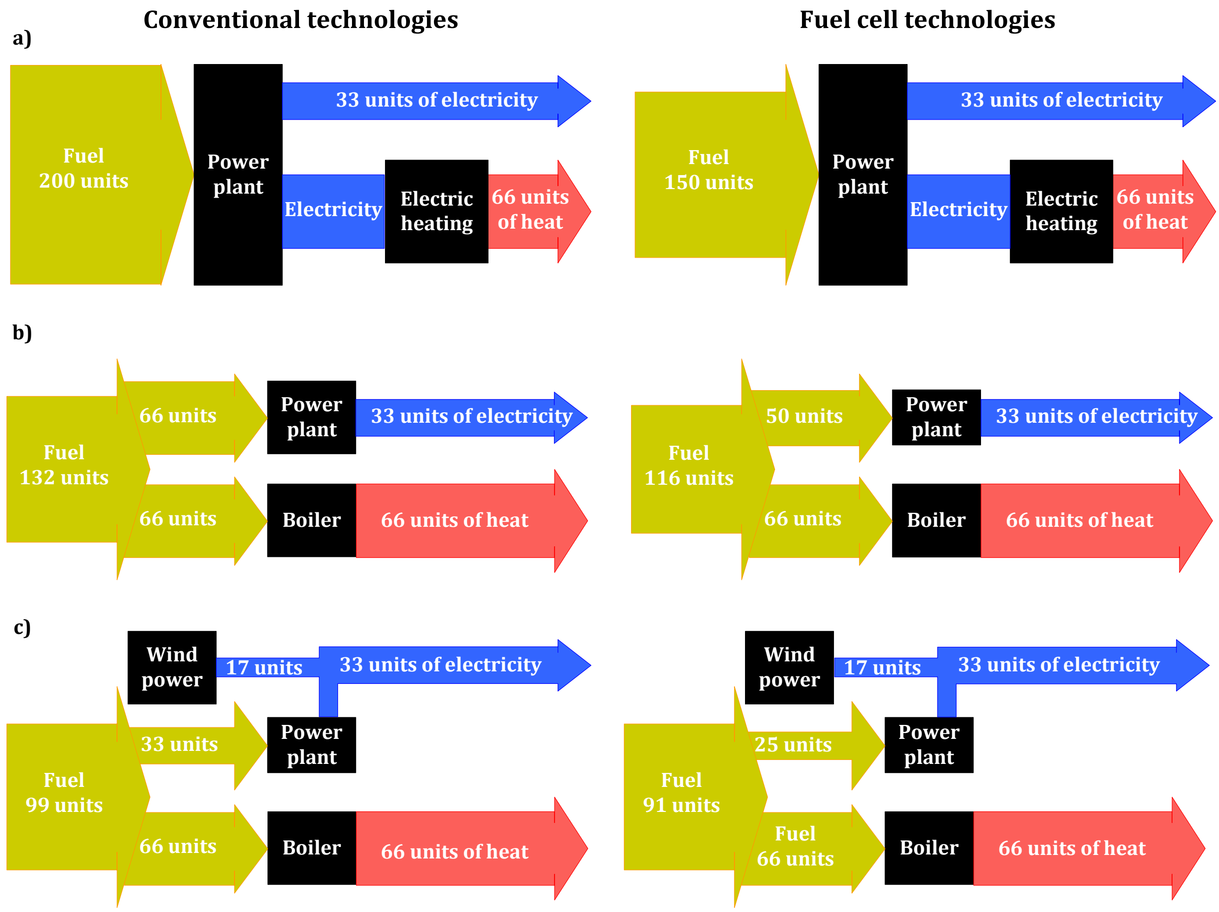

Fig. 2, Schema of energy systems with and without wind power, in which the electricity and heat supplies are met by electricity from power plants alone or from power plants and fuel boilers.

In Fig. 2 a), b) and c), the electricity and heat supplies are met by electricity from power plants alone or by power plants and fuel boilers. In these systems, fuel cell power plants would result in significantly lower fuel consumption, also when intermittent resources, such as wind power, are added to the system.

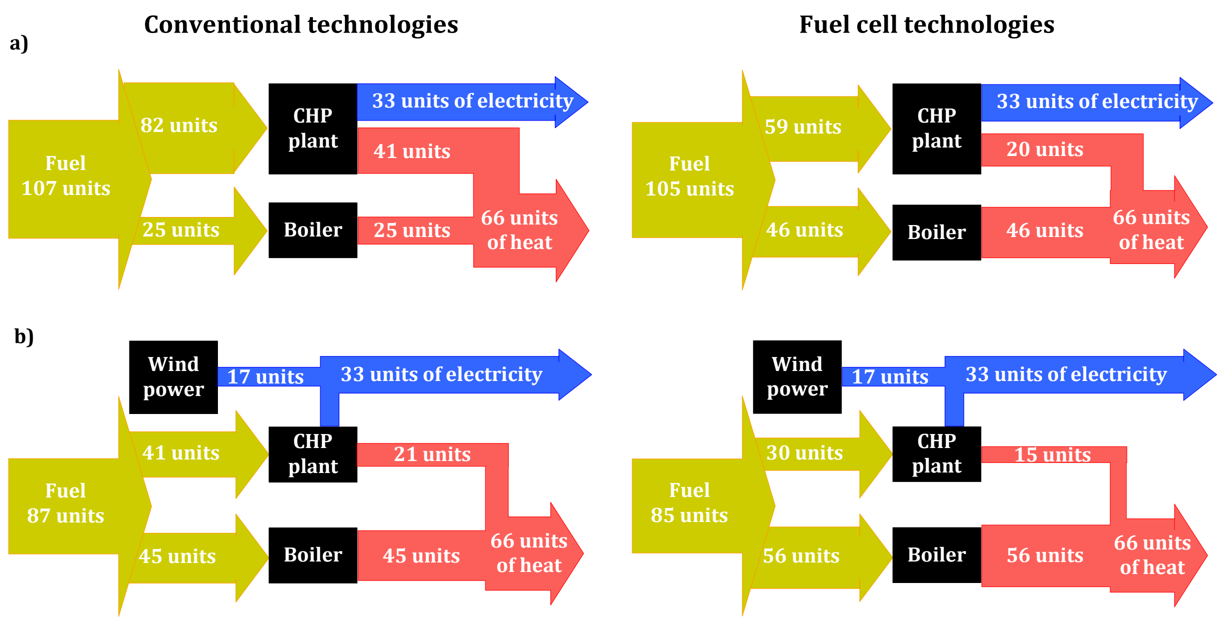

Fig. 3, Schema of energy systems with and without wind power, in which the electricity and heat supplies are met by combined heat and power (CHP) and fuel boilers.

Fig. 3 presents a schema of the effects of replacing existing CHP plants with fuel cell CHPs. The results show that fuel consumption is only marginally lower; the savings in heat and power generation from fuel cells are lost in boilers, which have to meet more of the heat demand. If the relation between heat and power demands is adapted to reflect the relation between heat and power production from fuel cells, fuel savings would improve. This could be the case with significant heat savings in the future; however, significant savings may also be achieved in the electricity demand.

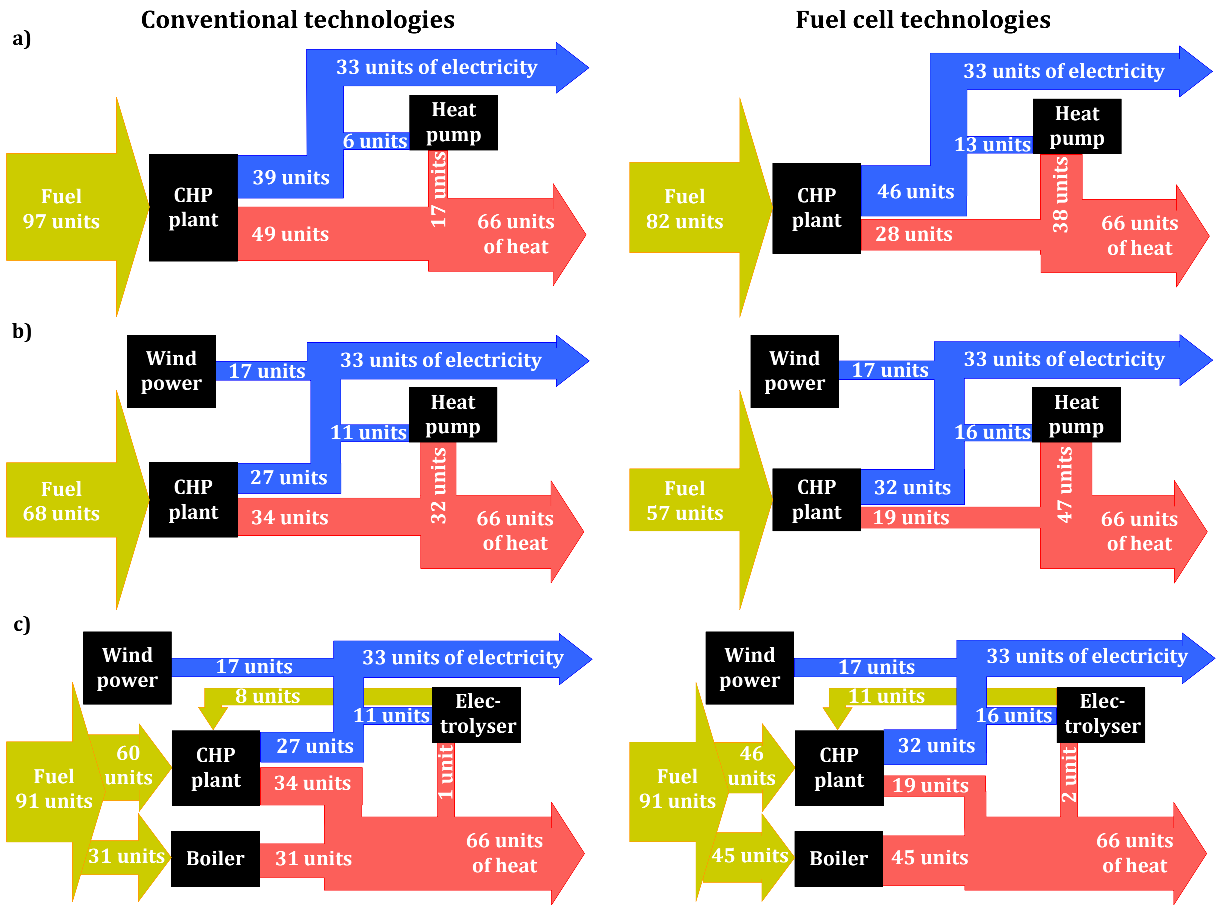

Fig. 4, Schema of energy systems with and without wind power, in which the electricity and heat supplies are met by combined heat and power (CHP) and heat pumps or electrolysers.

In Fig. 4 a) and b), schemas of integrated energy systems are presented in which large heat pumps make it possible to adjust the production from CHP and heat pumps to the demand for heat and power. Here, boilers can be replaced by heat pumps. In these systems, the increased electricity efficiencies of fuel cells are able to lower the total fuel consumption significantly, also when intermittent renewable resources are added to the system. While the improved efficiency in fuel cells may result in a higher production in fuel boilers, it increases the general electrical efficiency and improves the opportunity of replacing boiler heat production with large heat pumps in the integrated energy systems.

In Fig. 4 c), the schema of an energy system with CHP, boilers, wind and electrolysers is presented. Instead of using wind power in large heat pumps, it is used for replacing fuels in CHP plants and boilers. In the schematic results presented, it is more fuel-efficient to replace electricity generation in CHP plants with wind and supply the rest of the heat demand with boilers, than to use the wind power in electrolysers, i.e. Fig. 3 b) and Fig. 4 c). If the aim is to preserve fuels, this indicates that CHP plants, intermittent resources and heat pumps should be used, and that the electrolysers should only be used when fuels are required from the electrolysers in order to e.g. replace fossil fuels.

In the current energy system, electricity and heat are commonly produced separately, or the supply of heat is based on electric heating in most countries. In future efficient renewable energy systems, an interdependent electricity and heat supply is produced at CHP plants and the systems involve large heat pumps, an integrated transport sector, large shares of intermittent renewable energy, as well as savings in end demand. In such systems, the identification of suitable applications becomes more complex. Changes in production or demand in one part of the system may have unexpected effects elsewhere. The structure of different energy systems described here becomes more complex when taking into account the distribution of the electricity and heat demand through a day, a week or a year. Especially in the case of heat, significant differences can be found between summer and winter, also when taking into account large savings in demand [6]. The complexity increases with the introduction of intermittent resources, as the production from these also changes over time. In reality, the situation changes between the schemas described from hour to hour; and thus, when designing efficient energy systems, the main task is to ensure that as many solutions as possible are defined which enable the most fuel-efficient electricity and heat supply and transport services.

The paths of converting renewable energy to end demands through fuel cells and/or electrolysers can be constructed in many different ways. These conversion paths may have different effects on other parts of the energy systems. In order to identify suitable applications of fuel cells and electrolysers, energy system analyses are required which can take into account the effects of these technologies in systems with changing demands and productions from intermittent renewable resources.

1.5 Socio-economic & life cycle environmental impacts of fuel cells and electrolysers

Future energy systems involve high investments in demand side savings, intermittent renewable energy sources, and efficient conversion technologies. In future energy systems, fuel costs are converted into investment costs [11]. The socio-economic gains or losses of fuel cells and electrolysers are dependent on the different applications of the technologies in these systems. As illustrated in the schemas above, the effects of fuel cells and electrolysers depend on the energy systems of which they form part, and, thus, the socio-economic gains or losses also depend on the applications to these [10]. Likewise, the environmental impacts and resource consumptions of such technologies, seen in a life cycle perspective, depend highly on the applications and hence also the energy system in which they are used. Since the environmental impacts and resource consumptions of conventional power plants and CHP plants are by far the most significant in the use phase [14], energy system analyses are essential for the environmental results. This is also the case of potential future SOFC, because these have a primary energy consumption in the construction phase which is similar to that of power and CHP plants [2]. The life cycle effects of changing demands or adding technologies, such as fuel cells and electrolysers, to energy systems are complex; i.e. technologies interact with the energy system and should thus be analysed by applying energy system analyses [15;16].

1.6 The analyses of potential applications

The analyses of undeveloped technologies involve many uncertainties; however, like for other new technologies, scenarios for the development of fuel cells and electrolysers can uncover their potentials and enable the analysis of these in different energy system contexts [1]. The main purpose of this dissertation is to identify different applications of fuel cells and electrolysers in future renewable energy systems. Focus is placed on energy system analyses of fuel cells and electrolysers, as well as an account of the socio-economic consequences and life cycle environmental impacts of these technologies. The specific subject of study is solid oxide cells; however, most conclusions are also applicable to other types of fuel cells and electrolysers. SOFCs are rather fuel-flexible and, compared to other fuel cells, they have potentially higher efficiencies. Solid oxide electrolyser cells (SOECs) are more efficient than other electrolysers. However, it should be noted that SOFC and SOEC are still at the development stage and require further development.

In the next chapters, I summarise and conclude on the research conducted for this dissertation. The potential applications of fuel cells and electrolysers in future energy systems are analysed. More details and assumptions as well as more results are available in the appendices.

2 The energy system analysis methodology

In this chapter, an energy system analysis tool is introduced and a three-step energy system analysis methodology is presented which enables the identification of suitable applications of e.g. fuel cells and electrolysers in different future energy systems. The three-step energy system analysis methodology described in this chapter is based on "Energy system analyses of fuel cells and distributed generation" and "Solid oxide fuel cells in renewable energy systems" [10;17]. This methodology builds on the methodology of designing 100 per cent renewable energy systems used in "Danish Society of Engineers' Energy Plan 2030" [11-13].

2.1 Energy system analyses model

When conducting energy system analyses, an energy system analysis tool is needed. Such tools have been designed and used by public planning authorities, utility companies and different NGOs. Sometimes operation models originally developed to design suitable operating strategies on a day-to-day basis have been used for planning purposes. They were typically designed in the context of the current energy supply system with the aim of identifying lowest-cost electricity production strategies with several productions units. In order to be able to calculate exact operational costs and emissions, the models are typically rather comprehensive and detailed in their description of each individual power plant. In such models, the possibilities of introducing radical changes are rather limited.

In this dissertation, the energy system analysis and planning model EnergyPLAN is used [18]. The aim of a planning model is to design suitable future investment strategies or to analyse environmental impacts of different initiatives. The EnergyPLAN model is a deterministic input/output energy system analysis model, which has been developed and expanded on a continuous basis since 1999. It involves total national or regional energy systems on an aggregated basis and emphasises the evaluation of different operation strategies. The main purpose of the model is to facilitate the design of energy planning strategies. The model defines technical and economic consequences of different energy system designs or investments in new technologies. It includes interaction between CHP and fluctuating renewable energy sources in steps of one hour throughout one year as well as different regulation strategies. This integration is needed in order to be able to determine both technical and economic impacts of fuel cells and electrolysers in future energy systems. General inputs are demands, renewable energy sources, energy plant capacities, costs, and a number of optional regulation strategies emphasising import/export and excess electricity production. Outputs are energy balances and resulting annual productions, fuel consumption, CO_2 emissions, import/export, and total costs including income from the international exchange of electricity.

The EnergyPLAN model enables the analysis of radical technological changes. The model describes current fossil fuel systems in aggregated technical terms, which can be changed into radically different systems, e.g. systems based on 100 per cent renewable energy sources. The model divides the input to market economic analyses into taxes and fuel costs and thereby makes it possible to analyse different institutional frameworks in the form of different taxes. Moreover, if more radical institutional structures are to be analysed, the model can provide purely technical optimisations. This makes it possible to separate the discussion of institutional frameworks, such as specific electricity market designs, from the analysis of fuel and/or CO_2 emissions alternatives. Compared to many other models, the EnergyPLAN has not incorporated the institutional set-up of the electricity market of today as the only institutional framework.

Though the EnergyPLAN model is able to analyse different energy systems, it does not provide an overview of which power plants are built in which years. The CHP and power plants are pooled into categories according to their location in the district heating areas. This enables the integrated analyses of energy systems as well as faster data handling, but it also limits the level of details in the results for the individual types of technologies in the model. Instead, the model enables an exploration and identification of suitable applications of technologies, such as fuel cells and electrolysers, and the design of future energy systems. The model conducts one-point energy system analyses; i.e. no internal bottlenecks in Denmark are assumed, but it includes the possibilities of analysing different ancillary service designs.

2.2 The three-step energy system analysis methodology

This methodology includes technical modelling with different regulation strategies to reduce the fuel consumption and improve the integration of intermittent resources. It also involves the economic optimisation of the performance of electricity market exchange analyses and socio-economic analyses.

2.2.1 Technical and market economic energy system analyses

The first step in the methodology is the *technical or market economic energy system analysis*. In this analysis, the design of large and complex energy systems at the national level and under different technical or market regulation strategies is investigated. In such energy system, the effects on fuel efficiency or the ability of different technologies to integrate intermittent renewable energy can be analysed. In the technical energy system analyses, inputs include energy demands, production capacities and efficiencies, energy sources and distributions. In the market economic optimisations, further inputs are needed in order to determine marginal production costs, such as variable operations and maintenance costs (O&M), fuel costs and CO_2 emission costs. This modelling is based on the assumption that plants optimise according to business-economic profits, including current taxes. Output consists of annual energy balances, fuel consumptions and CO_2 emissions, fuel costs, etc.

The technical and market-economic analyses can be conducted under different regulation strategies, i.e. in closed or open systems or with different regulations of CHP plants and critical excess electricity production as well as ancillary service designs, etc. In open energy systems, the ability to integrate excess electricity production can be investigated; while in closed energy systems, the abilities of the fuel cell and electrolysers to improve the fuel efficiency are analysed. In a closed energy system, all excess electricity production is either converted or avoided. It is not the aim to avoid electricity trade, but in order to analyse the fuel efficiency of the different energy systems and the technologies involved, it is necessary to apply these to a closed system.

Such analyses have been conducted in several of the publications which form part of this dissertation; both in the construction of future energy systems and the analyses of fuel cells and electrolysers [2-6;9-13;15-17;19-21].

2.2.2 Electricity market exchange analyses

In the next step, a *market exchange analysis* is conducted in which the ability of the different energy systems to trade and exchange electricity on international markets and according to prices is analysed. Such analyses can reveal the flexibility of energy systems or technologies, when large amounts of CHP and intermittent electricity are produced. Additional inputs are different external electricity market prices as well as market price distributions and a price dependence factor, which are applied in order to determine the response of the market prices to changes in production or demand, import or export. Hence, the ability of the system to profit from exchange can be identified [22].

These analyses are performed in an open energy system with international electricity trade and are compared to a market economic optimisation of a closed system. This enables the identification of the net earnings made on electricity trade. The results represent the socio-economic profits of electricity trade, excluding taxes. Different variations of such analyses have been conducted of fuel cells, electrolysers and other technologies in different energy systems. The results are presented in a selection of the publications which form part of this dissertation [5;6;10-13;15;16;19-21].

2.2.3 Socio-economic feasibility studies

Finally, as the third step, *the socio-economic feasibility* of the system is investigated in terms of total annual costs under different designs and regulation strategies. In this step, inputs are investment costs as well as fixed O&M costs together with plant lifetime and an interest rate. In this analysis, a market energy system analysis is conducted in which the operation is optimised economically. In the feasibility study, total socio-economic costs exclude taxes. The costs are divided into 1) fuel costs, 2) variable operation costs, 3) investment costs, 4) fixed operation and maintenance costs, 5) electricity exchange costs and benefits, and 6) CO_2 payment costs. Such analyses can also be conducted either in open or closed systems. The socio-economic feasibility of technologies can also be analysed on the basis of technical or market economic energy systems analyses, using modelling results and combining these with the costs etc. of these technologies. This type of analysis has been conducted of energy systems and technologies in several of the publications forming part of this thesis [3;5;6;10-13;19;21].

A further step along this path is to use the result from the three-step energy system analyses methodology for constructing new public regulation. This involves an analysis of the current institutional and regulatory setup in terms of taxes, levies, and access to markets, technical requirements etc., as well as recommendations on how to change these. Such recommendations can make the business-economic situation reflect socio-economic cost or technically suitable technologies [6].

The outputs from the technical analyses, the electricity market exchange analyses or the socio-economic feasibility study can also be used as input to other types of analyses, such as life cycle assessments of the energy system or a technology forming part of this system [15;16;20].

The three-step energy system analyses methodology leads to a conclusion on the technical potentials for the integration of renewable energy sources, fuel efficiency, CO_2 emissions as well as the ability of the system to trade electricity, taking into account system restraints, e.g. in relation to heat demand. Finally, it enables analyses of the total socio-economic feasibility of a system or a technology.

3 Reference systems and the design of future renewable energy systems

In this chapter, the methodology and selected results of the construction of future energy systems are presented based on the publications forming part of this dissertation. First, the characteristics are presented of reference energy systems and future energy systems with a high and a low production from CHP plants or wind turbines, respectively. Finally, renewable energy systems are described.

3.1 Introduction

For the purpose of analysing future technologies such as fuel cells and electrolysers, it is necessary to identify several appropriate future energy systems. In order to identify such systems, it is necessary to know the characteristics of the current energy system; i.e. we need to know where we are in order to know where we are going and where we could go. With the current legislation, the current energy system can be projected into a future energy system. By using such a reference system, which builds on the current system, it is possible to identify different appropriate future energy systems.

3.2 Reference energy systems

The design of a reference energy system takes its point of departure in the contemporary energy system or in projections which are connected to the current energy system. As mentioned, the EnergyPLAN model enables analyses of different regulation strategies and different technologies in energy systems; however, the development of capacities, technologies or demands, etc., does not take place in the model. Contemporary energy systems can be reconstructed in the model by applying inputs from annual statistics or using official publications and energy system modelling from one year to another, e.g. business-as-usual projections from the Danish Energy Authority. Such data is often referred to as reference energy systems. They do not involve any changes in public regulation compared to the day on which the calculations were made. These projections are used as the point of departure for the energy system analyses conducted here; however, energy systems could also have been constructed with no connection to actual or projected future circumstances.

In the official projections, different models are used to include changes in e.g. electricity and transport demands or capacities. When using statistical data or projections as input to the model, the consistency of the reference energy systems can be controlled technically, tested in the market exchange analyses of the model, and compared with the statistical data or data from projections [10-12;17]. Discrepancies occur and should always be described to ensure transparency in the analyses [12].

Considerations must also be made of the projections of fuels, electricity and CO_2 quotas, as these are of crucial importance to the market exchange analyses as well as the feasibility study. The interest rates used as well as the operations and maintenance costs and lifetimes are also important inputs to the socio-economic feasibility studies. [3;5;6;10-12;16]

Often it is an advantage to use coherent projections of all parts of an energy system, such as those made by the Danish Energy Authority. This enables the use of a rather well described total energy system, which also has a direct connection to the current energy system [23]. Such reference energy systems have been used as the point of departure for the analyses of fuel cell and electrolyser technologies; thus comparing these to the technologies of the reference system. Such projections, however, do not reflect the variety of energy systems of which fuel cells and electrolysers may eventually form part; hence, other types of energy systems are also needed for the analyses.

3.3 Renewable energy systems

On the basis of the reference systems, it is also possible to design new energy systems making significant changes in all parts of the system design [5;11-13]. The advantage of designing renewable energy systems in this manner is the fact that it is possible to reconstruct the projected energy system in the model, for e.g. year 2030 in this case, and compare it to the official projection when implementing significant savings in demand, high shares of intermittent renewable energy, and more efficient and flexible conversion technologies. This enables the use of a rather well described energy system, such as the one presented by the Danish Energy Authority (BAU 2030) [23], and makes it possible to introduce changes, thus constructing a renewable energy system which can be explained in relation to the well described system.

In 2006, the BAU 2030 reference energy system was used to design two renewable energy systems. They were designed during the “Energy Year” organised by the Danish Association of Engineers (IDA) and are published in the “IDA Energy Plan 2030”. A large number of experts and researchers from universities and industry were involved in constructing and providing inputs to this vision for the Danish energy system. The Energy Plan concluded that it is technically possible to construct a 100 per cent renewable energy system in Denmark in e.g. 2050; and, as a step along this path, a 50 per cent renewable energy system is feasible in 2030, including 60 per cent reductions in CO_2 emissions. The means of constructing such an energy system involve energy savings; more efficient conversion technologies; the replacement of fuels with intermittent renewable resources, as well as flexible technologies such as large heat pumps, electric vehicles, etc., all of which have been included in the vision. In the systems analysed, SOFCs were also included in order to increase the efficiency of the system. The cost structure of the IDA energy systems changes radically, as investment costs increase and fuel costs decrease heavily. In October 2006, annual savings of 2 billion € were found when comparing the reference energy system with the IDA 2030 system, and, in an update from May 2008, these savings had doubled, because of higher fuel costs. [5;11-13]

3.4 Future energy systems

The reference energy system, whether a contemporary system or a projected system for 2030, can be reconstructed to contain more or less wind power or more or less CHP production. Such systems can reflect the scenarios presented in Fig. 1 to Fig. 4 in which technologies, such as fuel cells and electrolysers, were analysed in different contexts.

The official projection of the Danish energy system with high shares of CHP and wind power is adapted to fundamentally different energy systems: An electricity-based energy system, in which both heat and power are supplied by electricity from power plants, and an energy system with separate supplies of electricity and heat from power plants and boilers [6;10;17]. In addition, the wind power share is increased in the energy systems in order to construct a system with a high share of intermittent resources. The wind power introduced corresponds to half of the electricity demand in the projection from the Danish Energy Authority.

Fig. 5 illustrates how the primary energy supply changes from the projection from the Danish Energy Authority to different configurations, going from an electricity-based system to an integrated 100 per cent energy system (IDA 2050). The introduction of wind power, especially in the electric and traditional energy systems, has a large effect on solid fuel consumption, because it replaces power plant production.

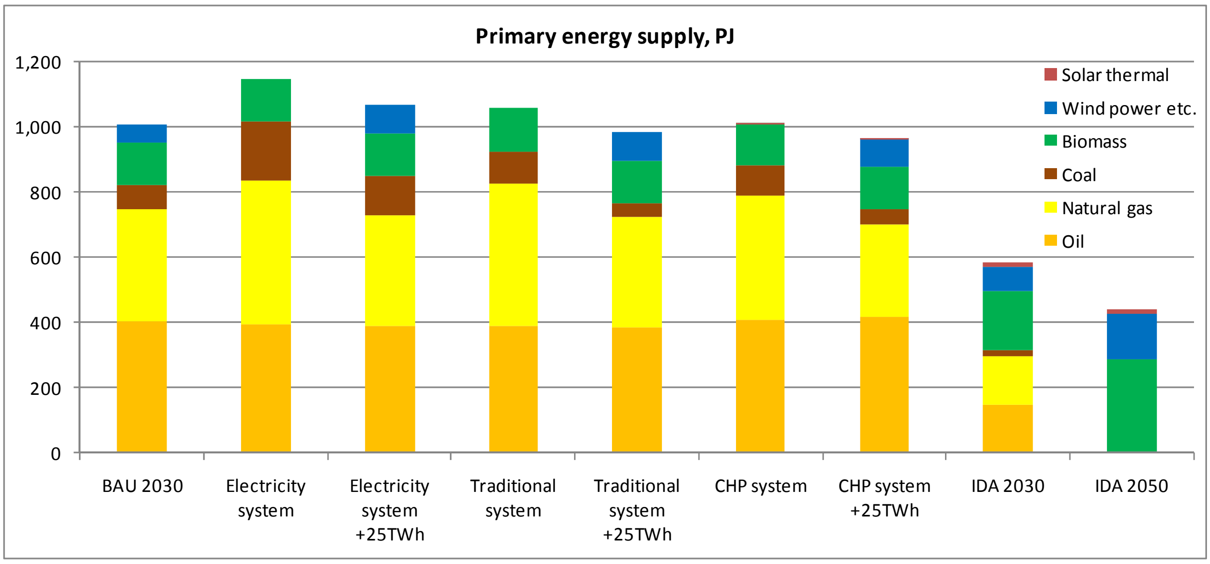

Fig. 5, Primary energy supply of a projection from the Danish Energy Authority for 2030 [23] and six fundamentally different energy systems based on this projection [10] as well as for the two 50 and 100 per cent renewable energy systems [11;12].

In the electric, the traditional and the CHP systems with wind power, excess electricity produced increases gradually; because the systems gradually have lower possibilities of integrating wind power production during certain hours. In such situations, the following options can be defined: to export electricity, typically at low prices; to stop the turbines, or to install technologies that can utilise the power. The latter has been applied to the integrated system, IDA 2030, also illustrated in Fig. 5. In such a system, heat pumps, flexible demands and electric vehicles are able to integrate almost all of the wind, wave and photovoltaic power produced, although the demands are rather low.

The results of the technical energy system analyses of the six systems based on the projection show that a difference of 180 PJ can be identified in the total primary energy supply, when comparing the most inefficient electricity-based system to the CHP system with 50 per cent wind power. In the two renewable energy-based systems, primary energy supply is further reduced.

In terms of socio-economic costs, the integrated energy system (IDA 2030) generates the lowest total costs. This gradually increases towards the electricity-based system, which involves the highest socio-economic costs [10]. In Fig. 6, total socio-economic costs are illustrated for the energy systems, except the 100 per cent renewable energy system.

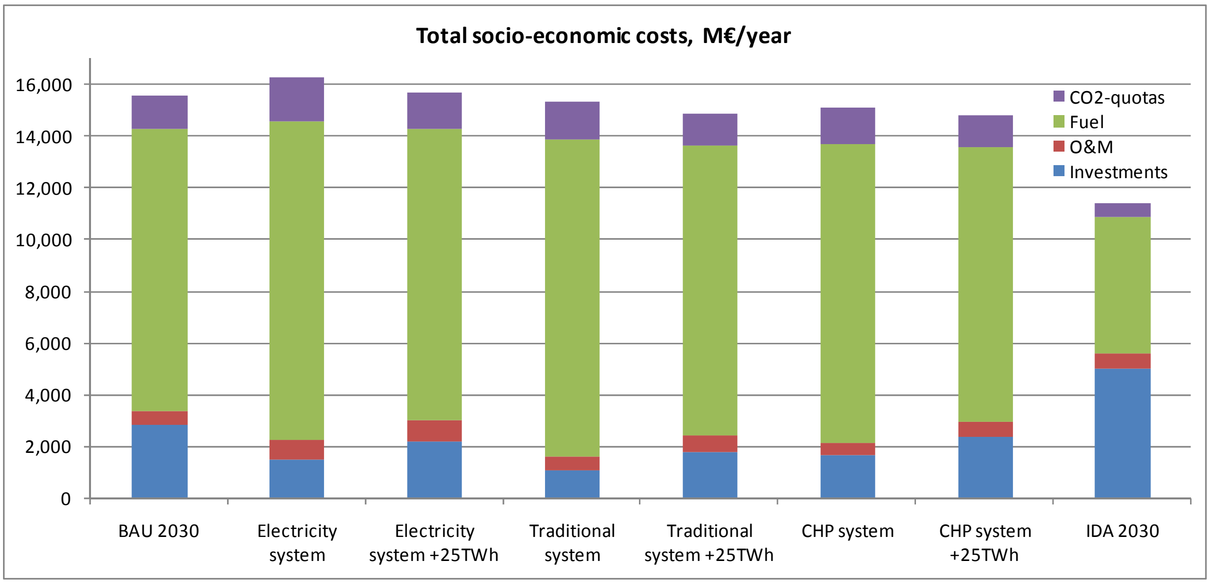

Fig. 6, The socio-economic costs (120 $/bbl oil) of a projection from of the Danish Energy Authority for 2030 [23] and six fundamentally different energy systems based on this projection [10] as well as for the two 50 and 100 per cent renewable energy systems [11-13].

Once energy systems are constructed, it is also possible to gradually change the share of intermittent renewable energy resources in these systems, e.g. from 0 to 100 per cent wind power, in order to analyse the effects on fuel efficiency or the ability of the systems to gradually integrate wind power. Such analyses can reveal the ability of different technologies to improve the integration of renewable energy resources into energy systems, and are conducted in some of the applications which form part of this dissertation [2-4;9].

The integrated energy systems, as well as the less efficient energy systems presented above, are used for the analyses of applications of fuel cells and electrolysers in this dissertation.

4 The nature of fuel cells

In this chapter, the status and future potential of five different types of fuel cells are presented. This chapter is based on "The nature of fuel cells" [1] included in appendix I.

In this review, focus is on fuel cell systems for CHP production in future energy systems; however, the review also includes aspects of other applications of fuel cells. The operation principles as well as the characteristics and applications of the different types of fuel cells are considered. High temperature polymer exchange fuel cells (HT-PEMFCs) seem to have the best potential in terms of transport and micro-CHP, while SOFCs have the potential for replacing existing technologies in distributed local or central CHP plants. Significant challenges have to be overcome, before broad commercial use of fuel cells in future energy systems can be expected.

4.1 Introduction

In most countries, the energy supply consists of a small percentage of intermittent resources as well as combustion technologies in vehicles, power plants and CHP plants. The perspective in replacing conventional technologies with more efficient fuel cells is dependent on the characteristics of the different fuel cell types available.

Fuel cells generally consist of the *cell*, in which an electrochemical reaction takes place; the *stacks,* in which the cells are combined to the desired power capacity; and the balance of the plant, which comprises systems for handling fuel, heat, electric power conditioning, and other systems required around the cell.

Fuel cells are comparable to batteries, except from the fact that they are not limited by the amount of energy stored in the cell itself. In these cells, chemical energy is converted directly into electricity. This provides higher efficiencies than in traditional technologies, in which the energy content in fuels is converted into thermal energy, then mechanical energy and finally electricity. The higher efficiencies also imply a significant reduction of emissions.

Although certain types of fuel cells are mainly considered for mobile and others for stationary use, this is not determined yet. The characteristics of the fuel cell types, however, make certain potential applications more probable than others. Fuel cell types are named after their electrolyte, which also determines their operating temperature. In Table 1, the main characteristics of the five main types of fuel cells are listed.

Please note the fact that such comparisons are subject to the different preconditions and characteristics of the different fuel cells. Thus, these preconditions should be taken into account when comparing e.g. efficiencies. In Mathiesen and Nielsen (2008) [1], the data sheets for different fuel cell systems are presented.

Fuel cells	AFC	PEMFC	PAFC	MCFC	SOFC
Name (electrolyte)	Alkaline	Polymer exchange membrane	Immobilised phosphoric acid	Immobilised molten carbon-ate	Solid oxide conducting ceramic
Catalyst	Platinum	Platinum[2]	Platinum	Nickel	Perovskite[3]
Operating temp.	40-100 ºC	60-200 ºC	180-220 ºC	550-700 ºC	500-1000 ºC
Fuel(s)	Perfectly pure H_2	Pure H_2 or CH_3OH	Pure H_2	H_2, CO, NH_3, hydrocarbons, alcohols	H_2, CO, NH_3, hydrocarbons, alcohols
Intolerant to	CO, CO_2	CO, S, NH_3	CO, S, NH_3	S	S
Potential electric eff. %[4]	60	40-55	45	60	60
Potential applications	Mobile units space, military	Mobile units, micro-CHP	Smaller CHP units	Larger CHP units	From large to micro-CHP

Table 1, Characteristics of the five main types of fuel cells and potential areas of use. [24-37].

In all fuel cell types, the core consists of a cell with an electrolyte and two electrodes; the anode and the cathode. In Fig. 7, the reactions in different fuel cells are illustrated. Hydrogen and oxygen are converted into water producing electricity and heat. The conversion of fuels takes places in a chemical process, in which the catalytic active electrodes convert the fuel into positive ions and oxygen into negative ions. The precise reactions depend on the type of fuel cell. The ions cross the electrolyte and form water and possibly CO_2, depending on the fuel and the fuel cell. Only protons can cross the electrolyte while creating a voltage difference between the anode and the cathode in the cell; thus, the electrons cross to the anode section in an external circuit. The output is DC electricity from the flow of electrons from one side of the cell to another. [25]

The advantages of *lower temperature* fuel cells are mainly related to the fact that they are compact, lightweight and have a quick start-up and shut-down potential. This, combined with the fact that the efficiency of the fuel cells cannot compete with other larger power-producing technologies, makes transport and mobile applications most promising. In these cases, fuel cells can compete with the efficiencies of existing technologies. They may potentially contribute to the supply as small-scale micro-CHP plants. For larger stationary applications, other technologies have already today proven to have better efficiencies.

Alkaline fuel cells (AFCs) are highly reliable, rather compact, and have low material costs; but no widespread commercial use is expected, because of the costs related to the extensive gas purification needs [25;26]. AFCs have been used for extraterrestrial applications,

[2] May also consist of platinum in combination with ruthenium and molybdenum depending on the CO contents in the fuel. This is especially the case of DMFC. In HT-PEM, the catalyst is often pure platinum.
[3] May contain nickel if the fuel is hydrocarbons, e.g. natural gas or methanol.
[4] Potential efficiencies depend on the stack load. Total efficiency may be more than 90 per cent, but is dependent on the cooling system and the operation temperature. For AFC, the efficiency is dependent on the existence of perfectly pure hydrogen at the anode and pure oxygen at the cathode. For HT-PEMFC, a 55 per cent net system efficiency has been achieved. For SOFC, the efficiency is dependent on the development of cell materials, anode gas recirculation and integrated steam reforming when using other fuels than hydrogen. In MCFC and SOFC, a 70-75% electricity efficiency can be achieved, when combined with gas turbines and/or steam turbines.

e.g. the manned Apollo missions, which has no price issue, availability of pure oxygen problems, and in which the excess water is useful for astronauts. The lifetime of AFCs is rather short and is not expected to increase with further research; thus, mainly mobile applications should be considered. In recent years, research has shown that the purification needs may be lower than expected. Micro-CHP based on AFC is also still being investigated [27].

Phosphoric acid fuel cells (PAFCs) are widely used today as emergency power and stand-alone units in hospitals, schools and hotels. They have been commercially available since 1992, but the costs of PAFCs are still about three times higher than those of other comparable alternatives. The main problems related to PAFCs are based on the fact that they are dependent on noble metals for the electrodes and the fact that their reported efficiencies are not considerably better than those of other technologies. [24-26;38]

The AFCs and the PAFCs are often considered the most developed fuel cells of the five types mentioned [28]. However, although variants of both types are still developed, it will hardly be possible to improve the two main challenges, namely the lifetime of AFCs and the cost level of PAFCs, respectively [25;27].

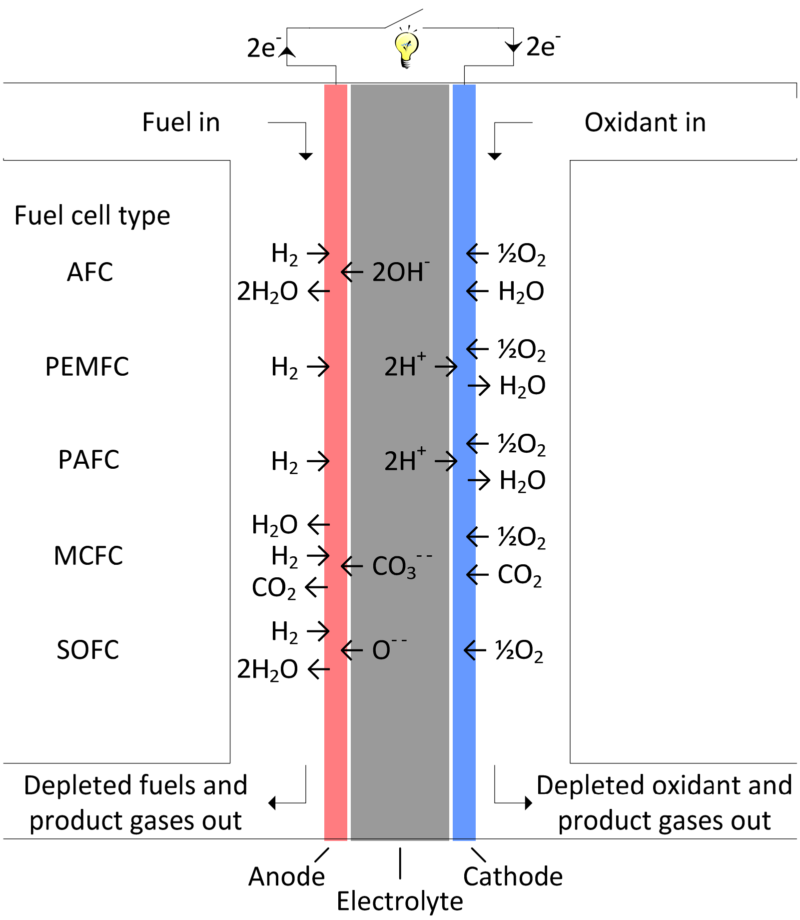

Fig. 7, Schemas of different fuel cell types

PEMFCs are characterised by a rather simple design and fast start-up. Different variants of PEMFCs are available, including low temperature fuel cells operating at 60-80 ºC; high temperature fuel cells (HT-PEMFC) operating at 140-200 ºC, and direct methanol fuel cells (DMFCs)) typically operated at temperatures somewhat below 60 °C due to issues related to the system water balance. PEMFCs and HT-PEMFCs can be utilised in almost all applications in which high temperature heat is not required, such as in micro-CHP as household heating systems, transport or smaller devices. DMFCs are mainly considered for small portable devices, such as mobile phones, computers, etc. [25;29;39]

The main advantages of *high temperature* fuel cells are the higher efficiencies and the fuel flexibility which they offer. Other advantages include high operating temperatures, which allow internal reforming or direct conversion and thus enable a rather simple system design as well as the option of integrating these systems with heat engine based bottoming cycles enabling even better net system efficiencies. Moreover, they are constructed from rather cheap materials and do not contain noble metals.

While molten carbonate fuel cells (MCFCs) have high efficiencies, they require the input of CO_2 with ambient air on the cathode side. Also the electrolyte of the MCFC is heavily corrosive, which is the main problem in these cells today. Research is still being conducted in order to improve the cells, mainly for applications to larger CHP and power plants, though the efforts have decreased. [25;34]

SOFCs may be more promising in the future. They have already proven to have rather long lifetimes when not thermally cycled, and theoretically, high efficiencies may be achieved in SOFC systems. However, SOFCs may have problems with thermal stresses and degradation. Third generation metal-supported cells, which are currently being developed, are expected to reduce these problems and increase the power density of the cells [40].

All fuel cells can operate on hydrogen. While some fuel cells require higher hydrogen purities than others, high temperature SOFCs and MCFCs can operate directly on methane rich fuels, such as natural gas. Electrolyses as well as biomass-derived fuels can be combined with a synthesis process, thus enabling the production of other fuels than hydrogen for fuel cells.

In the MCFC and the SOFC, the electrolyte conducts ions from the cathode side to the anode side. In the PEMFC and PAFC, hydrogen passes from anode to cathode. For the two high temperature fuel cells, this means that a wide range of fuels, including natural gas, biogas, ethanol, diesel, LPG, methanol, etc., can be used without reforming the fuel completely into hydrogen and CO_2 [41;42].

Some fuel cells are very versatile in terms of their ability to utilise different fuels. Others can only use one kind of fuel and have strict limits for impurities. The fuels and conversion paths can be divided into two categories; one involving the fuels that can be converted directly, i.e. meets the required characteristics, and the second involving the fuels that can be procured to meet these standards.

PEMFCs and SOFCs are described in further detail below, as are the balance of plant equipment and the start-up, operation and regulation abilities of grid-connected fuel cells. Further details about AFCs, PAFCs and MCFCs are included in Mathiesen and Nielsen (2008) [1].

4.2 The characteristics and applications of proton exchange membrane fuel cell

PEMFCs are based on a solid polymer membrane as the electrolyte. The electrolyte of the cell only allows hydrogen ions or protons (H^+) to cross and it consists of fluorinated sulfonic acid fixed in a polymer. This is commonly known as Nafion, which has properties similar to those of Teflon. The anode and cathode consist of one or more noble metals, supported on carbon, typically platinum, and the amount of platinum required is higher than the amount required for PAFCs. The rather low operating temperatures of PEMFC enable very fast start-up, rapid load-following as well as less expensive construction materials and less insulation. This also results in rather compact designs. The power densities of PEMFC systems are also rather high compared to other fuel cells, except for AFCs. A critical element is the water management, as the membrane has to stay hydrated; thus, the water cannot evaporate faster than produced in the cell [25;26].

PEMFCs are CO_2 tolerant; they can operate on hydrogen from reformed hydrocarbons as well as on atmospheric air, as the oxidant. They are rather sensitive to CO, which poisons the anode. This is the main challenge combined with the water management and the heat removal required. The reforming of hydrocarbons requires higher temperatures than those delivered by the PEMFC. The processes require several units and this reduces the fuel efficiency and increases the costs of the system. [25]

The operating temperatures of PEMFCs are typically 60-80 ºC; however, more attention is being paid to high temperature cells, operating between 140 and 200 ºC. These have rather simple system designs in combination with the processing of natural gas or other hydrocarbons [29;43]. HT-PEMFCs are able to increase the tolerance to CO to more than 1% and eliminate the critical element of water management. These fuel cells are typically based on a pure platinum catalyst. Recently, anode gas recirculation in HT-PEMFC has proven to result in higher efficiencies than low temperature PEMFC, because unused hydrogen is utilised through anode gas recirculation [44]. Such a strategy excludes reformatted gases.

PEMFCs are mainly applied to emergency power, portable devices, residential household heating with micro-CHP, or transport [45]. The low temperatures limit the use of PEMFCs, but, in combination with the compact designs, they also enable an extension of the operation time in portable devices [25]. Significant efforts are made to solve the problem of integrating fuel processing into the PEMFC system. As mentioned, natural gas can be combined with HT-PEMFC; however, methanol, DME (dimethyl-ether), ethanol and others are also considered [46;47]. Here, methanol is especially promising, because it is hydrogen-dense and works at rather low temperatures. For methanol HT-PEMFCs, the fuel processing system only requires a reformer. An integrated reforming HT-PEMFC system also gives smaller cell stacks and requires no water management. These systems are also called Reformed Methanol Fuel Cells (RMFC).

Direct methanol fuel cells (DMFC) are also being developed which use methanol directly without prior external reforming. Due to the lower efficiencies, these are mainly considered for small portable devices. However, they are more compact and require little maintenance [39]. They operate at lower temperatures, which makes them unfit for CHP applications, and they have higher contents of noble metal in the catalysts.

4.3 The characteristics and applications of solid oxide fuel cells

As opposed to other fuel cells, the electrolyte in SOFCs is a solid, not a liquid. The electrolyte ceramic mainly consists of yttria-stabilised zirconia, while the anode mainly consists of nickel and yttria-stabilised zirconia. The cathode is typically strontium-doped lanthanum manganese. The catalysts which are being developed are perovskite ion conductors and the charge carrier is oxide ions (O^{2-}). For the direct reforming of hydrocarbons in the SOFC, the catalyst may contain nickel. SOFCs are promising, as they have already proven to have rather long lifetimes at constant operation as well as high efficiencies. A tubular design of the SOFC, which was the design initially developed, is now abandoned in favour of a planar alternative with a more compact scalable design and lower production cost. The first generation planar cells are electrolyte-supported. The second generation cells, which are primarily in focus at the moment, are anode-supported. Third generation, metal-supported cells are currently being developed and tested. These will potentially lower the costs of the cells and enable better start-up performances. [40;48-50]

The main challenges for the SOFCs are temperature gradients in operation, start-up and shot-down. The ceramics are rather porous and the different thermal expansion coefficients of the materials pose a challenge to the cell lifetime. The series of cells required in the stacks all have to be intact for the SOFC to operate, and the replacement of one cell without damaging others is rather difficult. This problem could require new solutions, such as a better match of materials with thermal expansion characteristics, the introduction of thermal management systems or a mechanical solution. Another challenge to the further improvement of SOFCs is to replace some of the ceramics with lower-cost metals, since the ceramics are rather expensive to produce. This requires a reduction in temperatures to around 550 ºC. At present, the temperature has been reduced from 1.000ºC to 650ºC. Efforts are being made to reduce temperatures further in order to enable the use of metal-supported SOFCs [51;52]. This could also contribute to a mechanical solution to the problems of different thermal gradients.

The operation at high temperatures makes the fuel cells less sensitive to impurities, thus enabling fuel flexibility. The SOFCs can be constructed for internal reforming of different gaseous hydrocarbons. They may also be combined with gas and steam turbines. In order to achieve high efficiencies, the main challenge is to develop anode gas recirculation systems and integrate steam-reforming systems, when using other fuels than hydrogen. SOFCs are mainly intended for stationary use, as the high temperatures may be less suitable for transport. All ranges from micro-CHP to larger CHP and power plants are considered suitable applications for SOFCs. SOFCs are expected to be available for commercial use from 2015 [12].

4.4 Fuel cell balance of plant equipment

Previously, tubular fuel cell designs were most common, especially for high temperature cells. However, nowadays, most fuel cells have a more compact planar design, which facilitates mass production and reduces losses in the cell.

In order for a fuel cell to deliver direct current at high voltage and to have sufficient capacity, many individual cells are required. In a stack, individual cells are connected in series divided by interconnectors. The interconnectors function as a bipolar metal plate that distributes the electricity produced. Typically, these interconnectors are also designed with channels which transport fuels and output gases to and from the cell. The interconnectors provide a serial connection of the individual cells, while also separating the gases in the cells. The individual cells and interconnectors are separated with sealings. Different planar designs are available for different arrangements of the gas flows and the different types of fuel cells.

While interconnectors diffuse the gas in the cell, these have to be provided with manifolds enabling the gas streams to enter and exit. This can be constructed to run through cells; be integrated into interconnectors, or be localised externally to the cell and interconnector [38].

To form a functioning power unit, the fuel cell also has to be accommodated to an appropriate support system. Some parts of the systems are similar; i.e. fuel preparation, air/oxidant supply, thermal management, water management, electric power conditioning, and, of course, a system control unit for the fuel cell. The principle scheme of the balance of plant equipment for SOFC is illustrated in Fig. 8. The exact structure and operation of the support system varies with different types of fuel cells. [26;38]

Except when pure hydrogen is used, fuel processing removes impurities. Typically, this also involves steam-reforming processes to ensure hydrogen-rich fuels. All cells are intolerant to sulphur, and, depending on the type of fuel, the fuel cells must be fitted with a desulphur-iser. In lower temperature cells, CO, CO_2 and NH_3 must also be removed, depending on the type of cell and the type of fuel used. The fuel processing system must also provide fuel and air under the right conditions, i.e. temperature, pressure, moisture and mix, which involves air compressors or blowers as well as air filters. Many of the proposed systems re-use the waste heat and water in the fuel processing, and they also include afterburners in order to utilise the unused fuel from the fuel cell. In HT-PEMFCs, anode recirculation has proven to generate high efficiencies [44]. In integrated methanol-reforming HT-PEMFCs, purification measures can be avoided. The SOFC is still at the development stage and such systems as well as an integrated fuel-reforming system still need to be developed.

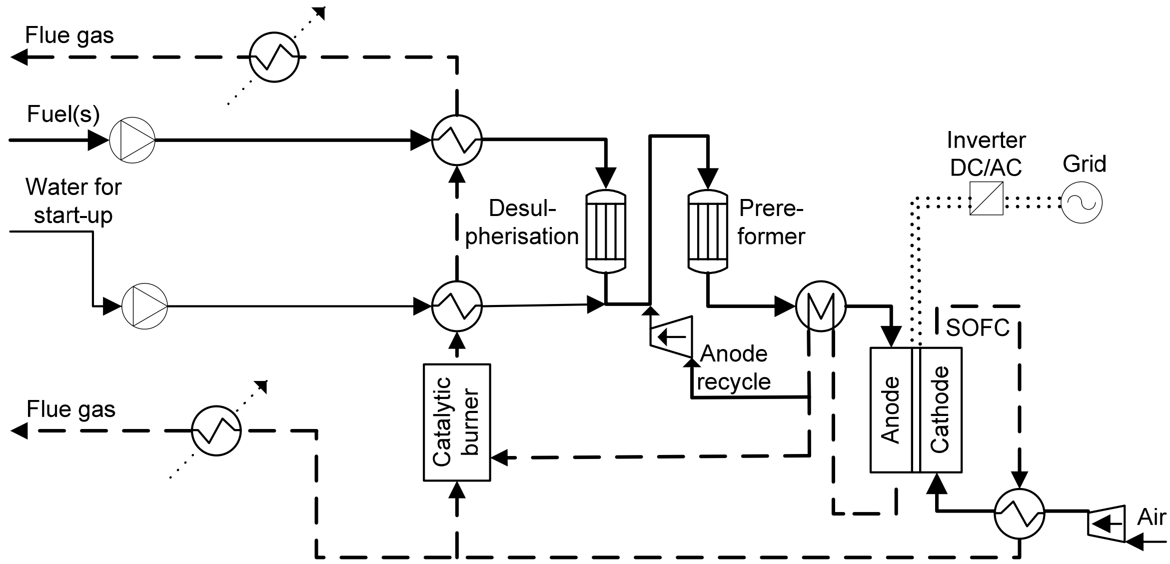

Fig. 8, Principle balance of plant scheme for SOFC. Based on Hansen (CHP) [53].

For all fuel cell systems, a careful management of the temperatures in the fuel cell stack is required. Water/steam is needed in some parts of the fuel cells. While water is a reaction product, a water management system is required in most fuel cells systems to avoid the feed-in of water in addition to fuel and to ensure a smooth operation of the cell. Large differences can be seen between the specific designs of the fuel cells in terms of fuel and oxidant handling. For high temperature fuel cells, such as SOFCs, this processing typically also helps to ensure a constant stack temperature as well as longer fuel cell lifetimes by smoothly distributing the different gasses through the cell.

In high temperature fuel cells, such as MCFC and SOFC, the fuel processing system may be integrated with a fuel-reforming system, enabling the use of high temperature heat for reforming e.g. biogas or natural gas to H_2. Lately, also HT-PEMFCs have been developed with integrated fuel processing, leading to improved total efficiencies [29]. For high temperature fuel cells, namely MCFC and SOFC, the system may also be integrated with gas and/or steam turbines, in which the high grade heat is used to increase electricity efficiency. This process integration poses a major challenge to fuel cells at the system level. These issues are intensively researched in order to improve the performance of fuel cell systems. [26;38]

In order to be able to integrate the fuel cell unit into the electricity grid, an inverter must change the current from DC to AC. Like other parts of the systems surrounding the cells, this is associated with losses. Additional power electronics and integrated system control can provide the fuel cells with the same abilities as other traditional power supply units in terms of grid stability, i.e. ancillary services enabling them to contribute to maintaining the voltage and frequency stability of the grid [25]. Recent studies show that the feedback from the inverters to the cells may have negative effects on the lifetime of stacks; these are challenges that will have to be dealt with in the power conditioning supply.

The balance of plant equipment uses a part of the electricity from the cell. Even though the cell itself is scalable for all types of fuel cells, the energy consumed in order to improve the balance of the plant increases with lower cell capacities, especially in the case of high temperature fuel cells. These effects differ from one cell type to another. The higher the pressures used in the cell, the more losses result from the balance of the plant. This is especially a challenge to the SOFCs, which are operated at high pressures, and makes the application of hybrid SOFC gas turbines to small-scale systems unlikely.

4.5 Start-up, operation and regulation abilities of grid-connected fuel cells

The operation and regulation abilities of fuel cells have to be addressed from a system perspective, since factors such as electrochemical reactions, current and voltage change, gas flow controls, fuel processing, pressure, and water management interact with changing loads. Demands are made on fuel cells in order to meet certain requirements for power quality. In general, all types of fuel cells can respond quickly to an experienced load change; however, differences exist in the start-up performances of the fuel cells. While stacking the cells increases the voltage of the direct current from the fuel cell; voltage decreases as the amount of power drawn from the cell increases. This is solved by use of appropriate power electronics. A DC/DC converter, and possibly also a DC/AC inverter, can convert the output voltage DC to the voltage DC or AC required for the specific application. When converting output DC to AC, the voltage peaks of the cell as well as the voltage and current relation can be regulated. The grid-connected fuel cells have to meet certain requirements if they are to support the electricity grid stability. A battery can supply start-up power and assist in the power conditioning. Furthermore, a transformer can convert lower voltage power into higher voltages, if needed for the supply to the electricity grid, at the distribution or transmission level. An example of the principle of such a grid-connected system is illustrated in Fig. 9. Stand-alone systems also have to meet the requirements of the applications which they supply. In transport applications, fuel cells are combined with batteries in order to ensure good start-up capabilities. [25;26;38]

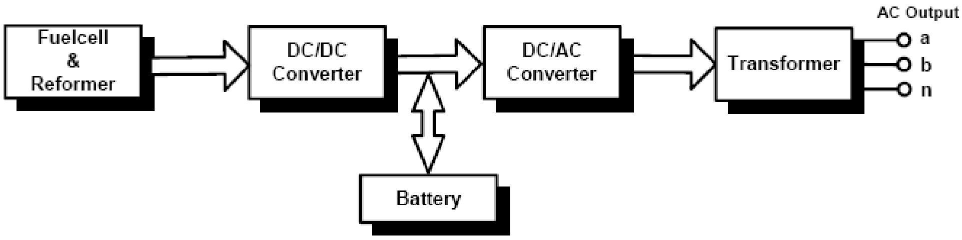

Fig. 9, Principle diagram of grid-connected fuel cells.

For low temperature fuel cells, such as PEMFCs and AFCs, start-up time is only a few minutes or instant, depending on the system design [26-28;32]. Efforts are also being made to design these systems in such way that they enable a fast cold start-up from below-freezing temperatures [45;54]. The low operating temperatures enable a fast fuel supply and a rapid heat up of the cell to the operation temperature without material problems; however, due to pressure control and liquid water, the system designs meet challenges when operating at low temperatures. The system design of the intermediate temperature HT-PEMFC is promising in this respect, as the systems are less sensitive to pressure changes because the water is gaseous. The question is whether the water in the membranes can flush the acid in the electrolyte; however, no evidence of this effect has been documented yet.

For high temperature fuel cells, such as MCFCs and SOFCs, the situation is somewhat different. Here, the temperature poses a challenge because of problems with temperature gradients within the cells. Because of their high operating temperature and the temperature gradients, these cells have a start-up of several hours. These problems, however, can be reduced by making intelligent stack designs, such as placing the manifolds horizontally along the stacks or making hexagonal designs; fitting the cells with start-up burners; introducing buffers enabling a smooth start-up load; or, as a potentially more promising alternative, keeping the cells at a high temperature by operating them periodically and with insulation. Insulation has been investigated for SOFCs [55]. It was found that SOFCs can be operated on low amounts of fuel; producing very little electricity, but keeping the temperature at the right operation level. This enables a very fast start-up. However, when temperatures are high, the regulation ability of the fuel cell is system-dependent, i.e. depending on the supply and support system and gas turbine in hybrid systems. Hence, it is possible to eliminate start-up time, start-up and idle fuel consumption in SOFCs by operating at least once a day or by cyclic reheating. This, however, requires the development of an integrated fuel supply system, anode recirculation to maintain high efficiencies, and a better stack design to increase lifetime. The insulation of such high temperature cells also increases the volume of the fuel cell, especially in small-scale systems, like e.g. micro-CHP [44]. In combination with higher losses relating to the balancing of the plant with small-scale applications, the insulation required makes larger CHP plant applications more likely, no matter if this insulation increases the possibility of load following or not. Good regulation may also be possible for MCFC and PAFC, but no analyses of this ability have been identified. For SOFCs, metal-supported cells may improve the rapid start-up ability, because the tolerance to thermal gradients in the cells is improved [40;50;56].

The fuel cell systems also have to be designed for the load changes in the applications in which they are potentially used. While all low temperature fuel cells can follow load changes rapidly, thermal cycling and gas flow handling pose a challenge to high temperature fuel cells, such as SOFC and MCFC with load changes, and thus have to be handled carefully in the fuel cell system control and design. The electrochemical processes and gas transport can respond quickly. The temperature changes in the cell take place at a slower rate, because of the density of the cells [57]. The temperatures in the cell affect the current and voltage and, thus, the operational characteristics. Since the load response itself is quick, while the temperature changes have longer responses, it is possible to make control systems which can regulate the temperature, in order to achieve the desired responses [42;55;58;59].

In high temperature fuel cells, good load-following abilities have been accomplished in the cases of both MCFCs and SOFCs. In a MCFC, the thermal transients normally have long time constants, e.g. from 100 to 1000 seconds, which is due to the relatively large mass of the cell. However, thermal cycling affects the performance of high temperature fuel cells. This indicates that a good fuel cell control system is important both in terms of dynamic responses due to load changes and to the lifetime of the cell. For MCFCs, experiments with stepwise changes in applied load resistance show that a dynamic response is possible by use of controllable heaters, thermocouples, and insulating materials. Also control systems have been proposed to efficiently avoid thermal cycling. [42;57]

Normally, 20 per cent of full load is the minimum load for fuel cells. This is a not technical limit but the level at which efficiencies are significantly reduced. The data on load balancing and response times are still limited for both MCFCs and SOFCs. AFC, PAFC and PEMFC have good load-following characteristics, and HT-PEMFC may solve some of the problems for this type of cells. For SOFCs, good load-following abilities have been achieved with existing technology and also good efficiencies at part load [60;61]. Different operation strategies can be applied; however, research into the balance of plant systems is still required for high efficiencies in SOFC. New systems need to be developed in order to achieve faster start-up and to maintain good lifetimes in load-following applications of SOFC.

In CHP applications, heat storages and boilers can reduce the requirements for start-up and shutdown as well as load following. However, good load-following abilities are still required in order to reduce the peak load capacity installed.

Thus, when in operation, all types of fuel cells may have very fast regulation abilities, providing them with properties similar to those of batteries. With the right control systems, start-up times can be reduced significantly or almost eliminated for high temperature fuel cells.

4.6 Conclusion

In this review, the characteristics and potential applications of five different fuel cells have been elaborated. Significant challenges must be overcome, before fuel cells can be applied to broader uses than niche areas. HT-PEMFCs seem to be especially promising for transport or micro-CHP applications. SOFCs may eventually replace combustion technologies in CHP plants; however, start-up times, load-following capabilities, lifetime and efficiencies still have to be improved.

5 Efficiency of fuel cell CHP and large-scale integration of renewable energy

In this chapter, the applications of SOFC to local and central CHP plants in future energy systems are presented. The significance of a change from gas and steam turbines to SOFCs as well as the possibility of improving the integration of wind power presented are based on "Solid oxide fuel cells and large-scale integration of intermittent renewable energy" [9] included in appendix II and "Fuel Cells for Balancing Fluctuating Renewable Energy Sources" in "Long term perspective for balancing energy sources" [2] included in appendix III.

SOFC can play a key role in the balancing and integration of intermittent renewable energy such as wind power. In future energy systems, generation is distributed and, compared to gas and steam turbines, SOFCs have the potential for increasing fuel efficiency in both large central and small distributed CHP. SOFCs also have the potential for participating in the grid stabilisation task; thus, enabling further reductions in fuel consumption and improving the integration of intermittent resources. SOFCs may provide a new design of the ancillary service supply, which requires new technologies, as existing base load plants become less important. The start-up and thermal cycling of the SOFC may pose material problems and reduce the lifetime of the cells. The analyses in this chapter conclude that it is less important to develop SOFC for continuous operation, than it is to develop SOFC with fast dynamics to improve load balancing in future electricity systems with high amounts of intermittent production. With increasing shares of renewable energy, the number of operation hours decreases and, hence, the lifetime of the cells becomes less significant. Efficient SOFC may play a key role in future 100 per cent renewable energy systems and can be a more suitable technology in such systems than gas and steam turbines.

5.1 Introduction

New technologies can increase the fuel efficiency and feasibility of energy systems with very large shares of distributed renewable energy and CHP, such as SOFC in CHP plants instead of gas and steam turbines. This requires good load-following abilities of the SOFC. Compared to other technologies, SOFC may eventually also represent a good alternative to other technologies which provide ancillary services. Such abilities become very important in future distributed renewable energy systems, in which base load plants are less significant. SOFCs may eventually be both more efficient and more flexible. [1;9]

In this chapter, the effects of SOFC on the performance of energy systems are analysed. The fuel cells are analysed in three different energy systems; the 2030 business-as-usual projection of the energy system presented by the Danish Energy Authority (BAU 2030), as well as a 50 per cent and a 100 per cent renewable energy system (IDA 2030 and IDA 2050). The analyses are conducted with gas and steam turbines as a reference, with regulating

CHP, and under four ancillary service supply scenarios. The results are assessed in terms of fuel efficiency and the ability of the system to integrate intermittent renewable energy.

5.2 The replacement of gas and steam turbines

Six versions of the energy systems are constructed; three with gas and steam turbines and three with SOFC. In the original IDA 2030 energy system, a third of the central CHP and power plant capacity is large central SOFC plants, i.e. 1.500 MW. Half of the decentralised gas turbine CHP plants, 600 MW, are small-scale local SOFC CHP. In the IDA 2030 system, the SOFCs are removed and replaced by gas turbines in order to analyse the significance of SOFC in terms of total fuel efficiency. In the BAU 2030 energy system, the same amount of gas turbines is replaced by SOFC as in the IDA 2030 system.

For large central CHP and power plants, SOFC gas turbine hybrids with 66 per cent electricity efficiency are installed, and for small local SOFC CHP plants, with a 56 per cent electricity efficiency. Both have a total efficiency of 90 per cent. In the IDA 2050 energy system, the electricity efficiencies of SOFC are reduced by 2 per cent, as an approximation of losses due to the reformation of gases derived from biomass. In the original IDA 2050 energy system, SOFCs have replaced all other technologies. In the analyses here, these are replaced by local and central single and combined cycle gas and steam turbines (SCGT and CCGT). In the central areas in the IDA 2050 energy system, half of the plant capacities are assumed to be large CCGT CHP (>100 MW) with a 62 per cent efficiency and half are assumed to be CCGT CHP (>10 MW) with a 52 per cent efficiency. In local areas, small SCGT (5-40 MW) with a 41.5 per cent efficiency are installed. All have a total efficiency corresponding to 91 per cent. SOFC power plants are assumed to be replaced by large CCGT power plants.

5.3 Ancillary service design scenarios

Different approaches can be applied to incorporate grid stability and reserve capacity considerations in hour-by-hour energy system analyses. In grid flow models, electro-technical data are used for the individual system components; however, the aim is to analyse the effects on the system seen from a wider angle than merely focusing on grid stability. The consequences of continuing the current top-down ancillary service supply are analysed in terms of fuel efficiency and compared to the integration of other technologies in distributed renewable energy systems. Although the capacities and recommendations above give some indication of the capacities required, this has to be interpreted in a way which makes it possible to model the systems in a load-balancing energy system analysis model. In 2001, the ancillary service restrictions of the Danish energy system were assessed for energy system modelling in a working group under the Danish Energy Authority for such purposes. The assessment led to the following results:

- The minimum share of technologies able to supply ancillary services at any given point in time must be 30 per cent.
- The minimum load from these plants was set at 350 MW in the western part of Denmark and 280 MW in the eastern part.
- All centrally dispatched power plants are able to supply ancillary services.
- Wind turbines and locally dispatched CHPs are not ably supply ancillary services. [62;63]

The Danish electricity grids are divided into two areas, but considering the fact that the two Danish electricity areas will be connected in 2010, they can cooperate in the supply of ancillary services [64]. Hence, the ancillary service control design is analysed in the case of the entire Danish system. With the interconnection, the requirements for minimum load are assumed to change for the technologies able to supply ancillary services. In order to assess the impact of the interconnection, one must understand that the present requirements are mainly based on the frequency impact of wind turbines fitted with asynchronous generators on the energy system of today. The interconnection will enable some ancillary service load sharing; thus, the minimum momentary production required for plants able to supply ancillary services will be lower in the interconnected system, than the sum of the requirements for the individual systems. For the analyses, a value of 450 MW is assumed for the interconnected area. The stipulation that the momentary production of ancillary service-producing units cannot drop below 30 per cent is upheld; however, as production units with unstable frequency still need a firm frequency against which they can produce; the larger the system, the more wind power, the more the production on ancillary service-providing units is required.

In future energy systems, new wind turbines can be expected to form part of the ancillary service supply, as these demands are present for new offshore wind turbines today. Four different ancillary service scenarios are hence established, which differ in terms of the technologies which provide the services. The first ancillary service scenario reflects the current situation. In the second scenario, locally distributed SOFC CHPs take part in the ancillary service supply. In the third scenario, also 50 per cent of the installed offshore wind turbines take part in the ancillary service supply. In the fourth scenario, the option of replacing minimum production with SOFC CHPs on standby is also implemented. The four scenarios are listed in Table 2.

Grid-stabilising plants	Current top-down control design	+ local SOFC CHP	+ wind	+ local SOFC CHP standby
30 per cent	Central power plants	Central power plants and local SOFC	Central power plants, 50 per cent offshore wind and local SOFC	Central power plants, and local SOFC
Min. production of 450 MW	Central power plants	Central power plants	SOFC CHP on standby	SOFC CHP on standby

Table 2, Ancillary service scenarios analysed, from the current top-down control design to a future bottom-up control design.

5.4 Results of replacement of gas and steam turbines and new ancillary service designs

The analyses of the four ancillary service scenarios are performed for the three different energy systems described. The scenarios are analysed through two types of diagrams, by which the importance of the ancillary service design can be compared in the different energy systems.

The first diagram illustrates the annual excess electricity production in TWh, as a function of renewable energy input in an open energy system. In the open system, CHP plants with heat storages and, if present, heat pumps and flexible electricity demands are used to balance heat and electricity demand during the given hours and with the aim of minimising excess electricity production. The energy system analyses are performed with due consideration for the different ancillary service designs, which restrict the operation possibilities of the plants involved. Hence, the ability of the system to reduce excess electricity production also depends on the restrictions made in relation to ancillary services. In this energy system analysis, a low excess electricity production represents a good ability of the system to integrate fluctuating renewable energy sources.

The second type of diagram illustrates annual fossil and/or biomass fuel consumption in TWh in a closed energy system excluding renewable energy sources, in this case wind power. In the closed system, the same regulation applies as above. However, the following strategy for handling excess wind power production is used: First, CHP production is replaced by boilers in the district heating systems and then wind turbines are stopped. When fuel consumption is lowered, the energy system is able to efficiently utilise intermittent renewable energy sources.

In both diagrams, the production from wind turbines varies between 0 to 100 per cent of the electricity demand in the three energy systems analysed. In the analyses of the IDA 2030 and the IDA 2050 energy systems, other intermittent renewable resources have been removed.

In Fig. 10, the excess electricity diagram is presented. The first step in the task of integrating renewable energy is to enable CHP plants to produce electricity independently of the momentary heat demand by using heat storages.

Excess electricity does not decrease when changing from gas and steam turbines to fuel cells in the current top-down control of the ancillary service supply. When enabling the local SOFC CHP plants to take part in grid stabilisation, fuel savings of between 0.5 and 1 TWh are achieved in the BAU 2030 energy system. In the two renewable energy systems, IDA 2030 and IDA 2050, the ability to reduce excess electricity production is lower than in the BAU 2030 energy system, when enabling the local SOFC CHP plants to take part in grid stabilisation. This is due to the fact that other flexible technologies form part of these energy systems, such as heat pumps and flexible demand, which make it possible to integrate more wind power than in the BAU 2030 energy system.

In the situation in which 50 per cent of the offshore wind turbines are able to assist in the grid stabilisation task, all three energy systems experience large reductions in excess electricity production. In the fourth scenario, in which the 450 MW minimum production at central plants is replaced by SOFC on standby, excess electricity production is further decreased. The importance of SOFC on standby increases together with the share of wind power.

In Fig. 11, the annual fuel consumption excluding renewable energy sources is illustrated. As expected, fuel consumption decreases, as the ability of the energy system to integrate excess electricity is improved. In the renewable energy systems, the replacement of gas and steam turbines is especially important to the reduction of fuel consumption. Fuel cells are more important in future renewable energy systems than in the BAU systems. Even with more than 50 per cent wind power production in the renewable energy systems, they enable a decrease in fuel consumption of 2 to 2.5 TWh.

In the first ancillary service scenario, in which local SOFC CHPs participate in grid stabilisation, fuel consumption is marginally reduced. Again, when wind power also contributes to the supply of ancillary services, fuel consumption decreases significantly. With a wind power share of more than 50 per cent, the integration of standby SOFC further decreases fuel consumption.

In the renewable energy systems, the other components installed also reduce fuel consumption by replacing boiler production at CHP plants with large heat pumps and by using flexible demands. Such demands are placed in situations with high shares of wind power. In these systems, the operation hours of SOFC CHP decrease, as a higher share of the electricity demand is met by renewable energy and a higher share of the heat demand is met by heat pumps.

In the IDA 2030 energy system, a share of 21.5 TWh of intermittent renewable energy is proposed. In this situation, the SOFC CHP must participate in the grid stabilisation task in order to avoid excess electricity production. In the 100 per cent renewable energy system, IDA 2050, 38.8 TWh of intermittent renewable energy is installed; hence, the flexibility of SOFC is also important in this system. The potential flexibility in the operation of SOFC, which improves the efficiency by replacing gas and steam turbines and participating in grid stabilisation, is important in renewable energy systems because biomass-derived fuels constitute a limited resource. In the BAU 2030 projection from the Danish Energy Authority, 14.9 TWh of electricity is produced from onshore and offshore wind turbines. In such a situation, local SOFC CHP participating in grid stabilisation would improve fuel efficiency and improve the integration of installed wind power.

The fast start-up and the good regulation abilities of SOFCs are important measures in future energy systems, since they improve the ability of the systems to integrate renewable energy and reduce fuel consumption. Base load plants are not needed in future renewable energy systems.

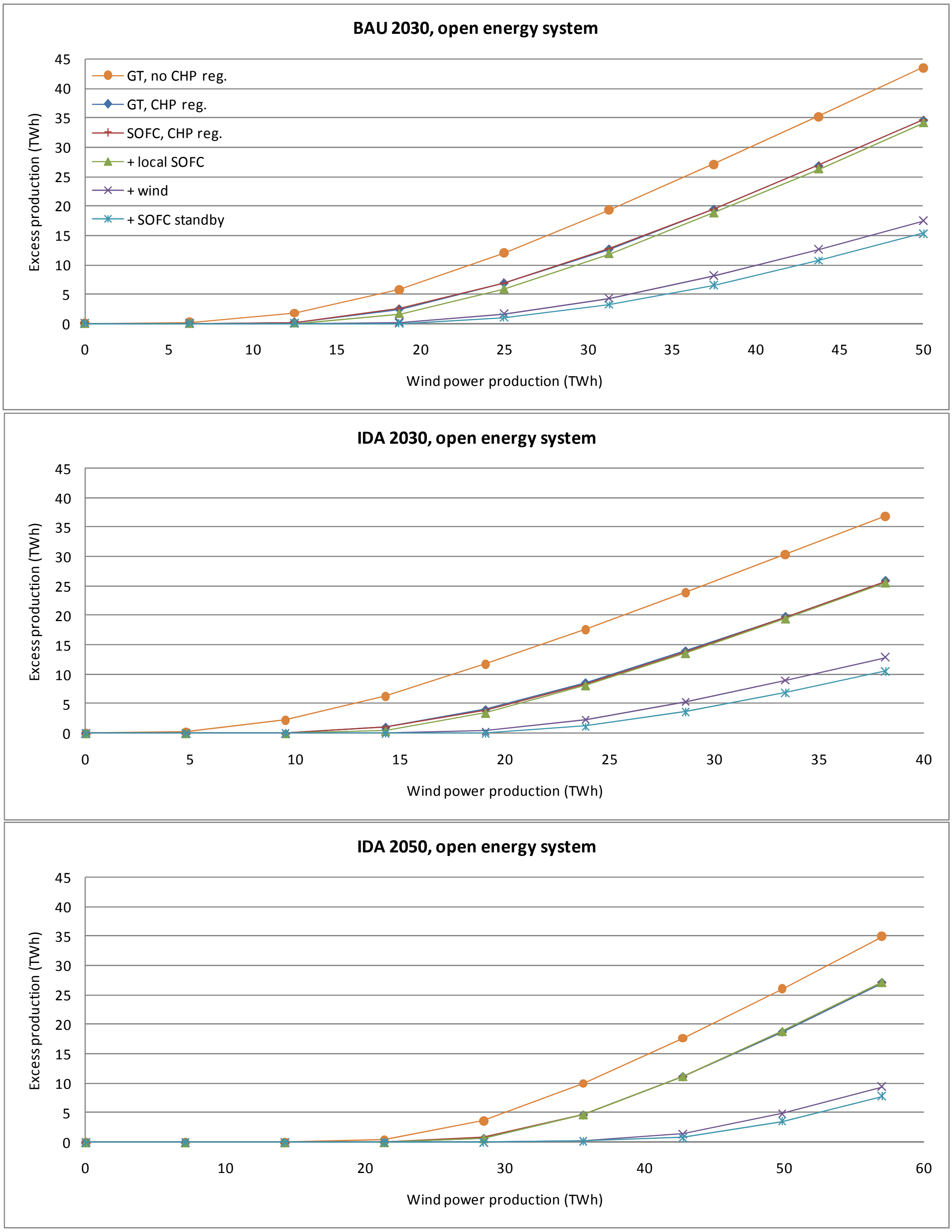

Fig. 10, Excess electricity diagrams of replacing CCGT and SCGT with SOFCs and for the four ancillary service scenarios in the three energy systems.

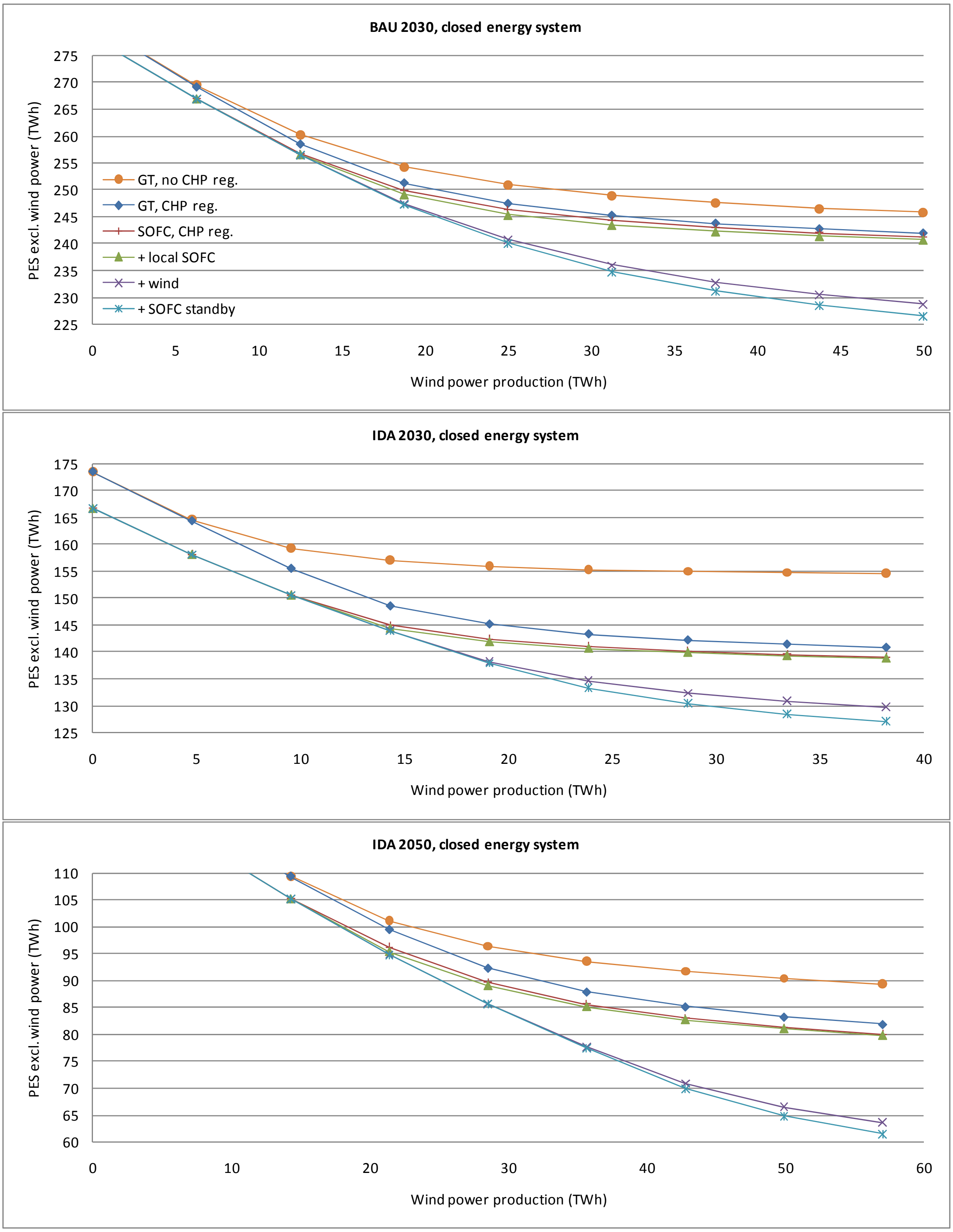

Fig. 11, Primary energy supply excl. wind power diagrams of replacing CCGT and SCGT with SOFCs and for the four ancillary service scenarios in the three energy systems.

5.5 Conclusion

Currently, the ancillary service supply is designed for traditional energy systems based on few central power plants. However, energy systems are changing towards renewable energy systems with many distributed producers. In a system with high shares of intermittent renewable energy, SOFC have the potential for increasing fuel efficiency and improving the integration of wind power by participating in the grid stabilisation task and being on standby.

Compared to single cycle and combined cycle gas and steam turbines, SOFC are more fuel-efficient for CHP plants. Furthermore, they may eventually have better regulation abilities and a very fast start-up. Further development is required to provide such flexibility; however, flexibility and fuel efficiency are key characteristics in future energy systems. SOFC is more important in terms of replacing gas and steam turbines in 100 per cent renewable energy systems, than in terms of fuel efficiency in business-as-usual energy systems.

The integration of SOFC into distributed CHP should be developed in order to create flexible market players that can follow load variations rapidly. Base load power plants are not required in such efficient renewable energy systems. While the lifetime of the cells may represent a potential development challenge, this may be less of a problem if they have less operation hours, but can operate when needed in the system.

Start-up and thermal cycling pose material problems dealt with in current research; thus, it may seem feasible to develop SOFC for constant operation. Such a development, however, does not take into account the nature of future efficient renewable energy systems.

6 Applications of solid oxide fuel cells future energy systems

In this chapter, six different applications of SOFC are analysed in eight fundamentally different future energy systems. The chapter is based on "Solid oxide fuel cells in renewable energy systems" [10] included in appendix IV.

SOFCs in CHP plants have the potential for improving the fuel efficiency of the energy system, especially in local distributed CHP plants, where they replace SCGT. Both large hybrid SOFC/gas turbines and smaller SOFC CHPs are important in future renewable energy systems. Micro-fuel cell CHP (FC-CHP) are less efficient and less feasible, especially in renewable energy systems. In the most efficient integrated renewable energy systems, electrolysers are less important, since other technologies are able to integrate most of the fluctuating renewable energy. However, in 100 per cent renewable energy systems, electrolysers may be important in terms of replacing other fuels. Base load FC-CHP plants are not required in renewable energy systems and, hence, SOFC CHP should be developed to enable flexible operation. The higher efficiencies of local FC-CHP can potentially compensate for the costs of replacing stacks.

6.1 Introduction

Six different applications of SOFCs and SOECs are analysed: Central FC-CHP, Local distributed FC-CHP, and Micro FC-CHP plants, as well as the three technologies in combination with electrolysers. All applications are analysed in technical energy system analyses; however, the market exchange analyses and feasibility study are only performed of the first four of the mentioned applications as well as for the Micro FC-CHP in combination with electrolysers. The analyses are conducted in eight fundamentally different energy systems, i.e. going from the electricity based energy system, to the traditional and the CHP system, to the integrated energy system (IDA 2030) and the 100 per cent renewable energy systems (IDA 2050). The 100 per cent renewable energy system, however, is only used in the technical energy system analyses.

The six applications analysed are:

1. Expansion of district heating replacing individual boilers with central FC-CHP, based on SOFC technology and corresponding to 500 MWe.
2. Expansion of district heating replacing individual boilers with Local FC-CHP, based on SOFC technology and corresponding to 500 MWe.
3. Instead of expanding district heating with Local FC-CHP, the same heat demand is met by Micro FC-CHPs in individual households.
4. Application no. 2 with central FC-CHP is combined with electrolysers producing hydrogen and replacing fuels whenever feasible.

5. Application no. 3 with Local FC-CHP is combined with electrolysers producing hydrogen and replacing fuels whenever feasible.

6. Application no. 4 with Micro FC-CHP is combined with electrolysers producing hydrogen which meets the entire fuel demand of the system.

The heat production from FC-CHP, the heat storages and peak load boilers are identical with the installed capacity and the district heating demand in the BAU 2030 system. In the central FC-CHP application, this corresponds to a district heating demand of 1.69 TWh. With an annual heat and hot water demand of 18 MWh, this corresponds to approx. 75,000 households. In the Local FC-CHP application, the production of heat is higher due to higher electric efficiencies. In the Local FC-CHP application, this corresponds to a district heating demand of 2.63 TWh and approx. 120,000 households. 20 per cent losses are assumed in the district heating systems.

In the Micro FC-CHP applications, the 2.63 TWh supplied by Local FC-CHP are now supplied by systems within the household, which reduces the demand to 2.11 TWh. The installed Micro FC-CHP is able to supply half of the peak hour demand, corresponding to more than 95 per cent of the annual demand. The system is equipped with a one-day storage and peak load boilers.

The capacity of the installed electrolysers is based on the demand of hydrogen in the Micro FC-CHP system in application 7. The fuel demand in this system is 4.6 TWh, if the Micro FC-CHP covers as much of the heat demand as possible. Assuming that the Micro FC-CHPs have an operation time of 25 per cent, this corresponds to 2,900 MWe electrolyser capacity. Fourteen days of hydrogen storage at full electrolyser capacity, corresponding to 1,100 GWh, has been installed. These capacities are also used in applications 5 and 6 in combination with Central and Local FC-CHP plants. In the Micro FC-CHP, the excess heat from the electrolysers replaces the heat produced by individual boilers; and in the Central and Local FC-CHP, the heat is used in the district heating system.

6.2 Effects on fuel efficiency and integration of renewable energy

The characteristics of the energy systems to which fuel cells and electrolysers are applied are very important to the ability of the applications to improve these systems. In very inefficient energy systems, the fuel cells improve the fuel efficiency to a larger extent than in energy systems which are already rather efficient. However, in renewable energy systems, fuel cells are also important, as they improve the total efficiency of the system. The fuel efficiency improvements identified in the technical energy system analyses of the different applications are illustrated in Fig. 12.

In the two CHP systems, substantial amounts of small CHP plants with gas turbines are already installed. In the CHP system with no wind power, the FC-CHP can replace the production of power plants and improve the fuel efficiency. In the CHP system with wind power, the FC-CHPs are more efficient than the gas turbines already installed. However, the fuel savings achieved are limited, because the heat at these plants is now produced by boilers. The fuel savings in the 100 per cent renewable energy system are larger than in the integrated energy system, because the rather inefficient wood pellet boilers are replaced. In the 100 per cent renewable energy system, however, SOFC are already installed in all CHP plants; hence, FC-CHP is very important to the total fuel efficiency of the system. In the integrated energy system, the penetration of SOFCs is also rather high already at this point, and thus, an improvement in fuel efficiency can only be achieved with central FC-CHP. For these energy systems, the flexible operation of FC-CHP is important to the integration of fluctuating renewable energy. Renewable energy and CHP replace power plants in these systems and, hence, traditional base load plants are not important in future fuel-efficient renewable energy systems.

Along the path towards renewable energy systems, the analyses of fuel efficiency show that improvements can be achieved by expanding the CHP areas. For Central FC-CHP and Local FC-CHP, the largest fuel efficiency improvements are achieved in the two electricity energy systems, because both electricity and heat demands previously covered by power plants are replaced. In the electricity energy systems with 24 TWh of wind power, the improvements are almost the same as in the system without wind, because the FC-CHPs are able to utilise heat storage and move their production to hours with no wind power, thus replacing power plant production. In these two energy systems, the electricity demand is rather high; thus, both Central and Local FC-CHP plants have the potential for producing heat in FC-CHP plants. For Central and Local FC-CHP in the remaining energy systems, the savings are lower due to the fact that individual boilers are now replaced instead of electric heating. Fuel savings are generally lower in systems with wind power, because these systems offer limited opportunities to replace production at power plants with production at FC-CHP.

The Micro FC-CHP applications replace a heat share similar to the amount supplied to households from district heating in the Local FC-CHP application. The Micro FC-CHP also replaces power plant production whenever possible; but the fuel savings achieved are in general lower than in the previous applications, mainly due to lower efficiencies. In the energy systems with already installed CHP plants, the Micro FC-CHPs produce at times when these would normally be operating, and thus, the heat demand in district heating areas must now be covered by boilers. This is not a big problem in energy systems in which CHP plant efficiencies are lower than those of the Micro FC-CHP; but it does pose a problem in renewable energy systems in which the efficiencies of installed CHP plants are higher than those of Micro FC-CHPs. Due to this situation, a small increase in fuel consumption takes place in the integrated energy system. Again, savings in the 100 per cent renewable energy system are higher than those of the integrated energy system, because wood pellet boilers are replaced and Local and Central FC-CHPs are more efficient.

In the cases of Central and Local FC-CHP combined with electrolysers, marginally higher fuel efficiencies can be identified in systems with excess electricity production, because other fuels can now be replaced. Here, the electrolysers only produce at times with excess electricity production. Most fuels are replaced in the traditional energy system with 24 TWh wind power, because this system has the largest excess electricity production. For the Micro FC-CHPs combined with electrolysers, the hydrogen demand must be met, and thus, excess electricity from wind power cannot cover the entire demand. This eliminates the fuel savings achieved by such applications, as identified in the case of Micro FC-CHPs operated on natural gas.

For comparison, 500 MWe central FC power plants have been included in the technical energy system analyses. The technology is identical with Central FC-CHP except from the fact that no heat is produced by FC power plants. As wind power often replaces central power plants, and thus, FC power plants have fewer possibilities of operating in these systems, the best fuel efficiency improvement is achieved in energy systems without wind power. In the integrated energy system and in the 100 per cent renewable energy systems, fuel savings are very low. This is based on the following facts: 1) A large proportion of the demand is met by fluctuating renewable energy; 2) the operation hours of power plant are reduced to a minimum with CHP plants in order to improve fuel efficiency; and 3) the efficiencies of the existing power plants are already quite high.

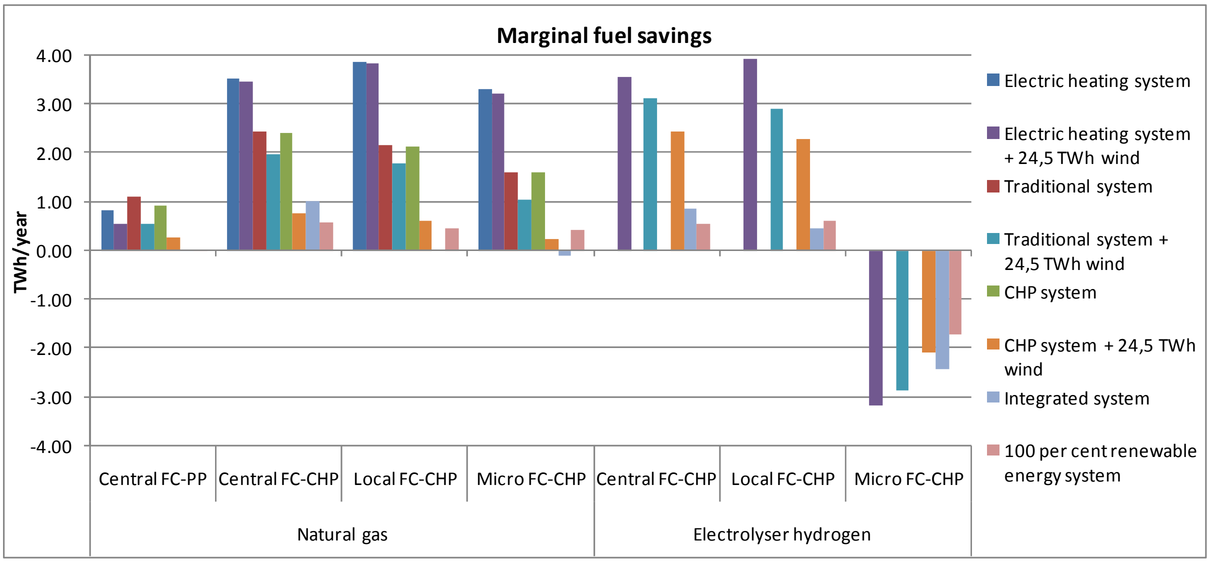

Fig. 12, Marginal fuel savings of the six applications analysed in the eight different energy systems. Central fuel cell power plants (FC-PP) have been included for comparison.

In Fig. 13, the changes in excess electricity production are illustrated. In the Central and Local natural gas FC-CHP systems, the excess electricity production does not change. In the hydrogen Central and Local FC-CHP systems, the excess electricity can now be utilised. The natural gas Micro FC-CHP application increases the excess electricity production marginally in energy systems with wind power. Although heat storages are used, these are less flexible than central and local FC-CHP plants. This is due to the fact that the units are prioritised to increase the total efficiency, but are sometimes forced to produce electricity at times when the demand is already met by wind power and the production of power plants and other CHP plants has already been reduced to a minimum. This is also the case in the hydrogen Micro FC-CHP system in the traditional and the 100 per cent renewable energy systems. Here, electrolysers reduce excess electricity production, but this is increased again during some hours due to the electricity produced by Micro FC-CHP.

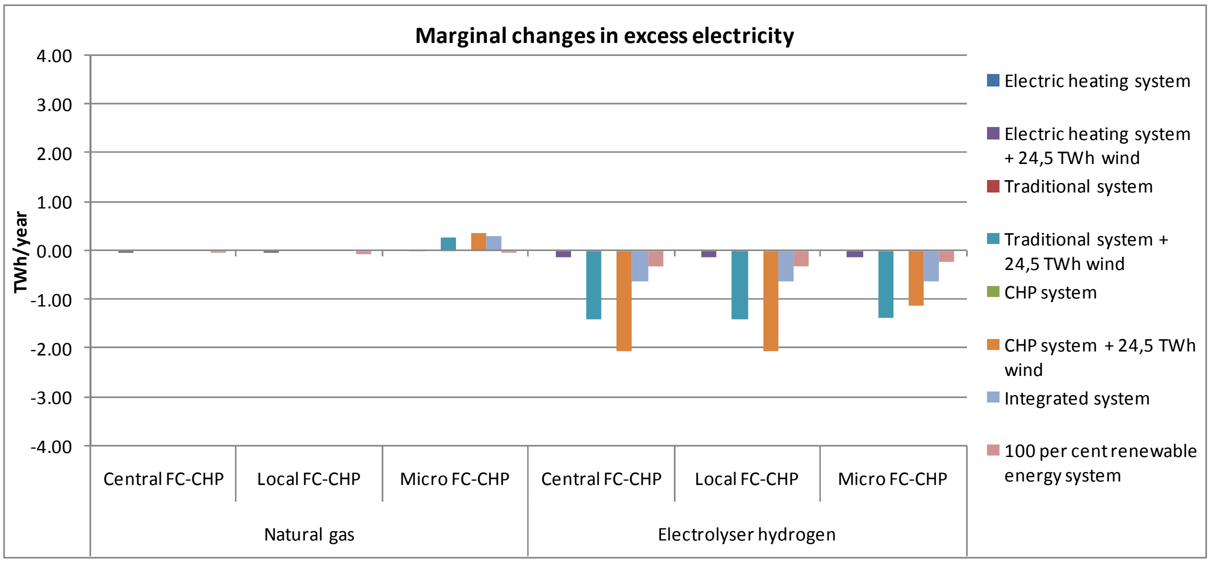

Fig. 13, Marginal changes in excess electricity production of the six applications analysed in the eight different energy systems.

6.3 Cost of electricity generation and effects on electricity trade

Extensive international electricity market exchange analyses of the Central, Local and micro FC-CHP applications as well as the hydrogen Micro FC-CHP have been conducted. Here, the aggregated results of such analyses are presented, but first the expenses related to FC-CHP are compared to the costs of competing future technologies.

In Table 3, the long-term electricity cost targets of the FC-CHP and competing technologies are listed in terms of different fuel and CO_2 quota prices. Onshore and offshore wind turbines are expected to have the lowest power generation costs, also when including trade and balancing costs in the fixed O&M [65]. The operation time of the turbines is 30 per cent for onshore and 40 per cent for offshore wind turbines. For the remaining technologies, the operation time is assumed to be 50 per cent.

Large Central FC-CHPs cannot compete with coal-based CHP, but they have long-term costs similar to those of CCGT and have lower costs than biomass-based CHP, especially if the long-term cost goals are met.

Small Local FC-CHPs are able to compete with small SCGT, also in case that only the cost goals for 2015 are met. The better efficiencies of FCs can compensate for the high costs of replacing stacks in Local FC-CHP, represented by the high fixed O&M. Two different price levels of Micro FC-CHP have been included, assuming that, in the long term, it is possible to scale the Local FC-CHP; but the efficiencies do not increase due to larger auxiliary power requirements in small-scale generation. In all the fuel and CO_2 quota price scenarios, the Micro FC-CHPs are unable to compete with the other technologies. Some may argue that the main purpose of Micro FC-CHP technologies is to produce heat, and that this element should be taken into account. This, however, is the also the case for some of the other future CHP technologies listed.

One mayor problem for the FC-CHPs is the fuel prices, because natural gas is more expensive than coal. This is, however, also the case of gas turbines. If the electrolysers were able to operate solely on wind power, the long-term costs of hydrogen would be approx. 15 €/GJ, not taking into account the costs of the electrolysers. Such prices cannot compete with the fuel costs used in FC-CHP included here.

Future technologies	Inv. costs	Life-time	Fixed O&M	Var. O&M	Efficiency		Total €/MWh incl. CO_2 quotas	
							Low fuel	High fuel
	M€/MW		(%)	€/MWh	el.	th.	Low CO_2	High CO_2
Wind On-shore	1.07	20	3.0	12	-	-	38	38
Wind Off-shore	1.87	25	2.8	15	-	-	44	44
Large Coal CHP (2030)	1.20	30	1.3	1.8	55.0	38.0	46	80
Large Biomass CHP (2030)	1.30	30	1.9	2.7	48.5	41.5	137	160
Ngas CCGT (>100MW)	0.55	30	2.3	1.5	61.5	29.5	62	116
Ngas CCGT (>10 MW)	0.70	25	1.4	2.8	52.0	39.0	74	138
Ngas SCGT (40-125)	0.49	25	1.5	2.5	46.0	46.0	79	151
Ngas SCGT (5-40)	0.70	25	1.1	3.3	41.5	50.5	130	209
Ngas Large FC-CHP '15	0.80	30	6	-	66	24	68	118
Ngas Large FC-CHP '30	0.40	30	6	-	66	24	58	108
Ngas Small FC-CHP '15	0.80	20	10	-	56	34	116	175
Ngas Small FC-CHP '30	0.40	20	6	-	56	34	97	156
Ngas Micro FC-CHP '15	1.87	20	6	-	45	45	254	328
Ngas Micro FC-CHP '30	0.80	20	10	-	45	45	231	305

Table 3, Long-term electricity prices of future technologies. For the FC-CHP technologies, the prices are based on potential future costs and efficiencies for 2015 and 2030. The low fuel prices represent costs equivalent to 62 $/bbl oil and the high fuel costs represent costs equivalent to 172 $/bbl oil. The low CO_2 quota costs represent 23.3 €/ton, and in the high cost scenario, this level is doubled. Low fuel-high CO_2, high fuel-low CO_2 and the base fuel costs, representing costs equivalent to 120 $/bbl, have been left out. For coal CHP and gas turbines, potential future efficiencies are listed; however, the costs of these are approx. current costs [49;65]. Electricity prices are based on a 3 per cent interest rate.

The combinations of seven different future energy systems, four different applications, six different fuel and CO_2 quota prices, and three different electricity price levels result in more than 650 energy system analyses in the market exchange analyses. The electricity market exchange analyses are presented in detail for the Local FC-CHP in the CHP system with 24 TWh of wind power. Subsequently, the aggregated results of the analyses are presented for all energy systems and all applications.

In Fig. 14, the electricity trade effects of the reference CHP system with 24 TWh of wind power are illustrated, in combination with Local FC-CHP in this energy system. In the normal year, the Local FC-CHPs are able to marginally increase net earnings by reducing import and increasing export due to a more efficient fuel conversion. In the wet year, electricity prices are rather low and net earnings are mainly connected to imports. The Local FC-CHPs reduce import and, when electricity prices are rather low, this results in decreased net earnings, even though the Local FC-CHPs are very efficient. In the dry year, the Local FC-CHPs are able to increase net earnings based on larger earnings from more efficient electricity exports. When applying the assumptions on the frequency of the different electricity, fuel and CO_2 quota cost levels described above, the electricity market analyses of Local FC-CHP show that the net earnings are unchanged.

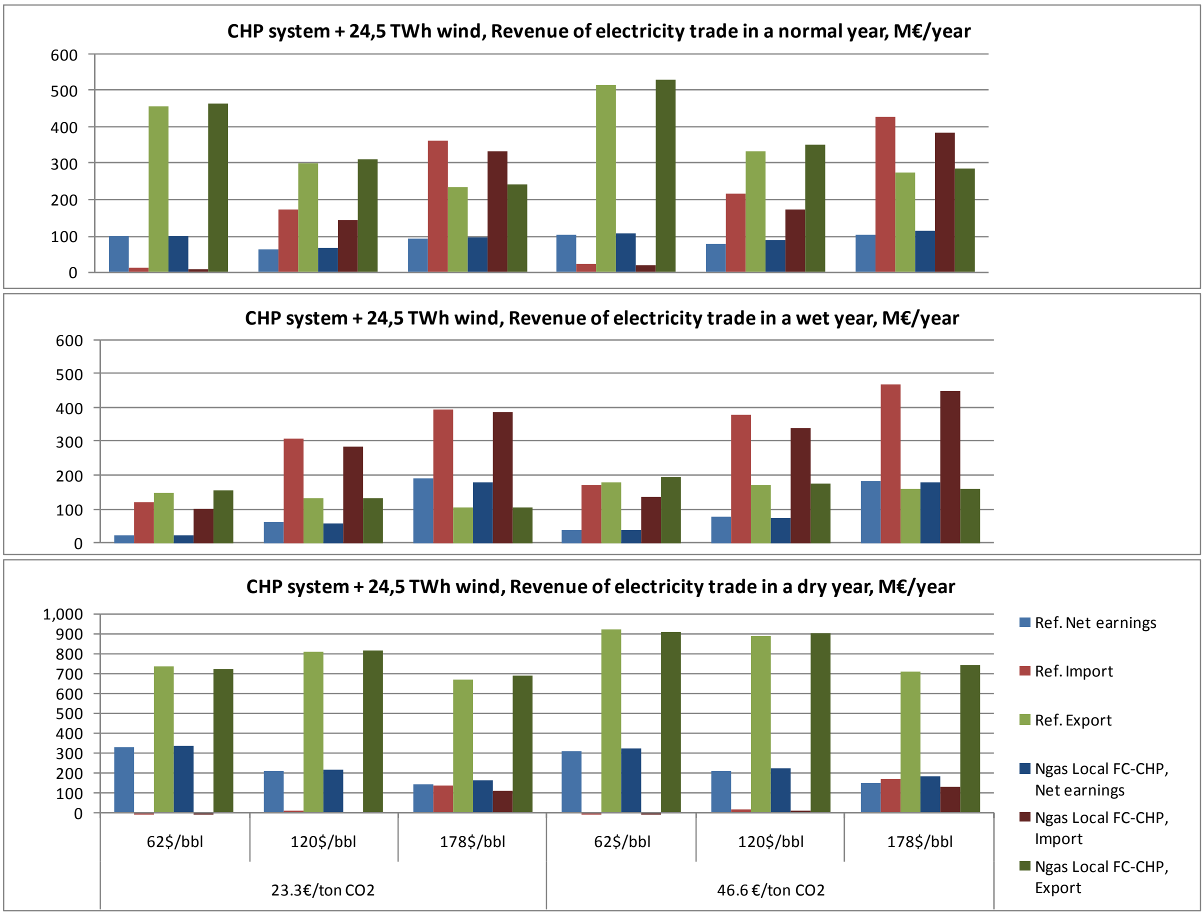

Fig. 14, Electricity market exchange analyses of the reference CHP system with 24 TWh of wind power and Local FC-CHP added to this system. The results are illustrated for three electricity and three fuel prices and two CO_2 quota costs.

In Fig. 15, the total average revenue of electricity trade of the reference energy systems is shown. The total net revenue of electricity trade in the references is between 110 and 170 M€/year. In the four electricity and traditional systems, the main earnings on trade are connected to imports, due to rather high production costs. This is also the case of the CHP system; while in the CHP system with 24 TWh of wind power as well as in the integrated system, the earnings on trade are reduced, due to lower system flexibility with a high penetration of CHP and fluctuating renewable energy.

In Fig. 15, the net average revenue of the four applications added in the reference energy systems is also illustrated. In all energy systems, the production of electricity in FC-CHP, replacing the production of heat in boilers, generates rather low marginal production costs. Still for the natural gas Central, Local and Micro FC-CHP applications, the changes in revenue are rather low in most systems. The large import in wet years and high fuel costs hamper the ability of the FC-CHP to increase earnings on trade. In the reference systems, imports would reduce power plant production and thus enable more fuel savings than when replacing FC-CHP, because the replaced FC-CHP production leads to a higher boiler production. This poses a problem for the increase of earnings from international electricity trade when fuel prices are high, especially on the Nordic electricity market where prices are often low due to the Norwegian hydro power production.

In normal years, the profits of trade increase significantly in the CHP energy system with 24 TWh of wind; hence, FC-CHP has good abilities to compete with the gas turbine CHPs in this system, which use the heat storages. In normal years, smaller profits can also be generated for FC-CHPs in the CHP energy system.

In dry years, FC-CHPs generate profits in most systems; especially in the CHP systems in which they compete with gas turbines. In the dry year, however, the Local FC-CHP performs better than the Central FC-CHP in the CHP energy system with wind power. This is due to the larger heat storages of the local systems.

For the hydrogen Micro FC-CHP, electrolysers are able to profit from fluctuations in the traditional energy system with wind power. This system is rather inflexible compared to the CHP system with wind and the integrated energy system, in which CHP plants already adjust prices and hence hydrogen Micro FC-CHPs are able to increase profits. In the integrated system, the net earnings on international trade decrease marginally, as the other components in the system are, among others, flexible demands and heat pumps.

Fig. 15, Total average revenue of electricity trade and total socio-economic feasibility of the reference energy systems and net change in revenue of the four applications. Please note that the scales vary.

6.4 Socio-economic consequences

In terms of socio-economic costs, the integrated energy system generates the lowest total costs. This gradually increases towards the electricity-based system, which generates the highest socio-economic costs. In Fig. 15, net changes in total socio-economic costs are illustrated.

The implementation of FC-CHP more or less balances in the case of the Central FC-CHP, while the Local FC-CHP has additional socio-economic costs. In the CHP system and the integrated systems, the costs of FC-CHP increase. This is due to the fact that extra CHP capacity is not feasible in these systems, unless e.g. gas turbines are replaced instead of expanding CHP capacity as done here. The Micro FC-CHP system generates the highest increase in costs, also in the situation with electrolysers, because price fluctuations are involved which do not necessarily reflect fuel-efficient solutions.

The analyses were conducted with potential technologies for year 2015. If the potential technologies in 2030 are considered, the Central FC-CHP solutions would improve by 22 M€ and the Local FC-CHP by 41 M€. Such improvements would make the expansion of CHP and district heating with FC-CHP profitable in most systems. The costs of the district heating systems would, however, balance these savings, assuming district heating costs of 0.26 M€/GWh ab net. If it is assumed that the costs of Micro FC-CHP are reduced to Local FC-CHP costs expected for 2015, the costs would be reduced by 40 M€, making the total costs balance more or less.

As presented in Table 3, the long-term electricity production costs of the Local FC-CHP are lower than those of small gas turbines, even when using the potential costs for 2015. In the CHP energy systems and in the integrated energy system, this means that, rather than expanding CHP and district heating, the existing CCGT or SCGT gas turbine CHP plants could be replaced by FC-CHP. This would reduce the total costs, because the FC-CHPs are more efficient.

Hence, in the systems without CHP, it is feasible to expand CHP; and in future fuel-efficient renewable energy systems with high penetrations of small gas turbines in CHP plants, it is feasible to replace these with FC-CHP.

6.5 Conclusion

SOFC can improve the fuel efficiency of future renewable energy systems by replacing gas turbines. Large central FC-CHP plants based on hybrid SOFC gas turbines create marginally larger fuel savings than smaller local SOFC-based CHP plants; however, both technologies are able to improve fuel efficiency compared to gas turbines. In renewable energy systems, local SOFCs are very important, as they can increase fuel efficiency significantly compared to SCGT. On the other hand, large FC-CHPs compete with CCGT, which are not significantly less efficient. If the efficiency and cost targets for SOFC are met, they can improve fuel efficiency and generate lower long-term production costs than gas turbines.

The expansion of CHP plant capacity can improve fuel efficiency and serve as the first step on the path towards integrated renewable energy systems. The expansion of CHP with central FC-CHP may be limited, as this requires large connected rural areas. In renewable energy systems, CHP can reduce costs and increase fuel efficiency. In such case, Local FC-CHPs have better fuel efficiencies and a higher feasibility than Micro FC-CHPs. Electrolysers may contribute to the integration of excess electricity. Fuel consumption, however, may increase if connected to Micro FC-CHP, because a fixed demand must be met and excess electricity production cannot always cover the electricity demand. In the most efficient integrated renewable energy systems, electrolysers are less important, since other technologies are able to integrate most of the fluctuating renewable energy. However, in 100 per cent renewable energy systems, electrolysers may be important in terms of replacing other fuels.

Both efficiencies and costs are uncertain for technologies which are still at the development stage. However, the SOFCs have the potential for reducing the dependence on fuels in future energy systems. Local 5-40 MW-size SOFC FC-CHPs that can improve the efficiency of SCGT distributed CHP plants are particularly important, as is the development of SOFC to operate with the fluctuation of renewable energy instead of serving as base load plants.

7 Individual household heating systems, fuel cells and electrolysers

In this chapter, six different heating systems for individual households are analysed. Two of these are based on fuel cell technologies and one is combined with electrolysers. The heating systems are analysed in different energy systems. The chapter is based on "Comparative energy system analyses of individual house heating systems in future renewable energy systems" [6], included in appendix V.

Micro-FC-CHP systems are compared to the conventional technologies: heat pumps (HP), natural gas and wood pellet boilers. They are analysed hour-by-hour in renewable energy systems with and without large amounts of district heating CHP plants. As fuel cell systems are often connected to the utilisation of excess electricity, both systems have a wind power share of 50 per cent. HP have the lowest fuel consumption, CO_2 emissions and socio-economic costs. Natural gas and biogas micro-FC-CHP are more efficient than wood boilers; however, they use approx. the same amount of fuel as gas boilers and have higher costs. Electrolysers with micro-FC-CHP are rather inefficient and economically unfeasible. If the aim is to reduce CO_2 emissions, it can be recommended to increase the use of HP, replace boilers and use the fuels in CHP plants instead. In the case of Denmark, however, the current tax system encourages the use of boilers and hinders the use of HP. A two-stage tax reform is introduced taking into account fuel efficiency and "opportunity costs" of using scarce biomass and fossil fuels in inefficient boilers instead of CHP plants.

7.1 Introduction

Micro-FC-CHP systems are considered for individual houses in future energy systems in order to expand the co-generation of heat and power, to improve energy efficiency, to use renewable energy, and, in combination with electrolysers, to integrate renewable energy sources into the system. Micro-FC-CHP technology is, however, not the only option when integrating renewable energy into heating systems and thus introducing flexibility in the integration of large shares of fluctuating renewable energy sources.

Heating systems, such as micro-FC-CHP, cannot be evaluated in a stand-alone situation, but must be analysed as part of an energy system. The aim of this analysis is to compare different alternatives for individual heating in renewable energy systems with 50 per cent wind power. The comparison is made in terms of fuel efficiency; the ability to reduce excess production; the impact on electricity trade; as well as socio-economic and business-economic costs. A comparative analysis is made of individual heating based on: natural gas boilers, wood pellet boilers, micro-FC-CHP operated on natural gas, or hydrogen from electrolysers as well as geothermal and air to water HP. Two types of HPs are included in order to consider the fact that not all dwellings have access to the same heat source. Biogas in individual boilers and biogas for micro-FC-CHPs for individual house heating are also included as sub alternatives. District heating systems with local CHP plants replacing individual heating systems are not included in the analyses.

Two fundamentally different energy systems are defined in which the heating systems are compared by use of energy system analysis modelling. The BAU 2030 energy system has a high share of CHP, which is not the case in most countries. For the same reason, a Non-CHP reference has also been defined, simply by replacing all CHP in the reference by heat production from boilers and electricity production from power plants. In the analyses, the wind power share is 50 per cent leading to an excess electricity production of 1.66 TWh/year (approx. 7 per cent of the wind power production).

The micro-FC-CHP is assumed to have a heat capacity equal to half of the peak heat demand. In the very few situations in which the FC-CHP cannot meet the demand, a fuel boiler is activated. In all alternatives, central heating with a heat storage capacity corresponding to one day of average heat demand is assumed to be installed. Such storage enables the utilisation of the flexibility of HP and micro-FC-CHP.

A coefficient of performance (COP) of 3.2 is used for geothermal and a COP of 2.6 is used for air/water HP. Current commercially available electrolysers have an electricity-to-fuel efficiency of 60 per cent. However, an efficiency of more than 80 per cent may be possible and is used in the sensitivity analysis here, in combination with a 10 per cent thermal efficiency. Hydrogen storage may eventually achieve efficiencies between 95 per cent. 5 per cent losses are assumed in hydrogen storage and in inverters, which results in a total electricity-to-fuel efficiency at households of 72 per cent. The micro-CHP units consist of SOFCs or PEMFCs. Both electric and thermal efficiencies are 45 per cent in the analysis, when operated on hydrogen. When operated on natural gas or biogas, an additional loss is included for the reforming process; hence 30 per cent electric and 60 per cent thermal efficiencies are estimated to be possible.

The heating systems are analysed in the case of supplying 300,000 individual houses. Each of these houses has an annual heat demand of 15,000 kWh, equal to a total of 4.5 TWh. Typical Danish hour distribution and duration curves have been used for the heat demand, as illustrated in Fig. 16. For each house, the peak heat demand is approx. 4.5 kW. Out of the annual 15,000 kWh, 3,750 kWh is hot water and 11,250 kWh is heating. A sensitivity analysis is conducted in which houses are insulated and the heat demand is decreased by 50 per cent, leading to a total annual heat demand of 9,375 kWh and a peak demand of 1.5 kW.

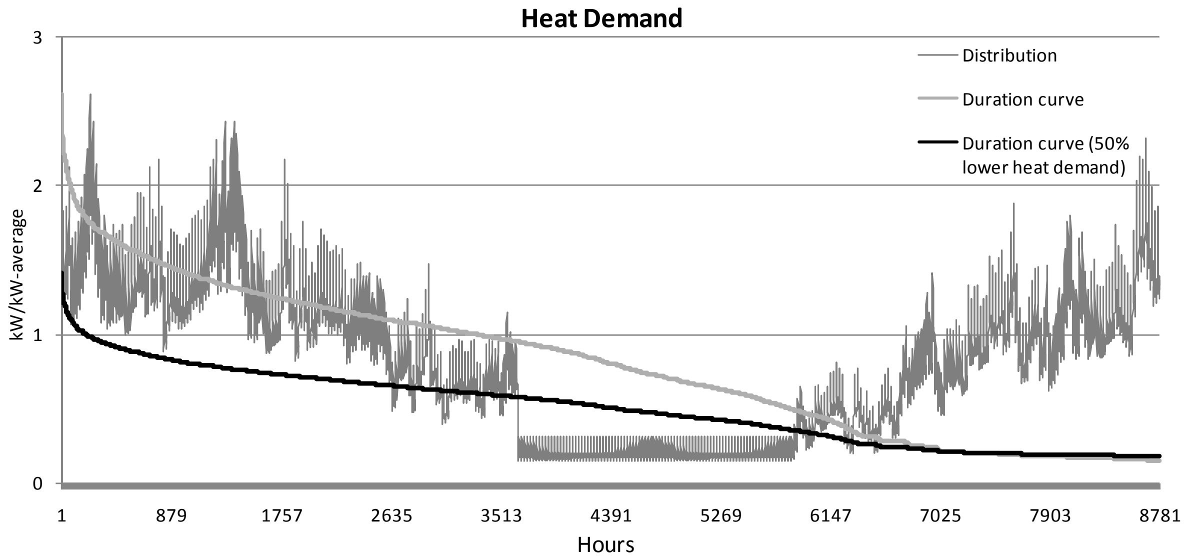

Fig. 16, Distribution and duration curves of the heat demand in individual houses.

7.2 System fuel efficiency of individual house heating alternatives

The fuel efficiency and the excess electricity production of the alternatives are described in detail for the analyses of the BAU 2030 CHP system. Subsequently, the energy system analyses of the Non-CHP system are described. The heat demand for the population of 300,000 houses is supplied from boilers involving 4.5 TWh of natural gas/biogas or 5.3 TWh of wood pellets, as illustrated in Fig. 17. Such house heating does not influence the electricity supply or the excess electricity production, which is 1.66 TWh/year.

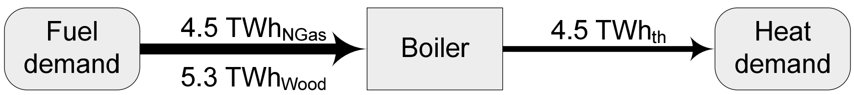

Fig. 17, Annual natural gas, biogas or wood pellet consumption of supplying 300,000 houses with heat from individual boilers.

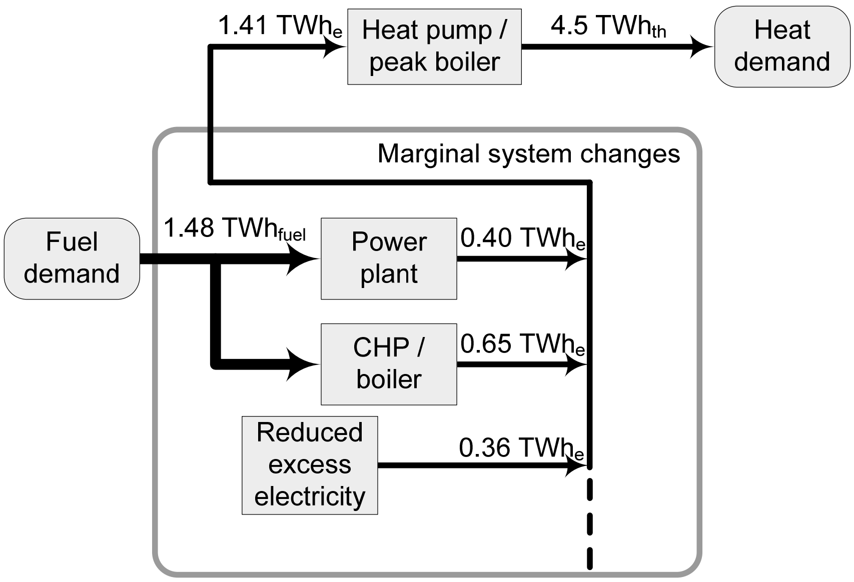

Fig. 18, Annual fuel consumption of supplying 300,000 houses with heat from individual geothermal HP incl. electric peak load boiler in the BAU 2030 CHP energy system.

In Fig. 18, energy conversion with geothermal HP is illustrated. Combined with peak load electric boilers, the HPs require 1.41 TWh of electricity to meet the demand. During some hours, electricity consumption can be met by excess electricity production. Here, the excess production is reduced by 0.36 TWh from 1.66 TWh in the reference energy system. During other hours, the increased electricity demand has to be produced either by CHP or power plans. When additional electricity is produced by CHP plants, more boiler heat production is replaced in the CHP district heating systems and, consequently, the marginal extra fuel consumption is relatively low. In total, the annual extra fuel demand is 1.48 TWh, most of which is used in the condensing power plants. In a sensitivity analysis, all wind power is removed, and thus, fuel consumption is increased for all electricity consumed in HP. The results for air/water HP resemble the results for geothermal HP. The electricity demand is 1.73 TWh and the total fuel demand is 1.87 TWh. Electricity productions from power plants, CHP and reduced excess electricity are now 0.53, 0.79 and 0.42 TWh, respectively.

In Fig. 19, the energy conversion with micro-FC-CHP based on either natural gas or biogas is illustrated. In this case, 7.37 TWh of gas is consumed in order to meet the heat demand of 4.5 TWh. However, 2.14 TWh of electricity is also produced. The excess production is raised by 0.39 TWh and the remaining electricity is saved at CHP and power plants. At CHP plants, the reduced production leads to a change in the heat production, which is then met by peak load boilers. This leads to relatively small marginal fuel savings in the BAU 2030 CHP system. In total, 2.63 TWh of fuel is saved in the energy system. The net result is 4.73 TWh, which is a minor increase compared to the 4.5 TWh used in gas boilers. If biogas is used in the micro-FC-CHP shown in Fig. 19, the net fuel consumption is the same; but the use of biogas is 7.37 TWh and the net saving of natural gas is 2.18 TWh.

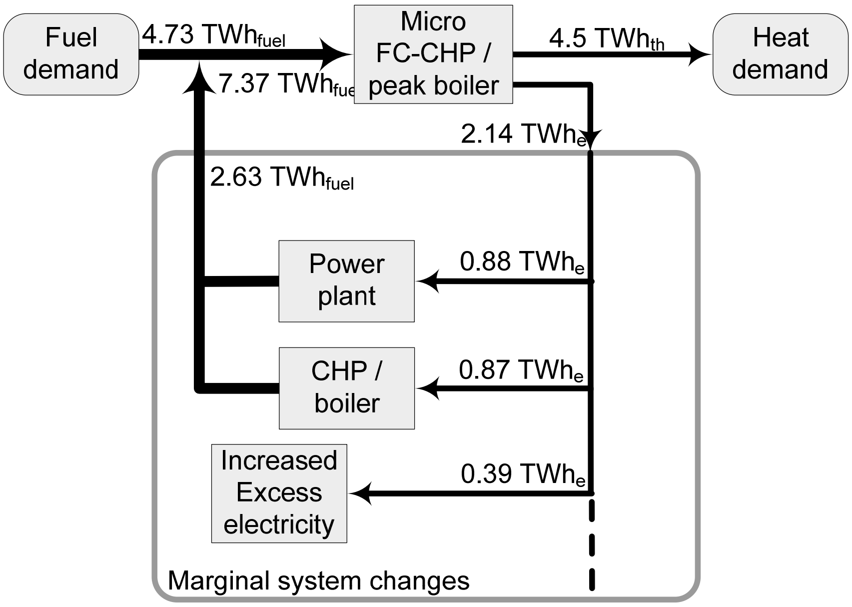

Fig. 19, Annual fuel consumption of supplying 300,000 houses with heat from individual micro-FC-CHP based on natural gas or biogas in the BAU 2030 CHP energy system.

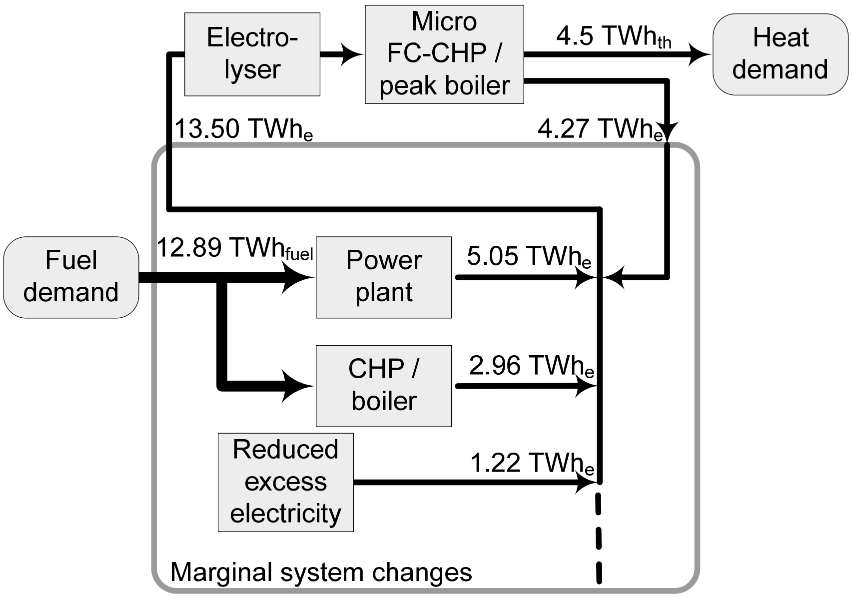

Fig. 20, Annual fuel consumption of supplying 300,000 houses with heat from individual micro-FC-CHP based on hydrogen in the BAU 2030 CHP energy system.

In Fig. 20, the energy conversion with hydrogen micro-FC-CHPs is illustrated. Electricity production is higher because of higher efficiencies. On the other hand, a substantial amount of electricity is needed for hydrogen production in electrolysers. The higher electricity demand decreases the excess production by 1.21 TWh. This decrease is a net reduction. In most situations, the electrolysers use the excess electricity produced. However, in other cases, the micro-FC-CHP will increase the excess electricity production. 8.02 TWh of electricity has to be supplied to the electrolysers from an increased production of CHP and power plants, leading to a fuel consumption of 12.89 TWh.

CHP plants play an important role in the analyses of the alternatives in the BAU 2030 CHP system. The alternatives are also analysed in a system without CHP, also with 50 per cent wind. In such a case, the fuel consumption generated by the production of electricity for the heat pumps becomes higher and the micro-FC-CHP systems improve, since more fuel is saved at power plants.

In Fig. 21 and Fig. 22, the resulting fuel consumption of the heating systems in the energy system with and without CHP plants is shown. In both cases, HPs have by far the lowest fuel consumption and the hydrogen micro-FC-CHP has the highest. The fuel consumption of natural gas-based micro-FC-CHP is 0.23 TWh higher than the natural gas boiler in the BAU 2030 CHP system and 0.5 TWh lower than in the BAU 2030 Non-CHP system. The oil savings achieved in the HP and electrolyser alternatives are related to an increased CHP production, which provides an extra electricity demand replacing oil-based boiler district heating production. In both energy systems, micro-FC-CHP provides a displacement of coal-based power plants. While this displacement results in savings in the micro-FC-CHP based on natural gas or biogas, it creates net increases in the system based on hydrogen, because of the heavy increase in electricity demand.

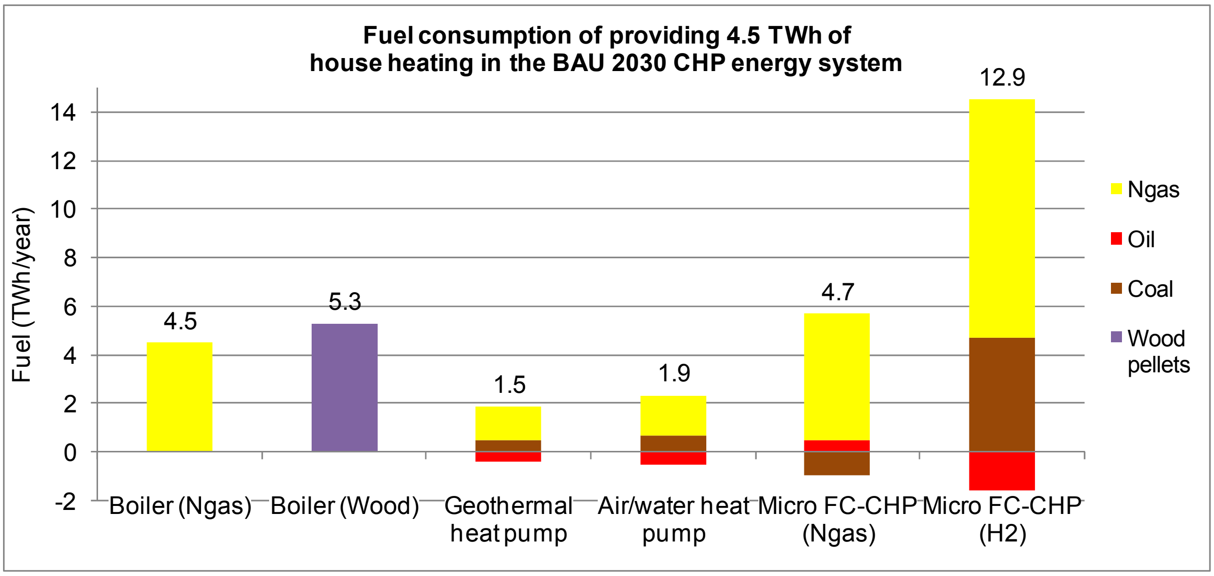

Fig. 21, Total annual fuel consumption of supplying 300,000 houses with heat in the CHP energy system.

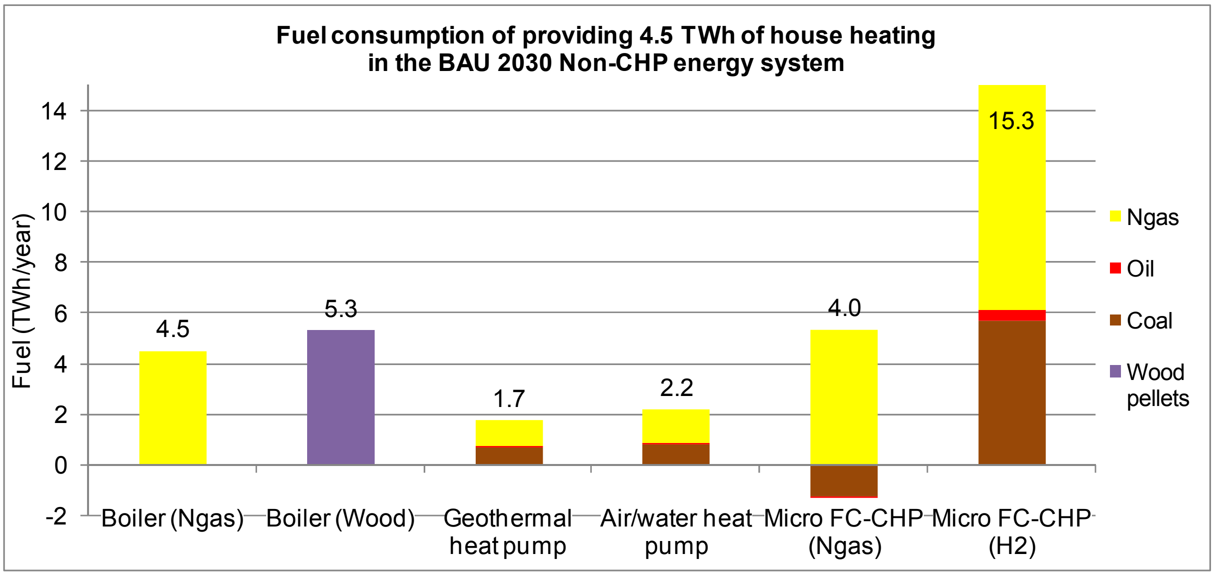

Fig. 22, Total annual fuel consumption of supplying 300,000 houses with heat in the Non-CHP energy system.

In Fig. 23, the CO_2 emissions resulting from the individual heating supply of 300,000 households are illustrated for the heating systems analysed. Except for the case of wood pellet boilers, the HP systems have the lowest CO_2 emissions, even though these systems involve an increase in the coal consumption, while the natural gas micro-FC-CHP system involves a decrease. The electrolyser systems have the highest emissions. The natural gas micro-FC-CHP in the Non-CHP energy system leads to lower emissions than those in the CHP system, because they replace more coal-based power plant production.

When comparing the technical systems, the HP has the lowest CO_2 emissions, since biogas and wood pellets could also be used in the fuel supply for the production of electricity for HPs. An example of CO_2 opportunity costs of the wood boiler is also illustrated in Fig. 23. Wood pellets used in boilers are CO_2 neutral. However, the 5.3 TWh of wood could also replace coal in large central CHP and power plants, which in all alternatives could reduce CO_2 emissions by approx. 1.8 Mton. If 5.3 TWh of wood pellets are used for supplying electricity for HP, this enables a CO_2 neutral heat supply of at least 850,000 households. Several other opportunity costs can be defined which are not listed here.

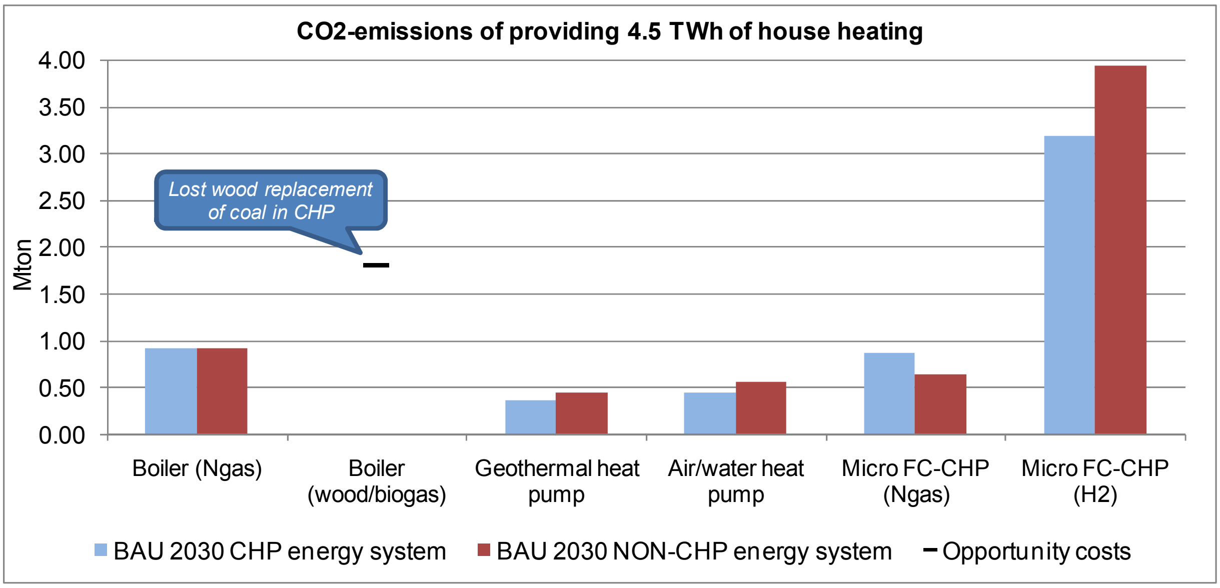

Fig. 23, CO_2 emissions of supplying 300,000 houses with heat in the two reference energy systems and including an example of opportunity costs.

If the aim is to reduce CO_2 emissions, the most fuel-efficient system should be implemented in individual households; and fuels, either fossil or biomass-based, should be used to replace other fuels in the system.

7.3 Socio-economic feasibility study and market exchange analyses

The total annual cost of supplying 300,000 individual houses with heat is illustrated in Fig. 24 in the BUA 2030 CHP system, on the basis of the energy system analyses presented above. The total annual costs include investments, fuel, fuel handling, O&M and CO_2 quotas. Base line fuel costs are used, i.e. the current level. The air/water HP system has the lowest costs, while the geothermal HP carries marginally lower costs than the gas boiler. The hydrogen micro-FC-CHP system is by far the least feasible. The geothermal HP has the lowest fuel costs and the largest investment costs, while the gas boiler carries high variable costs. In Fig. 24, the results are shown for the alternatives analysed in relation to the CHP system. The general picture is the same in the Non-CHP system.

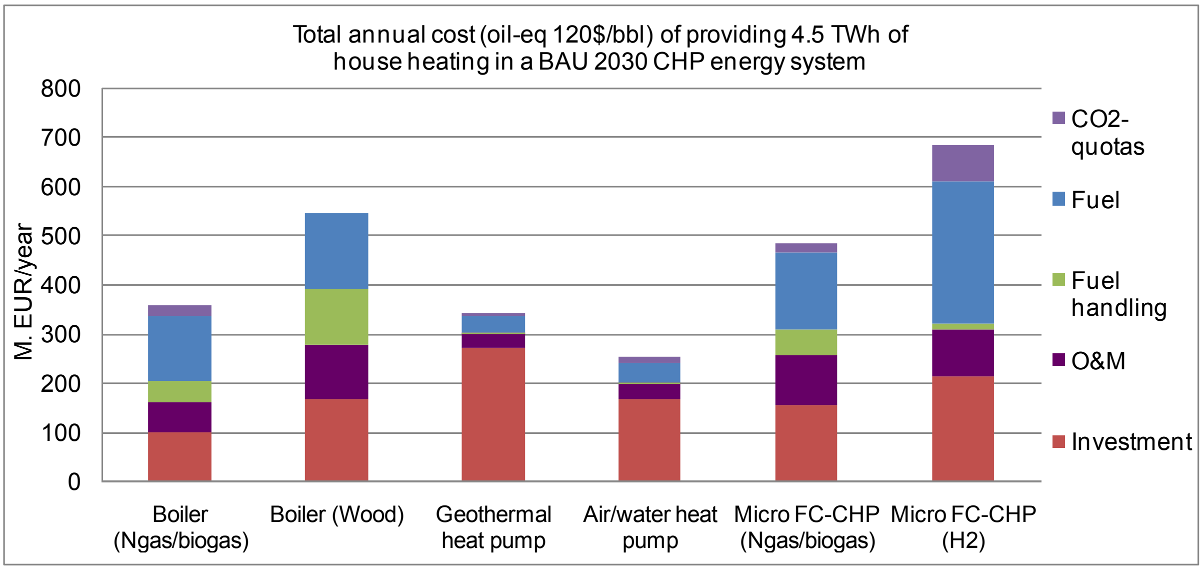

Fig. 24, Socio-economic costs of supplying 300,000 houses in the CHP energy system.

7.4 Electricity market exchange analysis

In this analysis, the components of the system aim at optimising electricity and heat production. The ranking of the systems, both in terms of fuel efficiency and socio-economics, does not change. This is mainly due to the fact that the regulation used in the technical energy system analyses of HP, micro-FC-CHP and electrolysers described above to a large extent reflects marginal electricity production costs. The main difference is the possibility of trading. Furthermore, due to the technological limitations of the individual household heating solutions, a market-economic optimisation of the electricity trade cannot change the operation of the units much in comparison with the results of the technical energy system analyses.

While the HP system increases import and decreases export, the micro-FC-CHP alternative has the opposite effect. The HP system enables the use of electricity at times with low prices, while the electricity sold from micro-FC-CHP does not improve the costs enough compared to the alternative heating systems analysed.

In the electrolyser micro-FC-CHP system, the resulting fuel consumption is considerably lower; import is increased significantly, and export is reduced. This hydrogen-based system uses significant amounts of wind power as well as imported electricity and produces electricity from micro-FC-CHPs. As a result, the net electricity costs increase the total costs to a level similar to that of wood pellet boilers.

The socio-economic feasibility of the alternatives in the market exchange analysis of the CHP energy system is illustrated in Fig. 25. The same analysis has been conducted in the Non-CHP system. Such analyses do not change the relation between the alternatives.

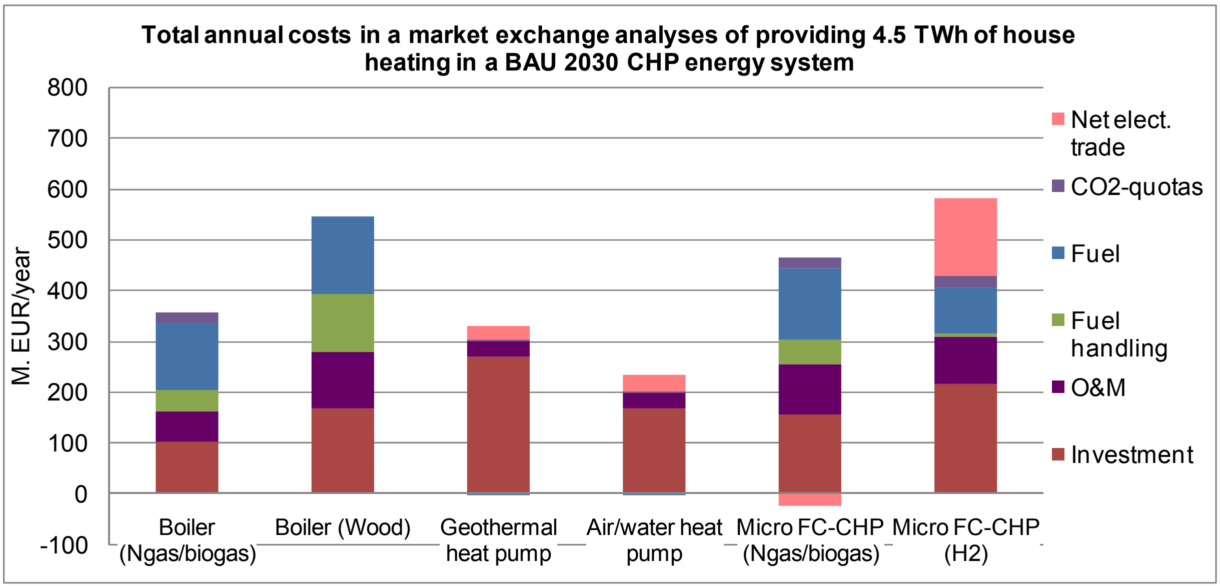

Fig. 25, Socio-economic costs of supplying 300,000 houses with heat in an electricity market exchange analysis of the CHP energy system.

7.5 Technical and economic sensitivity analysis

Lower fuel prices (equivalent to 62 $/bbl) make the gas boilers marginally more feasible than the geothermal HP. Although the cost of the electrolyser alternative is reduced, the system is still not feasible in comparison with the other alternatives. The use of higher fuel prices (equivalent to 178 $/bbl) does not change the socio-economic conclusion presented in Fig. 24.

The COP of both HP systems must be lowered by approx. one in order to make gas boilers more feasible. A gas boiler efficiency lower than 100 per cent would increase fuel costs. If heat storage time is increased from an average of one day to five days, the fuel efficiency of the HP systems is improved by 0.2 TWh and excess production is reduced by 0.1 TWh. The micro-FC-CHP systems only achieve minor improvements, too.

When using waste from electrolysers, fuel consumptions decrease by 2.5 to 3.0 TWh/year, as illustrated in Fig. 26. The fuel consumption is still higher than in all other systems analysed, as are the socio-economic costs.

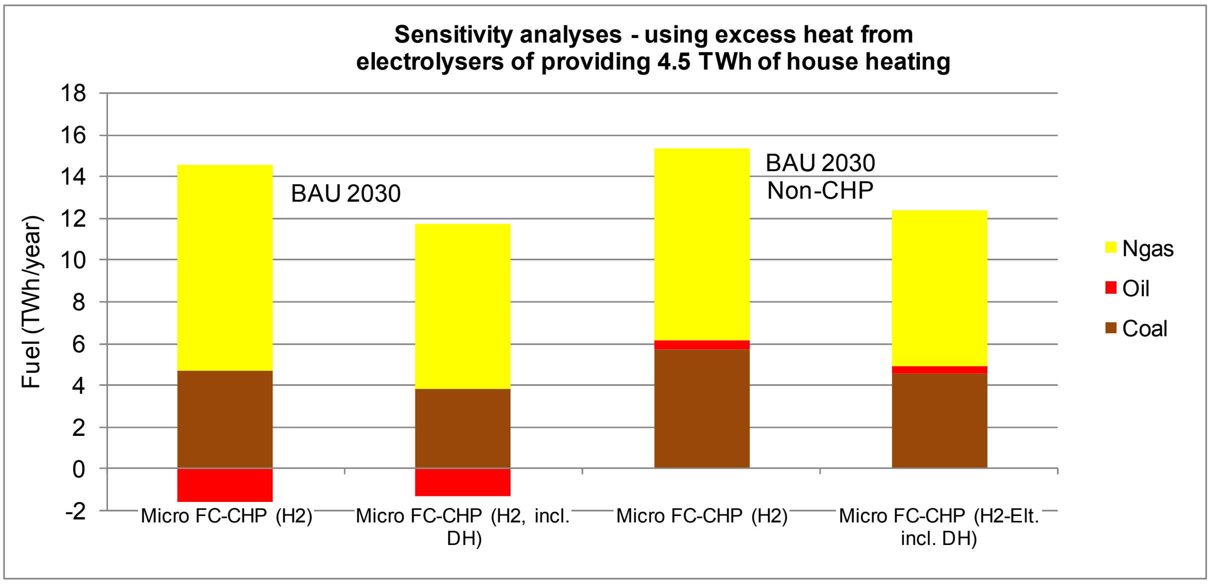

Fig. 26, Fuel consumption of supplying 300,000 houses with heat in the hydrogen micro-FC-CHP alternative. The columns show two different energy systems with and without the utilisation of waste heat from the electrolysers, but both with 50 per cent wind.

Assuming that the alternatives have an effect on the power plant installed in the long term, this can be included in the feasibility analyses. The result only changes in one case. If the geothermal HPs could provide the maximum potential increase of the power plant capacity, the gas boiler would be marginally more feasible. However, this is not likely to happen, since it would imply that all HPs installed were operated simultaneously; that the COP was very low, and that the heat storage was not used in these hours. Furthermore, it would require that all operation was placed at times with high electricity demand, instead of periods with high shares of wind and low electricity demand.

With a 50 per cent lower heat demand, a changed distribution and half of the capacities described above are used and the investment and O&M costs are assumed to be 10 per cent lower for all systems. The geothermal HP has the lowest fuel consumption, but the gas boiler can now compete with the geothermal HP.

In order to make a comparison of the alternatives without any fuel "free" excess electricity, the alternatives have been modelled in a system with no wind power. This makes the gas boiler marginally more feasible than the geothermal HP. If the extreme situation is considered that 1) the electricity consumption is "free", i.e. that e.g. wind turbines have been installed and paid for, even though the demand was not present, and 2) that the HP and electrolysers are able to adjust perfectly to the wind power production, the excess electricity production is reduced significantly more by the electrolysers than by the HP systems. However, the fact that the capacity of the HP systems is much lower than the capacity of the electrolysers has to be considered, as well as that the electricity demand varies. The geothermal HPs use 1.41 TWh; the air/water HPs use 1.73 TWh, while the electrolysers require

13.5 TWh. “Free” electricity from wind turbines would hardly be the case in practise; however, if this was the case, the technologies required in order to use this electricity would be competing and it would have to consider with which technology can displace the largest amount of fuel. In this situation, HPs constitute the most fuel-efficient technology.

The long-term goal of some producers of micro-FC-CHP is to reduce the investment costs to the price of the gas boiler; this would lower the cost to 430 M€/year. However, in order to obtain the same total socio-economic costs as gas boilers, the O&M costs of micro-FC-CHP would also have to be reduced to the level of those of gas boilers. This would lower the socio-economic costs of micro-FC-CHP to a level which, more or less, would balance with that of gas boilers in the Non-CHP energy system. In the CHP energy system, the ranking of the technologies does not change.

7.6 Evaluation of feasibility and a new public regulation scheme

Both HP systems have marginally lower socio-economic costs than gas boilers and lower costs than wood boilers and the two micro-FC-CHP alternatives. In the feasibility studies, the fossil fuel opportunity costs of using limited resources were not included, such as natural gas in boilers only producing heat, instead of in CHP plants producing both heat and power.

The geothermal HPs have the lowest CO_2 emissions. Here, it is assumed that the alternatives analysed have opportunity costs. A CO_2 emission could be allocated to the use of wood or biogas in boilers. As an example, wood boilers can reduce emissions by around 900 Mt $CO_{2,}$ when compared to natural gas boilers. If wood is used in CHP plants instead, it can replace approx. 1,800 Mt CO_2 from coal. By using wood in boilers instead of in CHP plants, a CO_2 opportunity cost of around 900 Mt tons CO_2 can be defined. The situation is similar for natural gas boilers, which could allocate CO_2 emission, including lost CO_2 opportunity costs, by not using natural gas in CHP plants; thus, also replacing coal CHP.

When compared with the micro-FC-CHP and boiler alternatives, the HP systems analysed for 300,000 households have the following advantages:

a) The lowest socio-economic costs; although in the case of geothermal HP, these costs are only marginally lower than those related to natural gas boilers.

b) For geothermal HP, 40 to 50 per cent CO_2 emissions compared to natural gas boilers, approx. 80 per cent of the emissions from natural gas micro-FC-CHP, and 10 per cent of the emissions from hydrogen micro-FC-CHP.

c) They have future possibilities for further reducing fuel use and CO_2 emissions by introducing larger heat storages. The socio-economic value of this has not been quantified here.

d) Compared with other fossil fuel alternatives, HPs reduce the dependence on fossil fuels by 30 to 40 per cent. The socio-economic value of this has not been quantified here.

e) Compared with other fossil fuel alternatives, HPs decrease the emissions to air from the conversion of fuels. The socio-economic value of externalities connected to environmental effects or health, etc., has not been quantified here.

The socio-economic evaluation of the results concludes that the HP systems have the largest advantages and that geothermal HPs provide the most fuel-efficient solution with the highest reduction in CO_2 emissions.

In Fig. 27, current Danish taxes and levies (2008) are included in the evaluation made in the market exchange analyses previously presented. Under present market and taxation conditions, the geothermal HP cannot compete with natural gas or wood boilers.

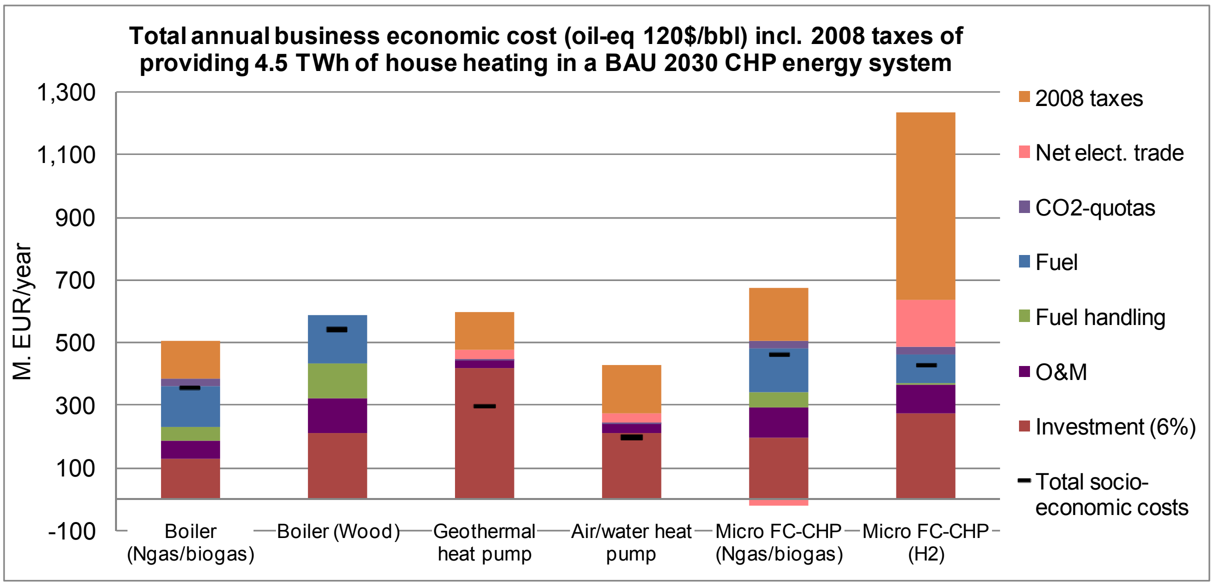

Fig. 27, Total annual business-economic costs of the CHP energy system supplying 300,000 houses with heat, including Danish 2008 fuel and electricity taxes. The socio-economic costs of the systems are also illustrated for comparison.

This inability to compete is due to these factors:

a) The geothermal HP carries the highest investment costs of the alternatives, which make this investment very risk sensitive.

b) The geothermal HP has a high investment share in pipes with a very long technical lifetime. This makes heavy demands on the financial system. It requires an incentive to make long-term investments and the opportunity to take out loans for 30 years for these heating systems, as is the case of investments in house improvements.

c) In the Danish tax system, the HP alternative has a higher taxation of "fuel used" than the other alternatives. Wood for boilers has no taxation.

When considering the current taxation, HPs are taxed much higher per unit of fuel used than natural gas boilers. In Table 4, the taxes per KWh for HP have been converted into taxes per MJ fuel. The large difference between the fuel taxes linked to boilers and those linked to the HP system is based on the fact that, for HP, the tax is levied on electricity, whereas the tax of natural gas boilers is levied on fuel. If, for instance, the HP system had been 20 per cent less efficient, the tax per MJ fuel would have been 20 per cent lower. As a consequence, no reward is given for the fuel efficiency of the HP system. Also, there is no tax on biomass fuels which are even less efficient than gas boilers.

	Geothermal HP	Air/water HP	Ngas boiler	Wood boiler
2008 taxation	0.086 €/KWh	0.086 €/KWh	0.0076 €/MJ	-
2008 taxation related to fuel efficiency	0.023 €/MJ	0.022 €/MJ	0.0076 €/MJ	-
New taxation rewarding fuel efficiency (first step)	0.028 €/KWh (0.0076 €/MJ)	0.028 €/KWh (0.0076 €/MJ)	0.0076 €/MJ	-

Table 4, Present taxation, taxation connected to fuel efficiency and suggestions for the first step of a new taxation for the HP and boiler heating systems.

The present tax system causes at least four problems. First, it promotes wood and natural gas boilers, even though HP systems carry lower socio-economic costs. Secondly, it results in socio-economic allocation losses, as there is a high taxation on renewable energy if it is wind power, but no taxation if it is, for instance, imported biomass. Moreover, taxation at the electricity use levels gives no direct incentive to reduce fuel use for electricity production. Thus, the tax system for individual house heating does not in general support the development of fuel-efficient energy systems, when these use electricity. The last problem mentioned here is the fact that there is no scarcity and CO_2 tax on the "inefficiency opportunity costs" created by using limited resources, like natural gas and wood in boilers, instead of more efficient CHP systems.

A new public regulation scheme should solve these problems and thus give incentives to install socio-economically feasible and fuel-efficient systems as well as systems with low CO_2 emissions. As the first step, a tax reform should have the same fuel tax level for HP as for natural gas boilers, as listed in Table 4. This step is called a minimum step, since it does not involve any extra payment to the HP system as a compensation for its ability to integrate more wind power or any tax on the opportunity cost of the fuel use and CO_2 emissions of using boilers instead of CHP. These two factors should be included in the second step.

In the first step, no tax on wood for wood boilers is included, and the tax on electricity used in HP is reduced to a third of the present level. In order to ensure that only fuel-efficient systems are installed, such low taxation on HP should only be given to licensed systems. A licensed system could have the following characteristics:

1. The HP system should supply 100 per cent of the heat and hot water demand not supplied by other renewable heating solutions.

2. A metering system should monitor the COP on an hourly basis and calculate the average COP monthly. The monthly tax is calculated as fuel taxation linked to the average fuel use of the month. This means that very efficient HP systems will have a lower taxation than less efficient HP systems.

3. If the HP owner purchases a share in a wind turbine, the production amount and profile of the share will be known. The owner of the HP should, therefore, pay zero tax in periods when the wind turbine share produces electricity. The remaining time, the taxation is calculated according to 2.

The business-economic results of implementing the first step of such a taxation system are illustrated in Fig. 28. The first step in such a reform promotes a better accordance between socio-economic costs and market costs, and more HP systems should be installed due to such a reform.

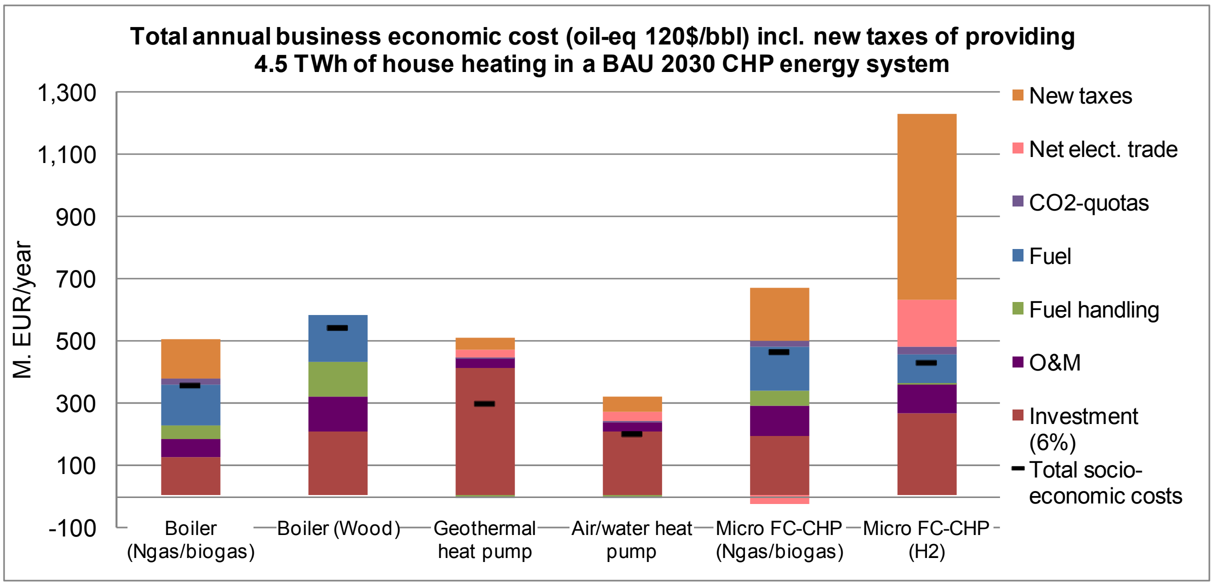

Fig. 28, Total business-economic costs of supplying 300,000 houses with heat, including the first step in a tax reform. The socio-economic costs of the system are also illustrated for comparison.

In the second step of a tax reform, the fuel use and CO_2 emission opportunity costs should be included in order to increase the tax on natural gas and biomass used in boilers. The first stage should be implemented as soon as possible and the second step should be decided in Parliament. It is suggested that the second step is implemented e.g. five years from now.

Hence, this could introduce a reward and an incentive to efficiently use natural gas and biomass in the tax system.

7.7 Conclusion

The geothermal and air/water HPs have the lowest fuel consumption and lowest CO_2 emissions of the individual heating systems analysed as well as the lowest costs, based on current fuel prices (equivalent to 120$/bbl). While the micro-FC-CHP based on natural gas reduces CO_2 emissions by displacing coal in the energy systems, it is not more fuel-efficient or cost-effective than natural gas boilers. The micro-FC-CHP can, however, almost compete with natural gas boilers, when the investments as well as the operation and maintenance costs of these are reduced to an expense similar to that of boilers. Wood pellet boilers are not feasible in comparison with the other technologies analysed.

In the energy systems analysed here, micro-FC-CHPs replace coal power plant with natural gas or biogas. However, in the long term, this may not be a good solution in renewable energy systems which depend on a gas supply. When evaluating the use of renewable resources, such as biogas or wood pellets, in terms of their reduction of CO_2 emissions, these should be used in the electricity and heat production at CHP plants to supply e.g. electricity for HP, rather than in household boilers or the micro-FC-CHP systems analysed here.

If fuel prices are lowered to half of the current level in the spring/summer 2008 or if the heat demand is reduced by 50 per cent, natural gas or biogas boilers carry lower socio-economic costs than geothermal HP. Fuel prices, however, are likely to continue to fluctuate, and thus, the HPs represent a solution with low variable costs in all fuel price scenarios.

In future renewable energy systems, the fuel efficiency of the technologies is important, as well as the efficient integration of intermittent resources, such as wind power. It is important to ensure that the HPs are operated with high COP and at times with low electricity demands and high wind power production. However, even if this is not the case, HPs are feasible systems.

In systems with high shares of wind power, electrolysers are often referred to as technologies required in order to integrate wind power and use “free” excess electricity. Although the electrolysers can decrease excess electricity production, more efficient alternatives can be found, such as the HPs analysed here. Electrolysers combined with micro-FC-CHP are not fuel or cost-efficient in energy systems with a 50 per cent wind power share, as analysed here.

At present, the public regulation in Denmark supports natural gas and wood boiler systems. This results in socio-economic losses, a high usage of fossil fuels and high CO_2 emissions. In order to eliminate these disadvantages of the present taxation system, energy taxation should be changed in order to levy the same fuel tax on HP and natural gas boilers for a given heat production. A system is proposed in which fuel efficiency is rewarded and opportunity costs are included.

8 Electrolysers and integration of large shares of intermittent renewable energy

In this chapter, electrolysers are compared to other technologies for the integration of intermittent renewable energy. The chapter is based on "Comparative analyses of seven technologies to facilitate the integration of fluctuating renewable energy" [3], included in appendix VI.

Seven technologies are analysed in terms of integrating fluctuating renewable energy sources, such as wind power production, into the electricity supply. Comprehensive hour-by-hour energy system analyses are conducted of a complete system meeting electricity, heat and transport demands, and including renewable energy sources, power plants, and CHP for district heating and transport technologies. In conclusion, the most fuel-efficient and least-cost technologies are identified through energy system and feasibility analyses. Large heat pumps prove to be especially promising as they efficiently reduce the production of excess electricity. Flexible electricity demand and electric boilers are low-cost solutions, but their improvement of fuel efficiency is rather limited. Battery electric vehicles constitute the most promising transport integration technology compared to hydrogen fuel cell vehicles. The costs of integrating intermittent renewable energy with electrolysers for hydrogen fuel cell vehicles, CHP and micro-FC-CHP are reduced significantly with more than 50 per cent intermittent renewable energy in the electricity supply.

8.1 Introduction

In Denmark, a current wind power capacity of 3,149 MW is installed at 5,200 different locations, which is able to supply approx. 20 per cent of the electricity demand [66;67]. Another 2,200 MW is small-scale CHP plants or industrial production at more than 700 different locations, of which more than 650 are smaller than 10 MW [67]. In addition, the energy supply system also includes 17 central power plants and CHP plants with a total capacity of 7,968 MW [65]. This current energy supply status is the result of a transition from a classical centralised system with very few and large power plants to a distributed system, which has taken place over the last 20 years [68]. The development towards an even more distributed generation system is expected to continue. In 2012, the total wind power installed is planned to be 4,124 MW, as offshore wind power is planned to increase from 423 MW in 2008 to 1,223 MW in 2012 and onshore wind power is planned to increase by 175 MW in the same period. The development is illustrated in Fig. 29.

Already now, the integration of wind turbines and CHP poses challenges to the Danish electricity supply in terms of excess electricity production during a few hours per day. Excess electricity production combined with bottlenecks in the transmission lines to the neighbouring countries during certain hours have substantial influence on the market prices. The Danish case can reveal problems and solutions which may be faced by other energy systems in the coming years, as the European initiatives to promote CHP and renewable energy are implemented.

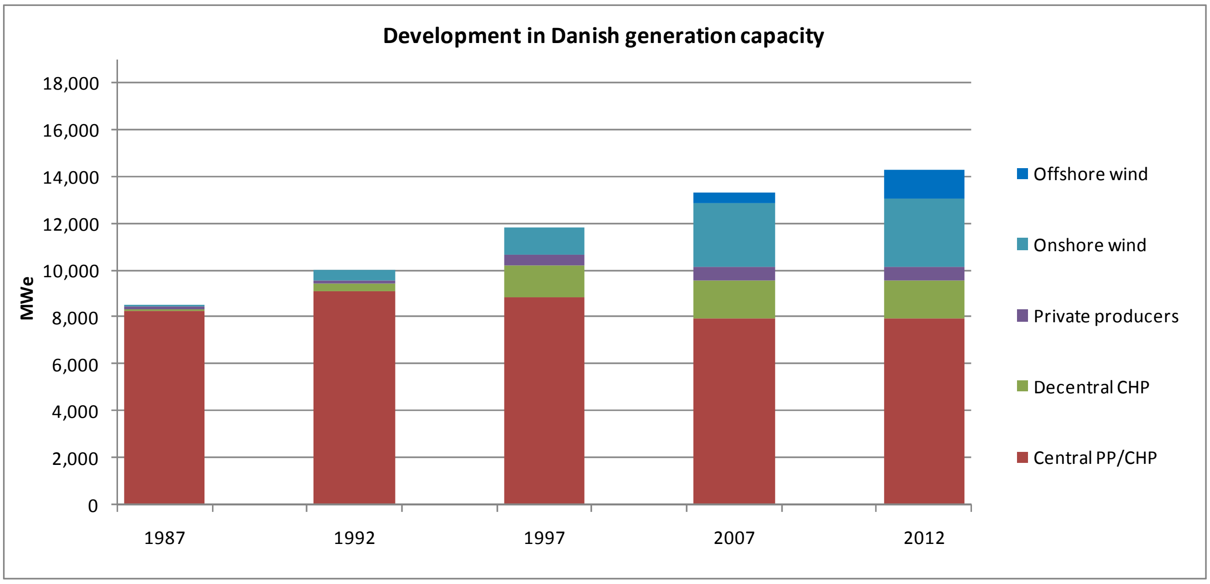

Fig. 29, Capacities of technologies in the Danish energy system from 1987 until 2007 and in the anticipated scenario in 2012.

The seven integration technologies analysed here are electric boilers (EB), heat pumps (HPs), electrolysers with local CHP (ELT/CHP), electrolysers with micro FC-CHP (ELT/micro), hydrogen fuel cell vehicles (HFCV), battery electric vehicles (BEV), and flexible electricity demand (5%FLEX). The different integration technologies are analysed and compared in terms of their ability to integrate intermittent renewable resources (RES) and their fuel efficiency. The analyses are conducted in the BAU 2030 energy system, in which the shares of RES vary from 0 to 100 per cent of the electricity demand. In the analyses, RES is represented by wind power. Subsequently, the costs of the integration technologies are compared in terms of their ability to improve fuel efficiency.

The technical energy system analyses are conducted for a period of one year, taking into consideration demands and RES during all hours. The ability of the reference energy system to integrate fluctuating renewable energy is defined by applying two different regulation strategies: 1) the capability of the system to avoid excess electricity production, and 2) the ability of the system to reduce fuel consumption and thus improve fuel efficiency. Hour-by-hour the electricity production from RES is prioritised as well as the production of electricity at CHP plants, industrial CHP or micro-FC-CHP. The remaining electricity demand is met by power plants and the remaining district heating demand is met by boilers. By utilising extra capacity at the CHP plants combined with heat storages, the production at the condensation plants is minimised and replaced by CHP production. At times when the demand is lower than the production from CHP and renewable energy sources, the electricity production is minimised mainly by use of heat pumps at CHP plants, or by balancing production and demand by introducing electrolysers or other available flexible technologies, such as the ones analysed here.

The system analysed constitutes an *open energy system* in which the technologies are utilised with the aim of supplying demands. The measures introduced to secure the balance between the supply from CHP and RES and the electricity demand described may NOT be sufficient to reduce electricity production, and thus forced electricity export will be the result. This type of technical energy system analyses enables the investigation of the flexibility of the seven integration technologies. The analyses focus directly on the effect on excess electricity production, i.e. regulation strategy 1) of the two types of energy system analyses. Such analysis is presented by showing the ability of the reference energy system to integrate fluctuating RES. In Fig. 30, the x axis illustrates the wind turbine production between 0 and 50 TWh, equal to a variation from 0 to 100 per cent of the demand (49 TWh), in excess electricity diagrams in an *open energy system* [69]. The y axis illustrates the excess electricity production in TWh. The less ascending curve illustrates a better integration of RES. In Fig. 30, a situation without CHP plants regulating according to the electricity demand is illustrated. The purpose of this is to show that the first step which must be taken is to introduce CHP and boiler regulation with heat storages. This can significantly reduce excess electricity production with low investments in thermal storages and also reduce the production at power plants by utilising the extra capacity of the CHP plants. In Fig. 30, a total of nine energy system analyses have been conducted hour-by-hour for a year for both types of CHP regulations. For each of the seven integration technologies, these nine energy system analyses are performed.

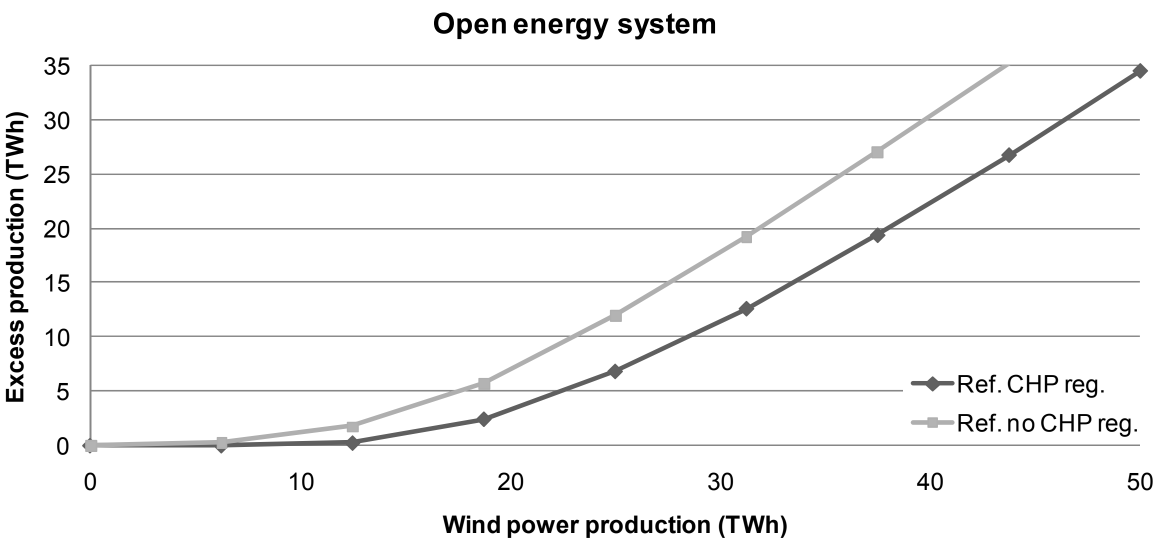

Fig. 30, Wind power production and excess electricity production in an open energy system analysis of the reference energy system with and without the regulation of CHP plants.

The second of the two types of energy system analyses, i.e. regulation strategy 2), builds on the first analyses. However, here any excess electricity production is converted or avoided; first, by replacing CHP production by boilers in the district heating systems and, secondly, by stopping wind turbines. The import/export is of course zero, as it is a closed system. The entire primary energy supply (PES) excl. the RES of the system is presented.

The result of such analyses represents a *closed energy system* and is illustrated in Fig. 31.The x axis shows the wind production and the y axis illustrates the PES excl. the RES of the entire energy system. The less PES excl. the RES, the more flexible and fuel-efficient is the energy system. In Fig. 31, the same two analysis systems with and without heat storage are presented. Again, it can be seen that the first step is to introduce heat storage in order to increase the production potential of CHP plants at times with a low share of RES, instead of using boilers to supply heat at times with a high RES share. The heat storage also increases the opportunity to replace the production at power plants with CHP if the capacity is available. Again, a total of nine energy system analyses have been conducted hour-by-hour for a year for both types of CHP regulation. These nine energy system analyses have been performed for each of the seven integration technologies analysed in this chapter. The advantage of presenting PES excl. RES instead of PES incl. RES is the fact that such results can reveal the ability of a technology to utilise RES, such as wind power, to efficiently replace fuels in power plants, CHP, boilers and internal combustion engines.

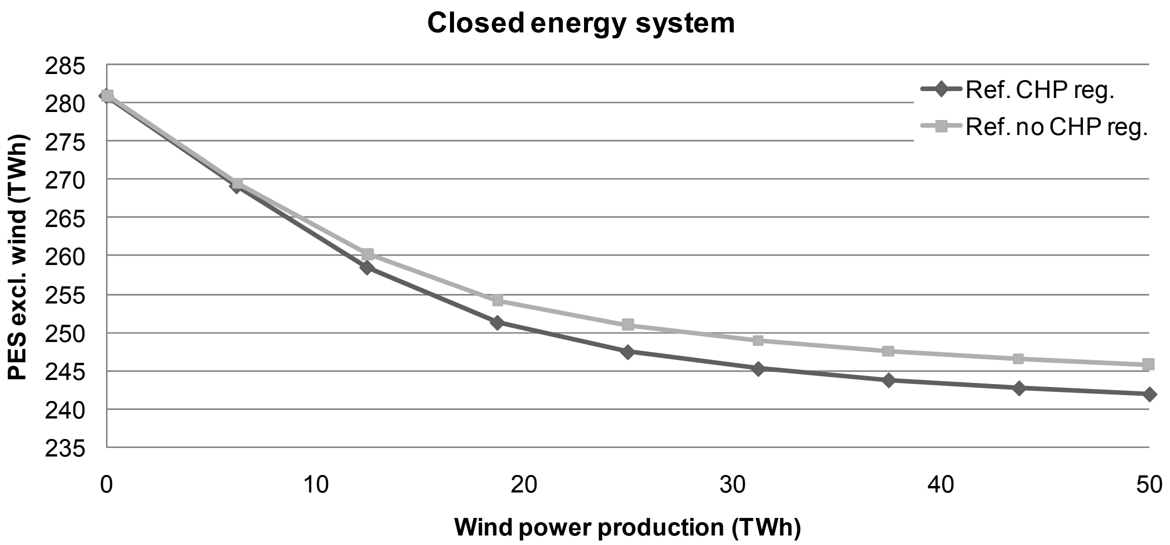

Fig. 31, Primary energy supply (PES) in a closed energy system analysis of the reference energy system with and without the regulation of CHP plants.

8.2 Integration technologies analysed

In the energy system analyses, the end demands for electricity, heat and transport are the same in all cases, but the technologies introduced provide the energy system with more flexibility. The technologies are explored in the alternatives described below. The principle relations between the different components in the seven alternatives are shown in Fig. 32 to Fig. 35.

Alternative 1 – Electric boilers (EB): EBs are used in CHP units after the production of the units has been reduced by use of fuel boilers at times with excess electricity production. EBs can replace fuel boilers in order to further reduce excess electricity production and fuel consumption.

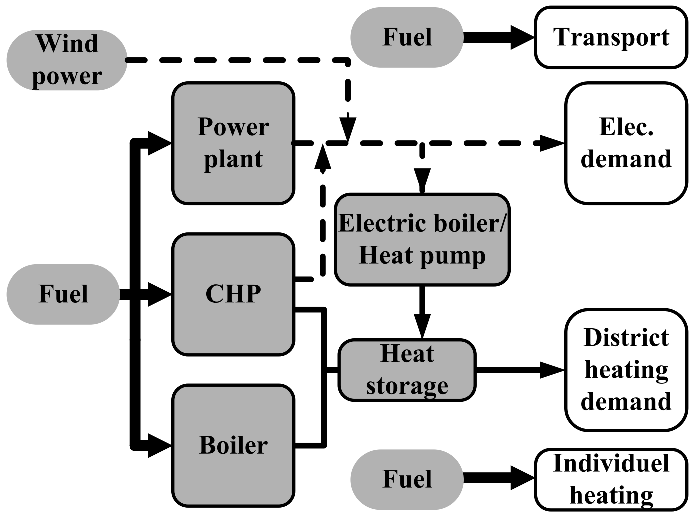

Fig. 32, The electric boiler and the heat pump energy systems.

Alternative 2 - Heat pumps (HP): Large HPs are used in CHP units with the purpose of replacing heat production from CHP and fuel boilers. Consequently, the excess electricity produced at times with high productions of wind power and heat-dependent CHP is decreased. The production of CHP units is decreased and, at the same time, the electricity consumption of the HP can utilise wind power production. Individual heat pumps are analysed in a sensitivity analysis.

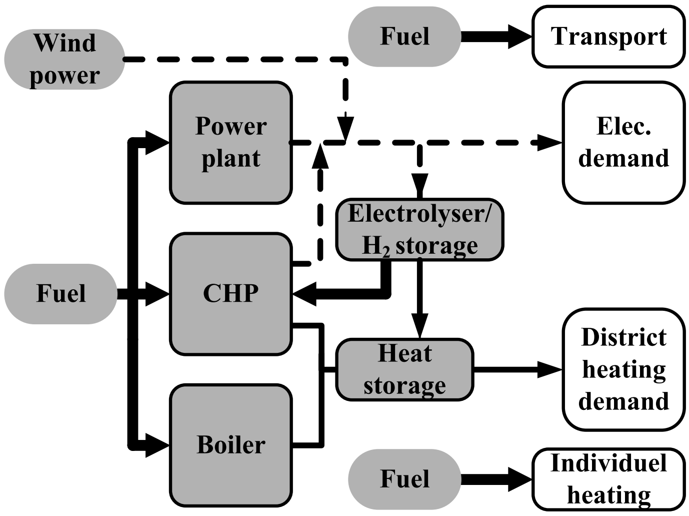

Fig. 33, The electrolyser CHP energy system.

Alternative 3 – Electrolysers/CHP (ELT/CHP): ELTs produce hydrogen for the CHP plants at times with excess electricity production. Waste heat from the process is utilised in the district heating system. The hydrogen storage is used in order to enable electricity consumption at times with a high wind power production. No fixed amount of hydrogen is required; thus, the electrolysers only produce at times with excess electricity production.

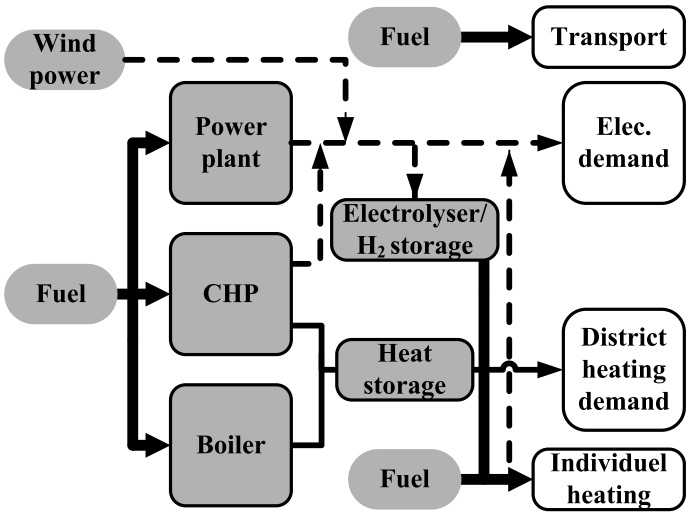

Fig. 34, The electrolyser micro FC-CHP energy system.

Alternative 4 – Electrolysers/micro FC-CHP (ELT/micro): Here, natural gas boilers in individual houses are replaced with micro-hydrogen fuel cell CHP units. Like in alternative 3, ELTs produce hydrogen at times with high wind power production, utilising the hydrogen storage. The micro FC-CHP needs a fixed amount of hydrogen, which means that the electrolysers in some situations may produce when there is no or little wind production. The ELT units are decentralised and waste heat is utilised to replace natural gas boilers. The flexibility of the electricity production of the micro-FC-CHP units is limited by the heat demand and heat storage of one average day. The micro-FC-CHP units are able to meet half of the peak heat demand. The rest of the heat demand, i.e. approx. 5 per cent of the total annual demand, must be met by boilers. Whenever possible, the micro-FC-CHP units produce at times when power plants would otherwise produce electricity, in order to increase the fuel efficiency of the system.

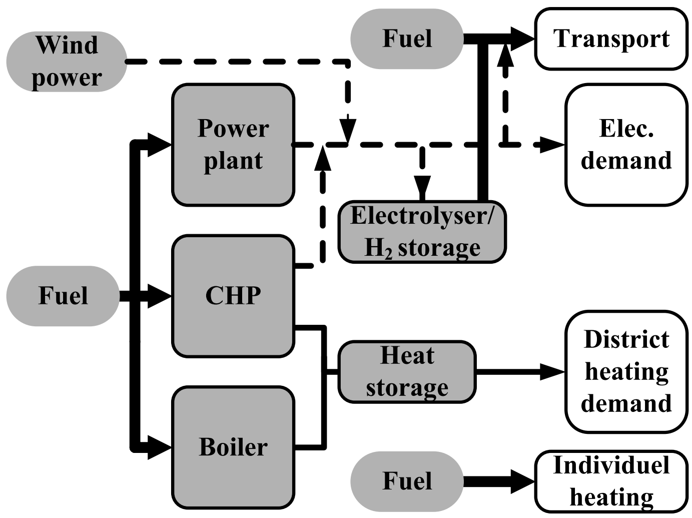

Fig. 35, The hydrogen fuel cell vehicle and the battery electric vehicle energy systems.

Alternative 5 – Hydrogen fuel cell vehicles (HFCV): Here, HFCV have replaced petrol-driven internal combustion engine vehicles (ICE). The hydrogen demand for transport is distributed according to driving habits and the number of parked vehicles at a certain time. As in the case of alternative 4, the hydrogen demand is fixed; the hydrogen storage is utilised in order to place electricity consumption at times with wind production, and waste heat is utilised to replace natural gas boilers.

Alternative 6 – Battery electric vehicles (BEV): V2G BEV have replaced ICE and the demand is distributed according to driving habits and the same amount of parked vehicles as for HFCV. Like in the hydrogen alternatives, the BEV are charged at times with high wind power production whenever possible. Similar to the alternatives in which hydrogen is used in CHPs, the BEV are capable of discharging the batteries at times when the electricity demand is otherwise met by power plants. A dump charge vehicle has been included in a sensitivity analysis, only taking into account the transport demand with no discharge available.

Alternative 7 – Flexible electricity demand (5%FLEX): 5 per cent of the electricity demand is flexible within one day and can be moved according to the wind power and CHP productions in order to achieve better fuel efficiency and decrease the electricity produced by power plants.

The seven integration technologies are analysed with comparable capacities. For technologies used in combination with CHP, an electricity demand of 450 MW has been added, i.e. alternatives 1-4. For the transport technologies of alternatives 5 and 6, the 450 MW effect has been used for identifying the number of vehicles. The flexible demand alternative is comparable to the other alternatives in the sense that the amount of flexible electricity corresponds to a decrease in the peak electricity demand by 450 MW. The capacities, efficiencies and costs of the technologies are presented in Table 5. Further details are available in Mathiesen and Lund (2008) [3].

Alternatives	Capacities		Efficiencies % el.	th.	fuel	Costs M€		Lifetime (years)	O&M costs/y	Total cost M€/y	Ref.
1 EB	450	MWe	-	100	-	0.13	/MWe	20	0%	4.0	-
2 HP	450	MWe	-	350	-	2.52	/MWe	20	0.2%	78.1	[49]
3 ELT/CHP											
Electrol.	450	MWe	95	10	80	0.25	/MWe	20	2%	9.9	[49]
H2 storage	300	GWh	-	-	95	0.06	/GWh	25	0%	1.0	[49]
4 ELT/micro											
Electrol.	450	MWe	95	10	80	0.25	/MWe	20	2%	9.9	[49]
H2 storage	300	GWh	-	-	95	0.06	/GWh	25	0%	1.0	[49]
Micro-CHP	61	MWe	45	45	-	1.87	/MWe	20	6%	14.5	[12]
5 HFCV											
Electrol.	97	MWe	95	10	80	0.25	/MWe	20	2%	2.1	[49]
H2 storage	77	GWh	-	-	95	0.06	/GWh	25	0%	0.3	[49]
Vehicles	450	MWe	-	-	45	0.53	/MWe	15	0%	19.9	[12]
6 BEV	450	MWe	95	-	90	1.20	/MWe	15	0%	45.2	[12]
7 5%FLEX	450 2.45	MWe TWh	-	-	-	20	/TWh	20	1%	3.8	[12]

Table 5, Capacities, efficiencies and costs of alternatives.

8.3 Effects of integration technologies with 50 per cent annual wind power production

The results of the energy system analyses of the alternatives are presented in diagrams depicting the marginal changes in relation to the reference energy system presented in Fig. 30 and Fig. 31. A negative marginal effect in the diagrams indicates that the alternative is more flexible and/or more efficient than the reference energy system.

The results of the energy system analyses of the integration technologies with 25 TWh RES (wind power production corresponding to 50 per cent of the electricity demand) are presented in Fig. 36. The *ELT/CHP* has the best abilities to utilise excess electricity production. It can integrate almost 2 TWh more wind power than the reference. The *HP*, *EB* and *BEV* can each provide more than 1 TWh reductions in excess production. The *ELT/micro* contributes with a lower improvement. The *HFCV* and the *5%FLEX* have almost no effect on reducing excess electricity production compared to the ability of the reference.

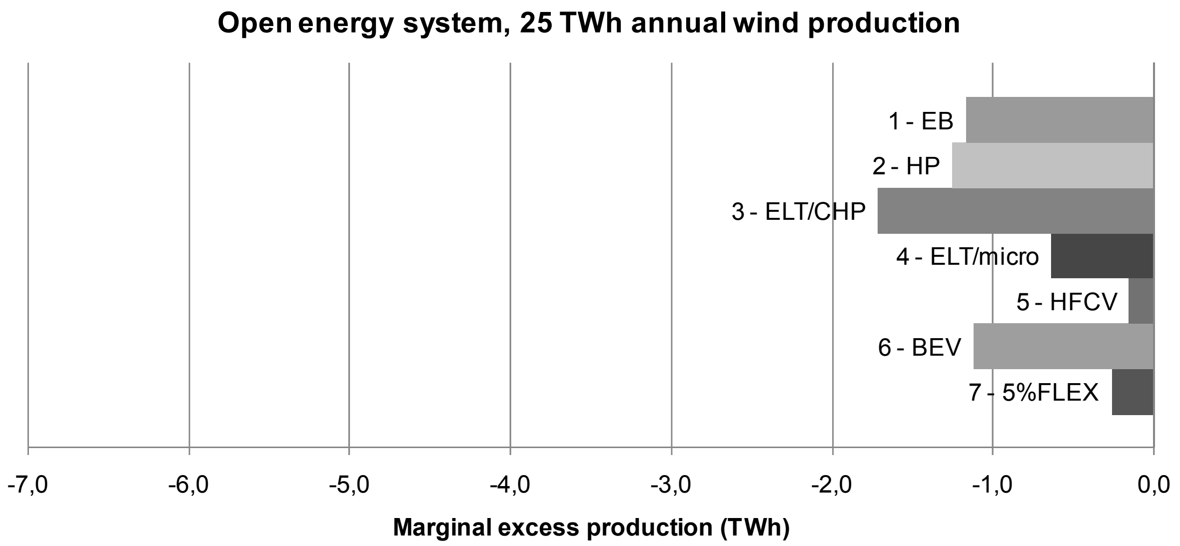

Fig. 36, The marginal excess electricity production at 25 TWh wind power production in an open energy system in relation to the reference with 25 TWh wind power.

In Fig. 37, the effects of using the different integration technologies are illustrated in terms of marginal changes in fuel consumption. The *HP* is by far the most fuel-efficient technology. In comparison with the reference, at an annual wind power production of 25 TWh, *HP* can reduce fuel consumption by 7 TWh; thereby reducing total fuel consumption excl. RES from 248 TWh to 241 TWh. *BEV* can reduce fuel consumption by approx. 1.5 TWh. *ELT/CHP*, *ELT/micro* and *HFCV* result in the lowest fuel savings.

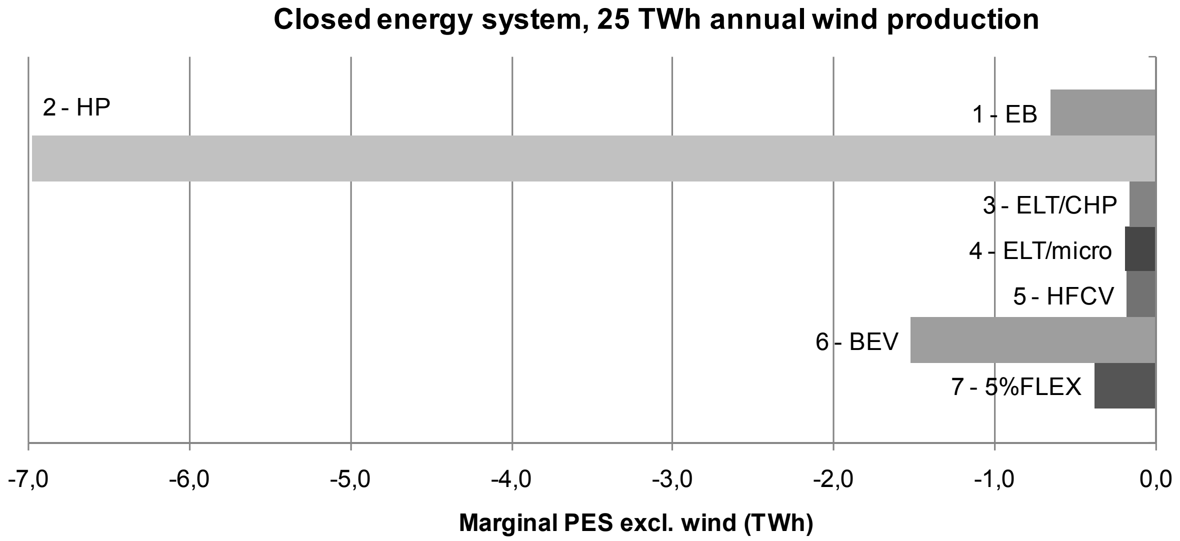

Fig. 37, The marginal fuel savings at 25 TWh wind power in a closed energy system in relation to the reference with 25 TWh wind power.

8.4 Effects of integration technologies with varying annual wind power production

The marginal effects with an annual wind power production varying from 0 to 50 TWh are presented in Fig. 38 and Fig. 39. Again, negative effects in the diagrams represent better wind integration abilities than those of the reference energy system.

In Fig. 38, it is evident that the seven alternatives have different abilities to integrate wind power although comparable capacities are introduced. *ELT/CHP* has the best ability to integrate excess electricity production, while *HP*, *EB* and *BEV* have similar effects until a share of 30 TWh of wind power production is reached. *ELT/micro*, *HFCV* and *5%FLEX* have almost no effect on reducing excess electricity production.

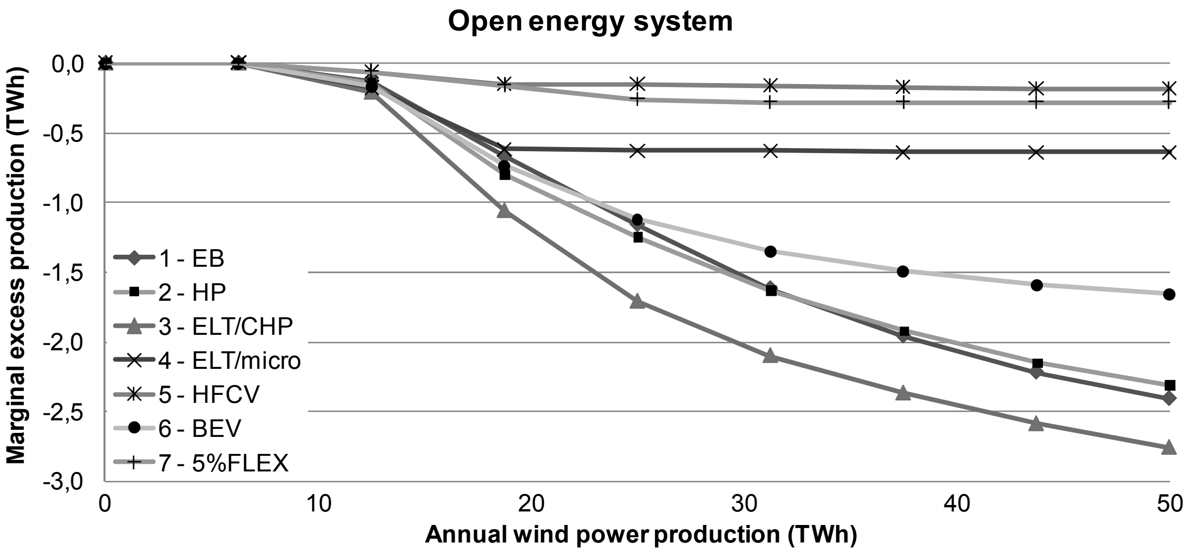

Fig. 38, Marginal excess electricity production at varying annual wind power productions in an open energy system seen in relation to the reference with varying annual wind power.

In Fig. 39, the results are presented as marginal effects on PES excl. RES in relation to the reference energy system. *HFCV*, *ELT/micro*, *ELT/CHP* and *5%FLEX* add almost no fuel efficiency to the energy system, no matter how much wind power is introduced. With less than 6 and 12 TWh of wind power production, respectively, *HFCV* and *ELT/micro* increase PES excl. RES. *HP* and *BEV* improve the fuel efficiency of the energy system in combination with any amount of wind power.

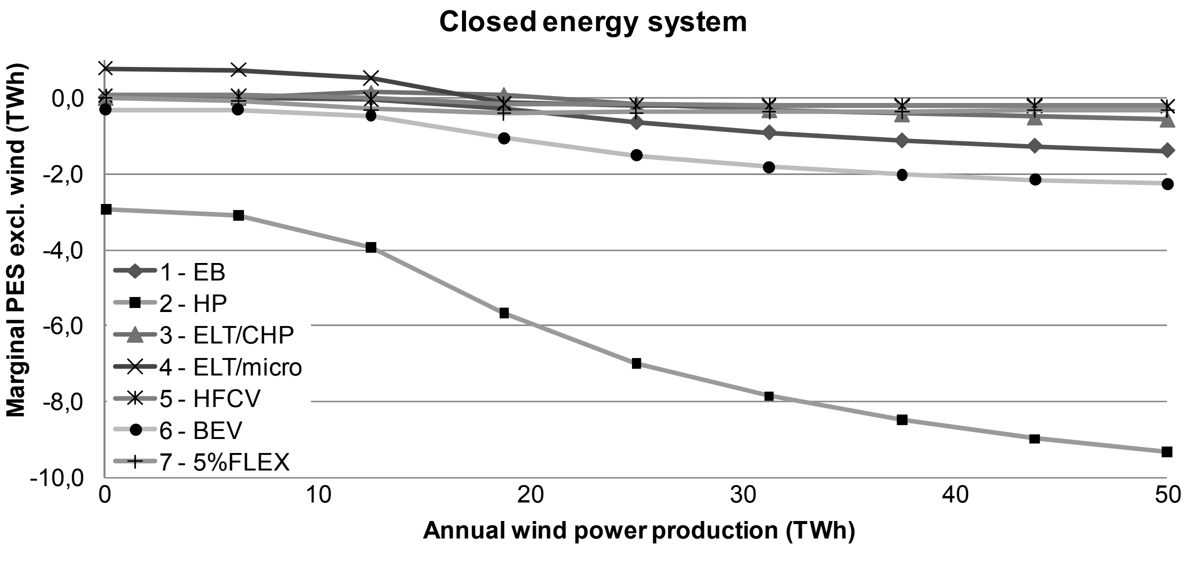

Fig. 39, Marginal fuel savings with varying annual wind power production in a closed energy system seen in relation to the reference with varying wind power.

In the energy system analyses, *HP* proves to have the best performance. It can reduce excess electricity as well as fuel consumption in all wind power production scenarios. Like *HP*, *EB* is rather good at integrating excess wind; however, the fuel savings achieved are rather low. If not implemented correctly, *EB* may even result in increased fuel consumption. For transport, *BEV* is the best alternative both in terms of wind power integration and fuel efficiency. *ELT/micro* and *HFCV* have a fixed annual hydrogen demand. This significantly limits the possibility of these systems of producing hydrogen at times with high excess electricity production. Furthermore, it results in low fuel savings due to the fact that hydrogen must sometimes be produced at power plants. For *ELT/micro*, an additional problem is the fact that the production of electricity displaces CHP production elsewhere in the system; thus, district heating has to be produced by fuel boilers.

ELT/CHP has higher fuel savings than the other electrolyser alternatives, because it is able to place production at times with excess electricity and is not dependent on a fixed demand for hydrogen. Although *ELT/CHP* has good abilities to reduce excess production, the fuel savings achieved are rather limited compared to other alternatives analysed. *5%FLEX* gives both low reductions in excess production and fuel savings. This is connected to the typical distribution of electricity demand and the capacity of the flexible demand; hence, there is a limit to how much can be moved from peak demand to low demand hours.

8.5 Least-cost integration technologies

The analyses have revealed different potentials of integration technologies with comparable capacities. The costs of the technologies, however, vary significantly. In Table 5, these costs are presented. Here, the seven alternatives are compared in terms of total annual costs and their ability to increase the fuel efficiency of the energy system over a year.

In Fig. 40, the costs in M€/TWh fuel saved are illustrated at 25 TWh of wind power production, corresponding to 50 per cent of the annual electricity consumption in the reference energy system. *EB*, *5%FLEX*, *HP* and *BEV* have significantly lower fuel saving costs than the other alternatives at 25 TWh of wind power production. The *HFCV* alternative has the highest costs per TWh of fuel saved.

In Fig. 41, the total annual costs of fuel savings from 0 to 50 TWh of wind power production are illustrated. It is evident that *EB*, *HP*, *5%FLEX* and *BEV* have similar low fuel saving costs when wind production is above 20 TWh. However, *HP* has rather low fuel saving costs even with no wind production. *ELT/micro* has rather high costs no matter how much wind power is introduced into the energy system. The fuel saving costs of *HFCV* are rather constant at approx. 50 M€/TWh. However, these fuel savings can only be achieved with an annual wind power production above approx. 20 TWh. When wind power production exceeds 25 TWh, the performance of *ELT/CHP* improves, as the wind power share increases further.

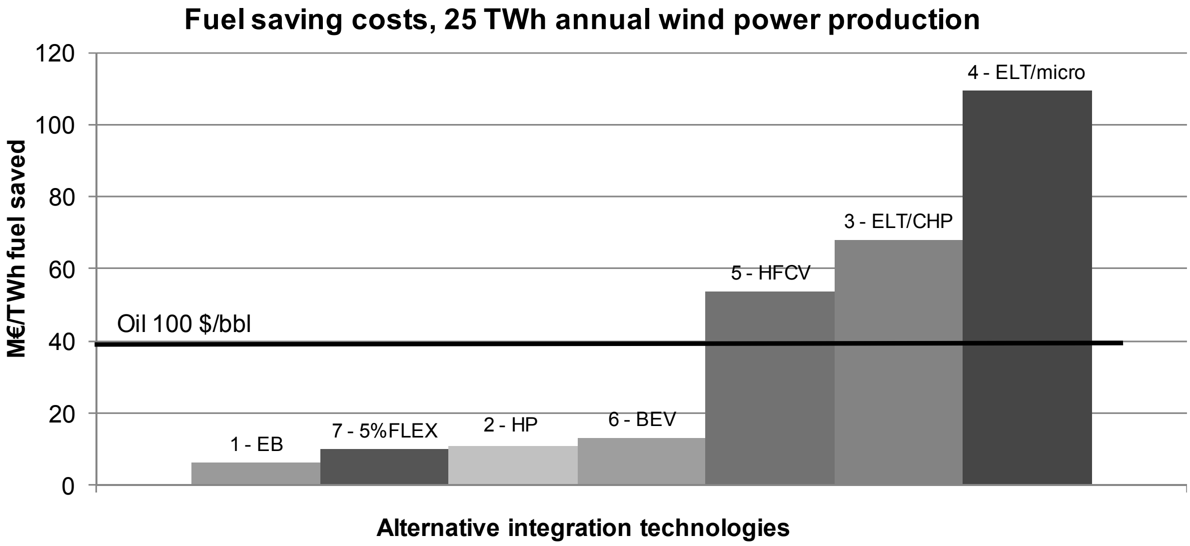

Fig. 40, The total annual costs of saving 1 TWh of fuel at 25 TWh of wind power production for the seven alternatives.

EB, *HP*, *5%FLEX* and *BEV* may all have rather low costs per TWh of fuel saved, but their effects on fuel savings differ to a great extent. Although *HP* and *BEV* have the highest total annual investment costs, they also provide the largest fuel savings in all scenarios. Therefore, they should be the first options to implement if a fuel-efficient and cost-effective integration of wind power is the main objective.

The investments in integration technologies can be compared to fuel costs. In May 2008, oil prices were more than 120 $/bbl and coal prices were more than 150 $/ton. For oil, 100 $/bbl is equivalent to 39 M€/TWh, which is included for comparison in Fig. 40 and Fig. 41. *ELT/CHP* and *HFCV* have larger fuel saving costs than 39 M€/TWh in all the scenarios analysed.

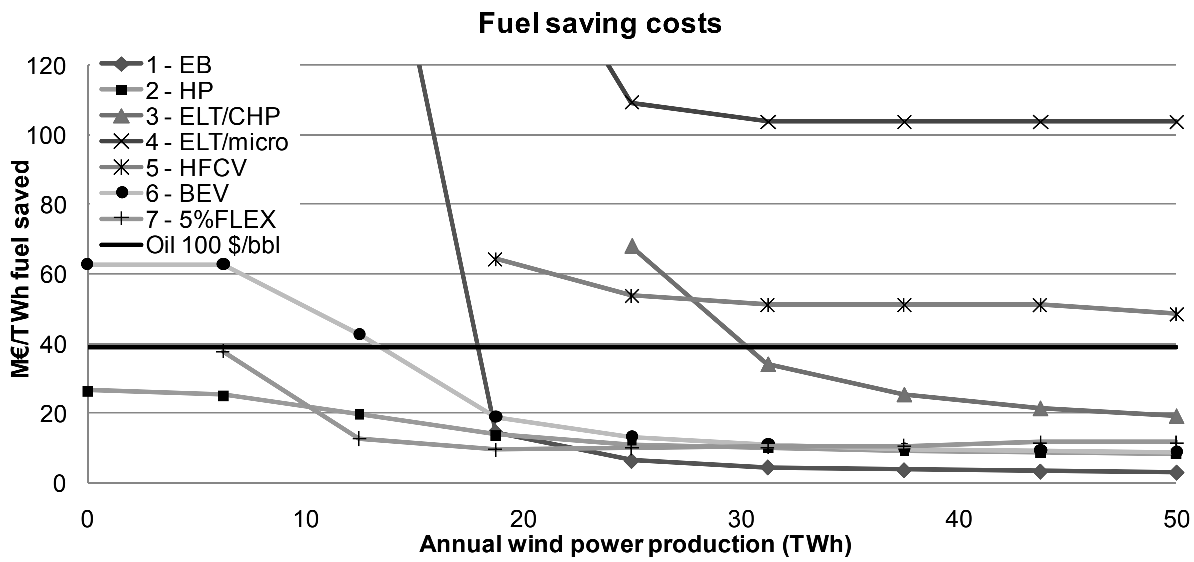

Fig. 41, The total annual costs of saving 1 TWh of fuel from 0 to 50 TWh of wind power production. Situations with increased fuel consumption or costs above 120 M€/TWh are not included.

8.6 Sensitivity analyses

In order to test the reliability of the results, a series of sensitivity analyses have been performed. In a sensitivity analysis for *EB*, another regulation strategy has been analysed using *EB* before replacing the CHP with boilers. The regulation strategy used in the analysis above is defined as the best of the two regulation strategies.

For *HP*, the COP used may prove rather conservative and the share of delivered heat at any given hour is limited to 50 per cent, due to limitations of the heat source. With a 20 per cent share of heat delivered from HP, fuel savings are 0.3-0.5 TWh lower and the effect on excess electricity production remains in the same range. If the COP is 2.5, fuel savings are reduced by between 1.5 and 3 TWh. *HP* fuel saving costs start at 55 M€/TWh with this COP and with more than 10 TWh of wind power production, it is lower than the oil price. An analysis of individual heat pumps applying a COP of 3 and involving 450 MWe reveals that such a solution reduces excess production and fuel savings to approx. 60 per cent of those of large heat pumps. Assuming that these pumps cost the double of the large heat pumps listed here, the cost saving curve is similar to the one for *HP* in Fig. 41, starting at 50 M€/TWh and ending at 27 M€/TWh. Hence, such a solution also has rather low costs.

Half of the fuel savings of *ELT/micro* and *ELT/CHP* result from the production of heat by electrolysers. If the heat is not utilised, the fuel saving costs of these alternatives would double. For *HFCV*, almost all fuel savings stem from the replacement of regular vehicles. Thus, the heat production of electrolysers is not significant for the results of this alternative. The same picture can be seen if the electrolyser efficiency is lowered to 70 per cent. Again, half of the efficiency gains are lost in *ELT/CHP* and *ELT/micro*, while *HFCV* is less affected, because the efficiency gains stem from the replacement of regular vehicles. For

ELT/CHP, no fixed amount of hydrogen is required and the 450 MWe electrolysers are given by the premises of the comparative analysis, i.e. comparing 450 MWe integration technologies. This enables *ELT/CHP* to perform better than other electrolyser alternatives, also in the sensitivity analysis. The 300 GWh storage is applied, since a larger storage does not improve the alternative and given the fact that this storage size does not influence the economy of the system significantly. Larger heat storages in households in *ELT/micro* do not improve the fuel efficiency significantly, either.

ELT/micro and *HFCV* have been modelled with 25 per cent electrolyser operation. An analysis of 50 per cent running time instead of 25 per cent decreases the electrolyser capacity and thus the costs. This has almost no effect on the fuel savings of *HFCV*, again because they replace other vehicles. For *ELT/micro*, though, more than 35 TWh of wind power production is required to gain fuel savings and fuel saving costs are significantly increased.

In the V2G *BEV* alternative, the vehicles are able to discharge to the grid in situations with power plant production. If this was not the case, the maximum fuel saved would be 0.5 TWh and not 2.2 TWh, as illustrated in Fig. 39. This would increase the fuel saving costs of *BEV* to between 40 and 62 M€/TWh, at all times more than 8 M€/TWh lower than the costs of *HFCV*. The V2G technology is a part of the *BEV* alternative, but it is not included in the costs. If the costs of *5%FLEX* are added, these conclusions do not change.

5%FLEX is analysed by applying a one-day flexible demand. With one-week flexible demand or more, fuel savings would almost double. This would lower the costs; however, the fuel savings of *5%FLEX* are still moderate compared to those of the other alternatives.

Halving the investment costs of the integration technologies does not change the relative relation between the alternatives and does not make *ELT/micro* competitive with the oil price. If the investment costs of *HFCV* and *BEV* were halved, a net saving would be achieved compared to regular vehicles.

With double investment costs, *5%FLEX*, *HP* and *EB* are still defined as the least-cost alternatives. In this situation, *5%FLEX, HP*, *EB*, *BEV* and *ELT/CHP* have lower costs than the oil equivalent at above approx. 10.0 TWh,12.5 TWh, 19 TWh, 28 TWh and 44 TWh of wind power production, respectively. The remaining alternatives have much higher fuel saving costs.

In the case that the costs of *ELT/micro* can be reduced to the price of a natural gas boiler, fuel saving costs are approx. 3 M€/TWh more than those of *HFCV*. Thus, *ELT/micro* is still one of the integration technologies with the highest costs, because it is rather inefficient compared to the other alternatives in terms of integrating RES.

For all alternatives, doubling the capacity gives an additional reduction in PES of approx. 70-110 per cent in comparison with the savings identified above. For the alternatives in which no savings were achieved with low amounts of fuel, the additional fuel consumption increases. For electrolyser alternatives, these analyses confirm that a certain amount of wind power production needs to be present in order to obtain fuel savings. Otherwise, increased fuel usage will be the result. Doubling the capacities does not change the results.

When combining the integration technologies, the effects on fuel consumptions accumulate to a large extent. However, this depends on whether the technology in question is dependent on wind power production in order to provide fuel savings, or will provide fuel savings in any case. The effect on excess electricity production is gradually smaller when the integration technologies are combined.

For land-based wind turbines, the same production requires almost the double installed capacity. The costs of these are, however, also about half the costs of offshore wind turbines. A sensitivity analysis is conducted with land-based turbines with a 28 per cent load factor. The distribution of wind power production has much larger peaks, and thus, fluctuations are heavier. This does not change the results of the analyses significantly; although the fuel savings of *5%FLEX* improve by a factor 2 to 3, *HP* and *BEV* still have much higher fuel savings.

8.7 Conclusions

Seven different integration technologies have been analysed with a focus on improving the balance between demand and supply in a renewable energy system with a high penetration of CHP and fluctuating RES. The seven technologies have been analysed in terms of their ability to integrate fluctuating wind power production, their influence on the system fuel efficiency, and their annual costs in relation to fuel savings.

Large heat pumps have good abilities to integrate RES and constitute by far the most fuel-efficient solution. Electrolysers, which produce without depending on a fixed demand for hydrogen for CHP plants, are able to integrate RES better, but are, on the other hand, rather inefficient in terms of utilising RES, compared to other technologies. Electrolysers with a fixed annual production rate are unable to place all the production of hydrogen at times with high amounts of wind power, and are thus even more inefficient.

Heat pumps and flexible demand are the most promising technologies in respect of costs. These technologies should be implemented first. Electric boilers also have rather low costs, but only with a RES share above 40 per cent of the electricity demand. Heat pumps make up a good investment even with lower amounts of wind power than those expected for the future. This makes it a low-cost technology in years with less wind, whereas other technologies will not be feasible in years with low shares of wind power production. If the electric boiler is not implemented correctly into the energy system, it can result in increased fuel consumption and is not feasible in years with low wind power production. Flexible demand has rather low fuel saving cost, even though the technology analysis made here only covers one day and does not include potential savings in the power plant capacities. For both electric boilers and flexible demand, an extra installed capacity does not improve fuel savings much compared to heat pumps. This indicates that the heat pumps are more important than these technologies in terms of reducing excess electricity and, at the same time, increasing fuel efficiency at low costs.

For transport battery electric vehicles, fuel and cost-efficient solutions both comprise a vehicle to grid solution and a dump charge solution compared to the hydrogen fuel cell vehicles.

With more than 40-50 per cent of the electricity demand produced by wind turbines, the costs of integrating renewable energy sources with electrolysers for hydrogen fuel cell vehicles, CHP plants and micro FC-CHPs are reduced. However, if the aim is fuel-efficient and low-cost integration of RES, the other technologies mentioned should be implemented first. The results of using electrolysers are very sensitive to the efficiency of these and to the use of waste heat, except for the hydrogen fuel cell vehicles if these replace regular internal combustion engine vehicles.

Although these analyses conclude that other technologies should be implemented first, the electrolyser technologies may prove important in 100 per cent renewable energy systems with large shares of intermittent RES and in which biomass is a limited resource [11].

These results are based on technical energy system analyses. The investment costs, O&M costs and the lifetimes of the technologies and solutions analysed are most sensitive to the efficiencies used and, thus, the results are rather robust against changing fuel prices.

The first step in the integration of wind power production is to use CHP plants with heat storages and boilers and to move CHP production to times with low wind power production. If technologies are developed to change the current centralised ancillary service design using only large centralised power stations, excess electricity production is significantly reduced. Thus, the regulation ability of CHP plants and the decentralised ancillary service supply are more important measures than the introduction of integration technologies in terms of efficiently reducing excess electricity production.

9 Life cycle screening of solid oxide fuel cells

In this chapter, a life cycle screening of solid oxide fuel cells is presented. The chapter is based on "Fuel cells for balancing renewable energy sources" [2], included in appendix VII.

The environmental impacts of the construction phase of SOFC may be reduced significantly and may be lower than those of traditional power plants, if the lifetimes and the current density of the SOFCs are increased. Materials such as rare earths used in the ceramics of the cells have not been investigated and may pose a problem if not re-cycled. The SOFCs have lower environmental impacts in the use phase because of lower emissions and higher efficiencies than traditional power plants. The higher efficiencies also reduce resource consumption in the use phase, compared to other technologies.

9.1 Introduction

In a cradle-to-grave perspective, the overall life cycle of a SOFC can be divided into the construction phase, the use phase, and the demolition phase. The life cycle screening of the SOFC is not conducted by applying the attributional or consequential methodology normally used in life cycle assessments (LCA). In general, the main purpose of conducting LCA is to convey a coherent and holistic support for decision-making affecting the environment. Recommendations have been made in the previous chapters based on energy system analyses for the use phase of SOFCs and SOECs applied to different energy systems. Suitable applications in future energy systems have been identified. The life cycle environmental impacts of changing demands or adding technologies, such as fuel cells and electrolysers to energy systems, are complex; i.e. technologies interact with the energy system and should thus be analysed by applying energy system analyses in combination with LCA [15;16].

At this point, it is uncertain when large-scale manufacturing of SOFCs will commence and which materials will be used. According to both attributional and consequential LCA studies, information about markets affected and existing production facilities delivering materials for the SOFCs has to be investigated. Such research has not been conducted here, as SOFCs are still at the development stage and the future production facilities may be different from those in the current energy system.

For conventional power plants and CHP plants, the environmental impacts and resource consumption are by far most significant in the use phase [14]. As SOFCs are still in the development phase, the environmental impact and resource consumptions of these in the manufacturing phase are still uncertain. In this chapter, the environmental impacts regarding emissions in the use phase are presented as well as a life cycle screening of a second generation SOFC, using the primary energy supply for the construction of the SOFC. The SOFC is compared to coal-fired power plants and gas turbines.

9.2 Environmental impacts in the use phase

The environmental impacts of a fuel cell in operation are minute in comparison with other technologies. The global warming potential and emissions of CO_2 are directly linked to the fuel used in the cells. When using fossil fuels such as natural gas in SOFCs, the CO_2 emissions per kWh are, however, lower than those of traditional gas turbines, because of higher efficiencies.

Other emissions such as sulphur, NO_x and CO are expected to be very low, because of the fuel pre-treatment, higher efficiencies and direct chemical conversion. Sulphur has to be removed from the fuels, which means that SO_x will not constitute a problem, as it does in combustion technologies. Sulphur emissions are virtually nonexistent. NO_x emissions are also significantly lower and these emissions are connected only to the catalytic burner, which utilises unused fuel from the fuel cell for heat production in the fuel supply system. The emissions of CO are rather low for all types of fuel cells, since it is used as a fuel in the higher temperature cells and its poison is hence removed from the low temperature cells. There may be emissions of unused hydrocarbons, but this can be reduced in the system design. No non-methane volatile organic compounds (NMVOC) or particles are emitted from the cells. Furthermore, the cells are very quiet during operation with no noise pollution.

9.3 Life cycle screening of the construction phase

The primary energy consumption related to the production of the SOFC is used as an indicator of the environmental impacts and resource consumptions in the production phase. A tubular design of the SOFC, which was the design initially developed, is now abandoned in favour of a planar alternative with a more compact scalable design and lower production cost. The first generation planar cells are electrolyte-supported. The second generation cells, which are primarily in focus at the moment, are anode-supported. Third generation, metal-supported cells are currently being developed and tested [1]. These will potentially lower the material costs, as the use of rare earth is minimised in favour of more stainless steel. Such a development is also associated with a reduction of operation temperature, increasing the lifetime and the efficiency of the SOFC by lowering internal resistance; hence, this development is required for the SOFC to be competitive.

In Fig. 42, the distribution of primary energy consumption for the production of materials and manufacturing of a first generation cell and system is illustrated. In the perspective of the development towards third generation cells, the first generation cell represents a worst case scenario. The data set used in Fig. 42 is based on a planar 1 kW SOFC from Karakoussis (2001) [70] and can be considered as the first estimate of the potential primary energy consumption related to the construction of SOFCs. For this type of fuel cell, the main part of the energy consumption is connected to the production of materials. The production of chromium alloy used in the interconnector and the production of steel used for heat exchangers, air and fuel supply, etc., are the two most important factors at the production stage of the life cycle of this fuel cell.

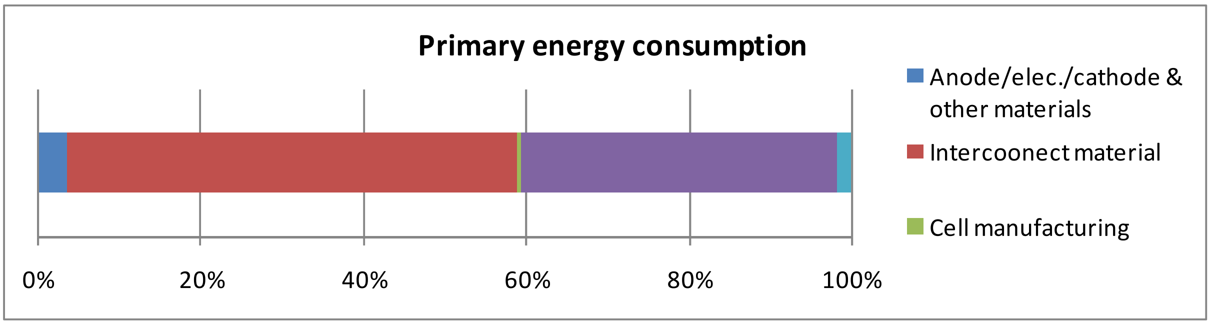

Fig. 42, Distribution of primary energy consumption for materials and manufacture of cell and system forming a fuel cell. The data is based on a first generation 1 kW planer SOFC.

When the cells develop towards third generation cells, the relative contribution from the anode/electrolyte/cathode will diminish, as these parts will become thinner and will be supported by the interconnector. The interconnector may also become thinner as the cells develop; thus, the system surrounding the cells will become more and more important. The energy consumption related to the manufacture of the anode, cathode and electrolyte has been assessed using the energy consumption for aluminium production per mass in the cell analysed here. Due to commercial confidentiality, no exact data have been acquired on the production of these ceramic materials in the cell itself. Doubling the energy use for manufacturing the anode, cathode and electrolyte will only increase the total energy requirement for materials and manufacturing by 1.6 per cent. This is due to the fact that the interconnector is made from chromium alloy and the fact that the steel for the system by far has the largest energy consumption in the cells themselves [70].

The production of the anode, cathode and electrolyte is not likely to generate higher energy consumption in the future. It is only expected to contribute marginally to the total energy consumption in the production of the fuel cells. In addition to the cells, the surrounding system also generates energy consumption. The system counts for approximately 40 per cent of the energy consumption of the cell and, also here, the material production has a significant contribution.

The processes used in Karakoussis (2001) [70] are not optimised for mass production. As an example, the anode and cathodes are not co-sintered, thus increasing the energy demand in the data used here. Furthermore, no recycling of the materials in the system has been assumed, which can prove important in terms of lowering the energy consumption for the production of materials for the fuel cell. Re-cycling may also prove important in terms of reducing the use of rare earth for the ceramics of the SOFCs.

The power density of the fuel cell, i.e. the capacity of the individual cell per cm^2, is 0.2 W/cm^2, and the cell has an operating temperature of 900°C.. The power density is expected to exceed to 0.5 W/cm^2 [55], which means that the energy consumption for producing a 1 kW fuel cell would decrease by 40 per cent. Electrolyte-supported cells have reached a power density of 0.48 W/cm^2, and experimental second generation cells have performed 0.8 W/cm^2 [55]. Third generation interconnector metal-supported cells are still at the experimental stage. However, these are expected to increase the power densities even more. The running temperature is lowered to 550-650°C, compared to 900-1.000°C in the first generation cells. This will lower the internal resistance. The power density will increase from the first generation cell analysed here and, subsequently, the overall energy consumption related to the production of 1 kW SOFC will decrease.

In Fig. 43, the energy consumption per kW of capacity related to the production of SOFCs and traditional power-producing units is illustrated. Two SOFCs are shown; one with a power density of 0.2 W/cm^2 and another SOFC using the same data, but scaled for an improved power density of 0.5 W/cm^2. These figures are compared to the primary energy consumption related to the production of a large coal-fired power plant and three sizes of gas turbine power plants, all of which represent current technologies. For these power plants, existing data from the EcoInvent database has been used. The EcoInvent database is one of the most comprehensive and up-to-date life cycle inventory databases available. The 2.500 processes, products, and services in the database are applicable to a European context [14]. This database contains data gathered in 2004 for processes, products, and services in the year 2000 and was constructed from several Swiss databases covering data for both Switzerland and Europe.

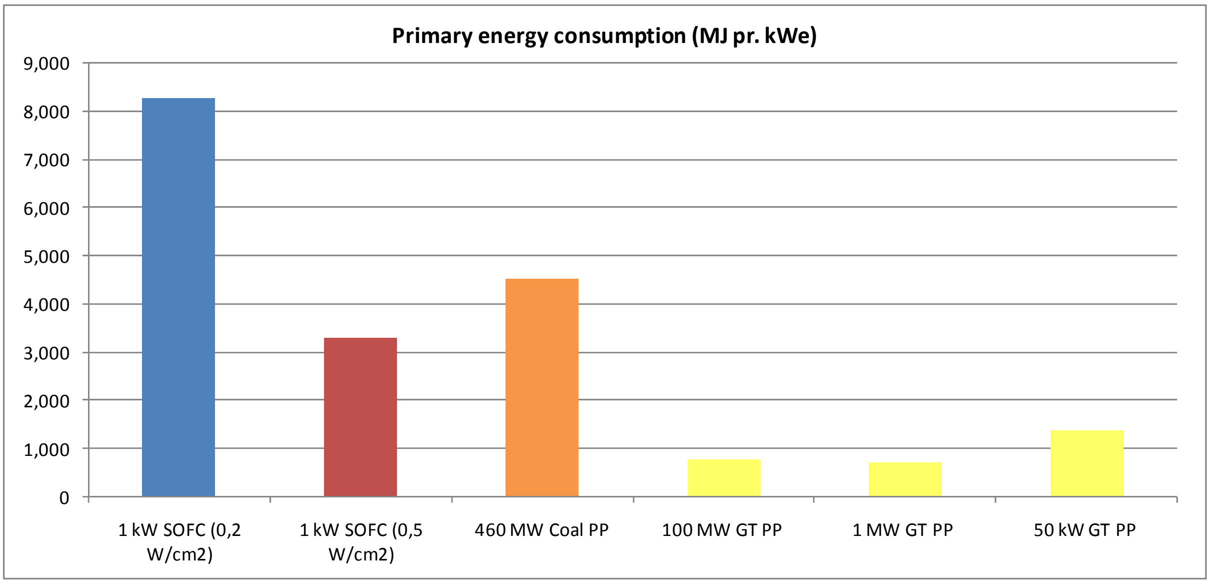

Fig. 43, *Primary energy consumption related to the production of power-producing unit per kWe*

In terms of primary energy consumption, the production of SOFC is already at this point more efficient than the production of large coal-fired power plants, as a power density higher than 0.5 W/cm^2 has been achieved. The lifespan, however, is still a problem which requires further development. Coal-fired power plants generate a large energy consumption per kW, because of the use of large amounts of steel for the production of the plants. The production of gas turbines is still less energy consuming than the production of SOFCs. The SOFC would have to reach a power density of 1 W/cm^2 and reuse at least one third of the interconnector and system material in order to be comparable to gas turbines at the production stage.

9.4 Conclusion

In a life cycle perspective, SOFCs can reduce environmental impacts and resource consumptions compared to combustion technologies. This requires, however, that suitable applications of the fuel cells are identified.

The main part of the environmental impacts of traditional power plants and CHP plants is located in the use phase of the plant lifetime. For SOFCs, the emissions in the use phase are very low, and efficiencies are higher than those of conventional technologies. Hence, CO_2 emissions are also lower and in terms of global warming, SOFC is potentially a preferable solution. However, since the SOFCs have low emissions in the use phase, compared to traditional technologies, the environmental impacts related to the construction of the SOFC are relatively more important. Higher efficiencies of SOFCs may reduce resource consumption in the use phase compared to other technologies. When considering the construction phase of SOFC, the primary energy consumption used in this phase can be reduced significantly and may be lower than that of traditional power plants, if the lifetimes and the current densities of the SOFC are increased and. Materials such as rare earths used in the ceramics of the cells have not been analysed, but they may pose a problem if not re-cycled.

SOECs have not been analysed in this aspect; however, they are based on the same technology as SOFCs and will most likely also have the highest impact in the use phase. Compared to other electrolysers, these are more efficient, and in a life cycle perspective, the environmental impact and resource consumption of SOECs are likely to be reduced. Like in the case of power plants, the most significant impacts will most likely be located in the use phase; hence, the identification of suitable applications is also crucial in the case of electrolysers.

10 Conclusion

Today, most electricity, heat and transport demands are met by combustion technologies, such as steam turbines, gas turbines, internal combustion engines, and boilers. Compared to these conventional technologies, fuel cells have the ability to significantly increase the efficiency of the system while meeting such demands.

However, although significant improvements in efficiency can be identified, when fuel cells replace other technologies, this is not necessarily the case seen in a system perspective. Energy system designs can be identified in which the fuel savings achieved are lost in technologies elsewhere in the system.

This dissertation is based on the fact that the improvements obtained by implementing fuel cells depend on the specific design and regulation possibilities of the energy system in which they are used. For the same reason, some applications of fuel cells add more value to the system than others. Energy systems have been identified, both in which fuel cell applications create synergy effects with other components of the system, as well as in which efficiency losses in some parts of the system outweigh the improvements in efficiency achieved by using fuel cells.

In order to identify suitable applications of fuel cells and electrolysers in future energy systems, the direction in which these systems develop must be considered. In this dissertation, fuel cells are analysed in the context of energy systems that are gradually changing from the current design, with large amounts of fossil fuel combustion technologies, to a future design based on 100 per cent renewable energy. The conclusions of the analyses refer to the application of fuel cells and electrolysers to such future renewable energy systems and should thus be seen in this context. Also it should be kept in mind that fuel cells and electrolysers are still at the development stage.

10.1 Fuel cells and renewable energy systems

In future energy systems, there is a risk that improvements in efficiency are lost, because the system design is not equipped for utilising the full potential of fuel cells. If fuel cells replace gas and steam turbines in combined heat and power (CHP) plants, the improvements may be lost, because a larger part of the heat demand must now be met by boilers. In integrated energy systems with large heat pumps, however, the decreased heat production from fuel cells at CHP plants can be met by heat pumps instead of boilers.

In energy systems combining fuel cells with heat pumps and heat storages, a synergy is created between these components and the full potential of the fuel cells is utilised. Fuel cells induce higher fuel savings in integrated energy systems with large shares of intermittent renewable energy than in conventional energy systems. They represent important measures on the path towards future 100 per cent renewable energy systems, because they are able to reduce the dependence on fuels more than combustion technologies, in such integrated energy systems.

10.2 Fuel cells in flexible combined heat and power plants

In locally distributed CHP plants with district heating grids, fuel cells are especially promising in terms of replacing conventional single cycle gas turbines. Fuel cells have higher efficiencies than these, also in part load, and can be combined with heat pumps and heat storages.

Fuel cells should not be developed for base load operation, but for flexible regulation in energy systems with large shares of intermittent renewable energy and CHP plants. Base load plants are not required in such energy systems.

In addition, fuel cells in distributed CHP plants may provide a new design for maintaining grid stability by replacing the steam turbines that currently deliver these services; especially, if fast start-up abilities are developed. Such abilities enable further reductions in fuel consumption and improve the integration of intermittent renewable resources.

Fuel cells should be developed to enable flexible operation while maintaining a high efficiency. Synergy can be achieved by using fuel cells in renewable energy systems, because the number of operation hours decreases and the lifetime of the cells becomes less significant.

10.3 Fuel cells in micro combined heat and power

Hydrogen micro-fuel cell CHPs in individual households are not suitable for renewable energy systems. This is due to the losses associated with the conversion to hydrogen and lower regulation abilities of such systems. In addition, more energy and cost-efficient alternative heating systems can be identified.

In a short-term perspective, natural gas micro-fuel cell CHP may spread the CHP production more than locally distributed fuel cell CHPs are capable of doing. This can potentially increase the efficiency of the energy system and displace the production at coal-fired power plants. Although, in some energy systems, there is a risk that the production at more efficient fuel cell CHP plants is displaced in other parts of the energy system.

In the long term, however, it should be considered which fuels such technologies can utilise and how these fuels can be distributed. Natural gas is not an option in future renewable energy systems and the demand for gaseous fuels, such as biogas or syngas, will increase significantly. In this long-term perspective, fuel cell CHP plants provide a more fuel-efficient option for using such scarce resources, and other technologies, such as heat pumps, are better options in terms of meeting the heat demand in individual houses not supplied from CHP plants.

10.4 Fuel cells and transport technologies

Both fuel cell and battery electric vehicles are more efficient options than conventional internal combustion engine vehicles. In terms of transport, battery electric vehicles are more suitable than hydrogen fuel cell vehicles in future energy systems. Electric vehicles are more efficient in terms of fuel and costs as well as the integration of intermittent renewable resources, compared to hydrogen fuel cell vehicles. Battery electric vehicles may, for a part of the transport demand, have limitations in their range. In such a situation, a hybrid solution may provide a good option, which can combine the high fuel efficiency of battery electric vehicles with efficient fuel cells in order to increase the range. Such hybrid vehicles have not been investigated in this dissertation.

10.5 Energy storage and electrolysers

In the short term, electrolyser hydrogen is not suitable for fuel cell applications; and in the long term, some applications of electrolysers are more suitable than others. Other energy storage technologies, such as large heat pumps in CHP plants and battery electric vehicles, should be implemented first, because these technologies are more fuel and cost-efficient.

In the long term, when more efficient solutions have been implemented, electrolyser applications may form part of the energy systems. Electrolysers should only be implemented in energy systems with very high shares of intermittent renewable energy and CHP; but in a 100 per cent renewable energy system, they play a key part by displacing fuels derived from biomass.

Electrolysers combined with fuel cells in CHP plants can supplement other fuels, such as biogas or syngas, in energy systems with high shares of intermittent renewable energy sources. With a renewable energy share constituting more than 50 per cent of the electricity supply, the performance of electrolysers in hydrogen fuel cell vehicles and CHP plants is improved significantly. In such applications, electrolysers should be developed to have the highest possible efficiency, the most flexible regulation abilities, and the lowest investment costs possible.

10.6 Fuel cells and electrolysers and socio-economic cost

As fuel cells are still under development, their socio-economic costs, including investment costs, operation and maintenance costs as well as lifetime, are rather uncertain. The additional costs of fuel cells used in CHP plants can, in suitable applications, be covered by the higher efficiencies, while the micro SOFC CHPs are not feasible compared to other technologies. Electrolysers are also less feasible than other alternatives, which should be implemented first. The socio-economic costs of fuel cells and electrolysers are dependent upon the energy system to which these technologies are applied; hence suitable applications should be identified, as in this dissertation.

10.7 Environmental impacts of fuel cells

In the construction phase, the primary energy consumption of fuel cells for CHP plants may eventually be comparable to the consumption of combustion technologies. However, in the use phase, important differences can be defined, and suitable applications of the cells should thus be found, as identified in this dissertation. If scarce materials are used in the construction of future fuel cells and electrolysers, it can be recommended to develop and establish specialised recycling schemes, in order to avoid depletion and higher costs.

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Appendix I

The nature of fuel cells

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Abstract

In this review, the status and future potential of five different types of fuel cells are presented. Focus is on fuel cell systems for combined heat and power production in future energy systems; however, the review also includes aspects of other applications of fuel cells. The operation principles as well as the characteristics and applications of the different types of fuel cells are considered. High temperature polymer exchange fuel cells seem to have the best potential in terms of transport and micro combined heat and power generation (CHP), while solid oxide fuel cells have the potential for replacing existing technologies in distributed local or central CHP plants. Significant challenges have to be overcome, before broad commercial use of fuel cells in future energy systems can be expected.

Keywords: Fuel cell review, alkaline fuel cells, phosphoric acid fuel cells, protone exchange membrane fuel cells, molten carbonate fuel cells, solid oxide fuel cells, CHP, fuel cell systems.

1 Introduction

In these years, fuel efficiency and environmental impacts of energy technologies play an important role in the long-term decisions to be made in the energy sector. The two main forces driving this focus in decision-making are the international debate and fear of global warming, on one hand; and the significant increases in global energy demands on the other. The solutions chosen by decision-makers require detailed knowledge about the features of the energy systems in question. Knowledge about their economic and environmental impacts is also required. This has resulted in a global revitalisation of research into renewable energy technologies, addressing both issues. This research has particularly accelerated due to increasing fuel prices along with a simultaneous increase in energy demand.

Fuel cells (FCs) and electrolysers are considered in this research. The increased focus on FCs is based on the fact that they have better efficiencies in comparison with conventional energy conversion technologies and also the fact that they have no or very low local environmental effects. Electrolysers are often seen as an important part of energy systems with high shares of fluctuating renewable energy, such as wind power. Furthermore, they are defined as an important means of integrating more renewable energy into the transport sector by use of FCs and hydrogen or hydrogen carriers. In a future energy system, there is a risk that improvements in efficiency are redundant, because the system design is not equipped to utilise the full potential of fuel cells. For the same reason, some applications of fuel cells add more value to the system than others [1]. In this review, data and recent developments of current and potential future FCs are presented.

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2 Fuel cell types

In most countries, the energy supply consists of a small percentage of intermittent resources as well as combustion technologies in vehicles, power plants (PP) and CHP plants. The perspective in replacing conventional technologies with more efficient FCs is dependent on the characteristics of the different FC types available.

FCs generally consist of the *cell*, in which an electrochemical reaction takes place; the *stacks,* in which the cells are combined to the desired power capacity; and the balance of the plant, which comprises systems for handling fuel, heat, electric power conditioning, and other systems required around the cell.

FCs are comparable to batteries, except from the fact that they are not limited by the amount of energy stored in the cell itself. In these cells, chemical energy is converted directly into electricity. This provides higher efficiencies than in traditional technologies, in which the energy content in fuels is converted into thermal energy, then mechanical energy and then finally electricity. The higher efficiencies also imply a significant reduction of emissions.

Fuel cells	AFC	PEMFC	PAFC	MCFC	SOFC
Name (electrolyte)	Alkaline	Polymer exchange membrane	Immobilised phosphoric acid	Immobilised molten carbonate	Solid oxide conducting ceramic
Catalyst	Platinum	Platinum[1]	Platinum	Nickel	Perovskite[2]
Operating temp.	40-100 ºC	60-200 ºC	180-220 ºC	550-700 ºC	500-1000 ºC
Fuel(s)	Perfectly pure H_2	Pure H_2 or CH_3OH	Pure H_2	H_2, CO, NH_3, hydrocarbons, alcohols	H_2, CO, NH_3, hydrocarbons, alcohols
Intolerant to	CO, CO_2	CO, S, NH_3	CO, S, NH_3	S	S
Potential electric eff. %[3]	60	40-55	45	60	60
Potential applications	Mobile units space, military	Mobile units, micro-CHP	Smaller CHP units	Larger CHP units	From large to micro-CHP

Table 1: Characteristics of the five main types of fuel cells and potential areas of use. [2-15].

Although certain types of FCs are mainly considered for mobile and others for stationary use, this is not determined yet. The characteristics of the FC types, however, make certain potential applications more probable than others. FC types are named after their electrolyte, which also determines their operating temperature. In Table 1, the main characteristics of the five main types of FCs are listed.

Please note the fact that such comparisons are subject to the different preconditions and characteristics of the different fuel cells. Thus, these preconditions should be taken into account when comparing e.g. efficiencies. In Annex I to Annex VI, the data sheets for different FC systems are presented.

In all FC types, the core consists of a cell with an electrolyte and two electrodes; the anode and the cathode. In Fig. 1, the reactions in different FCs are illustrated. Hydrogen and oxygen are converted into water producing electricity and heat. The conversion of fuels takes places in a chemical process, in which the catalytic active electrodes convert the fuel into positive ions and oxygen into negative ions. The precise reactions depend on the type of FC. The ions cross the electrolyte and form water and possibly CO_2, depending on the fuel and the FC. Only protons can cross the electrolyte while creating a voltage difference between the anode and the

[1] May also consist of platinum in combination with ruthenium and molybdenum depending on the CO contents in the fuel. This is especially the case of DMFC. In HT-PEM, the catalyst is often pure platinum.
[2] May contain nickel if the fuel is hydrocarbons, e.g. natural gas or methanol.
[3] Potential efficiencies depend on the stack load. Total efficiency may be more than 90 per cent, but is dependent on the cooling system and the operation temperature. For AFC, the efficiency is dependent on the existence of perfectly pure hydrogen at the anode and pure oxygen at the cathode. For high temperature PEMFC, a 55 percent net system efficiency has been achieved. For SOFC, the efficiency is dependent on the development of cell materials, anode gas recirculation and integrated steam reforming when using other fuels than hydrogen. In MCFC and SOFC, a 70-75% electricity efficiency can be achieved, when combined with gas turbines and/or steam turbines.

cathode in the cell; thus, the electrons cross to the anode section in an external circuit. The output is DC electricity from the flow of electrons from one side of the cell to another. [3]

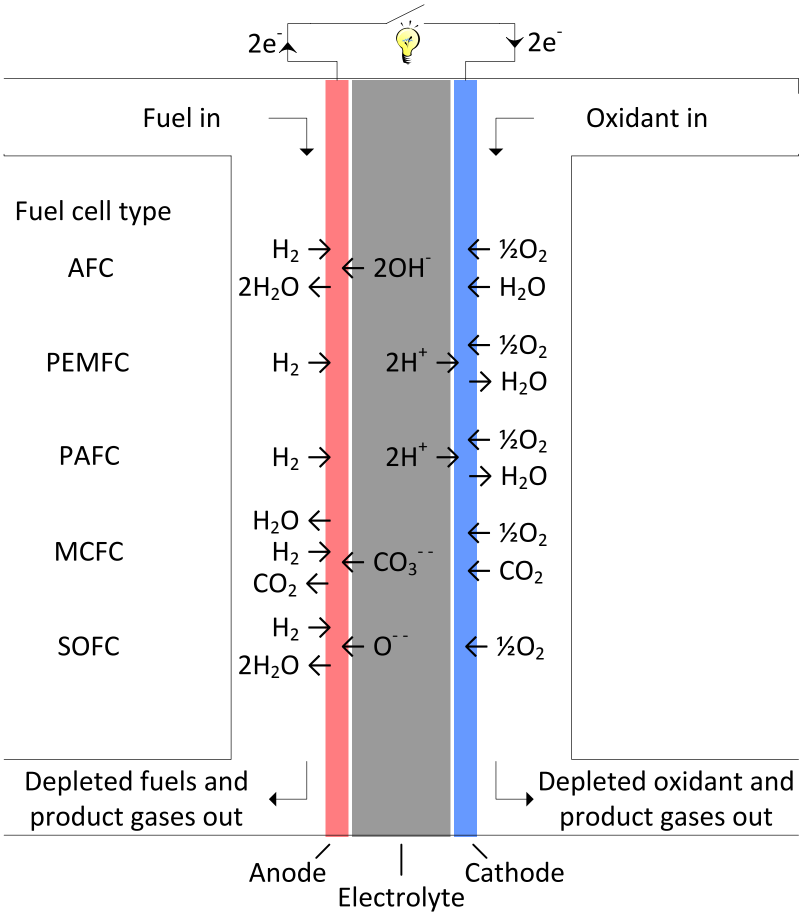

Fig. 1, Schemas of different fuel cell types.

The advantages of *lower temperature FCs* are mainly related to the fact that they are compact, lightweight and have a quick start-up and shut-down potential. This, combined with the fact that the efficiency of the FCs cannot compete with other larger power-producing technologies, makes transport and mobile applications most promising. In these cases, FCs can compete with the efficiencies of existing technologies. They may potentially contribute to the supply as small-scale micro-CHP plants. For larger stationary applications, other technologies have already today proven to have better efficiencies.

Alkaline FCs (AFCs) are highly reliable, rather compact, and have low material costs; but no widespread commercial use is expected, because of the costs related to the extensive gas purification needs [3;4]. AFCs have been used for extraterrestrial applications, e.g. the manned Apollo missions, which has no price issue, availability of pure oxygen problems, and in which the excess water is useful for astronauts. The lifetime of AFCs is rather short and is not expected to increase with further research; thus, mainly mobile applications should be considered. In recent years, research has shown that the purification needs may be lower than expected. Micro-CHP based on AFC is also still being investigated [5].

Phosphoric acid FCs (PAFCs) are widely used today as emergency power and stand-alone units in hospitals, schools and hotels. They have been commercially available since 1992, but the costs of PAFCs are still about three times higher than those of other comparable alternatives. The main problems related to PAFCs are based on the fact that they are dependent on noble metals for the electrodes and the fact that their reported efficiencies are not considerably better than those of other technologies. [2-4;16]

The AFCs and the PAFCs are often considered the most developed FCs of the five types mentioned [6]. However, although variants of both types are still developed, it will hardly be possible to improve the two main challenges, namely the lifetime of AFCs and the cost level of PAFCs, respectively [3;5].

PEMFCs are characterised by a rather simple design and fast start-up. Different variants of PEMFCs are available, including low temperature FCs operating at 60-80 °C; high temperature FCs (HT-PEMFCs) operating at 140-200 ºC, and direct methanol fuel cells (DMFCs) typically operated at temperatures somewhat below 60 °C due to issues related to the system water balance. PEMFCs and HT-PEMFCs can be utilised in almost all applications in which high temperature heat is not required, such as in micro-CHP as household heating systems, transport or smaller devices. DMFCs are mainly considered for small portable devices, such as mobile phones, computers, etc. [3;7;17]

The main advantages of *high temperature FCs* are the higher efficiencies and the fuel flexibility which they offer. Other advantages include high operating temperatures, which allow internal reforming or direct conversion and thus enable a rather simple system design as well as the option of integrating these systems with heat engine based bottoming cycles enabling even better net system efficiencies. Moreover, they are constructed from rather cheap materials and do not contain noble metals.

While molten carbonate FCs (MCFCs) have high efficiencies, they require the input of CO_2 with ambient air on the cathode side. Also the electrolyte of the MCFC is heavily corrosive, which is the main problem in these cells today. Research is still being conducted in order to improve the cells, mainly for applications to larger CHP and power plants, though the efforts have decreased. [3;12]

Solid oxide FCs (SOFCs) may be more promising in the future. They have already proven to have rather long lifetimes when not thermally cycled, and theoretically, high efficiencies may be achieved in SOFC systems. However, SOFCs may have problems with thermal stresses and degradation. Third generation metal-supported cells, which are currently being developed, are expected to reduce these problems and increase the power density of the cells [18].

All FCs can operate on hydrogen. While some FCs require higher hydrogen purities than others, high temperature SOFCs and MCFCs can operate directly on methane rich fuels, such as natural gas. Electrolyses as well as biomass-derived fuels can be combined with a synthesis process, thus enabling the production of other fuels than hydrogen for fuel cells.

In the MCFC and the SOFC, the electrolyte conducts ions from the cathode side to the anode side. In the PEMFC and PAFC, hydrogen passes from anode to cathode. For the two high temperature FCs, this means that a wide range of fuels, including natural gas, biogas, ethanol, diesel, LPG, methanol, etc., can be used without reforming the fuel completely into hydrogen and CO_2 [19;20].

Some FCs are very versatile in terms of their ability to utilise different fuels. Others can only use one kind of fuel and have strict limits for impurities. The fuels and conversion paths can be divided into two categories; one involving the fuels that can be converted directly, i.e. meets the required characteristics, and the second involving the fuels that can be procured to meet these standards. In the following sections, the characteristics of the different FCs are elaborated.

3 The characteristics and applications of alkaline fuel cells

The AFC was the first FC to be put into practical use; it was used in a tractor in the late 1950s. In the beginning of the 1970s, the first AFC battery hybrid was constructed. Research is still being conducted into these vehicles [5;8]. The lifetime of the AFCs between 5,000 and 15,000 hours and the expensive purification needs for both fuel and oxidant currently limits the applications of AFC to extraterrestrial applications [5;16]. CO_2 is highly poisonous to the cell; but until now, research into the degradation caused by CO_2 has been scarce, because the costs of purifying were not considered a major problem in space applications due to the availability of pure oxygen [5;9]. The AFCs need pure H_2 at the anode and pure O_2 at the cathode, making the use of reformed fuels and ambient air more expensive. The charge carriers are hydroxyl ions (OH^-), which cross an electrolyte consisting of a porous matrix with an alkaline solution of potassium hydroxide (KOH).

The AFCs using immobilised alkaline electrolytes are considered fully developed. Circulating aqueous electrolytes are still being developed and they may represent the technology that can prepare the AFC for terrestrial applications [9;21]. The CO_2 poisoning of the electrode from the oxidant may be reduced by circulating the electrolyte. Such a system can also remove water and heat from the cell. The circulation and water management system will increase the complexity and, most likely, the cost and the size of the system; but it may also increase the lifetime and does not necessarily cause problems for fast start-up. Some expect that this effort could increase the lifetime beyond 15,000 hours [5]. This variant may revitalise the competitiveness of AFCs. Poisoning may also be avoided electrochemically by drawing a high current and thus regenerating the cell performance [5].

Direct methanol, ethanol and sodium borohydride AFCs are also being investigated, but these still experience lower power densities and performances [22;23]. Recent research has indicated that CO_2 does not enhance degradation [24]. This has not been confirmed elsewhere, and, in most literature, CO_2 in ambient air is considered a problem, meaning that it has to be removed via e.g. scrubbing of the oxidant on the anode side or via a circulating electrolyte. The AFCs are mainly considered for transport applications, because of their rather limited lifetime.

4 The characteristics and applications of Phosphoric acid fuel cells

The PAFCs were the first FCs to be commercialised. The cells use phosphoric acid as the electrolyte contained in a Teflon-silicon matrix, and the cathode and the anode consist of platinum on porous graphite on either side of the electrolyte. Like in the PEMFC, hydrogen ions or protons (H^+) are the charge carrier. They were previously considered promising, since they were the only lower temperature cells with tolerance to hydrocarbon-based fuels. [4]

PEMFCs are considered to be well developed, and not many improvements have been reported since the mid-1980s. However, development continues. In spite of the fact that PEMFCs also contain platinum, they are considered to have better costs potentials than have been achieved at this point with PAFCs. An 8 atm. FC with a capacity of 11 MWe has been demonstrated. The high pressure improves the efficiency of the cell, but it also increases the complexity and thus the price of the system. Presently, most PAFCs are operated at nearly atmospheric pressure [16].

PAFCs are less affected by CO than AFCs and PEMFCs. As CO_2 serves as a diluent in the cell, the cells may operate on ambient air. The operating temperature is typically between 180ºC and 220ºC, which enables the use of cheaper materials than in the case of SOFCs. PAFCs are often referred to as intermediate temperature FCs. The potential applications of PAFCs are smaller micro-CHP systems for individual houses or small industries. The temperatures of the FC are not high enough for combined cycle power generation or for the internal reforming of fuels. This implicates that, if fuel processing is needed, the total efficiency is affected. Two other disadvantages of PAFCs are their rather low potential efficiency improvements and the fact that they contain noble metals. The highly corrosive phosphoric acid also requires expensive materials, such as Teflon and graphite separators. Moreover, improvements in stability are required for further expansion, even though long-term operation has already been achieved. [3;16;25]

5 The characteristics and applications of proton exchange membrane fuel cell

PEMFCs are based on a solid polymer membrane as the electrolyte. The electrolyte of the cell only allows hydrogen ions or protons (H^+) to cross and it consists of fluorinated sulfonic acid fixed in a polymer. This is commonly known as Nafion, which has properties similar to those of Teflon. The anode and cathode consist of one or more noble metals, supported on carbon, typically platinum, and the amount of platinum required is higher than the amount required for PAFCs. The rather low operating temperatures of PEMFC enable very fast start-up, rapid load-following as well as less expensive construction materials and less insulation. This also results in rather compact designs. The power densities of PEMFC systems are also rather high compared to other fuel cells, except for AFCs. A critical element is the water management, as the membrane has to stay hydrated; thus, the water cannot evaporate faster than produced in the cell [3;4].

PEMFCs are CO_2 tolerant; they can operate on hydrogen from reformed hydrocarbons as well as on atmospheric air, as the oxidant. They are rather sensitive to CO, which poisons the anode. This is the main challenge combined with the water management and the heat removal required. The reforming of hydrocarbons requires higher temperatures than those delivered by the PEMFC. The processes require several units and this reduces the fuel efficiency and increases the costs of the system. [3]

The operating temperatures of PEMFCs are typically 60-80 ºC; however, more attention is being paid to high temperature cells (HT-PEMFC), operating between 140 and 200 ºC. These have rather simple system designs in combination with the processing of natural gas or other hydrocarbons [7;26]. HT-PEMFCs are able to increase the tolerance to CO to more than 1% and eliminate the critical element of water management. These FCs are typically based on a pure platinum catalyst. Recently, anode gas recirculation in HT-PEMFC has proven to result in higher efficiencies than low temperature PEMFC, because unused hydrogen is utilised through anode gas recirculation [27]. Such a strategy excludes reformatted gases.

PEMFCs are mainly applied to emergency power, portable devices, residential household heating with micro-CHP, or transport [28]. The low temperatures limit the use of PEMFCs, but, in combination with the compact designs, they also enable an extension of the operation time in portable devices [3]. Significant efforts are made to solve the problem of integrating fuel processing into the PEMFC system. As mentioned, natural gas can be combined with HT-PEMFC; however, methanol, DME (dimethyl-ether), ethanol and others are also considered [29;30]. Here, methanol is especially promising, because it is hydrogen-dense and works at rather low temperatures. For methanol HT-PEMFCs, the fuel processing system only requires a reformer. An integrated reforming HT-PEMFC system also gives smaller cell stacks and requires no water management. These systems are also called Reformed Methanol Fuel Cells (RMFC).

Direct methanol fuel cells (DMFC) are also being developed which use methanol directly without prior external reforming. Due to the lower efficiencies, these are mainly considered for small portable devices. However, they are more compact and require little maintenance [17]. They operate at lower temperatures, which makes them unfit for CHP applications, and they have higher contents of noble metal in the catalysts.

6 The characteristics and applications of molten carbonate fuel cells

MCFCs are high temperature fuel cells, which have operating temperatures between 550 and 700 ºC. They do not require noble metals for catalysts and are rather tolerant to fuel impurities. The electrolyte of the cell consists of a molten carbonate salt mixture; however, the exact composition varies. At high temperatures, the salt mixture is liquid and conducts the carbonate ion well. The electrolyte is isolated in a porous ceramic and the charge carrier is carbonate ions (CO_3^{2-}). The anode and cathode are based on nickel. [4]

The MCFC has evolved from the 1960s from work based on the use of coal in FCs. MCFCs function well on gaseous fuels derived from fossil sources or biomass. The high operation temperatures make internal reforming possible, and the temperatures are low enough to make possible the use of materials such as stainless steel. MCFCs are still at the development stage, but have proven to have high efficiencies. Their potential efficiencies are as high as those of SOFCs and they can be combined with gas or steam turbines. MCFCs can be applied to large MW-size CHP or PP. The management of electrolyte and temperatures is critical to the MCFC performance. The main problem related to the application of MCFC is the potential corrosion from the electrolyte, which affects the lifetime of the cells. They require high grade stainless steel. Also the molten carbonate-electrolyte is mobile and a source of CO_2 is required at the cathode. The CO_2 required at the cathode can be recycled from the anode. [4;11;12;16;31;32]

7 The characteristics and applications of solid oxide fuel cells

As opposed to other FCs, the electrolyte in SOFCs is a solid, not a liquid. The electrolyte ceramic mainly consists of yttria-stabilised zirconia, while the anode mainly consists of nickel and yttria-stabilised zirconia. The cathode is typically strontium-doped lanthanum manganese. The catalysts which are being developed are perovskite ion conductors and the charge carrier is oxide ions (O^{2-}). For the direct reforming of hydrocarbons in the SOFC, the catalyst may contain nickel. SOFCs are promising, as they have already proven to have rather long lifetimes at constant operation as well as high efficiencies. A tubular design of the SOFC, which was the design initially developed, is now abandoned in favour of a planar alternative with a more compact scalable design and lower production cost. The first generation planar cells are electrolyte-supported. The second generation cells, which are primarily in focus at the moment, are anode-supported. Third generation, metal-supported cells are currently being developed and tested. These will potentially lower the costs of the cells and enable better start-up performances. [18;33-35]

The main challenges for the SOFCs are temperature gradients in operation, start-up and shot-down. The ceramics are rather porous and the different thermal expansion coefficients of the materials pose a challenge to the cell lifetime. The series of cells required in the stacks all have to be intact for the SOFC to operate, and the replacement of one cell without damaging others is rather difficult. This problem could require new solutions, such as a better match of materials with thermal expansion characteristics, the introduction of thermal management systems or a mechanical solution. Another challenge to the further improvement of SOFCs is to replace some of the ceramics with lower-cost metals, since the ceramics are rather expensive to produce. This requires a reduction in temperatures to around 550 ºC. At present, the temperature has been reduced from 1.000ºC to 650ºC. Efforts are being made to reduce temperatures further in order to enable the use of metal-supported SOFCs [36;37]. This could also contribute to a mechanical solution to the problems of different thermal gradients.

The operation at high temperatures makes the FCs less sensitive to impurities, thus enabling fuel flexibility. The SOFCs can be constructed for internal reforming of different gaseous hydrocarbons. They may also be combined with gas and steam turbines. In order to achieve high efficiencies, the main challenge is to develop anode gas recirculation systems and integrate steam-reforming systems, when using other fuels than hydrogen. SOFCs are mainly intended for stationary use, as the high temperatures may be less suitable for transport. All ranges from micro-CHP to larger CHP and PP are considered suitable applications for SOFCs. SOFCs are expected to be available for commercial use from 2015 [38].

8 Fuel cell balance of plant equipment

Previously, tubular FC designs were most common, especially for high temperature cells. However, nowadays, most FCs have a more compact planar design, which facilitates mass production and reduces losses in the cell.

In order for a FC to deliver direct current at high voltage and to have sufficient capacity, many individual cells are required. In a stack, individual cells are connected in series divided by interconnectors. The interconnectors function as a bipolar metal plate that distributes the electricity produced. Typically, these interconnectors are also designed with channels which transport fuels and output gases to and from the cell. The interconnectors provide a serial connection of the individual cells, while also separating the gases in the cells. The individual cells and interconnectors are separated with sealings. Different planar designs are available for different arrangements of the gas flows and the different types of FCs. In Fig. 1, the principle scheme of a FC stack is illustrated.

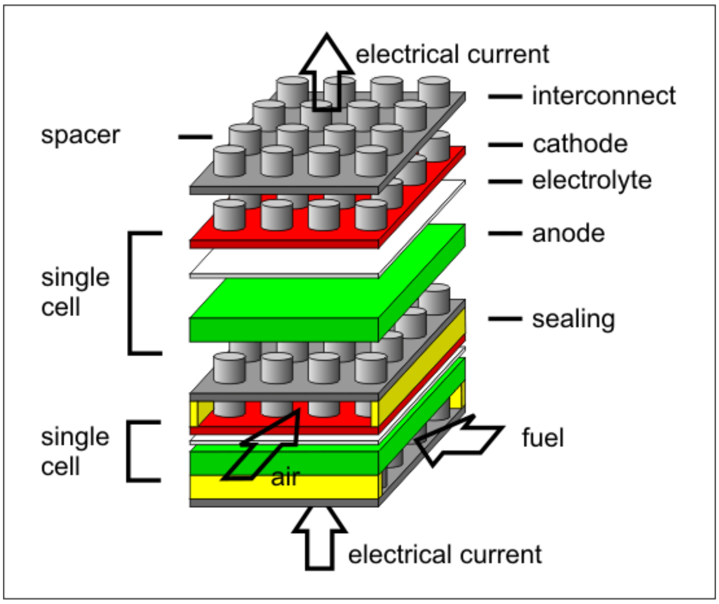

Fig. 1, Principle scheme of a fuel cell stack. [39]

While interconnectors diffuse the gas in the cell, these have to be provided with manifolds enabling the gas streams to enter and exit. This can be constructed to run through cells; be integrated into interconnectors, or be localised externally to the cell and interconnector [16].

To form a functioning power unit, the FC also has to be accommodated to an appropriate support system. Some parts of the systems are similar; i.e. fuel preparation, air/oxidant supply, thermal management, water management, electric power conditioning, and, of course, a system control unit for the FC. The principle scheme of the balance of plant equipment for SOFC is illustrated in Fig. 2. The exact structure and operation of the support system varies with different types of FCs. [4;16]

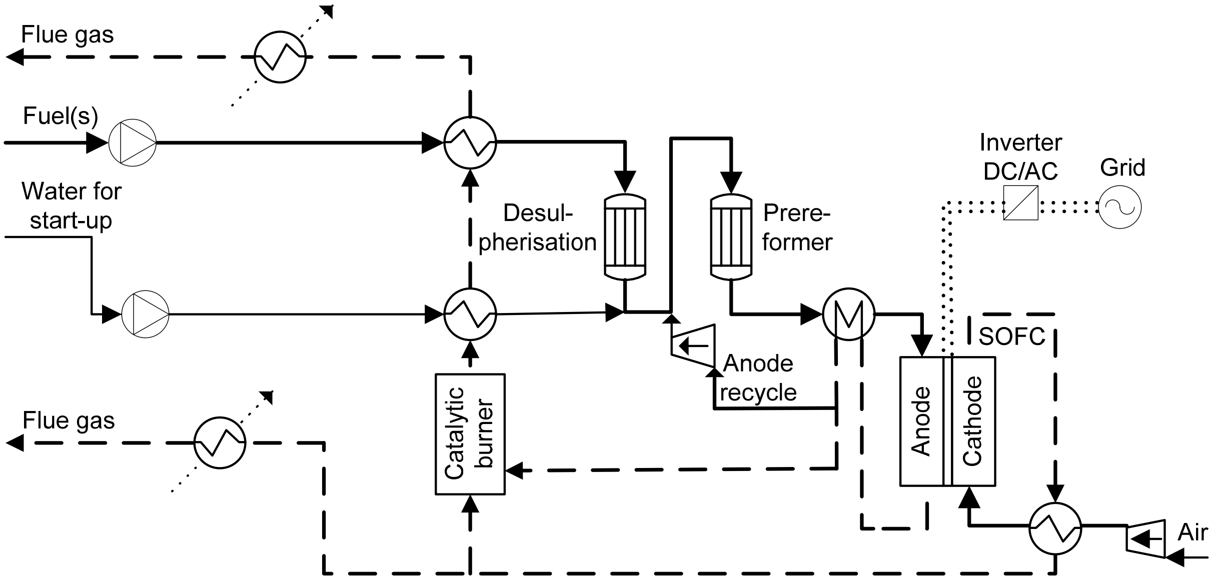

Fig. 2, Principle balance of plant scheme for SOFC. Based on Hansen (CHP) [40].

Except when pure hydrogen is used, fuel processing removes impurities. Typically, this also involves steam-reforming processes to ensure hydrogen-rich fuels. All cells are intolerant to sulphur, and, depending on the type of fuel, the FCs must be fitted with a desulphuriser. In lower temperature cells, CO, CO_2 and NH_3 must also be removed, depending on the type of cell and the type of fuel used. The fuel processing system must also provide fuel and air under the right conditions, i.e. temperature, pressure, moisture and mix, which involves air compressors or blowers as well as air filters. Many of the proposed systems re-use the waste heat and water in the fuel processing, and they also include afterburners in order to utilise the unused fuel from the FC. In integrated methanol-reforming HT-PEMFCs, purification measures can be avoided. The SOFC is still at the development stage and such systems as well as an integrated fuel-reforming system still need to be developed.

For all FC systems, a careful management of the temperatures in the FC stack is required. Water/steam is needed in some parts of the FCs. While water is a reaction product, a water management system is required in most FCs systems to avoid the feed-in of water in addition to fuel and to ensure a smooth operation of the cell. Large differences can be seen between the specific designs of the FCs in terms of fuel and oxidant handling. For high temperature FCs, such as SOFCs, this processing typically also helps to ensure a constant stack temperature as well as longer FC lifetimes by smoothly distributing the different gasses through the cell.

In high temperature FCs, such as MCFC and SOFC, the fuel processing system may be integrated with a fuel-reforming system, enabling the use of high temperature heat for reforming e.g. biogas or natural gas to H_2. Lately, also HT-PEMFCs have been developed with integrated fuel processing, leading to improved total efficiencies [7]. For high temperature FCs, namely MCFC and SOFC, the system may also be integrated with gas and/or steam turbines, in which the high grade heat is used to increase electricity efficiency. This process integration poses a major challenge to FCs at the system level. These issues are intensively researched in order to improve the performance of FC systems. [4;16]

In order to be able to integrate the FC unit into the electricity grid, an inverter must change the current from DC to AC. Like other parts of the systems surrounding the cells, this is associated with losses. Additional power electronics and integrated system control can provide the fuel cells with the same abilities as other traditional power supply units in terms of grid stability, i.e. ancillary services enabling them to contribute to maintaining the voltage and frequency stability of the grid [3]. Recent studies show that the feedback from the inverters to the cells may have negative effects on the lifetime of stacks; these are challenges that will have to be dealt with in the power conditioning supply.

The balance of plant equipment uses a part of the electricity from the cell. Even though the cell itself is scalable for all types of FCs, the energy consumed in order to improve the balance of the plant increases with lower cell capacities, especially in the case of high temperature FCs. These effects differ from one cell type to another. The higher the pressures used in the cell, the more losses result from the balance of the plant. This is especially a challenge to the SOFCs, which are operated at high pressures, and makes the application of hybrid SOFC gas turbines to small-scale systems unlikely.

9 Start-up, operation and regulation abilities of grid-connected fuel cells

The operation and regulation abilities of FCs have to be addressed from a system perspective, since factors such as electrochemical reactions, current and voltage change, gas flow controls, fuel processing, pressure, and water management interact with changing loads. Demands are made on FCs in order to meet certain requirements for power quality. In general, all types of FCs can respond quickly to an experienced load change; however, differences exist in the start-up performances of the FCs. While stacking the cells increases the voltage of the direct current from the FC; voltage decreases as the amount of power drawn from the cell increases. This is solved by use of appropriate power electronics. A DC/DC converter, and possibly also a DC/AC inverter, can convert the output voltage DC to the voltage DC or AC required for the specific application. When converting output DC to AC, the voltage peaks of the cell as well as the voltage and current relation can be regulated. The grid-connected FCs have to meet certain requirements if they are to support the electricity grid stability. A battery can supply start-up power and assist in the power conditioning. Furthermore, a transformer can convert lower voltage power into higher voltages, if needed for the supply to the electricity grid, at the distribution or transmission level. An example of the principle of such a grid-connected system is illustrated in Fig. 2. Stand-alone systems also have to meet the requirements of the applications which they supply. In transport applications, FCs are combined with batteries in order to ensure good start-up capabilities. [3;4;16]

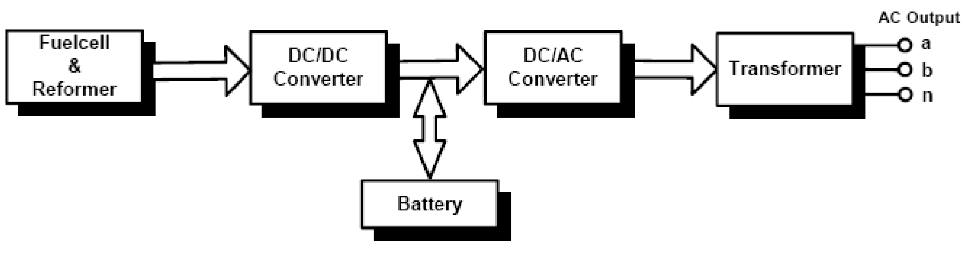

Fig. 2, Principle diagram of grid-connected fuel cells.

For low temperature FCs, such as PEMFCs and AFCs, start-up time is only a few minutes or instant, depending on the system design [4-6;10]. Efforts are also being made to design these systems in such way that they enable a fast cold start-up from below-freezing temperatures [28;41]. The low operating temperatures enable a fast fuel supply and a rapid heat up of the cell to the operation temperature without material problems; however, due to pressure control and liquid water, the system designs meet challenges when operating at low temperatures. The system design of the intermediate temperature HT-PEMFC is promising in this respect, as the systems are less sensitive to pressure changes because the water is gaseous. The question is whether the water in the membranes can flush the acid in the electrolyte; however, no evidence of this effect has been documented yet. In PAFCs, the phosphoric acid becomes solid at a temperature of 40 °C [42]. Unless the PAFCs are either operated continuously or insulated, the start-up time may be hours.

In high temperature FCs, such as MCFCs and SOFCs, the situation is somewhat different. Here, the temperature poses a challenge because of problems with temperature gradients within the cells. Because of their high operating temperature and the temperature gradients, these cells have a start-up of several hours. These problems, however, can be reduced by making intelligent stack designs, such as placing the manifolds horizontally along the stacks or making hexagonal designs; fitting the cells with start-up burners; introducing buffers enabling a smooth start-up load; or, as a potentially more promising alternative, keeping the cells at a high temperature by operating them periodically and with insulation. Insulation has been investigated for SOFCs [43]. It was found that SOFCs can be operated on low amounts of fuel; producing very little electricity, but keeping the temperature at the right operation level. This enables a very fast start-up. However, when temperatures are high, the regulation ability of the FC is system-dependent, i.e. depending on the supply and support system and gas turbine in hybrid systems. Hence, it is possible to eliminate start-up time, start-up and idle fuel consumption in SOFCs by operating at least once a day or by cyclic reheating. This, however, requires the development of an integrated fuel supply system; anode recirculation to maintain high efficiencies, and a better stack design to increase lifetime. The insulation of such high temperature cells also increases the volume of the FC especially in small-scale systems, like e.g. micro-CHP [27]. In combination with higher losses relating to the balancing of the plant with small-scale applications, the insulation required makes larger CHP plant applications more likely, no matter if this insulation increases the possibility of load following or not. Good regulation may also be possible for MCFC and PAFC, but no analyses of this ability have been identified. For SOFCs, metal-supported cells may improve the rapid start-up ability, because the tolerance to thermal gradients in the cells is improved [18;35;44].

The FC systems also have to be designed for the load changes in the applications in which they are potentially used. While all low temperature FCs can follow load changes rapidly, thermal cycling and gas flow handling pose a challenge to high temperature FCs, such as SOFC and MCFC with load changes, and thus have to be handled carefully in the FC system control and design. The electrochemical processes and gas transport can respond quickly. The temperature changes in the cell take place at a slower rate, because of the density of the cells [45]. The temperatures in the cell affect the current and voltage and, thus, the operational characteristics. Since the load response itself is quick, while the temperature changes have longer responses, it is possible to make control systems which can regulate the temperature, in order to achieve the desired responses [20;43;46;47].

In the high temperature FCs, good load-following abilities have been accomplished in the cases of both MCFCs and SOFCs. In a MCFC, the thermal transients normally have long time constants, e.g. from 100 to 1000 seconds, which is due to the relatively large mass of the cell. However, thermal cycling affects the performance of high temperature FCs. This indicates that a good FC control system is important both in terms of dynamic responses due to load changes and to the lifetime of the cell. For MCFCs, experiments with stepwise changes in applied load resistance show that a dynamic response is possible by use of controllable heaters, thermocouples, and insulating materials. Also control systems have been proposed to efficiently avoid thermal cycling. [20;45]

Normally, 20 per cent of full load is the minimum load for FCs. This is a not technical limit but the level at which efficiencies are significantly reduced. The data on load balancing and response times are still limited for both MCFCs and SOFCs. AFC, PAFC and PEMFC have good load-following characteristics, and HT-PEMFC may solve some of the problems for this type of cells. For SOFCs, good load-following abilities have been achieved with existing technology and also good efficiencies at part load [48;49]. Different operation strategies can be applied; however, research into the balance of plant systems is still required for high efficiencies in SOFC. New systems need to be developed in order to achieve faster start-up and to maintain good lifetimes in load-following applications of SOFC.

In CHP applications, heat storages and boilers can reduce the requirements for start-up and shutdown as well as load following. However, good load-following abilities are still required in order to reduce the peak load capacity installed.

Thus, when in operation, all types of FCs may have very fast regulation abilities, providing them with properties similar to those of batteries. With the right control systems, start-up times can be reduced significantly or almost eliminated for high temperature FCs.

10 Conclusion

In this review, the characteristics and potential applications of five different fuel cells have been elaborated. Significant challenges must be overcome, before fuel cells can be applied to broader uses than niche areas. High temperature polymer exchange fuel cells seem to be especially promising for transport or micro-CHP applications. Solid oxide fuel cells may eventually replace combustion technologies in CHP plants; however, start-up times, load-following capabilities, lifetime and efficiencies still have to be improved.

11 Acknowledgements

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Annex I. AFC

Technology (2008-prices)		AFC system			Ref.
Year		2001-4	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data					
Fuel[4 & 5]		Pure H_2	Pure H_2	Pure H_2	[5]
Poisonous substances[5]		CO, CO_2, O_2, S	CO, CO_2, O_2, S	CO, CO_2, O_2, S	[4;5;16]
Diluents		CH_4, NH_3	CH_4, NH_3	CH_4, NH_3	[3;4;50]
Operation temperature	˚C	60-100	60-100	60-100	[5;9;21]
System capacity	MWe	<0,007	<0,01	<0,01	[5;9]
Total system efficiency	%	90	90	90	[2]
Electricity efficiency[6]	%	50-60	50-60	50-60	[2;9;21]
Start-up fuel consumption	GJ/MW	-	-	-	
Time for start-up from cold	Minutes	Instant	Instant	Instant	[5;6]
Idle fuel consumption	MJ/hour	-	-	-	
Technical lifetime (system)	Years	-	15	18	[2]
Technical lifetime (cells/stacks)	Hours	5.000	>5.000	<15.000	[5;51]
Degradation	%/1.000 hours	1-4	1-4	1-4	[51]
Power density	W/cm^2	0,06-0,3	0,06-0,3	0,06-0,3	[5;51]
System weight	kg/kW	30-45	-	-	[8;9]
System volume	kW/l	0,01-0,016	-	-	[9]
Regulation ability					
Fast reserve	MW/15 min	-	all	all	[21]
Regulation speed	MW/second	-	<0,01	<0,01	[21]
Minimum load[7]	% of full load	-	20	20	[21]
Financial data[8]					
Specific investments	M€/MWel	1-7	0,8-4	0,5-0,6	[2;5;9;51]

[4] Direct AFCs operated on methanol, ethanol, sodium borohydride or natriumborohydride are also being investigated. However, these cells have a power density which is lower, by a factor three to ten, than the density of the AFCs presented here, and are thus most suitable for small portable equipment [23].

[5] The use of reformed gas as fuel has mostly been disregarded because of the CO and CO_2 contents [5]. The oxidant also has to be perfectly pure oxygen. The exact acceptable level of CO_2 is unclear, although 50 ppm of CO_2 have been reported, when using circulating electrolytes, which can lead to reversible effects [5;9;21].

[6] This efficiency is only possible with perfectly pure hydrogen with no CO_2.

[7] The minimum load is noted in order to ensure the high efficiency and is thus not a technical limit.

[8] Very few assessments have been made of the system costs. Investment cost are estimated to a range between 0,2-1,6 M€/MWel in [5]. The costs of replacing stacks are 75-90% of the investment costs indicated. 2015 data are assumed to be in the range in between now and 2030. The costs of the consumables for 5.000 operating hours, i.e. the soda lime and KOH electrolyte involved, are potentially between 6 and 9% of the total costs indicated [5]. The fixed O&M will increase for micro AFC-CHP depending on the number of operation hours and the lifetime of the stack.

Annex II. PAFC

Technology (2008-prices)		PAFC system			Ref.
Year		2000-4	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data					
Fuel		H_2	H_2	H_2	[16]
Poisonous substances		CO, S, NH_3	CO, S, NH_3	CO, S, NH_3	[3]
Diluents		CO_2, CH_4	CO_2, CH_4	CO_2, CH_4	[3]
Operation temperature	˚C	180-220	180-220	180-220	[2]
System capacity	MWe	0,2	0,05-5	0,05-5	[2;3;16]
Total system efficiency[9]	%	87	90-100	90-100	[2;3]
Electricity efficiency	%	37-42	37-42	45	[4;16;25;52]
Start-up fuel consumption	GJ/MW	-	-	-	
Time for start up from cold[10]	Hours	Several	Several	Several	[6]
Idle fuel consumption	MJ/hour	-	-	-	
Technical lifetime (system)	Years	-	-	-	
Technical lifetime (cells/stacks)	Hours	30.000-53.000	>50.000	>50.000	[3;16;51]
Degradation[11]	%/1.000 hours	0,2-0,7	-	-	[25;51]
Power density[12]	W/cm^2	0,1-0,26	-	-	[4;16;25;51]
System weight	kg/kW	-	-	-	
System volume	kW/l	0,07	0,08	0,1	[2]
Regulation ability					
Fast reserve	kW/15 min	All	All	All	
Regulation speed	kW/second	0,2	0,05-5	0,05-5	
Minimum load	% of full load	-	-	-	
Financial data[13]					
Specific investments	M€/MWel	2,5-4,4	2,5	1,9	[2;51;52]

[9] For HT-PEMFC, 90-100 per cent total efficiency has been achieved and may also be possible for PAFC.

[10] The start-up time, start-up and idle fuel consumption can be eliminated in SOFCs by operating at least once a day or by cyclic reheating. The same may be possible for PAFC, but no analyses of this ability have been identified. One of the problems are the fact that the phosphoric acid is solid at a temperature of 40 °C [42].

[11] Degradation was reported as 3% over 6.000 hours in 2002 [25].

[12] The power density has been proved to be 0,31 W/cm2 if the pressure is increased to approx. 8 atm., thus lowering the costs of the stacks. However, this requires high pressures which would increase the system costs again [16].

[13] Only one estimate of potential future investment costs have been identified [2]. Two references confirm the current prices between 2,500 and 4.000 €/KW [51;52]. Fixed operation and maintenance costs depend on the technical lifetime of the system compared to the lifetimes of the cells and stacks. Variable operation costs are between 0,004 and 0,011 €/KWh [52].

Annex III. LT-PEMFC

Technology (2008-prices)		LT-PEMFC system			Ref.
Year		2007	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data					
Fuel		H_2	H_2	H_2	[4]
Poisonous substances[14]		CO, S, NH_3	CO, S, NH_3	CO, S, NH_3	[3;4]
Diluents		CO_2, CH_4	CO_2, CH_4	CO_2, CH_4	[4]
Operation temperature	˚C	60-80	60-80	60-80	
System capacity	MWe	0,0001-0,005	0,001-0,2	0,001-0,2	[3]
Total system efficiency	%	80-90	>90	90-100	[7;34;53]
Electricity efficiency	%	30-37	30-37	40-50	[3;17;34;51]
Start-up fuel consumption	GJ/MW	-	-	-	
Time for start up from cold	Minutes	Instant	Instant	Instant	[4]
Idle fuel consumption	MJ/hour	-	-	-	
Technical lifetime (system)	Years	-	15-20	18-20	[2]
Technical lifetime (cells/stacks) [15]	Hours	20.000	>20.000	30-40.000	[34;51;54;55]
Degradation[15]	%/1.000 hours	-	-	-	
Power density	W/cm^2	0,25	0,25-0,5	>0,5	[5;51;56;57]
System weight	kg/kW	-	-	-	
System volume	kW/l	-	-	-	
Regulation ability					
Fast reserve	kW/15 min	All	All	All	[4]
Regulation speed	kW/second	All	All	All	[4]
Minimum load	% of full load	-	-	-	
Financial data[16]					
Specific investments	M€/MWel	10-20	1,0-1,9	0,3-1,0	[2;34;51;58]

[14] Normally, CO amounts must be reduced to below 10 PPM and the catalytic process involved can be integrated into the fuel processing system [4]. This increases the system complexity and costs, and no good solutions have been identified yet for low temperature PEMFC [10].

[15] The degradation is heavily dependent on the CO poisoning and the system looked upon. The cell lifetime of 40.000 hours is the target for use in stationary applications. There is a tradeoff between cell lifetime, costs, materials and the size of the system. Lower lifetime could be acceptable if periodic maintenance costs are low enough.

[16] The investment costs for 2015 are based on an intermediate towards potential end costs. Investment costs are valid for FC, i.e. boiler and heat storage have to be added in order to create a system. The fixed operation and maintenance costs depend on the technical lifetime of the system compared to the lifetimes of the cells and stacks.

Annex IV. HT-PEMFC

Technology (2008-prices)		HT-PEMFC			Ref.
Year		2007-8	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data					
Fuel		H_2	H_2	H_2	[4]
Poisonous substances[17]		CO, S, NH_3	CO, S, NH_3	CO, S, NH_3	[3;4]
Diluents		CO_2, CH_4	CO_2, CH_4	CO_2, CH_4	[4]
Operation temperature	˚C	140-200	140-200	140-200	[7;10;26]
System capacity	MWe	0,0001-0,005	0,001-0,2	0,001-0,2	[3]
Total system efficiency	%	85-90	90-95	90-100	[7;34;53]
Electricity efficiency [18]	%	55	55	55	[27]
Start-up fuel consumption	GJ/MW	-	-	-	
Time for start up from cold	Minutes	Instant	Instant	Instant	[4]
Idle fuel consumption	MJ/hour	-	-	-	
Technical lifetime (system)	Years	-	15-20	18-20	[2]
Technical lifetime (cells/stacks) [19]	Hours	11.000	>20.000	30-40.000	[34;51;54;58]
Degradation [19]	%/1.000 hours	0,9	-	-	
Power density	W/cm^2	0,25	0,25-0,5	>0,5	[5;51;56;57]
System weight	kg/kW	-	-	-	
System volume	kW/l	-	-	-	
Regulation ability					
Fast reserve	kW/15 min	All	All	All	[4]
Regulation speed	kW/second	All	All	All	[4]
Minimum load	% of full load	-	-	-	
Financial data[20]					
Specific investments	M€/MWel	10-20	1,0-1,9	0,3-1,0	[2;34;51]

[17] HT-PEMFCs reduce the sensitivity to CO significantly, thus lowering the demands for purity of e.g. reformed fuels [7]. Up to 30.000 PPM CO tolerance has been reported [10].

[18] Integrated natural gas and methanol HT-PEMFCs have been developed [7;17]. A benefit can be achieved by combining the reforming process with the FC system, especially if the HT-PEMFC is combined with steam reforming [7;53]. In this respect, methanol reforming is an advantage compared to natural gas, as a temperature of 250-300˚C is required for reforming, which is half the level of natural gas. For HT-PEMFC, 55 per cent electrical efficiency has been achieved when operating on hydrogen [27]. Here, an average electrical efficiency of 55-60% is assumed to be possible in the long term.

[19] The degradation is heavily dependent on the CO poisoning, which is lowered in HT-PEMFC. The lifetime, however, is still lower than in the case of LT-PEMFC, as the cells are less developed. The cell lifetime of 40.000 hours is the target for use in stationary applications. To increase the lifetime, power density can be lowered or more platinum can be added. There is a tradeoff between the cell lifetime, costs, materials and size of the system. Lower lifetime could be acceptable if periodic maintenance costs are low enough.

[20] The investment costs for 2015 are based on an intermediate towards the potential end costs. Investment costs are valid for FC, i.e. boiler and heat storage have to be added in order to create a system. The fixed operation and maintenance costs depend on the technical lifetime of the system compared to the lifetimes of the cells and stacks.

Annex V. MCFC

Technology		MCFC-systems			Ref.
Year		2006-7	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data					
Fuel(s)[21]		H_2, CO, NH_3, hydrocarbons, alcohols			[2;4;11;59]
Poisonous substances		S	S	S	[4]
Diluents		CO_2	CO_2	CO_2	[4]
Operation temperature	˚C	550-700	550-700	550-700	[3;12;31]
System capacity	MWe	0,25 -3	0,25-50	0,25 - > 100	[2;12;31;45;60]
Total system efficiency	%	80-85	85-90	90	[2;12;59;61]
Electricity efficiency[22]	%	45-55	45-55	55-60	[2;12;31;61;62]
Start-up fuel consumption	GJ/MW	-	-	-	
Time for start up from cold[23]	Hours	Several	Several	Several	[6]
Idle fuel consumption	MJ/hour	-	-	-	
Technical lifetime (system)[24]	Years	-	20-30	20-30	
Technical lifetime (cells/stacks)[24]	Hours	10.000	10-25.000	25-40.000	[32;63]
Degradation	%/1.000 hours	-	-	-	
Power density	W/cm^2	0,15	0,15-0,2	0,2-0,5	[6;12;32]
System weight	kg/kW	-	-	-	
System volume	kW/l	-	-	-	
Regulation ability[25]					
Fast reserve	MW/15 min	All	All	All	[45]
Regulation speed	MW/second	-	0,25-50	0,25 - > 100	[45]
Minimum load	% of full load	-	-	-	
Financial data[26]					
Specific investments	M€/MWe	4,8-5,3	2,0-4,8	1,2-1,5	[2;3;60;62]

[21] CH_4 is a fuel in external reforming and internal reforming cells. CO_2 has to be provided along with ambient air at the cathode side [3;4]. Higher hydrocarbons have to be removed.

[22] The MCFC can potentially be combined with gas or steam turbines, increasing the potential electrical efficiency to >70 %, where 15% is the output from the turbine [3;61].

[23] The start-up time, start-up and idle fuel consumption can be eliminated in SOFCs by operating at least once a day or by cyclic reheating. The same may be possible for MCFC, but no analyses of this ability have been identified.

[24] The same system lifetime as in the case of SOFCs is assumed to be possible. Only rather old estimates of the stack lifetime have been identified, thus the lifetimes for 2015 and 2030 are uncertain. The lifetime is dependent on whether the problems with the highly corrosive electrolyte are solved.

[25] The regulation abilities of MCFCs are poorly described. However, temperature and dynamic response control systems are being developed [20;45], which may eventually enable good regulation abilities without higher degradation and lower lifetimes because of thermal cycling. The regulation ability is also dependent on the support system.

[26] The costs in 2030 are based on a goal of reaching approx. 1.000 $/kW, described in a publication from 2001 [2]. The fixed operation and maintenance costs depend on the technical lifetime of the system compared to the lifetimes of the cells and stacks.

Annex VI. SOFC

Technology		SOFC-systems			Ref.
Year		2006-7	2010-15	2020-30	
Data type	Unit	Status	Potential	Potential	
General data[27]					
Fuel(s) [28]		H_2/CH_4	H_2, CO, NH_3, hydrocarbons, alcohols		[2;36;64-66]
Poisonous substances		S (>1 PPM)	S (>1 PPM)	S (>1 PPM)	[4]
Diluents		CO_2	CO_2	CO_2	[4]
Operation temperature	˚C	650-850	600-700	400-600	[35;36]
System capacity	MWe	0,005 - 0,2	0,25 - 5	0,25 - > 100	[2;38;66]
Total system efficiency	%	80-85	90	90	[2;34;38;65]
Electricity efficiency [29]	%	40	56	60	[13;34;38;48]
Start-up fuel consumption[30]	GJ/MW	-	2,3-4	2,3-4	[43;47]
Time for start up from cold[30]	Hours	10 to 20	10 to 20	1-20	[18;35;43;47;64]
Idle fuel consumption[30]	MJ/hour	-	0,12	0-0,12	[43;47]
Technical lifetime (system)[31]	Years	-	20-30	20-30	[38;65]
Technical lifetime (cells/stacks)	Hours	>8.000	40.000	50.000	[34;36;38;64;65]
Degradation	%/1.000 hours	0,5-1,0	<0,25	~0,1	[36;64;65]
Power density	W/cm^2	0,15-0,38	~0,4-0,5	~0,5-1	[18;35;36;43;44]
System weight[32]	kg/kW	-	8-20	8-20	[47;65]
System volume[32]	kW/l	-	0,3	0,3-0,6	[47]
Regulation ability[30]					
Fast reserve	MW/15 min	-	all	all	[43;46;70]
Regulation speed	MW/second	-	1-2	1-2	[43;46;70]
Minimum load[33]	% of full load	-	20	20	[69;70]
Financial data[34]					
Specific investments	M€/MWe	-	0,8-1,0	0,3-0,6	[2;16;34;38;51;65]

[27] The operation temperatures, the efficiency, the power density, etc., are dependent on the development stage of the SOFC. The current FCs are mainly anode supported, while in the future, metal-interconnects will most likely support the cell, lowering the temperature, the resistance and the degradation, while increasing the efficiencies.

[28] SOFCs have mainly been tested on pure H_2 and CH_4. CH_4 is a fuel in external reforming and internal reforming cells [3;4].

[29] The electrical efficiency can potentially reach 70-75 %, when combined with gas turbines in larger applications (>0,25 MWe) [3;13;34;67;68]. The electrical efficiency of micro SOFC CHPs (typically 1-5 kW-e) in 2015 is potentially between 40 and 50 % [38], and in 2030, the efficiency may increase to 50-55% [36;46;69]. The efficiencies are for natural gas-based systems and require the development of anode recirculation and integrated reforming fuel supply.

[30] The start-up time, start-up and idle fuel consumption may be eliminated by operating the SOFC at least once a day or by cyclic reheating. At high temperatures, the regulation ability is system-dependent, i.e. depending on the supply side/support system or gas turbine. Metal-supported SOFCs may improve rapid start-up [18;35;44]. The minimum load is noted in order to ensure the high efficiency and is not a technical limit.

[31] For small CHP, 20 years (0,25-50 MWe), and for large PP and CHP, 25-30 years [38;65].

[32] For mobile applications, the weight is in the lower end (7,7-9 kg/kW), and for stationary, in the higher end (15-20 kg/kW) [47;65]. For micro SOFC-CHP, the volume is several orders of magnitude higher because of the system size in comparison with the cells. The system volume has only been found for mobile applications.

[33] The efficiency of SOFCs is lower at part loads below 20%. Normally, the peak efficiency is between 20-25% of the capacity, although from 20 to 100%, the total system efficiency should be stable [70]. Modelling shows that control systems can maintain the high efficiencies at part loads [48;49].

[34] The costs of micro SOFCs are higher and, for CHP and PP, the costs of boilers and heat storages have to be added. The fixed operation and maintenance costs depend on the technical lifetime of the system compared to the lifetimes of the cells and stacks.

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Appendix II

Solid oxide fuel cells and large-scale integration of intermittent renewable energy

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Abstract

Solid oxide fuel cells (SOFC) can play a key role in the balancing and integration of intermittent renewable energy such as wind power. In future energy systems, generation is distributed and, compared to gas and steam turbines, SOFC have the potential for increasing fuel efficiency in both large central and small distributed combined heat and power plants (CHP). SOFC also have the potential for participating in the grid stabilisation task; thus, enabling further reductions in fuel consumption and improving the integration of intermittent resources. SOFC may provide a new design of the ancillary service supply, which requires new technologies, as existing base load plants become less important. The start-up and the'mal cycling of the SOFC may pose material problems and reduce the lifetime of the cells. The analyses in this paper conclude that it is less important to develop SOFC for continuous operation, than it is to develop SOFC with fast dynamics to improve load balancing in future electricity systems with high amounts of intermittent production. With increasing shares of renewable energy, the number of operation hours decreases and, hence, the lifetime of the cells becomes less significant. Efficient SOFC may play a key role in future efficient 100 per cent renewable energy systems and can be a more suitable technology in such systems than gas and steam turbines.

Keywords: solid oxide fuel cells, SOFC, renewable energy, ancillary services, wind power, energy system analyses, load balancing

1 Introduction

Wind turbines depend on wind and the cogeneration of heat and power (CHP) depends on heat demand. Therefore, energy systems with substantial distributed generation, such as wind power and CHP, need to be designed in ways which accommodate such climate-dependent technologies. The fact that many other renewable energy sources are also fluctuating and intermittent in nature adds to the challenge of utilising these in energy systems. Some of the potential solutions involve the use of heat storages in CHP plants to detach demand and production, as well as the instalment of large heat pumps in the plants. Thus, while producing electricity efficiently from CHP at times with low shares of wind power, the heat pumps and heat storages at CHP plants can replace CHP production in times with abundant wind resources. Research shows that flexible energy technologies are needed in order to integrate large amounts of wind power and that this flexibility is more cost-efficient than investments in larger transmission lines [1-6]. Research also shows how a wind power penetration of more than 50 per cent is technically achievable from a load balancing perspective. At the same time, it is economically feasible in the Danish energy system, provided that the system also encompasses flexible technologies integrating wind power [7-10].

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In Denmark, a current wind power capacity of 3,149 MW is installed at 5,200 different locations, which is able to supply approx. 20 per cent of the electricity demand [11;12]. Another 2,200 MW is small CHP plants or industrial production at more than 700 different locations, of which more than 650 are smaller than 10 MW [12]. In addition, the energy supply system also includes 17 central power plants (PP) and CHP plants with a total capacity of 7,968 MW [13]. This current energy supply status is the result of a transition from a classical centralised system with very few and large PP to a distributed system, over the last 20 years [14]. In Fig. 1, the development of the installed capacities is illustrated and the diminishing fraction of central plants is clear.

The development towards an even more distributed generation system is expected to continue. In 2012, the total wind power installed is planned to be 4,124 MW, as offshore wind power is planned to increase from 423 MW in 2008 to 1,223 MW in 2012 and onshore wind power is planned to increase by 175 MW in the same period.

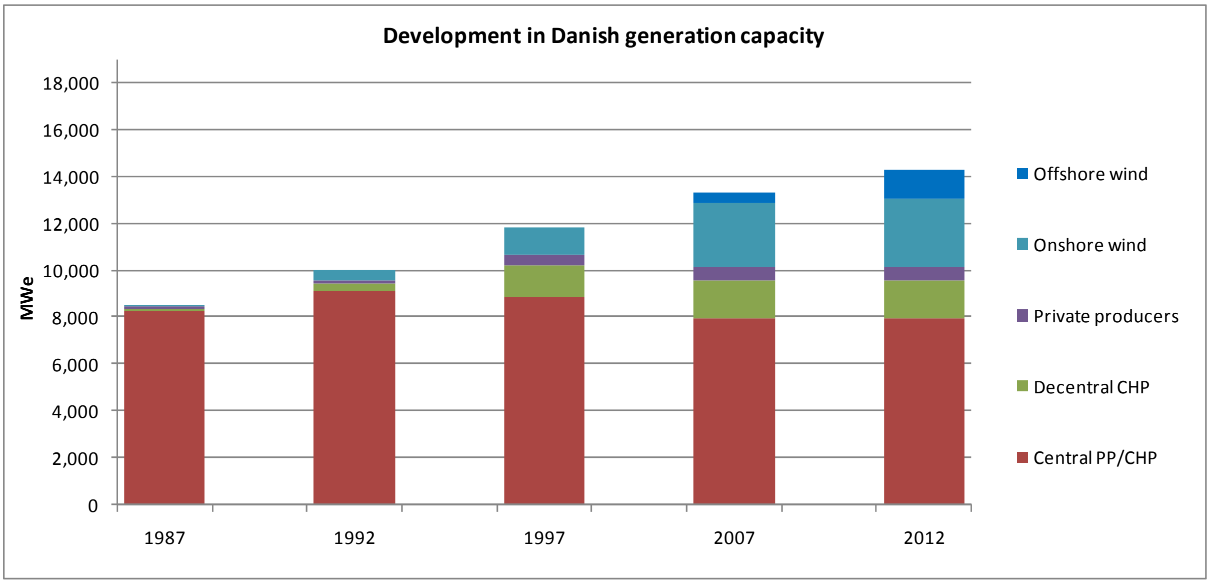

Fig. 1, Capacities of technologies in the Danish energy system from 1987 until 2007 and in the anticipated scenario in 2012.

In 2007, electric peak load was 4,981 MW in the summer and 6,124 MW in the winter. Minimum demand was 2,303 MW in the summer and 2,868 MW in the winter. Both in winter and summer time, it is hence possible for the distributed generation to cover the electricity demand.

The Danish electricity system consists of a western and an eastern system, of which the western system by far has the largest stock of wind turbines and distributed local CHP. The 400 kV transmission grid is illustrated in fig. 2. Data available from the Danish TSO (Transmission System Operator) Energinet.dk reveals that, in 2007, more than 300 hours could have been supplied solely by distributed generation in the western part; however, partly due to ancillary service restrictions and partly due to exports, this was not the case. During these hours, central PP generated 1,022 MW on average and had a minimum production of 560 MW [15]. During the whole year, the minimum production from central PP was 446 MW in the western part. In the eastern part, distributed generation was not able to meet the total demand at any hour; however, this is likely to change with the upcoming erection of wind turbines planned until 2012. In the eastern system, the minimum production from central PP was 185 MW during 2007. In addition to domestic generation equipment, both the eastern and western system has strong interconnections abroad, which are utilised for load balancing.

While the transition from a classic system with few producers to a system very much influenced by distributed generation has occurred, the control system has changed from an old-style technical-operational system to a market-based system with producers and consumers placing bids on a market.

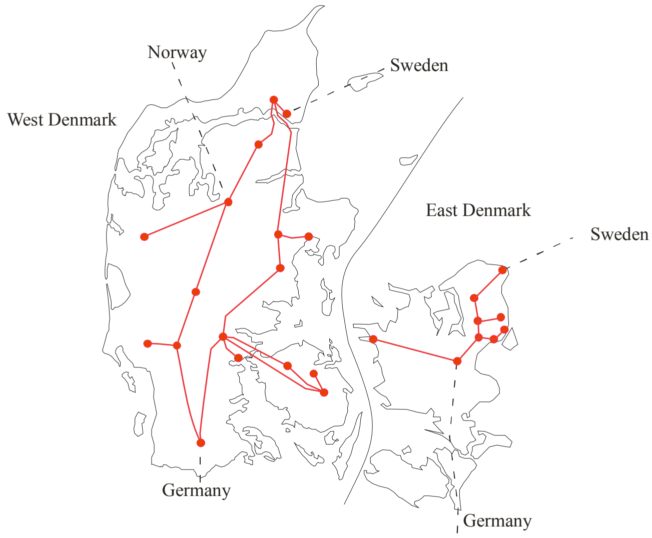

Fig. 2, The 400 kV transmission grid in Denmark and connections abroad.
The two systems will connect via a DC line in the future.

The electricity market is designed in a manner which takes into account the different services required and the technical properties of the technologies traded.. Fig. 3 illustrates the power trade markets. Generally, the market is divided into three categories: the market for intraday trading influenced by imbalances in production and demand; the day-ahead market for hour-by-hour spot market trading; and finally, the financial and ancillary service market.

Denmark is part of the Nordic power market area Nord Pool, which handles the financial market and the day-ahead spot market. The Danish TSO handles both the long-term trading of ancillary services, including reserve capacity, and the intraday utilisation and payment of these services.

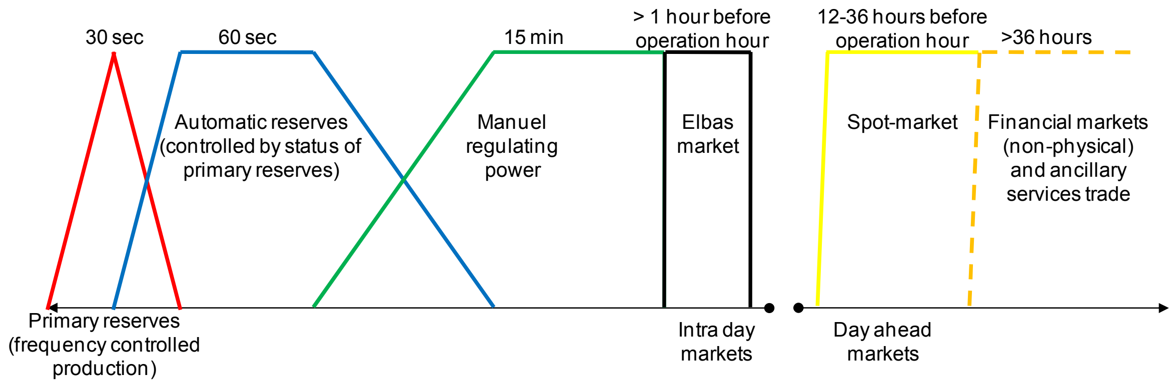

Fig. 3, Electricity market design in the Nord POOL area.

This market design makes it rather challenging for wind power to act on the market. Forecasts must be very accurate 12 to 36 hours ahead in order for producers to be able to bid on the day-ahead market. In the western part of Denmark, an error in the wind forecast of 1 m/s requires up to 320 MW of dispatchable power generation [16] – the cost of which should be covered by the wind turbine owners if they were to participate on the spot market on equal terms with other participants. The Elbas market has been introduced in order to facilitate better trading of intermittent resources, such as wind, after the spot market has been settled and before the hour of operation. Although several improvements have been made regarding wind forecast, extreme situations, such as the storm in Denmark on the 6th of January 2005, illustrates how rapid changes in wind production can occur. On that day, wind forecasts anticipated full wind power production; however, wind speeds rose to above 20 m/s; a speed which caused the shutdown of land-based wind turbines. Wind speeds even rose to approx. 30 m/s, shutting down the 160 MW offshore wind turbines at Horn Reef, operating with a cut-out speed of 25 m/s. This resulted in an unexpected power deficit of 1,800 MW, when wind speed reached its maximum [16].

In the case of Denmark, many local CHP plants have begun operating on the spot market using the flexible combination of CHP production, boilers and heat storages. As a step further along this path, local CHP plants also have the possibility of participating in the manual regulating power market, thus improving their economic performance, while reducing the demand for regulating power from central PP [16]. Still, only central PP supply primary and automatic reserves. Keeping in mind the fact that the share of intermittent renewable resources will increase in the coming years, the demand for regulating power and reserves will also increase. Other providers are needed, unless the system is to continue to rely on the existence of large central plants predominantly run on fossil fuels.

This technically rather complex Danish energy system represents challenges to the TSOs, which traditionally control voltage and frequency to secure grid stability by utilising central PP fitted with synchronous generators. As the electricity demand is increasingly supplied from distributed energy plants, other units are needed to supply these ancillary services. Previous studies have analysed how wind power, CHP and heat pumps can supply ancillary services, also in systems with a significantly more distributed energy supply [14;17-19]. The Danish TSO controls a full-size system currently experiencing a change and facing a challenge, which is elsewhere only seen in computer simulations. The TSO has initiated research on how to handle a system with even more distributed generation. One of the research areas is a power system that breaks up into cells with sufficient components to operate in island mode. This system can disconnect from the main system in situations with system faults and function autonomously by using local generation at CHP plants and wind turbines [14]. The TSO may also pursue better trade models for the utilisation of the interconnection to Norway and Sweden, thus using the highly flexible and potential rapidly changing hydro power of these countries, as well as involving the local CHP plants already installed in the regulation task [16]. Improved wind forecasting is another option; and the establishment of a Great Belt Link to connect the two electricity areas in Denmark will also give the TSO more balancing options [16]. However, as Østergaard (2008) [20] shows, there are limits to the flexibility which the interconnection of two TSO areas with substantial wind power can provide. Yet a possibility is virtual power plants, in which smaller units are pooled with the aim of gaining a feasible market access.

1 Scope of the article

New technologies can increase the fuel efficiency and feasibility of energy systems with very large shares of distributed renewable energy and CHP, such as load-following solid oxide fuel cells (SOFC) in CHP plants; electric vehicles, electrolysers and heat pumps. These technologies may also assume the role of providing reserves and ancillary services in the future.

In this paper, the requirements for ancillary service providers in the present Danish energy system are reviewed. These requirements are compared to SOFC and other fuel cell types in order to investigate whether or not these fuel cells would be able to meet the requirements and thus play a role as ancillary service providers in the future.

In order to determine the effects of SOFC on energy system performance, the fuel cells are analysed in three different energy systems replacing gas and steam turbines; a 2030 business as usual system as well as a 50 per cent and a 100 per cent renewable energy system. The analyses are conducted under four ancillary service supply scenarios and results are assessed in terms of fuel efficiency and the ability of the system to integrate intermittent renewable energy.

2 Ancillary service requirements

Ancillary service providers are the technologies that assist in maintaining grid stability. More specifically, this involves technologies assisting in maintaining frequency stability and voltage stability as well as ensuring that sufficient short-circuit power is available. Frequency and voltage control is accomplished through the control of active and reactive power production and the consumption of the units. Thus, frequency control is also linked to the dispatchability of the technologies in terms of the production (or consumption) of active power. In order for an electricity system to be stable, however, it does not suffice to focus on active power and whether or not the technology is dispatchable; the full range of ancillary services need to be supplied.

Different guidelines for reserves and different definitions of the various parts of the ancillary supply apply to different grid areas. In the European TSO cooperation, the UCTE, of which the western part of Denmark forms part, recommendations correspond to approx. 100 MW for both of the two Danish areas. This recommendation (R) is based on the minimum secondary control reserves, which can be estimated as:

$R = \sqrt{10\text{MW} * \max \text{load} + 150\text{MW}^2} - 150\text{MW}$ [21]

As mentioned, different technical requirements apply to different markets. Here, we look at some of the current generic requirements for areas where the Danish TSO is responsible for the control and operation of the system. The requirements described here are an excerpt based on data from the Danish TSO, Energinet.dk. In Table 1, the requirements regarding start-up and load gradients for participation on the Danish markets for physical power trading are listed, based on the technical regulation for grid connection of units [22] as well as the tenders for regulating power capacity of May and June 2008.

Type of service	Primary reserves	Automatic reserves	Manual regulating power	Elbas market	Spot market
Capacity	+30/-30 MW +14/0 MW	+140 /-140 MW +16/-16 MW	Constantly at disposal +320/-16 +300 / 0 MW Max. in 2007: +510/-330 MW +142/-170 MW	Dependent upon trading	Dependent upon trading
Required start-up time	Immediately, min. linear to 100% in: 30 s. 150 sec.	Activated within: 30 sec. 150 sec.	0-15 min.	<15 min.	<15 min.
Min. gradient required	100%/30 s. 100%/150 s.	Min. 10% of fuel load/min. *	Full load within 15 min.	Full load within 15 min.	Full load within 15 min.
Activation	Automatically by frequency deviation	Load-frequency control activation mechanism	Manually	Manually	Manually

Table 1, Generic requirements for participation on the physical power trading markets. Where two sets of data are presented, the first presented is applicable to the western part and the second to the eastern part.
* Only specified for the western part of Denmark

For the primary and automatic reserves, a total up and downward regulation capacity of approx. 200 MW has to be available – corresponding quite well to the UCTE recommendations. The main part of this capacity is located in the western part of Denmark. Here, the primary reserve is activated by power frequency regulators and is sustained for a minimum of 15 minutes or until the automatic reserves replace these. The primary reserves should be available for power frequency control again after 15 minutes.

In the next step, the capacities on the regulating power market can supply the up or downward regulation required. This is settled on the regulating power market. On this market, a part of the capacity is constantly at the TSO's disposal based on monthly tenders. Through this agreement, the TSO is obliged to bid on the regulating power market. The remaining bidders are producers who find it attractive to bid in the given situation.

In 2007, the total maximum of manual regulating power required was approx. 650 MW in upward and approx. 500 in downward regulation.

As an additional requirement, the Danish TSO has specified that a minimum of three large central plants in western Denmark, which are capable of supplying ancillary services, must be in operation and one must be on standby. The standby PP must be able to go online within six hours. Also in the eastern part of Denmark, a minimum of three PP must be operating. Considering the fact that a total of six central PP are required and assuming a typical PP block of 350 MW running at a minimum partial load of 20 %, this is equivalent to a minimum of 420 MW. In the Danish energy system, the central PP are mainly coal-fired PP, which sometimes run below optimal efficiency in order to stabilise the grid and secure rapid up and downward regulation capacities.

3 Potential start-up and regulation abilities of solid oxide fuel cells

In fuel cells, the operation and regulation abilities are controlled and designed from a fuel cell system perspective, with electrochemical reactions, current, voltage, gas flow, fuel processing, pressure, and water management interacting with changing loads. In addition, certain power condition requirements have to be met by fuel cell auxiliary equipment to enable the supply of ancillary services. Generally, all types of fuel cells can respond quickly to an experienced load change; however, different fuel cells have different start-up performances. While the stacking of the individual fuel cells increases the voltage of the direct current from these cells; voltage decreases if the power drawn from the fuel cell is increased. This is solved with the appropriate power electronics, such as DC/DC converters or DC/AC inverters, depending on the specific application. When converting the fuel cell DC output to AC, voltage and current can be regulated in such way that the system can supply ancillary services. Batteries are required to supply the start-up power needed in certain stand-alone systems. These can also assist in the power conditioning. Finally, conventional transformers are used to convert low-voltage power into power at the relevant electric grid voltage. [23-25]

In low temperature fuel cells, such as polymer exchange membrane fuel cells (PEMFC) or alkaline fuel cells (AFC), start-up time is only a few minutes or instantly depending on the specific system design [23;26-28]. The low operating temperatures enable a fast fuel supply and the rapid heat up of the cell to the operation temperature without material problems; however, the system designs face challenges when operating at low temperatures, because of the pressure control and the formation of liquid water taking place. The system design of high temperature PEMFCs is promising in this respect, as the systems are less sensitive to pressure changes because the water is gaseous. In phosphoric acid fuel cells (PAFC), the phosphoric acid becomes solid at a temperature of 40 °C [29]; thus, unless operated continuously or insulated, the start-up time may be hours. Systems for fast cold start-up below freezing are also investigated [30;31].

In fuel cells operating at higher temperatures, such as molten carbonate fuel cells (MCFC) and the SOFCs in focus in this article, the situation is somewhat different. Here, high temperatures pose a challenge because of problems with temperature gradients within the cells, which affects the lifetime of the cells. Start-up of these fuel cells may take several hours, because of their high operating temperature and the maximum temperature gradients. These problems can, however, be reduced with intelligent stack designs or by keeping the cells at a high temperature through periodical operation and using thermal insulation. Intelligent stack design involves placing the manifolds horizontally along the stacks or making hexagonal stack designs, fitting the cells with start-up burners. Insulation has e.g. been investigated for SOFCs [32]. It was found that SOFCs can be operated on low amounts of fuel, which produce very little electricity but maintain temperatures at operation level. As mentioned, the regulation ability of the fuel cells is system-dependent, i.e. influenced by the supply and support system and hybrid systems in which SOFC are combined with gas turbines to further increase efficiencies. Potentially, start-up times can be eliminated, and so can start-up and idle fuel consumption in SOFCs, by operating at least once a day or by cyclic reheating. This naturally requires a certain amount of fuel, though less than the alternative. The same may be possible for MCFC and PAFC, but no analyses of this ability have been identified. For SOFCs, metal-supported cells may improve the rapid start-up and thermal cycling ability, because these cells have a better tolerance to thermal gradients [33-35].

All low temperature fuel cells can follow load changes rapidly and handle thermal cycling and gas flow rather well; however, this is a challenge to high temperature fuel cells such as SOFC and MCFC. In these cases, load changes must be handled carefully in the control and design of the fuel cell system. The electrochemical processes and gas transport can respond quickly to changes. The temperature changes in the cell take place at a slower rate, because of the density and thermal capacity of the cells [36]. The temperatures in the cells affect the current and voltage and thus the operational characteristics. Since the load response itself is quick, while the temperature changes have a longer response time, it is possible to make control systems which can regulate the temperature in order to achieve the desired responses [32;37-39]. Good load-following abilities have been accomplished for both SOFCs and MCFCs. In the case of MCFCs, the thermal transients normally have long time constants, e.g. from 100 to 1000 seconds, because of the relatively large mass of the cell. However, thermal cycling affects the performance of high temperature fuel cells. This indicates that good control systems are important in relation to both dynamic responses due to load changes and lifetime. For MCFC, experiments with step changes in applied load resistance show that a dynamic response can be achieved by using controllable heaters, thermocouples, and insulating materials. Also, control systems have been proposed as a means to efficiently avoid thermal cycling [36;39].

For high temperature fuel cells, data on load balancing and response times are still limited. For SOFCs, good load-following abilities have been performed with the existing technology and also good efficiencies at part load [40;41]. However, many challenges are faced by SOFCs in dynamic load-change responses, which are easier to handle in base-load operation. As described, different operation strategies and designs are being investigated in order to be able to solve problems related to high operating temperature, temperature gradients, fuel and gas handling [32;42]. With the third generation metal-supported SOFCs, the problem of thermal gradients may be significantly reduced, giving way to very fast start-ups for SOFCs [33;34]. Simulations show, that future SOFCs may have better load-following capabilities [37]. During operation, SOFCs may have very fast regulation abilities, which give them properties similar to those of batteries. Start-up times can thus be reduced significantly or almost eliminated with the right design and control systems. This, however, requires further development and research.

4 Start-up, efficiencies and regulation abilities of SOFCs and other technologies

Here, the start-up abilities and ramp-up rates are compared for different current thermal power generation technologies as well as for wind turbines and potential abilities in future SOFC CHPs. In Table 2, minimum ramp-up rates for different power technologies are listed. Compared to gas engines, turbines and combine cycle PP, the lowest ramp-up rates are achieved by steam-based thermal power plants, and as these also have a slow start-up, they are normally regarded as base load plants. The gas and diesel turbines and engines have the highest ramp-up rates. Large steam-based PP have the ability to supply rapid primary and automatic reserves. This, however, is accomplished through throttling in which the steam pressure is withheld. The part load efficiencies of steam-based thermal plants are rather good compared to gas turbines and engines. Future SOFCs may have good part load efficiencies, in the range from 20 to 100 per cent [40;41].

Technology	Power range (% of full capacity)	Ramp-up rate (% pr. minute)
Coal or biomass dust-fired steam power plant	35-50	2
	50-90	4
	90-100	2
Straw, wood or fluid bed coal-fired steam power plant	50-90	4
	90-100	2
Oil or gas-fired steam power plant	20-50	2
	50-90	8
	90-100	2
Gas engine	35-100	10
Gas turbine	20-100	10
Gas turbine combined cycle	20-100 (gas turbine part)	10
	75-100 (steam turbine part)	10
Diesel engine	20-100	20
New offshore wind	0-100	Limit ramp-up to 2.5
Future SOFC	20-100	Potentially up to 100

Table 2, Rate of change possible for different technologies in different power ranges. Based on minimum requirements for Danish thermal power plants [22], new requirements for offshore wind [16] and the description of SOFCs.

According to the technical requirements for new offshore wind farms in Denmark, these must be able to limit the power gradient at ramp-up; help maintain grid stability; have active power control, and enable the adjustment of the production to a desired level. Historically, wind turbines have been very well distributed in Denmark in terms of geography; thus, limiting the effects of wind variations and resulting in gentler ramp-up gradients. With increasingly higher concentrations of wind turbines, the issue of ramp-up gradients becomes more important to address. In case of the next offshore wind farm to be erected in Denmark, the 200 MW Horn's Reef II, the maximum increase is set at 5 MW/min, i.e. 2.5 per cent per minute. This wind farm is to be situated next to the existing 160 MW Horn's Reef, making it necessary to be able to control what could otherwise constitute very large increases in production. During the previously mentioned storm, the gradient in Horn's Reef I was in periods -15 MW/min or 9.4% of full load per minute [16].

Even if the new wind turbines live up to the requirements, other parts of the system will still have to be able to react fast due to the share of older turbines in the system, which do not live up to the new requirements, and due to the sheer capacity of the wind turbines installed. In energy systems in which changes occur fast, prompt reactions and control practices have to be in place. Ramp down is still uncontrollable, unless the wind turbines are operated suboptimally. As described, the SOFCs may contribute to the solution of these problems, if they are developed to handle rapid load changes and fast start-up. For both smaller thermal plants and smaller SOFC CHPs, the limited sizes of heat storages may pose a problem. In Denmark, the current small CHPs typically have 5-10 hours of full production storage capacity. This means that, while the plants might be able to react fast, there is a limit to how long they can remain in operation in order to cover a deficit in wind power, without having to blow off heat.

5 Energy system scenarios and SOFC

The energy system scenarios described in this article reflect a transition from a fossil fuel-based energy system to a 100 per cent renewable energy system. The scenarios reflect very high shares of fluctuating intermittent energy sources, such as wind power and CHP generation, and they reflect a change in the available ancillary service providers from a centralised top-down structure to a decentralised bottom-up structure.

As a reference for the analyses, a business-as-usual (BAU) scenario for 2030 is used, i.e. implicating that no changes are made in public regulation compared to now. This scenario, BAU 2030, is an official forecast from 2005 from the Danish Energy Authority and it involves a 30 per cent wind power production. The other two scenarios have considerably higher renewable energy shares and a reduced end-demand for electricity, heat and transport. The IDA 2030 energy scenario has a renewable energy share of 50 per cent, including 55 per cent wind power production of the electricity demand. The IDA 2050 scenario is a 100 per cent renewable energy system with a wind power production corresponding to 68 per cent of the electricity demand. The remaining demand is supplied from biomass resources, wave power and photovoltaic power. These two scenarios were designed as part of the "Energy Year" organised by the Danish Society of Engineers (IDA) and are published in the IDA Energy Plan 2030 from 2006, described in [7;8;43]. They include the entire energy supply, i.e. electricity, heat, transport, and energy for industries. The scenarios in the IDA Energy Plan 2030 were analysed and designed in an iterative way, thus ending up with flexible renewable energy systems for 2030 and 2050, respectively, which are able to balance the supply and demand of electricity, heat and transport, throughout the year in question. In Fig. 4, the installed capacities of the three scenarios are illustrated, in combination with bars indicating current ancillary service providers. The two renewable energy systems are more flexible than energy systems with a central design, as they also have substantial amounts of flexible demand, as illustrated in Fig. 5.

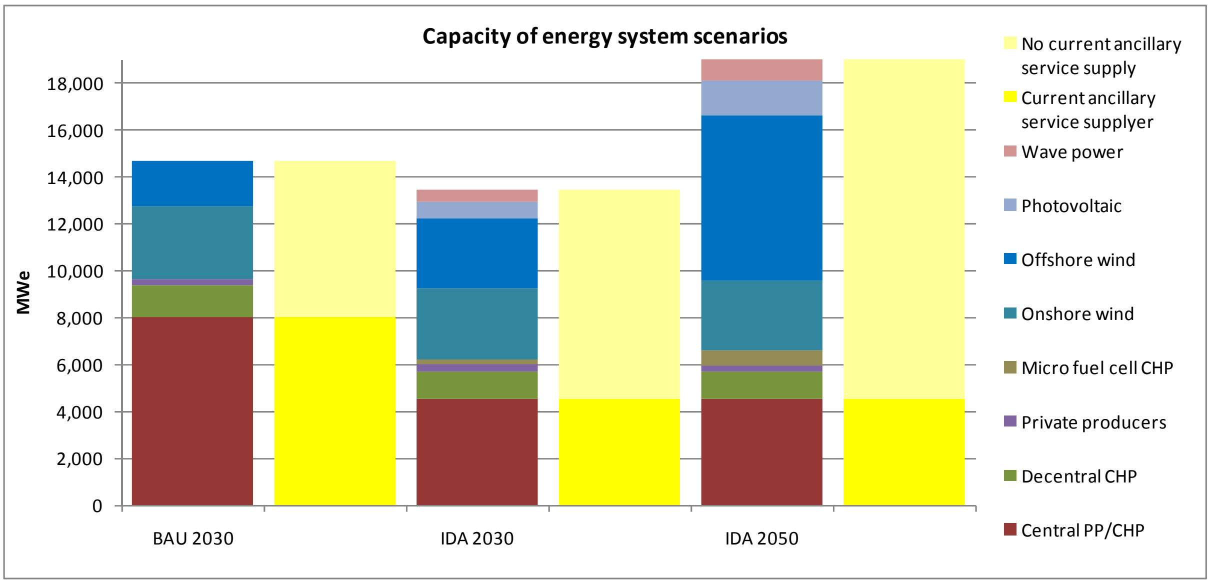

Fig. 4, Capacities and current ancillary service designs of a business-as-usual scenario in 2030, a system with 50 per cent renewable energy in 2030, and a system with 100 per cent renewable energy in 2050.

Six versions of the energy systems are constructed; three with gas and steam turbines and three with SOFC. In the original IDA 2030 energy system, a third of the central CHP and PP capacity is large central SOFC plants, i.e. 1.500 MW. Half of the decentralised gas turbine CHP plants, 600 MW, are small local SOFC CHP. In the IDA 2030 system, the SOFCs are removed and replaced by gas turbines in order to analyse the significance of SOFC in terms of total fuel efficiency. In the BAU 2030 energy system, the same amount of gas and steam turbines is replaced by SOFC as in the IDA 2030 system.

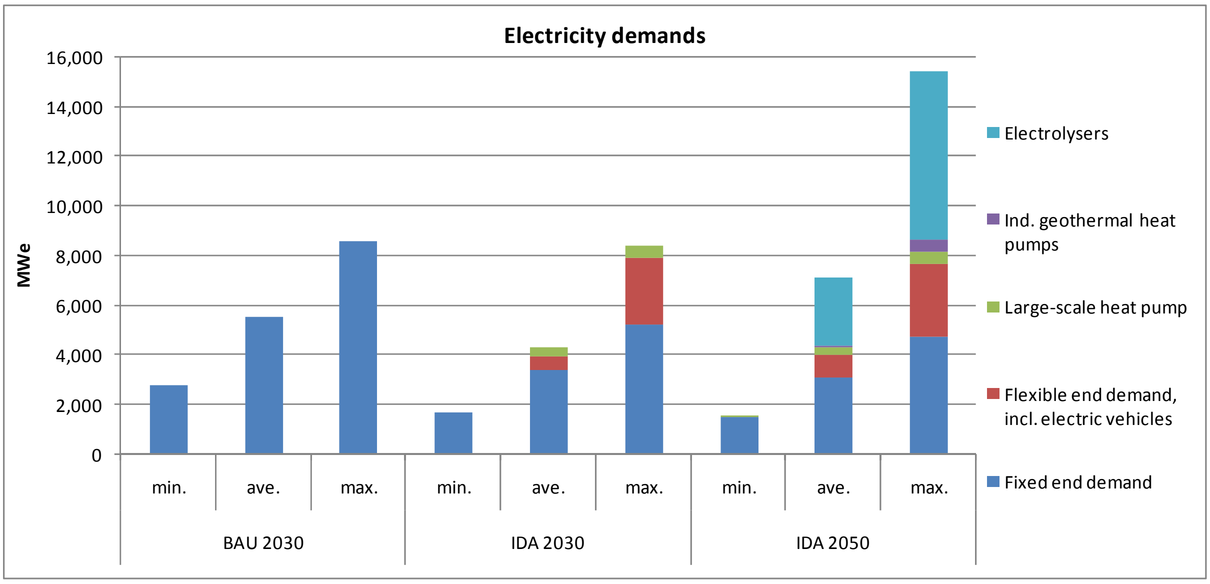

Fig. 5, Minimum, average and maximum electricity demands of the different components in the three energy systems.

For large central SOFC CHP and PP, gas turbine hybrids with 66 per cent electricity efficiency are installed, and for small local SOFC CHP plants, with a 56 per cent electricity efficiency [43-45]. Both have a total efficiency of 90 per cent. In the IDA 2050 energy system, the electricity efficiencies of SOFC are reduced by 2 per cent, as an approximation of losses due to the reformation of gases derived from biomass.

In the original IDA 2050 energy system, SOFCs have replaced all other technologies. In the analyses here, these are replaced by local and central single and combined cycle gas and steam turbines (SCGT and CCGT). In the central areas in the IDA 2050 energy system, half of the plant capacities are assumed to be large CCGT CHP (>100 MW) with a 62 per cent efficiency and half are assumed to be CCGT CHP (>10 MW) with a 52 per cent efficiency. In local areas, small SCGT (5-40 MW) with a 41.5 per cent efficiency are installed. All have a total efficiency corresponding to 91 per cent. SOFC PP are assumed to be replaced by large CCGT.

6 Ancillary service design scenarios

Different approaches can be applied to incorporate grid stability and reserve capacity considerations in hour-by-hour energy system analyses. In grid-flow models, electro-technical data are used for the individual system components; however, here we wish to analyse the effects on the system seen from a wider angle than merely focusing on grid stability. The aim is to analyse the consequences of continuing the current top-down ancillary service supply in terms of fuel efficiency and compare this to the integration of other technologies in distributed renewable energy systems. Although the capacities and recommendations above give some indication of the capacities required, this has to be interpreted in a way which makes it possible to model the systems in a load-balancing energy system analysis model. In 2001, the ancillary service restrictions of the Danish energy system were assessed for energy system modelling in a working group under the Danish Energy Authority for such purposes. The assessment led to the following results:

- The minimum share of technologies able to supply ancillary services at any given point in time must be 30 per cent.
- The minimum load from these plants were set at 350 MW in the western part of Denmark and 280 MW in the eastern part.
- All centrally dispatched power plants are able to supply ancillary services.

- Wind turbines and locally dispatched CHPs are not ably supply ancillary services. [4;18]

Considering the fact that the two Danish electricity areas will be connected in 2010, the areas can cooperate in the supply of ancillary services [16]. Hence, the ancillary service control design is analysed in the case of the entire Danish system. With the interconnection, it is assumed that the requirements for minimum load will change for the technologies able to supply ancillary services. In order to assess the impact of the interconnection, one must understand that the present requirements are mainly based on the frequency impact of wind turbines fitted with asynchronous generators on the energy system of today. The interconnection will enable some ancillary service load sharing; thus, the minimum momentary production required for plants able to supply ancillary services will be lower in the interconnected system, than the sum of the requirements for the individual systems. For the analyses, a value of 450 MW is assumed for the interconnected area. The stipulation that the momentary production of ancillary service-producing units cannot drop below 30 per cent is upheld; however, as production units with unstable frequency still need a firm frequency to produce against, the larger the system, the more wind power, the more the production on ancillary service-providing units is required.

In future energy systems, new wind turbines can be expected to form part of the ancillary service supply, as these demands are present for new offshore wind turbines today. Four different ancillary service scenarios are hence established, which differ in terms of the technologies which provide the services. The first ancillary service scenario reflects the current situation. In the second scenario, locally distributed SOFC CHPs take part in the ancillary service supply. In the third scenario, also 50 per cent of the installed offshore wind turbines take part in the ancillary service supply. In the fourth scenario, the option of replacing minimum production with SOFC CHPs on standby is also implemented. The four scenarios are listed in Table 3.

Grid-stabilising plants	Current top-down control design	+ local SOFC CHP	+ wind	+ local SOFC CHP standby
30 per cent	Central power plants	Central power plants and local SOFC	Central power plants, 50 per cent offshore wind and local SOFC	Central power plants, and local SOFC
Min. production of 450 MW	Central power plants	Central power plants	SOFC CHP on standby	SOFC CHP on standby

Table 3, Ancillary service scenarios analysed, from the current top-down control design to a future bottom-up control design.

7 The energy system analysis model

The analyses are performed in the energy system analysis tool EnergyPLAN, which is an input-output model performing annual analyses in steps of one hour. The inputs to this model are end demands; hourly demand distributions; generation capacities; fluctuating distributions of renewable energy, etc. The outputs are hour-by-hour energy balances and annual production; fuel consumption; imports and exports; CO_2 emissions, and different cost data, etc. In the model, it is possible to apply different regulation strategies securing the delivery of heat and power, including ancillary service restrictions for heat and power production plants. For more information about the model, please consult Lund (2007) [46]. The EnergyPLAN model has been used in several technical and socio-economic studies of energy systems for both the Danish government [6;47] and, most recently, for the Danish Society of Engineers [7;8;43]. The model treats the energy system as a one-point system, i.e. no internal bottlenecks in Denmark are assumed.

8 Results of the analyses of ancillary service designs

The analyses of the four ancillary service scenarios are performed for the three different energy systems described. The scenarios are analysed through two types of diagrams, by which the importance of the ancillary service design can be compared in the different energy systems.

The first diagram illustrates the annual excess electricity production in TWh, as a function of renewable energy input in an open energy system. In the open system, CHP plants with heat storages and, if present, heat pumps and flexible electricity demands are used to balance heat and electricity demand during the given hours and with the aim of minimising excess electricity production. The energy system analyses are performed with due consideration for the different ancillary service designs, which restrict the operation possibilities of the plants involved. Hence, the ability of the system to reduce excess electricity production also depends on the restrictions made in relation to ancillary services. In this energy system analysis, a low excess electricity production represents a good ability of the system to integrate fluctuating renewable energy sources.

The second type of diagram illustrates annual fossil and/or biomass fuel consumption in TWh in a closed energy system excluding renewable energy sources, in this case wind power. In the closed system, the same regulation applies as above. However, the following strategy for handling excess wind power production is used: First, CHP production is replaced by boilers in the district heating systems and then wind turbines are stopped. When fuel consumption is lowered, the energy system is able to efficiently utilise intermittent renewable energy sources.

In both diagrams, the production from wind turbines varies between 0 to 100 per cent of the electricity demand in the three energy systems analysed. In the analyses of the IDA 2030 and the IDA 2050 energy systems, other intermittent renewable resources have been removed.

In fig. 6, the results of the analyses are presented. The effects of replacing CCGT and SCGT with SOFC in the energy systems are also illustrated. On the left side of fig. 6, the excess electricity diagram is presented. The first step in the task of integrating renewable energy is to enable CHP plants to produce electricity, independently of the momentary heat demand, by using heat storages.

Excess electricity does not decrease when changing from gas and steam turbines to fuel cells in the current top-down control of the ancillary service supply. When enabling the local SOFC CHP plants to take part in grid stabilisation, fuel savings of between 0.5 and 1 TWh are achieved in the BAU 2030 energy system. In the two renewable energy systems, IDA 2030 and IDA 2050, the ability to reduce excess electricity production is lower than in the BAU 2030 energy system when enabling the local SOFC CHP plants to take part in grid stabilisation. This is due to the fact that other flexible technologies form part of these energy systems, such as heat pumps and flexible demand, which make it possible to integrate more wind power than in the BAU 2030 energy system.

In the situation in which 50 per cent of the offshore wind turbines are able to assist in the grid stabilisation task, all three energy systems experience large reductions in excess electricity production. In the fourth scenario, in which the 450 MW minimum production at central plants is replaced by SOFC on standby, excess electricity production is further decreased. The importance SOFC on standby increases as the amount of wind increases.

On the right side of fig. 6, annual fuel consumption excluding renewable energy sources is illustrated. As expected, fuel consumption decreases, as the ability of the energy system to integrate excess electricity is improved. In the renewable energy systems, the replacement of gas and steam turbines is especially important to the reduction of fuel consumption. Fuel cells are more important in future renewable energy systems than in the BAU systems. Even with more than 50 per cent wind power production in the renewable energy systems, they enable a decrease in fuel consumption of 2 to 2.5 TWh.

In the first ancillary service scenario, in which local SOFC CHPs participate in grid stabilisation, fuel consumption is marginally reduced. Again, when wind power also contributes to the supply of ancillary services, fuel consumption decreases significantly. With a wind power share of more than 50 per cent, the integration of standby SOFC further decreases fuel consumption.

In the renewable energy systems, the other components installed also reduce fuel consumption by replacing boiler production at CHP plants with large heat pumps and by using flexible demands. Such demands are placed in situations with high shares of wind power. In these systems, the operation hours of SOFC CHP decrease, as a higher share of the electricity demand is met by renewable energy and a higher share of the heat demand is met by heat pumps.

In the IDA 2030 energy system, 21.5 TWh of intermittent renewable energy is proposed. In this situation, the SOFC CHP must participate in the grid stabilisation task in order to avoid excess electricity production. In the 100 per cent renewable energy system, IDA 2050, 38.8 TWh of intermittent renewable energy is installed; hence, the flexibility of SOFC is also important in this system. The potential flexibility in the operation of SOFC, which improves the efficiency by replacing gas and steam turbines and participating in grid stabilisation, is important in renewable energy systems because biomass-derived fuels constitute a limited resource. In the BAU 2030 projection from the Danish Energy Authority, 14.9 TWh of electricity is produced from onshore and offshore wind turbines. In such a situation, local SOFC CHP participating in grid stabilisation would improve fuel efficiency and improve the integration of installed wind power.

The fast start-up and the good regulation abilities of SOFCs are important measures in future energy systems, since they improve the ability of the systems to integrate renewable energy and reduce fuel consumption. Base load plants are not needed in future renewable energy systems.

Even if all offshore wind turbines were able to provide ancillary services, instead of the 50 per cent shown in the analyses in Fig. 6, the performance of offshore wind turbines participating in grid stabilisation would not improve. Similar analyses have been conducted, in which wind power is additional to the intermittent renewable resources already installed, i.e. wave power and photovoltaic power in the two renewable energy systems. This does not change the results presented here, either.

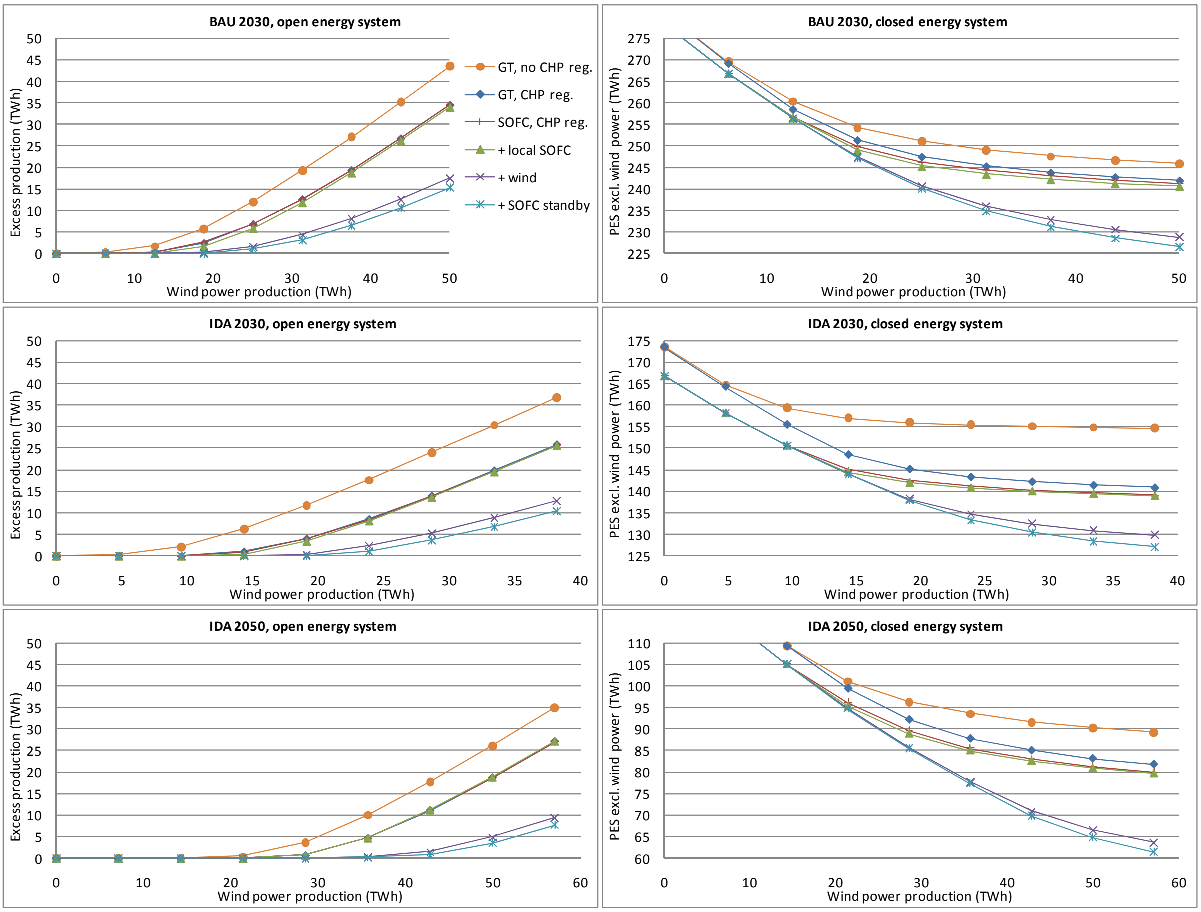

Fig. 6, Excess electricity diagrams and primary energy supply excl. wind power diagrams of the four ancillary service scenarios in the three energy systems. The effects of replacing CCGT and SCGT with SOFC in the energy systems are also illustrated.

9 Conclusion

Currently, the ancillary service supply is designed for traditional energy systems based on few central power plants. However, energy systems are changing towards renewable energy systems with many distributed producers. In a system with high shares of intermittent renewable energy, SOFC have the potential for increasing fuel efficiency and improving the integration of wind power by participating in the grid stabilisation task and being on standby.

Compared to single cycle and combined cycle gas and steam turbines, SOFC are more fuel efficient for CHP plants. Furthermore, they may eventually have better regulation abilities and a very fast start-up. Further development is required to provide such flexibility; however, flexibility as well as fuel efficiency are key characteristics for future energy systems. SOFC is more important for replacing gas and steam turbines in 100 per cent renewable energy systems than in business-as-usual energy systems in terms of fuel efficiency.

The integration of SOFC into distributed CHP should be developed in order to create flexible market players that can follow load variations rapidly. Base load power plants are not required in such efficient renewable energy systems. While the lifetime of the cells may represent a potential development problem, this may be less of a problem, if they have less operation hours, but can operate when needed in the system.

Start-up and thermal cycling pose material problems dealt with in current research; thus, it may seem feasible to develop SOFC for constant operation. Such a development, however, does not take into account the nature of future efficient renewable energy systems.

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Appendix III

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5 Energy system analysis of fuel cells and distributed generation

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Abstract

This chapter introduces Energy System Analysis methodologies and tools, which can be used for identifying the best application of different Fuel Cell (FC) technologies to different regional or national energy systems.

The main point is that the benefits of using FC technologies indeed depend on the energy system in which they are used. Consequently, coherent energy systems analyses of specific and complete energy systems must be conducted in order to evaluate the benefits of FC technologies and in order to be able to compare alternative solutions.

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In relation to distributed generation, FC technologies are very often connected to the use of hydrogen, which has to be provided e.g. from electrolysers. Decentralised and distributed generation has the possibility of improving the overall energy efficiency and flexibility of energy systems. Therefore, energy system analysis tools and methodologies must be thorough and careful when identifying any imbalances between electricity demand and production from CHP plants (Combined Heat and Power) and fluctuating renewable energy sources. This chapter introduces the energy system analysis model EnergyPLAN, which is one example of a freeware tool, which can be used for such analyses.

Moreover, the chapter presents the results of evaluating the overall system fuel savings achieved by introducing different FC applications into different energy systems. Natural gas-based and hydrogen-based micro FC-CHP, natural gas local FC-CHP plants for district heating and hydrogen fuel cell vehicles have been evaluated in different energy systems with or without large-scale wind power and with different means of house heating.

The overall result shows that the fuel savings achieved with the same technology differ very much from one system to another. The FC technologies have different strengths and weaknesses in different energy systems, but often they do not have the expected effect. Specific analyses of each individual country must be conducted including scenarios of expansion of e.g. wind power in order to evaluate where and when the best use of FC technologies can be made. However, some general points can be made. In the short and medium term, natural gas-based FC-CHP systems seem to be best practice in most energy systems, while hydrogen-based systems including vehicles only seem to be relevant in systems with considerably larger imbalances between electricity demand and supply.

1. Introduction

Renewable energy sources and distributed generation play a crucial role in supporting key policy objectives of combating the greenhouse effect, reducing the atmospheric pollution and improving the security of energy supply in may countries around the world. Consequently, there is a strong trend of supporting decentralised energy production and supply in many countries. Both the increase in decentralised production and the use of wind power will result in a growing number of small and medium-size producers which will be connected to energy networks and, in particular, to electricity grids originally designed for monopolistic markets. Therefore, many new problems will arise related to the management and the operation of energy transfer and to the efficient distribution of wind power and other renewable energy sources into the grids.

In order to create a substantial long-term penetration of distributed energy resources, it is necessary to address the key issues related to their integration into existing and future energy systems. One of the most important future challenges seems to be the integration of fluctuations into the electricity production from renewable energy sources and CHP plants. FC technologies represent one important option which must be considered when such future sustainable energy systems are to be designed.

Many different advantages of FCs can be emphasised. Two of the most important advantages are one: that they are more efficient than other technologies, and two: that they have no local environmental effects. Other advantages are excellent regulation abilities, lower maintenance, fuel flexibility, rather simple designs, and high power densities. Although many problems are still to be solved, these benefits constitute the main advantages stressed as the motivation for continuing and expanding the research and development of FCs.

These advantages all depend on the type of FC considered. More importantly, though, they also depend on the type of energy system of which they form part. The fuel efficiency of the FC themselves may potentially be better than competing alternatives. However, as an example, if hydrogen must be produced with power from extraction power plants, the fuel consumption may be higher than that of other alternatives which are not hydrogen-based. Another example shows that micro FC-CHP in households in a narrow perspective is better than boilers, but that may potentially displace more efficient local or central CHP plants. Even though better fuel efficiency and lower environmental impacts may be the case locally, the solution may have effects elsewhere in the system which increases the system's fuel consumption and environmental impacts locally elsewhere.

The implementation of sustainable energy plans calls for methodologies and tools for analysing energy systems both at the level of individual plants and at the regional and national level. The focus must be on balancing variations in consumer demands with fluctuations of renewable energy sources. This chapter introduces one such computer tool, namely the EnergyPLAN model.

The EnergyPLAN model was created for the analysis and design of suitable strategies for the integration of electricity production resources into the overall energy system at the national level. The model emphasises different regulation strategies, with the analysis carried out in hourly intervals. The consequences are analysed both by different technical regulation strategies, facilitated by specific investments in the energy system, and by different market economic optimisation strategies. Researchers at Aalborg University have been developing the model since 1999, and it was used in the work of an expert group conducted by the Danish Energy Agency for the Danish Parliament in 2001 [1;2] as well as in several research projects [3-7].

Whereas the analysis of energy companies focuses on one (or very few) energy plants, the analysis of national and regional energy systems considers many plants. Furthermore, the main aim is to analyse how the many individual units can interact and form a system which is able to secure a balance between supply and demand. The electricity supply is dependent on such requirements in order to be able to function successfully.

Energy System Analysis models for regional and national analyses can be divided into two different types of purposes – some models have been made with an *operation* purpose and others with a *planning* purpose.

The aim of *operation* models is to design suitable operating strategies on a day to day basis. Such models have been made and used by electricity system operators for designing lowest-cost production strategies of electricity supply systems with several productions units. The models are typically very comprehensive and detailed in their description of each individual power plant, in order to be able to calculate exact operational costs and emissions.

The aim of *planning* models is to design suitable future investment strategies. Such models have been designed and used by public planning authorities, utility companies and different NGOs. Sometimes operation models have been used for planning purposes or planning models have been created on the basis of operation models. In practice, such models have often proven to be very conservative in the sense that they have mainly been able to analyse small short-term adjustments to the existing system, rather than radical changes in the overall system design and regulation. Moreover, the use of such models is typically very time-consuming because of the need for detailed data and long calculation periods.

Both operation models and planning models have been influenced by the introduction of international electricity markets beginning in the late 1990s. Operation strategies for power production units are now determined by the market, and the models are used for identifying optimal market behaviour. Planning models have been facing the need to include the modelling of international electricity markets in the analyses.

The EnergyPLAN computer model is a *planning* model created with the purpose of analysing the consequences of different national energy investments. The model has a focus on the integration of fluctuating electricity production from renewable energy sources and, consequently, it emphasises the analysis of different regulation strategies. The model includes the option of describing an external electricity market and considering the price setting on such a market in the formulation of regulation strategies.

2. Energy system analysis tool and methodology

In order to evaluate any individual component such as e.g. FC technologies, an energy system methodology and tool is needed. Here the Energy System Analysis model EnergyPLAN has been used [8].

The analysis is carried out in hour by hour steps for one year. The consequences are analysed on the basis of different technical regulation strategies as well as market economic optimisation strategies.

The main purpose of the model is to facilitate the design of national energy planning strategies on the basis of an analysis of the consequences - technical as well as economic - of different national energy systems and investments. The model emphasises the analysis of different regulation strategies with a focus on the interaction between CHP and fluctuating renewable energy sources.

The model is an input/output model. General inputs are demands, renewable energy sources, energy plant capacities, costs and a number of optional different regulation strategies emphasising import/export and excess electricity production. Outputs are energy balances and resulting annual productions, fuel consumption, import/exports and total costs including income from the exchange of electricity. The model can be used for three main types of energy system analyses.

Technical analysis

In the technical analysis, the design of large and complex energy systems at the national level and under different technical regulation strategies is investigated. In this analysis, inputs include a description of energy demands, production capacities and efficiencies, and energy sources. Output consists of annual energy balances, fuel consumptions and CO_2 emissions, etc.

Market exchange analysis

Further analyses of trade and exchange on international electricity markets can be conducted as a market exchange analysis. In this case, the model needs further input in order to identify the prices on the market and determine the response of the market prices to changes in import and export. Input is also needed in order to determine marginal production costs on the individual electricity production units. The modelling is based on the fundamental assumption that each plant optimises according to business-economic profits, including any taxes and CO_2 emissions costs.

Feasibility Studies

Finally, feasibility in terms of total annual costs of the system under different designs and regulation strategies can be investigated. In such cases, inputs such as investment costs and fixed operation and maintenance costs have to bee added together with plant life time periods and an interest rate. The model determines the socio-economic consequences of the productions and demands in the energy system. The costs can be divided into 1) fuel costs, 2) variable operation costs, 3) investment costs, 4) fixed operation costs, 5) electricity exchange costs and benefits and 6) CO_2 payment costs.

In the following sections, the model has been used only for technical analyses. The principle of the energy system of the EnergyPLAN model is illustrated in Figure 2-1.

Basically, the input to the description of the energy systems analysed comprises:

~ Energy demands (heat, electricity, transportation etc.)
~ Energy production units and resources (wind turbines, CHP, power plants, boilers, heat storages, hydrogen storages etc. and the fuels used such as oil, biomass and coal etc.)
~ Regulation strategies (defining the regulation and operation of each plant and the system incl. technical limitations such as transmission capacity, grid stability etc.)
~ Costs (fuels, variable and fixed operation costs, taxes and investment costs etc.)

The EnergyPLAN model is divided into five overall structure components, namely input, cost, regulation, output and settings.

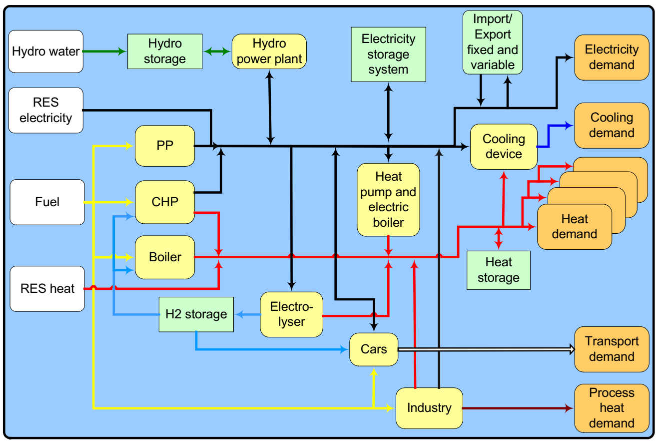

Figure 2.1. Principle diagram of the components of the EnergyPLAN Energy System Analysis model.

Any energy system analysis - technically as well as market economic - needs data in the "input" section. In a technical system analysis, the model requires no further input. But in the case of market economic regulation or if a feasibility study is conducted, further inputs are required in the "cost" section.

Through the use of the EnergyPLAN model, it can be learned step by step how to define relevant input data by consulting Exercise 1 and the guidelines to the model. Both can be found at www.EnergyPLAN.eu.

The following analyses comprise total energy systems including industry and transportation. District heating CHP systems are modelled by dividing the annual district heating consumption into three DH groups in hour by hour distributions. Capacities and operation efficiencies of CHP units, power stations, boilers and heat pumps are defined as part of the input data. Also the size of the heat storage capacities is given here.

Inputs to individual houses are basically defined as fuel inputs, since such figures normally constitute the basic data of statistics. When defining efficiencies of boilers, heat demands are calculated. To include micro CHP, heat demands and efficiencies must be defined. Moreover, capacity limits in the micro CHP in shares of the maximum heating demand (numbers between 0 and 1) can be defined. In this case, peak heat demands will be covered by boilers using the same efficiencies as defined for the boiler-only systems. In the case of hydrogen-based micro FC-CHP, the efficiency of the natural gas boiler is used, and in the case of heat pumps, electric heating is used.

For the transportation sector, input is given in terms of fuel for cars and other transport units divided into jet petrol, diesel, petrol, natural gas, biomass, and hydrogen vehicles. If a fuel demand is specified for hydrogen transportation, the minimum electrolyser capacity is calculated in the model which can provide the necessary hydrogen. If hydrogen storage is specified, such storage capacity is taken into account. For further information on the model please consult [8].

3. Case studies of fuel cells and distributed generation

The methodology applied to the analysis of the efficiency of distributed FC generation is described in an example of energy system analysis of FC technologies in different energy systems. Six fundamentally different energy systems are analysed and compared, with and without distributed FC generation, in technical analyses. These energy systems constitute the span from rather efficient energy systems with high amounts of CHP to rather inefficient energy systems with a high amount of electric heating. The fuel cells are also analysed in the context of a future energy system with high shares of fluctuating renewable energy, e.g. wind.

The six energy systems are analysed in combination with four different types of applications for distributed generation. In Figure 3-1, the four applications are illustrated. These are natural gas-based local FC-CHP and micro FC-CHP, electrolysers for storage of electricity, in cases in which the hydrogen is utilised for micro FC-CHP, or in hydrogen fuel cells vehicles (HFCV). The energy system modelling tool EnergyPLAN is used for conducting the analyses. Subsequently, the six energy systems and the FC technologies analysed are described.

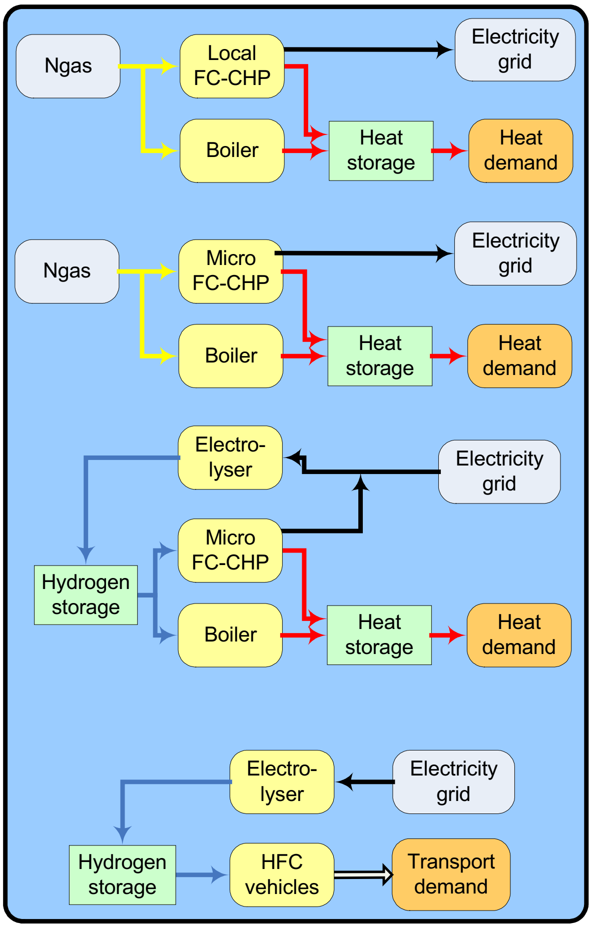

Figure 3.1. The four different FC technologies analysed.

3.1 The reference energy system

The starting point of the analysis is an official projection of the energy system in 2030, as presented by the Danish Energy Authority [9]. In this projection, the demand and production in the Danish energy system are simulated assuming that no new regulation is introduced and no major technology leaps take place. This energy system is modified to reflect six other types of energy systems worldwide in order to analyse distributed FC generation in different settings.

The projection was conducted by the Danish Energy Authority in 2005 as a business-as-usual-scenario which comprises energy consumption and production technologies including fuels for transport and industrial purposes. The electricity demand is expected to be 49.0 TWh in 2030. The district heating demand is 39.2 TWh and 23.1 TWh is used for boiler heat production in individual households. Large coal-fired power plants (PP) and local CHP steam turbines are replaced by plants which are capable of using biomass and by natural gas-fired combined cycle CHP units at times when old units expire. The existing heat storage capacities are assumed to be present in 2030. The electricity production from CHP units is as high as 40 per cent of the demand in this reference. The reference is described in further details in [5;9]. The data for this energy system are listed in Table 3-1 and illustrated in Figure 3-2.

This energy system can be characterised as an energy system developed under today's market conditions and rather low fuel prices compared with those of 2006. The characteristics of the system also differ from the trends seen in Denmark during the past 30 years. The system includes a high rate of increase in the energy demand as opposed to the rather stable historical development, hence a business-as-usual development with no interventions as opposed to the trend experienced from 1972 [10]. This illustrates the need for to make new initiatives, if the historic development is the objective.

3.1.1 The energy systems analysed

In order to conduct the modelling of distributed FC generation, the six energy systems needed in the analyses are constructed. In Table 3-1, the demands, fuel consumptions and key figures of the three energy systems used in the analysis are listed. The first column represents the data from the business-as-usual energy system projected by the Danish Energy Authority (DEA). The data from the DEA reference is used as input into the EnergyPLAN model. First of all, the wind power in the DEA reference system is removed, thus the *CHP system* is constructed. Secondly, the *traditional system* is constructed by removing the CHP-based district heat demand, and adding individual natural gas-based boilers instead. Thirdly, the *electricity system* is constructed by meeting this heat demand with electric heating. The

Table 3.1. Electricity, heat and fuel demand in the six energy systems used for the analyses of distributed FC generation.

		DEA ref, 2030	Electricity system	Traditional system	CHP system
Inputs					
Electricity demand	TWh/y	49.0	80.4	49.0	49.0
DH demand	TWh/y	39.2	0.0	0.0	39.2
Ind. boiler heat demand	TWh/y	19.7	19.7	51.0	19.7
Industry incl. service & refining	TWh/y	53.7	53.7	53.7	53.7
Transport	TWh/y	69.2	69.2	69.2	69.2
North Sea (oil extraction)	TWh/y	22.7	22.7	22.7	22.7
Primary energy demand					
Wind power	TWh/y	14.9	0.0	0.0	0.0
Coal	TWh/y	20.4	59.0	36.6	28.1
Oil	TWh/y	112.0	110.0	108.4	113.1
Natural gas	TWh/y	95.4	136.5	135.3	112.6
Biomass	TWh/y	36.4	12.7	12.7	27.4
Total	TWh/y	279.2	318.2	292.87	281.2
Key figures					
Net export	TWh/y	5.7	0	0	0
Av. eff. local CHP (elect./heat)	%	41 / 50	-	-	41 / 50
Av. eff. central CHP (elect./heat)	%	41 / 50	-	-	41 / 50
Av. eff. condensing power	%	52	52	52	52
Total excl. import/export of elect.	TWh/y	269.7	318.2	292.9	281.2
Condensing power of demand	%	28	100	100	49
DH boilers of DH demand	%	27	0	0	19
Condensing power plant capacity	MW	8,000	19,350	8,000	8,000
- hereof extraction power plant	MW	2,000	0	0	2,000
Local CHP capacity	MW	1,350	0	0	1,350

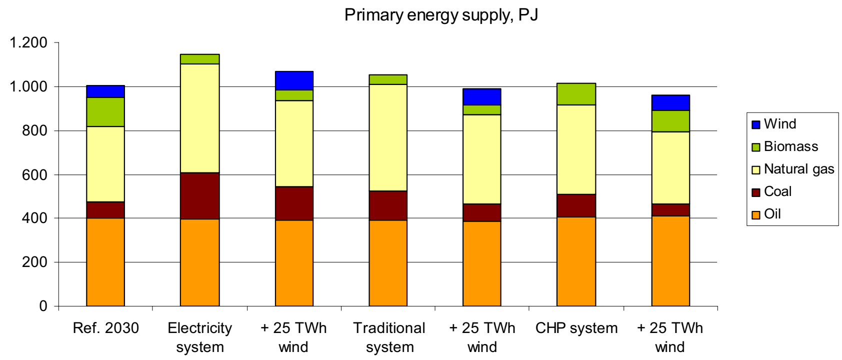

Figure 3.2. The primary energy supply in the six energy systems, used for the analysis of FC technologies.

capacity of the *electricity system* has to be more than doubled in order to meet the new peak hour electricity demand. The energy systems are analysed in the modelling tool EnergyPLAN.

The analyses are conducted with certain restrictions in ancillary services in order to achieve grid stability. More than 30 per cent of the power, or as a minimum 450 MW, must at any hour come from power production units capable of supplying grid stability, such as central condensing power plants and CHP. At least 450 MW running capacity in large power plants must be available at any moment. Distributed generation from renewable energy sources and local CHP units are not capable of supplying ancillary services in the analysis here.

One major difference between the DEA reference and the energy systems used in these analyses is the fact that the technical analyses are conducted in a *closed* system. This is done in order to analyse the ability of the FC technologies to improve the efficiency of an energy system. In a closed energy system, all excess electricity production is converted or avoided and it is possible to investigate the primary energy supply of the system. The message is not that electricity trade should be avoided, but that it is necessary to have a closed in order to analyse the efficiency of different energy systems and different technologies in energy systems.

All excess production is converted or avoided; first, by replacing CHP production by boilers in the district heating systems using the heat storages, and secondly, by stopping wind turbines. If technologies able to use electricity are present in the investigated energy system, these are used to avoid excess electricity production instead of stopping wind turbines. The import/export is of course zero, as it is a closed system.

This type of modelling provides the option of conducting an analysis of the energy systems' fuel efficiency taking into account the rigid components in the energy system such as intermittent wind and heat demands from CHP. As a result, it is also possible to investigate whether the energy system has good abilities to integrate wind or not. This aspect will be elaborated further in the analysis of hydrogen for FC.

The electricity demand in the *electricity system* and the *traditional system* is produced at condensing power plants. In the *CHP system*, the electricity demand is met partly by condensing power plants and partly by CHP. *The electricity, the traditional and the CHP systems* represent three generations of energy systems, from the most inefficient electricity-based system, to the more efficient CHP energy system.

The main differences between the energy systems mentioned above are the technologies they use in order to meet the heat demand. Each of these fundamentally different systems represents actual energy systems in regions and nations worldwide.

To analyse distributed FC in a situation with high amounts of wind power, the three energy systems have been modelled with 24.5 TWh wind. This corresponds to 50 per cent of the electricity demand in the DEA reference being covered by wind.

In Figure 3-2, the primary energy supply of each of the six energy systems is illustrated. Please note that from the most inefficient electricity system to the CHP system with 50 per cent wind, a difference of 185 PJ can be seen in the total primary energy supply, incl. wind. All of the six systems supply the same services.

3.1.2 The fuel cell technologies analysed

The fuel cell scientific community still works with rather different technologies on the drawing board and has rather different types of applications for the future utilisation in mind. Niche markets have already emerged for emergency generators and within military and space technology. One kind of FC is especially promising for distributed stationary appliances because of its high efficiency and fuel flexibility, namely solid oxide fuel cells (SOFC). However, several types of FCs are currently being developed and demonstrated, for large stationary appliances or micro FC-CHP in households. Other kinds of FCs may prove to be more suitable for mobile or smaller distributed generation. Proton exchange membrane fuel cells (PEMFC) have a rather simple design and quick start-up and may prove to be the most suitable technology within these applications.

In Table 3-2, the capacities and efficiencies of the FC technologies are listed. In the next sections, the FC technologies used here are described.

Table 3.2. The capacity and efficiencies of the fuel cell technologies analysed for distributed generation.

FC technologies	Capacities	Efficiencies			Ref.
		el.	*th*	*fuel*	
Local FC-CHP	450 MWe	56%	34%		[5]
Micro FC-CHP	352 MWe	45%	45%		[5]
HFCV	450 MWe	-	-	50%	[5]

The local FC-CHP

In the analyses in this chapter, local SOFC-based FC-CHP are introduced. The electricity efficiency is 56 per cent and the thermal efficiency is 34 per cent of the local FC-CHP systems. These efficiencies are considered achievable in 2015 [5].

The starting point chosen for the case studies here is a capacity of distributed generation equalling one third of the local CHP capacity in the *CHP system*, i.e. 450 MW_e capacity. When taking into account the thermal efficiency of the FC-CHP and the district heating supply of the existing CHP capacity in the *CHP system*, the heat demand which can be covered by 450 MW_e FC-CHP capacity can be calculated. The thermal capacity of the local FC-CHP is 237 MW_{th} and 20 per cent grid losses in district heating grids must also be considered. When considering these elements, a 450 MW_e FC-CHP must supply 2.37 TWh of heat annually. This system also requires heat storage and boilers, which are dimensioned according to the relative relationships between the boilers and heat storage and the CHP and heat demand in the DEA reference.

When analysing the local FC-CHP in the energy systems the capacity mentioned above is added to the system. In the *electricity system,* the FC-CHP replaces electric heating. In the *traditional system* and *CHP system,* they replace natural gas boilers.

The micro FC-CHP

For the micro FC-CHP, both the electric and thermal efficiency is 45 per cent in this analysis. These efficiencies are also considered achievable in 2015 [5]. The capacity of the micro FC-CHP should cover an equivalent amount of heat supplied to the end user compared to the local FC-CHP introduced above. The micro FC-CHPs are placed in individual households, thus the 20 per cent grid heat losses can be saved. As a result, the micro FC-CHPs have to produce 1.90 TWh heat annually. The micro FC-CHPs have been modelled so that the cells can cover half of the peak hour demand, which is equivalent to 95 per cent of the annual heat demand. The remaining 5 per cent are covered by electric boilers. The capacity to cover half of the peak hour demand is equivalent to 352 MW_e. Each household has a heat storage which is able to store an average day of heat.

The micro FC-CHP replaces electric heating in the *electricity system* and natural gas boilers in the *traditional system* and *CHP system*.

The hydrogen fuel cell vehicles

Efficiencies of more than 60 per cent may be achieved in FC vehicles and more than 50 per cent are considered possible taking into account losses caused by mass, drag, friction, drive train and other electricity consumptions. Here, the efficiency of HFCV is 50 per cent. These vehicles replace petrol internal combustion engine vehicles with an average efficiency of 20 per cent in 2030. To have comparable capacities, the HFCV alternative is modelled to equate 450 MW drive train. Assuming that each vehicle has a drive train of app. 18 MW, this can replace 1 per cent of the vehicle fleet presuming 2.5 million vehicles in 2030. Using the efficiencies for the vehicles and a future efficiency of exciting cars of 20 per cent the total amount of petrol saved has been calculated. The HFCV are able to replace 0.56 TWh petrol which is equivalent to 0.22 TWh hydrogen. In all of the energy systems analysed, the HFCV replace petrol vehicles.

The electrolysers

One of the possibilities of fuel cells and distributed generation is to use electrolysers for the integration of fluctuating renewable energy. Here, electrolysers are used for micro FC-CHP and for HFCV. The maximum electricity-to-hydrogen efficiency in electrolysis is 84.5 per cent. In the future, electrolysis may be based on reversed or reversible PEMFCs or SOFCs. Various losses such as the system energy usage, activation losses and leakages will, however, occur. Electrolysers are commercially available with app. 60 per cent electricity to fuel efficiency, but more than 80 per cent efficiency may eventually be possible. The efficiency of hydrogen storage devices is between 88 per cent and 95 per cent. Here, 80 per cent electricity to fuel efficiency is used. 5 per cent losses are assumed in both the hydrogen storage and in the inverters.

The capacity of the electrolysers for the micro FC-CHP is determined by the heat demand and the capacity of the micro FC-CHP. The minimum capacity is 1,100 MW_e. In the analyses here, 1,500 MW_e is used. The hydrogen storages for micro FC-CHP can store more than one month of hydrogen production from the electrolysers, which is equivalent to 300 GWh.

The capacity of the electrolysers for HFCV corresponds to a 50 per cent operation time. The hydrogen storage of the HFCV is equivalent to three months of the yearly hydrogen demand for the HFCV or two months of hydrogen production. The size of the hydrogen storage is 112 GWh and the size of the electrolyser is 70 MW_e.

3.2 Results

The results of the energy system analyses in the case of the three generations of energy systems with no wind are listed in Table 3-3. In general, the best results are achieved in the "electric heating" system. This is due to the fact that electric heating is a very inefficient technology. Especially, when electric heating is replaced by CHP systems substantial fuel savings are achieved.

Also in general, larger fuel savings can be achieved by applying natural gas FC technologies rather than hydrogen systems. This is especially the case in energy systems without wind power. In such energy systems, micro FC-CHP systems based on hydrogen loose efficiency because they cannot compete with individual boilers. Only in the case of electric heating, small fuel savings

Table 3.3. Marginal saving compared to basis in energy systems with no fluctuating renewable energy.

Marginal saving compared to basis			**Energy systems with no fluctuating renewables**			
TWh/y			***Natural gas***		***Electrolyser H_2***	
Generation	***Description***	*Basis*	***Local FC-CHP***	***Micro FC-CHP***	***Micro FC-CHP***	***HFCV***
1st	Electric heating system	318.2	-3.5	-3.0	-0.2	0.0
2nd	Traditional system	292.9	-1.9	-1.4	0.9	0.0
3rd	CHP system	281.2	-1.9	-0.2	1.2	0.0

can be achieved with hydrogen. In all three energy systems without wind, the HFCV has nearly no effect on the energy system efficiency. Such systems loose efficiency in the electrolysers and hydrogen storage systems, but win efficiency when FC replaces internal combustion engines.

In Table 3-4, the results of the energy system analysis with 24.5 TWh wind are listed. When comparing systems without wind power to systems with a large share of wind power, the effects of the FC technologies change. Natural gas-based local FC-CHPs loose a little in all systems, though they still have a positive effect on the efficiency. This is due to the fact that they contribute to a larger excess electricity production. On the other hand, the hydrogen FC technologies become better. This is again due to the excess production from wind, which can be utilised in the electrolysers. In energy systems with a lot of wind, small efficiency improvements can be achieved because electrolysers can benefit from excess wind productions.

In general, the analysis shows that fuel savings from FC systems indeed depend on the system to which they are applied. Natural gas FC technologies seem to have the highest relevance in the short and medium term in systems, i.e. in this case, even in systems with more than 50 per cent wind. The hydrogen technologies are mostly relevant in the long term in systems with considerable amounts of excess electricity productions from CHP, wind or other fluctuating renewables.

Table 3.4. Marginal saving compared to basis in energy systems with 24.5 TWh wind power.

Marginal saving compared to basis			**Energy systems with 24.5 TWh wind power**			
TWh/y			***Natural gas***		***Electrolyser H_2***	
Generation	***Description***	*Basis*	***Local FC-CHP***	***Micro FC-CHP***	***Micro FC-CHP***	***HFCV***
1st	Electric heating system	296.6	-3.3	-2.8	-0.6	0.0
2nd	Traditional system	274.6	-1.0	-1.1	-0.1	-0.1
3rd	CHP system	266.6	-0.6	-0.6	-1.5	-0.2

4. Conclusion

In this chapter, Energy System Analysis methodologies and tools, which can be used for identifying the best application of different FC technologies into different regional or national energy systems, have been presented. The benefits of FC technologies are indeed very dependent on the character of the energy system in which they are used. Consequently, coherent analyses of specific energy systems must be made in order to evaluate the benefits of FC technologies and in order to be able to compare these technologies with other potential solutions.

In relation to distributed generation, FC technologies are very often connected to the use of hydrogen, which has to be provided e.g. from electrolysers. Energy system analysis tools and methodologies have to be thorough and careful when identifying any imbalances between electricity demand and production from CHP plants and fluctuating renewable energy sources in order to identify the benefits of using hydrogen. This chapter introduces the energy system analysis model EnergyPLAN, which is one example of a freeware tool, which can be used for such analyses.

Distributed generation with FC, like other technologies, cannot be seen as an isolated improvement, but has to be assessed within the energy system surrounding it. In this chapter, the advantages and disadvantages of using FC for improving the efficiency of the energy supply has been analysed in the context of six fundamentally different energy systems. Natural gas FC-CHP-plants for district heating, Micro FC-CHP on natural gas or hydrogen and HFCV have been analysed in different energy systems with or without large-scale wind power and with different ways of house heating.

The overall result shows that the fuel savings achieved with the same technology differ very much from one system to another. Specific analyses must be conducted for each individual country, including scenarios of expansion of e.g. wind power, in order to evaluate where and when the best use can be made of FC technologies. However, some general points can be concluded: in the short and medium term, natural gas based FC-CHP systems seem to be the best practice in most energy systems, while hydrogen-based systems including vehicles seem to be only relevant in systems with considerable imbalances between electricity demand and supply, i.e. supplying more than 50 per cent of the electricity demand.

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Appendix IV

Solid oxide fuel cells in renewable energy systems

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Abstract

The development of solid oxide fuel cells (SOFCs) is still at the development stage. In this paper, potential SOFCs are explored in future renewable energy systems. SOFCs in CHP plants have the potential for improving the fuel efficiency of the energy system, especially in local distributed CHP plants, where they replace single cycle gas turbines. Both large hybrid SOFC/gas turbines and smaller SOFC CHPs are important in future renewable energy systems. Micro FC-CHP are less efficient and less feasible, especially in renewable energy systems. In the most efficient integrated renewable energy systems, electrolysers are less important, since other technologies are able to integrate most of the fluctuating renewable energy. However, in 100 per cent renewable energy systems, electrolysers may be important in terms of replacing other fuels. Base load FC-CHP plants are not required in renewable energy systems and, hence, SOFC CHP should be developed to enable flexible operation. The higher efficiencies of local FC-CHP can potentially compensate for the costs of replacing stacks.

Keywords: Solid oxide fuel cells (SOFC), combined heat and power, renewable energy, energy system analyses, electrolysers

1 Introduction

Renewable energy sources (RES) end energy efficiency measures are important to the achievement of several key international policy objectives. In countries around the world, three issues are high on the energy policy agenda: To improve the security of supply by displacing imported fuels and increasing fuel efficiency; to reduce emissions of climate gases and mitigate climate change; and, finally, to reduce local atmospheric pollution and improve health conditions. These objectives are hardly new. However, two additional developments have increased the focus on renewable energy and energy efficiency. Internationally, the prices of natural gas, oil and coal have increased significantly within a few years and the price of food products has followed.

Increasing the amount of RES and introducing fuel-efficient technologies into the energy supply inherently mean that the energy system changes from a centralised system to a distributed energy system. New legislation supports intermittent RES, combined heat and power production (CHP) and savings in end demand. In the EU, the cogeneration of power and heat for heating and cooling purposes is promoted because of its potential to increase total fuel efficiency [1]. The aim is to increase the share of electricity produced from CHP[1] from approx. 9 per cent now to 18 per cent in the EU-15 countries by 2010 [2]. According to the agreement from January 2007, the EU is committed to reaching a target of 20 per cent renewable energy supply of the primary energy demand and 20 per cent energy efficiency by 2020, as well as 20 to 30

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[1] Combined heat and power (CHP) production covers both energy for heat and for cooling purposes and hence the concepts described in this paper are also applicable to locations where cooling is required.

per cent reduction in greenhouse gas emissions, depending on the commitment of other developed countries. In a previous agreement, the target for the renewable energy share of electricity generation was defined as 21 per cent by 2010. In Fig. 1, the level of renewable energy sources and CHP in the EU countries in 2005 is illustrated and compared with targets for the RES share of electricity production in 2010.

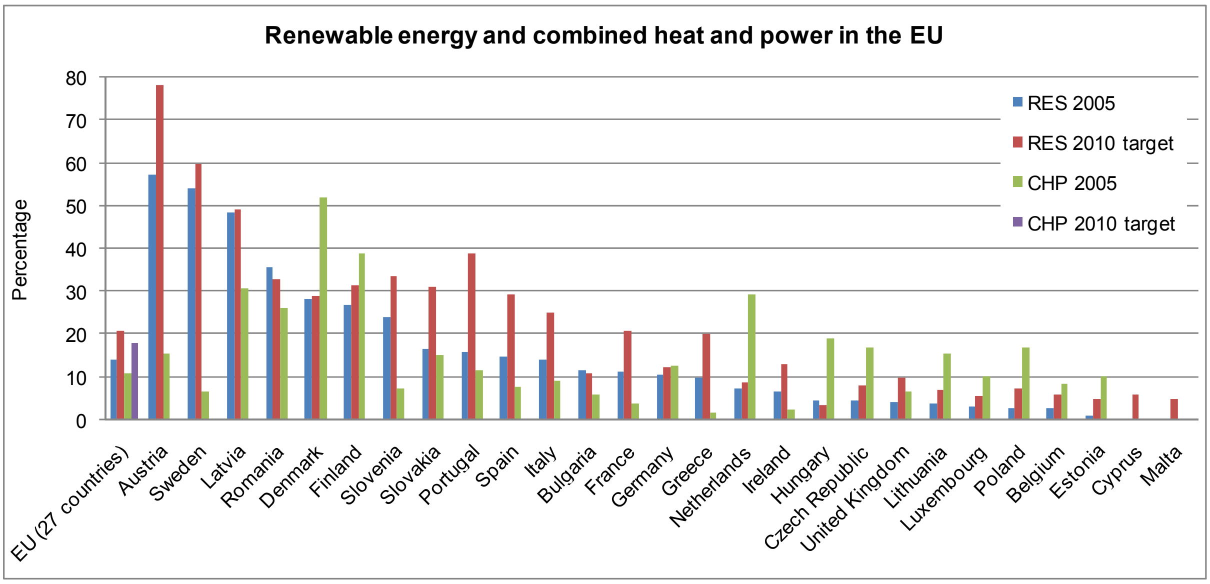

Fig. 1, Renewable energy sources (RES) and combined heat and power production (CHP) of the electricity supply in 2005 and targets for 2010. The target for CHP in 2010 is for EU-15 and is not specified for each country (from Eurostat [3]).

One of the technologies in focus in EU research programmes is solid oxide fuel cell (SOFC) for power plants (PP) and for combined heat and power production (CHP). This is due to the fact that these have higher efficiencies than other power generation technologies and higher efficiencies than other fuel cells. Furthermore, they have no or very low local environmental effects [4]. Another technology which attracts high attention is electrolysis, which is also being developed on the basis of solid oxide electrolyser cells (SOEC). These have higher efficiencies than traditional alkaline electrolysers. Most publications about both SOFC and SOEC are concerned with the status of research in new materials; which is hardly surprising, as the technology is still at the early development stage. Literature has also been published on the development of fuel cell stacks, small and large-scale SOFC or hybrid SOFC combined with gas turbines as well as modelling and testing of the operation of SOFC systems [5-10]. The demonstration of SOFC is moving into the next stage in the Danish village Vestenskov on the island of Lolland, where SOFCs are introduced in connection with electrolysers. Electrolysers have already been operated in connection with other types of fuel cells and wind turbines on the Norwegian island of Utsira [11].

When identifying the suitable applications of fuel cells and electrolysers, it is insufficient to analyse these in the current energy system designs. Rather, they must be analysed in relation to both contemporary and future energy systems. With the increased focus on intermittent renewable resources, CHP and energy savings in Europe, future energy systems may involve considerably more CHP and intermittent resources in the future. Worldwide, similar policies can be expected for CHP due to high fuel prices and aims of reducing greenhouse gases, and many initiatives have already been taken in promoting intermittent renewable resources. Future energy systems may look very different from the systems we know today.

The Danish energy system is a practical example of one configuration of such a future energy system. Approx. 20 per cent of the electricity supply comes from wind turbines, and 50 per cent is produced by CHP plants. Energy savings, especially in the heating sector, combined with a large penetration of CHP and wind power production have kept the primary energy supply at a stable level since the early 1970s [12]. The Danish case reflects many of the challenges faced by the international community within the energy supply sector. Until now, the changes in the Danish energy supply represent a transition from a situation with total oil dependence and separate heat and power supplies in the 1970s to an integrated system that currently consists of large amounts of CHP and intermittent renewable resources and utilises a variety of fuels.

Within 20 years, the energy supply has changed from a classical centralised system with very few and large power plants to a decentralised system with more than 5,000 wind turbines and 700 mainly small decentralised CHP plants under 10 MW. And with a wind power capacity expansion of 800 MW planned for 2012, this development can be expected to continue. The challenges of combining energy savings with intermittent renewable resources and CHP increased in October 2006, when the Danish Prime Minister announced the long-term target of 100 per cent independence from fossil fuels and nuclear power. In December 2006, a plan for how and when to achieve the goal of a 100 per cent renewable energy system was proposed by the Danish Association of Engineers [13-15]. In this energy plan, the three main changes compared to the current Danish energy system were: increased savings in demand; increased energy conversion efficiency with fuel cells and large-scale heat pumps; and renewable energy replacing fossil fuels, also by the use of electrolysers. This represents a flexible integrated energy system, with a combined heat and power supply from CHP plants and large-scale heat pumps as well as an integrated transport sector.

The Danish energy system represents a suitable case for identifying the applications of fuel cells and electrolysers. It involves both a historical and a future development, reflecting the transition which is also likely to occur internationally, in the design of other energy systems. Fig. 2 illustrates the development of the Danish primary energy supply from 1972 until now, in combination with a business-as-usual projection for 2030 modelled by the Danish Energy Authority (BAU 2030) [16]. The projection includes a high rate of increase in the energy demand. Hence, a business-as-usual development with no new regulation could increase the energy demand significantly, as opposed to the rather stable historical development experienced so far. Fig. 2 also shows the primary energy supply of the 100 per cent renewable energy systems for 2050 presented above, as well an integrated energy system for 2030, seen as a first step along this path [13;14].

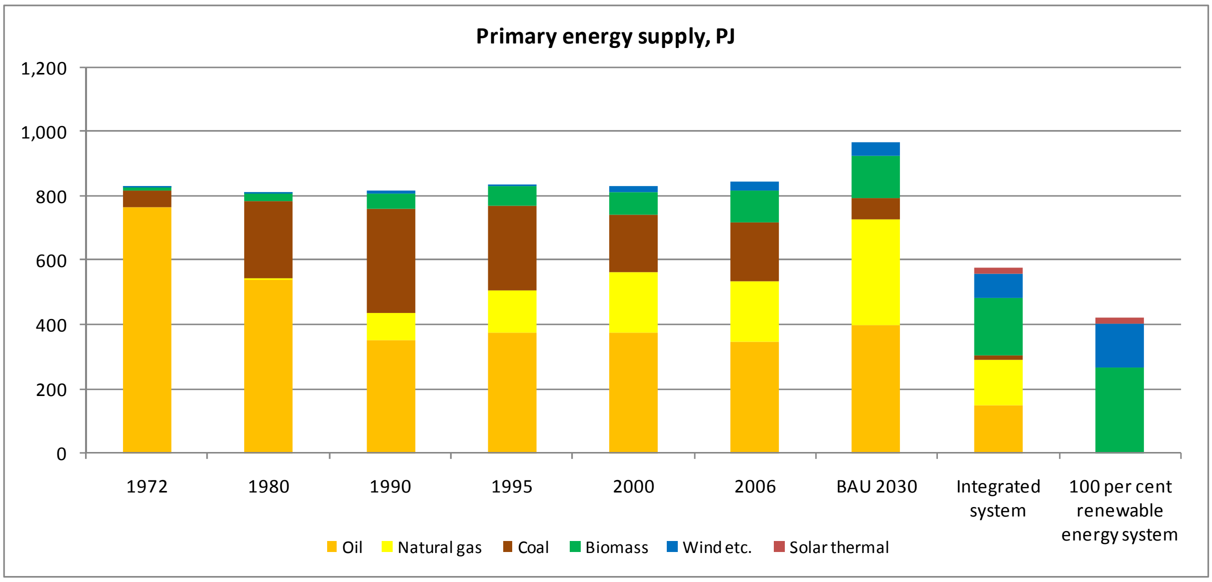

Fig. 2, The Danish primary energy supply from 1972 until 2006 compared to a business-as-usual system for 2030 as well as two proposals for future energy systems.

Here, we analyse the fuel efficiency and socio-economics of eight different future energy systems in combination with six different applications of SOFC and SOEC. The aim is to identify suitable applications in future energy systems, in the case that the technology is developed as expected by producers and researchers.

2 Methodology

Six different applications of SOFCs and SOECs are analysed: Central FC-CHP, Local distributed FC-CHP, and Micro FC-CHP plants, as well as the three technologies in combination with electrolysers. The applications are investigated in terms of fuel efficiency and socio-economics, incl. their ability to improve electricity trade, in different future energy systems. Here, a three-step energy system analyses methodology is introduced, together with the eight energy systems used for the analyses and the main input data for fuel cells and electrolysers.

2.1 The three-step energy system analysis methodology

The three-step energy system analysis methodology enables the identification of suitable applications of e.g. fuel cells in different future energy systems and builds on the analyses of renewable energy systems in [13;14;17].

In most cases, it is not sufficient to look at the technologies at specific points in time. Thus, when conducting energy system analyses, an energy system analysis tool is needed. In this paper, the energy system analysis and planning model EnergyPLAN is used [18]. The main purpose of the model is to facilitate the design of national energy planning strategies on the basis of analyses of technical and economic consequences of different energy system designs or investments in new technologies. The model includes regulation strategies and analyses the interaction between CHP and fluctuating renewable energy sources in steps of one hour throughout one year. The model is an input/output model and general inputs are demands, renewable energy sources, energy plant capacities, costs, and a number of optional regulation strategies emphasising import/export and excess electricity production. Outputs are energy balances and resulting annual productions, fuel consumption, CO_2 emissions, import/exports, and total costs including income from the international exchange of electricity.

The first step in the methodology is the *technical or market economic energy system analysis*. In this analysis, the design of large and complex energy systems at the national level and under different technical or market regulation strategies is investigated, such as in [13;19]. In such energy system, the effects on fuel efficiency or the ability of different technologies to integrate intermittent renewable energy can be analysed. In the technical energy system analyses, inputs include energy demands, production capacities and efficiencies, energy sources and distributions. In market economic optimisations further inputs are needed in order to determine marginal production costs, such as variable operations and maintenance costs (O&M), fuel costs and CO_2 emission costs. This modelling is based on the assumption that plants optimise according to business-economic profits, including current taxes. Output consists of annual energy balances, fuel consumptions and CO_2 emissions, fuel costs, etc.

The technical and market-economic analyses can be conducted under different regulation strategies, i.e. in closed or open systems or with different regulations of CHP plants and critical excess electricity production as well as ancillary service designs, etc. In open energy systems, the ability to integrate excess electricity production can be investigated; while in closed energy systems, the abilities of the fuel cell and electrolysers to improve the fuel efficiency are analysed. In a closed energy system, all excess electricity production is either converted or avoided, while this is not the case in open energy systems. It is not the aim to avoid electricity trade, but in order to analyse the fuel efficiency of the different energy systems and the technologies involved, it is necessary to apply these to a closed system. First, CHP production is replaced by boilers in the district heating systems using heat storages, if CHP plants are available in the system. Secondly, excess production is avoided by stopping wind turbines. If the system includes technologies which are able to use electricity, such as electrolysers, these are used to avoid excess electricity production instead of stopping wind turbines. Import/export is of course zero, since the system is closed.

In the next step, a *market exchange analyses* is conducted in which the ability of the different energy systems to trade and exchange electricity on international markets and according to prices is analysed. Such analyses can reveal the flexibility of energy systems or technologies, when large amounts of CHP and intermittent electricity are produced. Additional inputs are different external electricity market prices as well as the data needed in order to determine marginal production costs of the electricity production, such as variable O&M, fuel costs and CO_2 emission costs. Further inputs are market price distributions and a price dependency factor, which are applied in order to determine the response of the market prices to changes in production or demand, and import or export. Hence, the ability to profit from exchange can be identified [20]. The modelling is based on the assumption that plants optimise according to business-economic profits, including current taxes. These analyses are performed in an open energy system with international electricity trade and are compared to a market-economic optimisation of a closed system. This enables the identification of the net earnings made on electricity trade. The results represent the socio-economic profits of electricity trade, excluding taxes. Different variations of such analyses have been conducted of fuel cells, electrolysers and other technologies in different energy systems.

Finally, as the third step, *the socio-economic feasibility* of the system is investigated in terms of total annual costs under different designs and regulation strategies. In this step, inputs are investment costs as well as fixed O&M costs together with plant lifetime and an interest rate. In this analysis, a market energy system analysis is conducted in which the operation is optimised economically. In the feasibility study, total socio-economic costs exclude taxes. The costs are divided into 1) fuel costs, 2) variable operation costs, 3) investment costs, 4) fixed operation and maintenance costs, 5) electricity exchange costs and benefits, and 6) CO_2 payment costs.

2.2 Contemporary and future energy systems

In order to identify suitable applications of fuel cells and electrolysers, a total of eight energy systems are treated in the analyses. Six of the energy systems are constructed from the BAU 2030 system, while two correspond to the two visions for future renewable energy systems.

2.2.1 The reference energy system

The BAU projection was modelled by the Danish Energy Authority in 2005 and comprises energy demand and production of electricity and heat, as well as fuel for transport and industrial purposes for the entire energy system in 2030 [16]. The data of this system are listed in the first column of Table 6, and the primary energy supply is illustrated in Fig. 2 (BAU 2030). This data is applied as input to the EnergyPLAN model and thorough analyses of the system were conducted in connection with the design of renewable energy systems in previous publications [13;14]. Thereby, the consistency is assured between the energy system modelled in EnergyPLAN and the system projected by the Danish Energy Authority. The electricity demand is expected to be 49.0 TWh in 2030. The district heating demand is 39.2 TWh and heat demand in individual household is 19.7 TWh provided by boilers.

In the projection, large coal-fired power plants (PP) and local CHP turbines which expire are replaced by biomass-based plants and by natural gas-fired combined cycle CHP plants. The total production from wind turbines is expected to be 14.9 TWh. The electricity production from CHP plants corresponds to 40 per cent of the demand. This system can be characterised as an energy system developed under stable market conditions in 2005 and rather low long-term fuel prices for 2030 (35$/bbl), as recommended by the IEA in October 2004. The level of the primary energy supply in the recent business-as-usual projection from July 2008 is the same, while the latest IEA recommendations are used (62$/bbl). The main difference on the demand side, compared to the energy system of today, is the fact that electricity and transport demands are higher, while the heating demand is the approx. the same.

2.2.2 The design of contemporary and future energy systems

The BAU 2030 energy system is used to model six fundamentally different energy systems. First, the wind power in BAU 2030 is removed in order to construct the *CHP system*. Secondly, the *traditional system* is constructed by removing district heating produced by CHP plants, and adding individual natural gas boilers which meet the heat demand. The 20 per cent losses in the district heating systems are removed in the *traditional system.* However, the loss of co-generation in CHP plants calls for a total increase in the primary energy supply. Thirdly, the *electricity system* is constructed by meeting this heat demand by electric heating instead of individual fuel boilers. The new power plant capacities in the *electricity system* and the *traditional system* are based on the surplus capacity of the central plants in the reference, corresponding to approx. 15 per cent more than the peak electricity demand. The power plant capacity of the *electricity system* has to be more than doubled in order to meet the new peak hour electricity demand.

The electricity demand in the *electricity system* and the *traditional system* is produced at condensing power plants. In the *CHP system*, the electricity demand is partly met by CHP plants. *The electricity, the traditional and the CHP systems* represent three generations of energy systems, from the most inefficient electricity-based system, to the more efficient CHP system. The main differences are the technologies used in order to meet the heat demand. Each of these fundamentally different systems represents energy systems in regions and nations worldwide, even though they are constructed on the basis of an official Danish projection for 2030.

The three energy systems have been modelled with 24.5 TWh wind power in order to analyse the applications of fuel cells and electrolysers under conditions with high shares of intermittent resources. This corresponds to 50 per cent of the electricity demand in BAU 2030. All of the six systems supply the same services. Biomass is kept at the constant level of the BAU 2030 system, in the six energy systems.

The BAU 2030 energy system was used to design the two renewable energy systems presented in Fig. 2. They were designed during the “Energy Year” organised by the Danish Association of Engineers (IDA) and are published in the IDA Energy Plan 2030 from 2006 [13;14]. A large number of experts and researchers from universities and industry were involved in constructing and providing inputs to this vision for the Danish energy system. The Energy Plan concluded that it is technically possible to construct a 100 per cent renewable energy system in e.g. 2050 and, as a step along this path; a 50 per cent renewable energy system is feasible in 2030, including 60 per cent reductions in CO_2 emissions. The means of constructing such an energy system involve energy savings; more efficient conversion technologies; the replacement of fuels with intermittent renewable resources, as well as flexible technologies such as large-scale heat pumps, electric vehicles, etc., all of which have been included in the vision. In the systems analysed, SOFCs were also included in order to increase the efficiency. The cost structure of the IDA energy systems change radically, as investment costs increase and fuel costs decrease heavily. In October 2006, annual savings of 2 billion € were found when comparing the BAU 2030 system with the IDA 2030 system. These renewable energy systems are described in further detail in Lund & Mathiesen (2008) and related publications [13-15], and are here applied to the analyses of fuel cells and electrolysers.

The investment and O&M costs of the technologies used in the eight energy systems are based on Danish technology data [21], also used by the Danish Energy Authority. In the case of the IDA Energy Plan 2030, some technology data are not available from the Danish technology catalogue; thus, these costs are based on the inputs from the “Energy year” experts. In the spring of 2008, the socio-economic feasibility study presented in the IDA Energy Plan 2030 published in 2006 was updated with new fuel, electricity, CO_2 quota and biomass prices as well as new prices for wind turbines and photovoltaic power [22]. The Danish Energy Authority doubled the costs of wind turbines because of higher steel prices [23] and experts on photovoltaic energy increased the costs expectations by approx. 60 per cent. The updated costs for these technologies are used here.

Extensive investments have to be made in district heating systems when converting from the traditional system to the CHP system. The cost of reinvesting the total Danish district heating system has recently been assessed to 14.4 billion €, which is included in the CHP and integrated energy systems with a 40-year lifetime and 1 per cent O&M. The costs of the natural gas distribution and transmission systems have been included in fuel handling costs.

The technical energy system analyses in step one, the international market exchange analyses and the socio-economic feasibility studies in steps two and three all perform analyses of the applications of fuel cells and electrolysers in all eight energy systems; except from the 100 per cent renewable energy system, which is only analysed technically.

The energy systems are modelled taking into account ancillary services to ensure grid stability (voltage and frequency). A minimum of 450 MW must come from power-generating units capable of supplying grid stability, such as central power plants and CHP. Such a limitation represents a system in which 5-6 units are always operating above the level of technical minimum production. In the *electricity*, the *traditional* and the *CHP systems,* the distributed generation from renewable energy sources and local CHP units is not able to supply ancillary services. In the integrated system and the 100 per cent renewable energy system, however, the SOFC are assumed to start up rapidly, thus eliminating the requirement for a minimum production.

2.3 Fuel cell and electrolyser applications analysed

Six different applications of fuel cells are analysed, three of which are combined with electrolysers. Data on fuel cells and electrolysers are based on SOFC and SOEC technology. The six applications analysed are:

1. Expansion of district heating replacing individual boilers with central FC-CHP, based on SOFC technology and corresponding to 500 MWe.
2. Expansion of district heating replacing individual boilers with Local FC-CHP, based on SOFC technology and corresponding to 500 MWe.
3. Instead of expanding district heating with Local FC-CHP, the same heat demand is met by Micro FC-CHPs in individual households.
4. Application no. 2 with central FC-CHP is combined with electrolysers producing hydrogen and replacing fuels whenever feasible.
5. Application no. 3 with Local FC-CHP is combined with electrolysers producing hydrogen and replacing fuels whenever feasible.
6. Application no. 4 with Micro FC-CHP is combined with electrolysers producing hydrogen which meets the entire fuel demand of the system.

Natural gas boilers with 90 per cent efficiency have been replaced in the Central and Local FC-CHP applications. In the 100 per cent renewable energy system, individual house heating systems are based on heat pumps, Micro FC-CHP and wood pellet boilers. In this system, wood pellet boilers with 82 per cent efficiency are replaced with fuel cell systems. In the analyses, the FC-CHPs are assumed to operate on natural gas; although in 100 per cent renewable energy systems, fuels would be biogas or syngas.

The heat production from FC-CHP, the heat storages and peak load boilers are identical with the installed capacity and the district heating demand in the BAU 2030 system. In the central FC-CHP application, this corresponds to a district heating demand of 1.69 TWh. With an annual heat and hot water demand of 18 MWh, this corresponds to approx. 75,000 households. In the Local FC-CHP application, the production of heat is higher due to higher electric efficiencies. In the Local FC-CHP application, this corresponds to a district heating demand of 2.63 TWh and approx. 120,000 households. 20 per cent losses are assumed in the district heating systems.

In the Micro FC-CHP applications, the 2.63 TWh supplied by Local FC-CHP are now supplied by systems within the household, which reduces the demand to 2.11 TWh. The installed Micro FC-CHP is able to supply half of the peak hour demand, corresponding to more than 95 per cent of the annual demand. The system is equipped with a one-day storage and peak load boilers.

The capacity of the installed electrolysers is based on the demand of hydrogen in the Micro FC-CHP system in application 7. The fuel demand in this system is 4.6 TWh, if the Micro FC-CHP covers as much of the heat demand as possible. Assuming that the Micro FC-CHPs have an operation time of 25 per cent, this corresponds to 2,900 MWe electrolyser capacity. Fourteen days of hydrogen storage at full electrolyser capacity, corresponding to 1,100 GWh, has been installed. These capacities are also used in applications 5 and 6 in combination with Central and Local FC-CHP plants. In the Micro FC-CHP, the excess heat from the electrolysers replaces the heat produced by individual boilers; and in the Central and Local FC-CHP, the heat is used in the district heating system. Only technical energy system analyses are conducted of the Central and Local FC-CHP combined with electrolysers; hence, these systems are not included in the market exchange analyses.

The costs of future technologies, such as SOFC and SOEC, are rather hard to determine. Here, the investment costs are based on a medium-term goal of 0.8 M€/MWe and 6 per cent fixed O&M costs for large-scale central FC-CHP [14;21]. For these systems, a hybrid gas turbine SOFC system is assumed which can increase efficiencies from 56 per cent to more than 66 per cent and the total efficiency used to 90 per cent [9;10;14]. For small systems, the same investment costs are assumed; but here, no gas turbines are included and, thus, the O&M costs correspond to 10 per cent [14]. Such rather high O&M costs are used, because the fuel cell stacks must be replaced after 40.000 operations hours. For Micro FC-CHP, the inputs are based on potential data for individual systems in 2015 [14].

In the future, even lower costs can be expected, as production facilities as well as the lifetime of the stacks improve. It is expected that costs can be lowered to 0.4 M€/MWe [21;24], which is the figure used in the sensitivity analyses of all FC-CHP systems, in combination with 6 per cent O&M costs for 2030. For the systems as such, the technical lifetime is assumed to be 30 years for large systems and 20 years small systems. The cost inputs to electrolyses are based on SOEC technology and storage in caverns for 2030 [21]. The efficiencies of the electrolysers are based on lower heating value; an average efficiency of 80 per cent is assumed possible in combination with 5 per cent losses in both inverters and storage. The inputs to the energy system analyses and the feasibility studies are listed in Table 1.

The conversion from electric heating to water-based heating systems is associated with extra costs. These are not included here, because the extra costs of expanding the transmission lines are assumed to, as a minimum, compensate for these extra costs. The annual extra costs of the conversion amount to approx. 200 € [25]. The approx. 100,000 households converted to FC-CHP would thus enable an investment of 400 M€ in transmission lines, which would hardly be enough to accommodate the large increase in electricity demands.

Applications	Efficiencies %			Inv. costs		Lifetime	O&M
	el.	th.	Fuel	M€		(years)	costs/y
Central FC-CHP	66	34	-	0,8	/MWe	30	6%
Local FC-CHP	56	24	-	0,8	/MWe	20	10%
Micro FC-CHP	45	45	-	1,9	/MWe	20	6%
Electrolysers	95	-	80	0,25	/MWe	20	2%
Hydrogen storage	-	-	95	0,058	/GWh	25	0%

Table 1, Efficiencies, lifetimes, investment and O&M costs for the applications analysed.

2.4 Costs of fuels, fuel handling, electricity and CO_2 quotas

Three different sets of future fuel prices are related to the oil prices, assuming that oil prices will not be constantly high or low but will continue to fluctuate. The three price ranges are listed in Table 2. The base line level represent current fuel prices (spring/summer 2008) equivalent to an oil price of 120 $/bbl. The lower price level is based on the assumptions recommended by the Danish Energy Authority in February 2008 [26]. For wood pellets, though, the price level expected by the Danish Energy Authority is used as the base line, and the current price is at the lower level. The high fuel price level is calculated by adding the difference between the lower and the current fuel price level to the base line assumptions.

Current coal prices are 150 $/ton hard coal equivalent to approx. 3.3 €/GJ. Natural gas prices are based on crude oil prices by assuming a 62 per cent relation to the oil price, while for fuel oil, the relation is 70 per cent. For all biomass resources, straw costs are used for fuels in central and local plants, while wood pellet costs are used for biomass fuel costs in households. Please note that biomass-based fuels are also assumed to fluctuate in the analyses in this paper. The fuel transport and handling costs used are derived from the Danish Energy Authority [26] and listed in Table 2.

€/GJ	Crude oil	Coal	Natural gas	Fuel Oil	Gas oil / Diesel	Petrol / JP	Straw	Wood pellets
62 $/bbl	6.8	1.8	4.2	4.8	8.5	9.0	3.3	6.5
120 $/bbl	13.2	3.3	8.2	9.2	16.4	17.5	4.8	8.0
178 $/bbl	19.5	4.8	12.1	13.7	24.4	25.9	6.4	9.5

Table 2, Fuel costs depending on oil price per barrel (bbl).

€/GJ	Coal	Natural Gas	Fuel Oil	Gas oil Diesel	Petrol JP	Straw	Wood pellets
Power Stations (central)	0.07	0.43	0.23			1.61	
Distributed CHP, district heating & Industry		1.04	1.87			1.08	
Individual households		2.61		2.84			5.95
Road transport				3.08	4.16		
Airplanes					0.68		

Table 3, Fuel transport and handling costs per GJ.

A socio-economic interest rate of 3 per cent is used in the analysis. The socio-economic feasibility study does not include externalities, i.e. environmental or health effects, etc. CO_2 quota costs are included in the analyses; however, this does not reflect the externality costs of the emissions. CO_2 quota costs are currently approx. 26 €/ton. In accordance with the recommendations of the Danish Energy Authority, a long-term price of 23.3 €/ton is used here, although this level may prove conservative in a future with higher emission reduction targets. In a high price scenario for CO_2 quotas, these costs are doubled to 46.6 €/ton.

For the electricity market exchange analyses, long-term electricity costs are required. The long-term Nord Pool electricity prices recommended by the Danish Energy Authority are used as a baseline [26]. The annual average price is expected to be 49 €/MWh, which is used here in combination with the hour-by-hour fluctuations on the Nordic electricity market in 2005. CO_2 quotas are assumed to have a constant effect on the prices, corresponding to 9 €; thus, 40 €/MWh are expected to fluctuate. In the high CO_2 quota price scenario, a constant price effect of 19 €/ton is assumed. Each type of plant is expected to produce electricity according to its business-economic marginal costs including handling costs and taxes. In the results, taxes are excluded, representing socio-economic costs.

In the Nordic electricity system, prices depend heavily on the water content in the Norwegian water reservoirs. Variations typically occur in cycles of seven years with one dry year, three normal years and three wet years [20]. In Table 4 and Table 5, the electricity prices are listed for the seven year cycle with two CO_2 quota price levels.

€/MWh	Weight	Low CO_2 effect (constant)	Var. Nord Pool prices (fluctuating)	Total (average)
Wet year	3	9.3	23.3	32.6
Normal year	3	9.3	43.2	52.5
Dry year	1	9.3	78.4	87.7
7 year average		9.3	39.6	48.9

Table 4, Electricity prices in 2030 in the Nord Pool system with a CO_2 quota price of 23.3 €/ton.

€/MWh	Weight	High CO_2 effect (constant)	Var. Nord Pool prices (fluctuating)	Total (average)
Wet year	3	18.7	23.3	42.0
Normal year	3	18.7	43.2	61.8
Dry year	1	18.7	78.4	97.0
7 year average		18.7	39.6	58.3

Table 5, Electricity prices in 2030 in the Nord Pool system with a CO_2 quota price of 46.6 €/ton.

In the market electricity exchange analyses, current fuel prices are assumed to be most likely and are valid in 40 per cent of the time. Both low and high fuel prices are assumed to be present 30 per cent of the time. The analyses also include a fifty-fifty chance of low and high CO_2 quota prices and the seven-year cycle described above.

		BAU 2030	Electricity system	Electricity system +25TWh	Traditional system	Traditional system +25TWh	CHP system	CHP system +25TWh	Integrated energy system	100 per cent renewable energy system
Input:										
Electricity demand	TWh/y	49,0	80,4	80,4	49,0	49,0	49,0	49,0	38,1	59,9
DH demand	TWh/y	39,2	0,0	0,0	0,0	0,0	39,2	39,2	30,9	26,0
Ind. boiler heat demand	TWh/y	19,7	19,7	19,7	51,1	51,1	19,7	19,7	9,4	6,43
Industry incl. service and refining	TWh/y	53,7	53,7	53,7	53,7	53,7	53,7	53,7	32,8	23,2
Transport (incl. aviation & shipping)	TWh/y	69,2	69,2	69,2	69,2	69,2	69,2	69,2	44,76	30,3
North Sea (oil extraction)	TWh/y	22,7	22,7	22,7	22,7	22,7	22,7	22,7	14,0	-
Primary energy supply										
Wind power	TWh/y	14,9	0,0	24,5	0,0	24,5	0,0	24,5	18,7	34,3
Wave power and photovoltaic	TWh/y	0,0	0,0	0,0	0,0	0,0	0,0	0,0	2,5	4,5
Biomass	TWh/y	36,4	36,4	36,4	36,4	36,4	36,4	36,4	50,0	79,9
Solar thermal	TWh/y	0,0	0,0	0,0	0,0	0,0	0,0	0,0	4,1	3,5
Coal	TWh/y	20,4	50,2	32,8	27,8	11,3	26,5	12,5	4,2	0,0
Oil	TWh/y	112,0	109,4	108,1	107,7	106,4	112,7	115,9	41,3	0,0
Natural gas	TWh/y	95,4	122,3	94,3	121,1	94,5	105,5	78,7	41,6	0,0
Total	TWh/y	279,2	318,2	295,9	292,9	273,0	281,2	268,0	162,4	122,3
Key figures										
Net export	TWh/y	5,70	0,00	0,13	0,00	1,40	0,00	2,05	0,62	0,30
Av. eff. local CHP (elect./heat)	%	41 / 50	-	-	-	-	41 / 50	41 / 50	48 / 42	54 / 36
Av. eff. central CHP (elect./heat)	%	41 / 50	-	-	-	-	41 / 50	41 / 50	54 / 37	64 /26
Av. eff. power plants	%	52	52	52	52	52	52	52,0	55	64
Total excl. import/export of elect.	TWh/y	269,7	318,2	295,7	292,9	270,3	281,2	264,1	161,3	121,8
Power plant of demand	%	28	100	67	100	48	49	15	2	4
District heating boilers of demand	%	27	-	-	-	-	23	46	27	14
Power plant capacity	MW	8.000	23.500	23.500	10.000	10.000	8.000	8.000	4.500	8.000
- hereof extraction power plant	MW	2.000	-	-	-	-	2.000	2.000	2.000	2.000
Local CHP capacity	MW	1.350	-	-	-	-	1.350	1.350	1.200	1.200

Table 6, Electricity, heat and fuel demand in the projection from the Danish Energy Authority and the results of the technical energy system analyses of the eight energy systems used in the analyses of the applications of fuel cells and electrolysers.

3 Results

Here, the results of the three-step energy system analysis identifying feasible applications of fuel cells and electrolysers are presented. The results are divided according to the fuel efficiency, market exchange and socio-economic feasibility.

3.1 Fuel efficiency of energy systems

In Table 6, technical energy system analyses of the eight energy systems defined are presented. The introduction of wind power, especially in the electric and traditional energy systems, has a large effect on solid fuel consumption, because they replace PP. In the electric, the traditional and the CHP systems with wind power, excess electricity is produced during certain hours, when the demand is low and other plants are unable to integrate the wind power production. In such situations, the following options can be defined: to export electricity, typically at low prices; to stop the turbines, or to install technologies that can utilise the power. The latter has been applied to the integrated system, in which heat pumps, flexible demands and electric vehicles are able to integrate almost all of the wind, wave and photovoltaic power produced. The results of the technical energy system analyses of the six systems based on the BAU 2030 show that a difference of approx. 50 TWh can be identified in the total primary energy supply, when comparing the most inefficient electricity-based system to the CHP system with 50 per cent wind power. Previous analyses of the integrated system and the 100 per cent renewable energy system were included in Table 6, which revealed that it is technically possible to achieve significant further reductions in the primary energy supply.

3.2 Fuel efficiency and integration of renewable energy with fuel cells and electrolysers

The characteristics of the energy systems to which fuel cells and electrolysers are applied are very important to the ability of the applications to improve these systems. In very in-efficient energy systems, the fuel cells improve the fuel efficiency to a larger extent than in energy systems which are already rather efficient. However, in renewable energy systems, fuel cells are also important, as they improve the total efficiency of the system. The fuel efficiency improvements identified in the technical energy system analyses of the different applications are illustrated in Fig. 3.

In the two CHP systems, substantial amounts of small CHP plants with gas turbines are already installed. In the CHP system with no wind power, the FC-CHP can replace the production of PP and improve the fuel efficiency. In the CHP system with wind power, the FC-CHPs are more efficient than the gas turbines already installed. However, the fuel savings achieved are limited, because the heat at these plants is now produced by boilers. The fuel savings in the 100 per cent renewable energy system are larger than in the integrated energy system, because the rather inefficient wood pellet boilers are replaced. In the 100 per cent renewable energy system, however, SOFC are already installed in all CHP plants; hence, FC-CHP is very important to the total fuel efficiency of the system; i.e. as shown in Table 6. In the integrated energy system, the penetration of SOFCs is also rather high already at this point, and thus, an improvement in fuel efficiency can only be achieved with central FC-CHP. For these energy systems, the flexible operation of FC-CHP is important to the integration of fluctuating renewable energy. Renewable energy and CHP replace PP in these systems and, hence, traditional base load plants are not important in future fuel-efficient renewable energy systems.

Along the path towards renewable energy systems, the analyses of fuel efficiency shows that improvements can be achieved by expanding the CHP areas. For Central FC-CHP and Local FC-CHP, the largest fuel efficiency improvements are achieved in the two electricity energy systems, because both electricity and heat demands previously covered by PP are replaced. In the electricity energy systems with 24 TWh wind power, the improvements are almost the same as in the system without wind, because the FC-CHPs are able to utilize heat storage and move their production to hours with no wind power, thus replacing PP production. In these two energy systems, the electricity demand is rather high; thus, both Central and Local FC-CHP plants have the potential for producing heat in FC-CHP plants. For Central and Local FC-CHP in the remaining energy systems, the savings are lower due to the fact that individual boilers are now replaced instead of electric heating. Fuel savings are generally lower in systems with wind power, because these systems offer limited opportunities to replace PP.

The Micro FC-CHP applications replace a heat share similar to the amount supplied to households from district heating in the Local FC-CHP application. The Micro FC-CHP also replaces PP production whenever possible; but the fuel savings achieved are in general lower than in the previous applications, mainly due to lower efficiencies. In the energy systems with already installed CHP plants, the Micro FC-CHPs produce at times when these would normally be operating, and thus, the heat demand in district heating areas must now be covered by boilers. This is not a big problem in energy systems in which CHP plant efficiencies are lower than those of the Micro FC-CHP; but it does pose a problem in renewable energy systems in which the efficiencies of installed CHP plants are higher than those of Micro FC-CHPs. Due to this situation, a small increase in fuel consumption takes place in the integrated energy system. Again, savings in the 100 per cent renewable energy system are higher than those of the integrated energy system, because wood pellet boilers are replaced and Local and Central FC-CHPs are more efficient.

In the cases of Central and Local FC-CHP combined with electrolysers, marginally higher fuel efficiencies can be identified in systems with excess electricity production, because other fuels can now be replaced. Here, the electrolysers only produce at times with excess electricity production. Most fuels are replaced in the traditional energy system with 24 TWh wind power, because this system has the largest excess electricity production. For the Micro FC-CHPs combined with electrolysers, the hydrogen demand must be met, and thus, excess electricity from wind power cannot cover the entire demand. This eliminates the fuel savings achieved by such applications, as identified in the case of Micro FC-CHPs operated on natural gas.

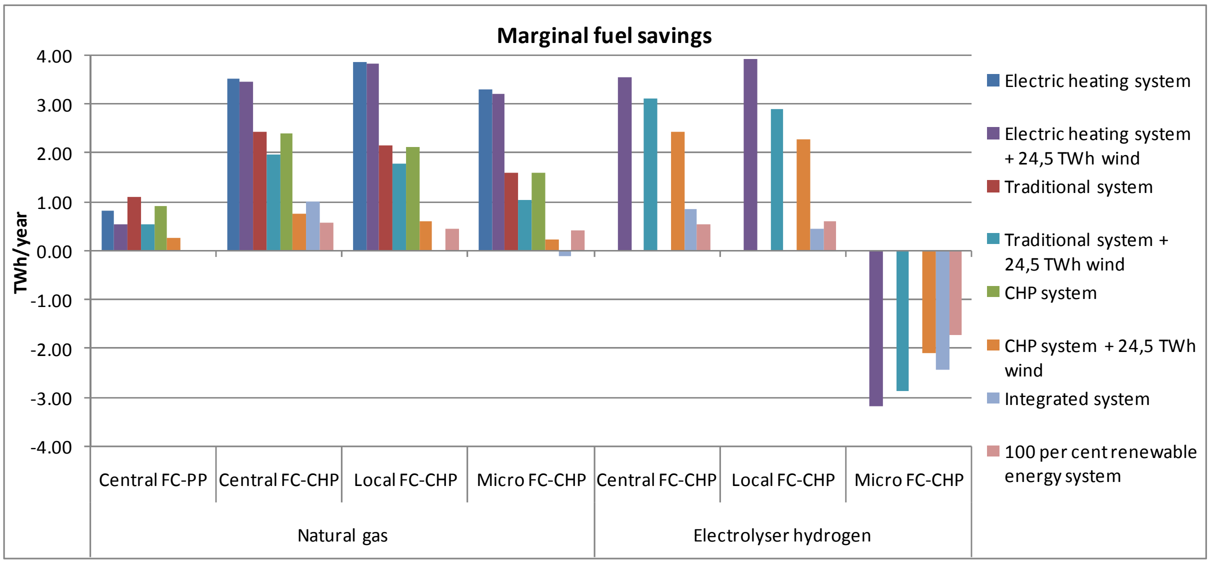

Fig. 3, Marginal fuel savings of the six applications analysed in the eight different energy systems. Central FC-PPs have been included for comparison.

For comparison, 500 MWe central FC-PP have been included in the technical energy system analyses. The technology is identical with Central FC-CHP except from the fact that no heat is produced by FC-PP. As wind power often replaces central PP, and thus, FC-PPs have fewer possibilities to operate in these systems, the best fuel efficiency improvement is achieved in energy systems without wind power. In the integrated energy system and in the 100 per cent renewable energy systems, fuel savings are very low. This is based on the following facts: 1) A large proportion of the demand is met by fluctuating renewable energy; 2) the operations hours of PP is reduced to a minimum with CHP plants in order to improve fuel efficiency; and 3) the efficiencies of the existing PP are already quite high.

In Fig. 4, the changes in excess electricity production are illustrated. In the Central and Local natural gas FC-CHP systems, the excess electricity production does not change. In the hydrogen Central and Local FC-CHP systems, the excess electricity can now be utilised. The natural gas Micro FC-CHP application increases the excess electricity production marginally in energy systems with wind power. Although heat storages are used, these are less flexible than central and local FC-CHP plants. This is due to the fact that the units are prioritised to increase the total efficiency, but are sometimes forced to produce electricity at times when the demand is already met by wind power and the production of PP and other CHP plants has already been reduced to a minimum. This is also the case in the hydrogen Micro FC-CHP system in the traditional and the 100 per cent renewable energy system. Here, electrolysers reduce excess electricity production, but this is increased again during some hours due to the electricity produced by Micro FC-CHP.

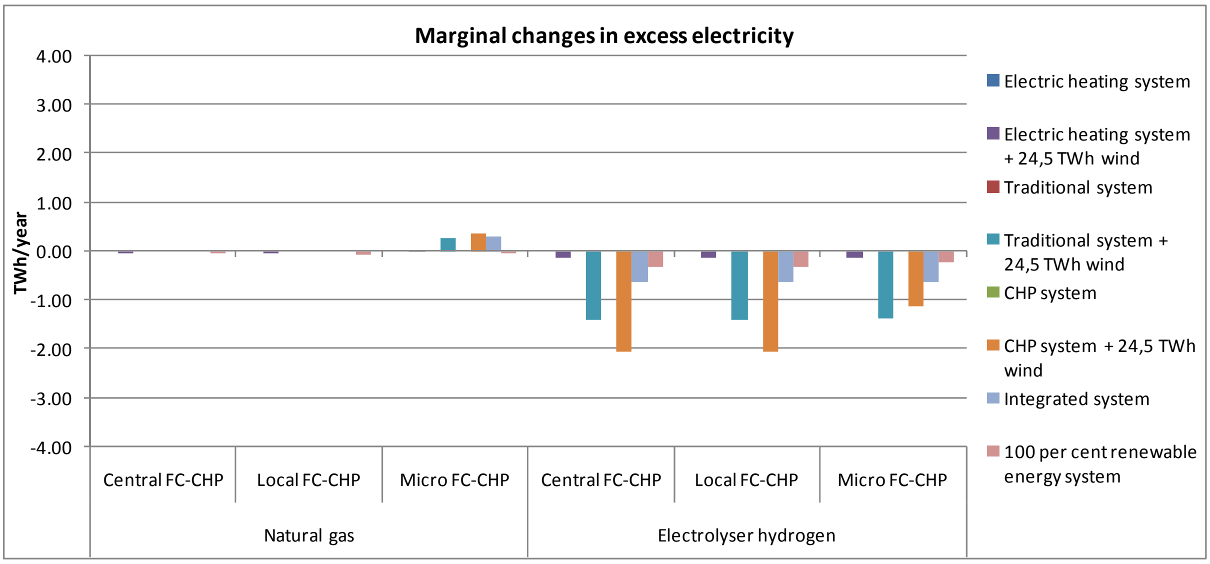

Fig. 4, Marginal changes in excess electricity production of the six applications analysed in the eight different energy systems.

3.3 Cost of electricity generation and effects on electricity trade

Extensive international electricity market exchange analyses of the natural gas FC-CHP applications as well as the hydrogen Micro FC-CHP have been conducted. Here, the aggregated results of such analyses are presented, but first the expenses related to FC-CHP are compared to the costs of competing future technologies.

3.3.1 Competing future technologies

In Table 7, the long-term electricity cost targets of the FC-CHP and competing technologies are listed in terms of different fuel and CO_2 quota prices. Onshore and offshore wind turbines are expected to have the lowest power generation costs, also when including trade and balancing costs in the fixed O&M [27]. The operation time of the turbines is 30 per cent for onshore and 40 per cent for offshore wind turbines. For the remaining technologies, the operation time is assumed to be 50 per cent.

Large Central FC-CHP cannot compete with coal-based CHP, but they have long-term costs similar to those of combined cycle gas turbines (CCGT) and have lower costs than biomass-based CHP, especially if the long-term cost goals are met.

Small Local FC-CHPs are able to compete with small single cycle gas turbines (SCGT), also in case that only the cost goals for 2015 are met. The better efficiencies of FCs can compensate for the high costs of replacing stacks in Local FC-CHP, represented by the high fixed O&M costs. Two different price levels of Micro FC-CHP have been included, assuming that, in the long term, it is possible to scale the Local FC-CHP; but the efficiencies do not increase due to larger auxiliary power requirements in small-scale generation. In all the fuel and CO_2 quota price scenarios, the Micro FC-CHPs are unable to compete with the other technologies. Some may argue that the main purpose of Micro FC-CHP technologies is to produce heat, and that this element should be taken into account. This, however, is the also the case for the some of the other future CHP technologies listed.

One mayor problem for the FC-CHPs is the fuel prices, because natural gas is more expensive than coal. This is, however, also the case of gas turbines. If the electrolysers introduced above were able to operated solely on wind power, the long-term costs of hydrogen would be approx. 15 €/GJ, not taking into account the costs of the electrolysers. Such prices cannot compete with the fuel costs used in FC-CHP included here.

Future technologies	Inv. costs	Life-time	Fixed O&M	Var. O&M	Efficiency		Total €/MWh incl. CO_2 quotas			
							Low fuel	Base fuel		High fuel
	M€/MW		(%)	€/MWh	el.	th.	Low CO_2	Low CO_2	High CO_2	High CO_2
Wind On-shore	1.07	20	3.0	12	-	-	38	38	38	38
Wind Off-shore	1.87	25	2.8	15	-	-	44	44	44	44
Large Coal CHP ’15	1.20	30	1.3	1.8	52.5	40.5	47	57	72	82
Large Coal CHP ‘30	1.20	30	1.3	1.8	55.0	38.0	46	55	70	80
Large Biomass CHP ‘15	1.30	30	1.9	2.7	46.5	43.5	142	154	154	166
Large Biomass CHP ‘30	1.30	30	1.9	2.7	48.5	41.5	137	149	149	160
Ngas CCGT (>100MW)	0.55	30	2.3	1.5	61.5	29.5	62	85	92	116
Ngas CCGT (>10 MW)	0.70	25	1.4	2.8	52.0	39.0	74	102	111	138
Ngas SCGT (40-125)	0.49	25	1.5	2.5	46.0	46.0	79	110	120	151
Ngas SCGT (5-40)	0.70	25	1.1	3.3	41.5	50.5	130	164	175	209
Ngas Large FC-CHP ‘15	0.80	30	6	-	66	24	68	89	96	118
Ngas Large FC-CHP ‘30	0.40	30	6	-	66	24	58	79	86	108
Ngas Small FC-CHP ‘15	0.80	20	10	-	56	34	116	141	150	175
Ngas Small FC-CHP ‘30	0.40	20	6	-	56	34	97	122	131	156
Ngas Micro FC-CHP ‘15	1.87	20	6	-	45	45	254	286	296	328
Ngas Micro FC-CHP ‘30	0.80	20	10	-	45	45	231	263	273	305

Table 7, Long-term electricity prices of future technologies. For the FC-CHP technologies, the prices are based on potential future costs and efficiencies previously described. Low fuel-high CO_2 and high fuel-low CO_2 costs have been left out. For coal CHP and gas turbines, potential future efficiencies are listed; however, the costs of these are approx. current costs [21;27].

3.3.2 Electricity market exchange analyses

The combinations of seven different future energy systems, four different applications, six different fuel and CO_2 quota prices, and three different electricity price levels result in more than 650 energy system analyses. Here, the electricity market exchange analyses are presented in detail for the Local FC-CHP in the CHP system with 24 TWh of wind power. Subsequently, the aggregated results of the analyses are presented for all energy systems and all applications.

In Fig. 5, the electricity trade effects of the reference CHP system with 24 TWh of wind power are illustrated, in combination with Local FC-CHP in this energy system. In the normal year, the Local FC-CHPs are able to marginally increase net earnings by reducing import and increasing export due to a more efficient fuel conversion. In the wet year, electricity prices are rather low and net earnings are mainly connected to imports. The Local FC-CHPs reduce import and, when electricity prices are rather low, this results in decreased net earnings, even though the Local FC-CHPs are very efficient. In the dry year, the Local FC-CHPs are able to increase net earnings based on larger earnings from more efficient electricity exports. When applying the assumptions on the frequency of the different electricity, fuel and CO_2 quota cost levels described above, the electricity market analyses of Local FC-CHP show that the net earnings are unchanged.

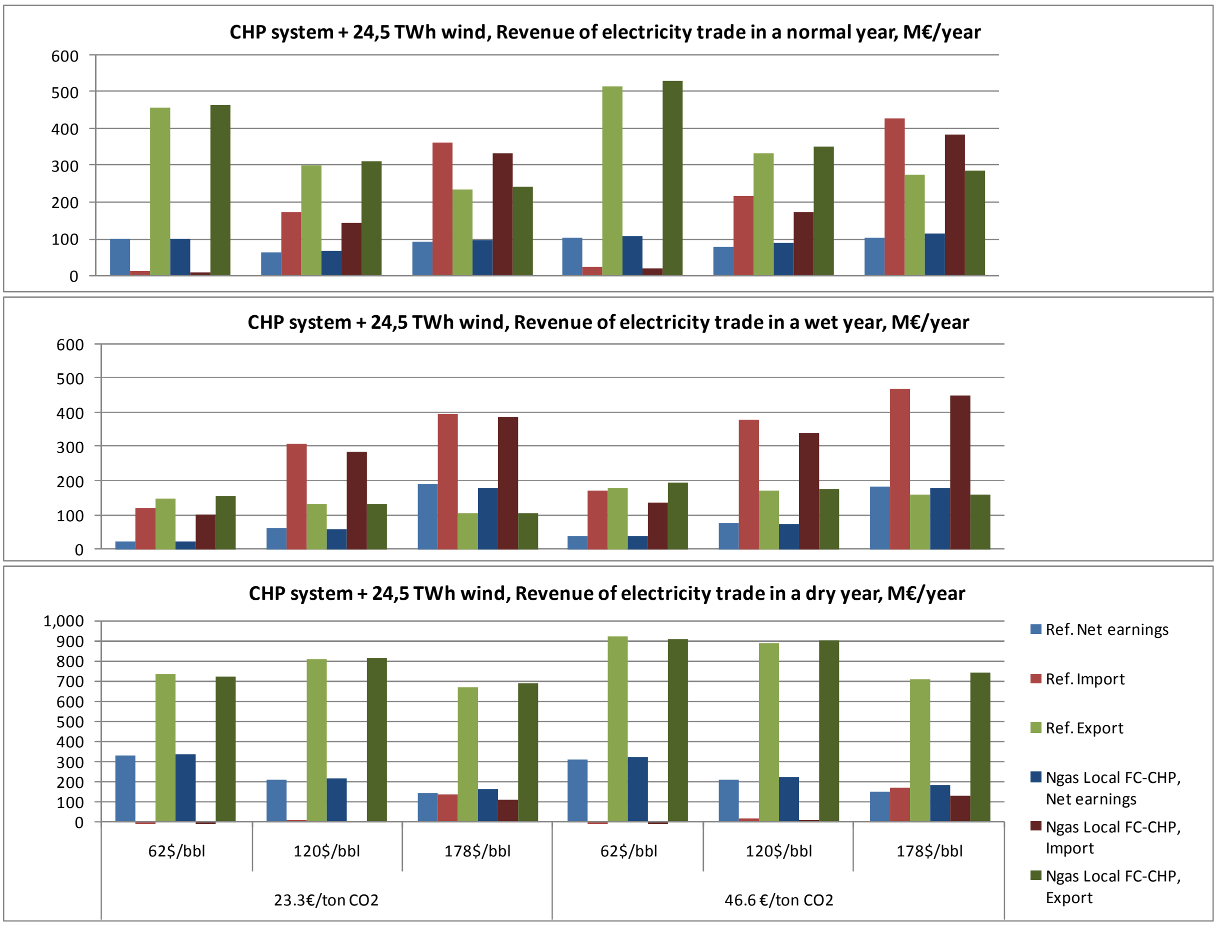

Fig. 5, Electricity market exchange analyses of the reference CHP system with 24 TWh of wind power and Local FC-CHP added to this system. The results are illustrated for three electricity and three fuel prices and two CO_2 quota costs.

In Fig. 6, the total average revenue of electricity trade of the reference energy systems is shown. The total net revenue of electricity trade in the references is between 110 and 170 M€/year. In the four electricity and traditional systems, the main earnings on trade are connected to imports, due to rather high production costs. This is also the case of the CHP system; while in the CHP system with 24 TWh of wind power as well as in the integrated system, the earnings on trade are reduced, due to lower system flexibility with a high penetration of CHP and fluctuating renewable energy.

In Fig. 6, the net average revenue of the four applications added in the reference energy systems is also illustrated. In all energy systems, the production of electricity in FC-CHP, replacing the production of heat in boilers, generates rather low marginal production costs. Still for the natural gas Central, Local and Micro FC-CHP applications the changes in revenue are rather low in most systems. The large import in wet years and high fuel costs hamper the ability of the FC-CHP to increase earnings on trade. In the reference systems, imports would reduce PP and thus enable more fuel savings than when replacing FC-CHP, because the replaced FC-CHP production leads to a higher boiler production. This poses a problem for the increase of earnings from international electricity trade when fuel prices are high, especially on the Nordic electricity market where prices are often low due to the Norwegian hydro power production.

In normal years, the profits of trade increase significantly in the CHP energy system with 24 TWh of wind; hence, FC-CHP has good abilities to compete with the gas turbine CHPs in this system, which use the heat storages. In normal years, smaller profits can also be generated for FC-CHPs in the CHP energy system.

In dry years, FC-CHPs generate profits in most systems; especially in the CHP systems in which where they compete with gas turbines. In the dry year, however, the Local FC-CHP performs better than the Central FC-CHP in the CHP energy system with wind power. This is due to the larger heat storages of the local systems.

For the hydrogen Micro FC-CHP, electrolysers are able to profit from fluctuations in the traditional energy system with wind power. This system is rather inflexible compared to the CHP system with wind and the integrated energy system, in which CHP plants already adjust prices and hence hydrogen Micro FC-CHP are able to increase profits. In the integrated system, the net earnings on international trade decrease marginally, as the other components in the system are, among others, flexible demands and heat pumps.

3.4 Socio-economic consequences

In terms of socio-economic costs, the integrated energy system generates the lowest total costs. This gradually increases towards the electricity-based system, which generates the highest socio-economic costs. In Fig. 6, net changes in total socio-economic costs are illustrated.

The implementation of FC-CHP more or less balances in the case of the Central FC-CHP, while the Local FC-CHP has additional socio-economic costs. In the CHP system and the integrated systems, the costs of FC-CHP increase. This is due to the fact that extra CHP capacity is not feasible in these systems, unless e.g. gas turbines are replaced instead of expanding CHP capacity as done here. The Micro FC-CHP system generates the highest increase in costs, also in the situation with electrolysers, because price fluctuations are involved which do not necessarily reflect fuel-efficient solutions.

The analyses were conducted with potential technologies for year 2015. If we consider potential technologies in 2030, the Central FC-CHP solutions would improve by 22 M€ and the Local FC-CHP by 41 M€. Such improvements would make the expansion of the CHP and district heating with FC-CHP profitable in most systems. The costs of the district heating systems would, however, balance these savings, assuming district heating costs of 0.26 M€/GWh ab net. If we assume that the costs of Micro FC-CHP are reduced to Local FC-CHP costs expected for 2015, the costs would be reduced by 40 M€, making the total costs balance more or less.

As presented in Table 7, the long-term electricity production costs of the Local FC-CHP are lower than those of small gas turbines, even when using the potential costs for 2015. In the CHP energy systems and in the integrated energy system, this means that, rather than expanding CHP and district heating, the existing CCGT or SCGT gas turbine CHP plants could be replaced by FC-CHP. This would reduce the total costs, because the FC-CHPs are more efficient.

Hence, in the systems without CHP, it is feasible to expand CHP; and in future fuel-efficient renewable energy systems with high penetrations of small gas turbines in CHP plants, it is feasible to replace these with FC-CHP.

Fig. 6, Total average revenue of electricity trade and total socio-economic feasibility of the reference energy systems and net change in revenue of the four applications. Please note that the scales vary.

4 Conclusion

SOFC can improve the fuel efficiency in future renewable energy systems by replacing gas turbines. Large central FC-CHP plants based on hybrid SOFC gas turbines create marginally larger fuel savings than smaller local SOFC-based CHP plants; however, both technologies are able to improve fuel efficiency compared to gas turbines. In renewable energy systems, local SOFCs are very important, as they can increase fuel efficiency significantly compared to single cycle gas turbines. On the other hand, large FC-CHPs compete with combined cycle gas turbines, which are not significantly less efficient. If the efficiency and cost targets for SOFC are met, they can improve fuel efficiency and generate lower long-term production costs than gas turbines.

The expansion of CHP plant capacity can improve fuel efficiency and serve as the first step on the path towards integrated renewable energy systems. The expansion of CHP with central FC-CHP may be limited, as this requires large connected rural areas. In renewable energy systems, CHP can reduce costs and increase fuel efficiency. In such case, Local FC-CHPs have better fuel efficiencies and a higher feasibility than Micro FC-CHPs. Electrolysers may contribute to the integration of excess electricity. Fuel consumption, however, may increase if connected to Micro FC-CHP, because a fixed demand must be met and excess electricity production cannot always cover the electricity demand. In the most efficient integrated renewable energy systems, electrolysers are less important, since other technologies are able to integrate most of the fluctuating renewable energy. However, in 100 per cent renewable energy systems, electrolysers may be important in terms of replacing other fuels.

Both efficiencies and costs are uncertain for technologies which are still at the development stage. However, the SOFCs have the potential for reducing the dependence on fuels in future energy systems. Local 5-40 MW size SOFC FC-CHPs that can improve the efficiency of SCGT distributed CHP plants are particularly important, as is the development of SOFC to operate with the fluctuation of renewable energy instead of as base load plants.

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Appendix V

Comparative energy system analysis of individual house heating in future renewable energy systems

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Abstract

Individual house heating and the integration of renewable energy are key issues when addressing global warming. One future technology which could address this is fuel cell (FC) micro combined heat and power (CHP) operated on natural gas, biogas or hydrogen. Here, this system is compared to the conventional technologies: heat pumps (HP), natural gas and wood pellet boilers. They are analysed hour-by-hour in renewable energy systems with and without large amounts of district heating CHP plants. As FC systems are often connected to the utilisation of excess electricity, both systems have a wind power share of 50 per cent. HP has the lowest fuel consumption, CO_2 emissions and socio-economic costs. Natural gas and biogas micro FC-CHP are more efficient than wood boilers; however, they use approx. the same amount of fuel as gas boilers and have higher costs. Electrolysers with micro FC-CHP are rather inefficient and economically unfeasible. If the aim is to reduce CO_2 emissions it can be recommended to increase the use of HP, replace boilers and use the fuels in CHP plants instead. In the case of Denmark, however, the current tax system encourages the use of boilers and hinders the use of HP. A two-stage tax reform is introduced taking into account fuel efficiency and "opportunity costs" of using scarce biomass and fossil fuels in inefficient boilers instead of CHP plants.

Keywords – distributed generation, micro CHP, fuel cells, electrolysers, hydrogen, heat pumps, wind power, renewable energy planning, CO2 abatement measures, energy storage

1 Introduction

The heating demand of Danish dwellings accounts for 24 per cent of the total Danish primary energy supply. 42 per cent is covered by fuel-efficient district heating and 23 per cent by renewable energy; mainly wood but also heat pumps and solar thermal systems. The remaining 35 per cent of the supply is covered by individual oil and gas boilers or electric heating [1;2]. Hence, there is still a considerable potential for fossil fuel savings in the heating of Danish dwellings.

In addition, electricity is increasingly produced by non-dispatchable technologies, such as wind turbines or local CHP plants supplying heat to district heating grids. In 2006, wind turbines accounted for 17 per cent of the Danish electricity demand, slightly less than the 18 per cent of the previous two years [1].

FCs operated on hydrogen are often seen as one of the potential bridges closing the gap created by a world-wide further expansion of wind power and other intermittent renewable energy sources. FCs are also seen as the means of integrating renewable energy sources into the heating of individual dwellings. Schenk et al [3] find that hydrogen is beneficial at large penetrations of wind power in the Netherlands; while Segura et al [4] define hydrogen systems as back-up systems for large-scale wind farms, though the modest efficiency of

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these systems is seen as an impediment. Becalli et al [5] consider hydrogen an important factor in developing energy systems which can supply dwellings with renewable energy-based services; while authors such as Samaniego et al [6] refer to a somewhat static perception in which wind and hydrogen systems render a constant power supply rather than a load-following power supply.

The European Union-funded project *Regional markets of Renewable Energy Source-fuel cell systems for households* [7] specifically targets the development of regional markets for FC systems. The project considers dwellings based on renewable energy sources; thus underlining the political importance associated with this issue.

Apart from the discussions within academia, hybrid wind-hydrogen systems have also been introduced by a number of initiatives, particularly in Europe. The Norwegian island of Utsira has already established a wind-hydrogen hybrid system based on two 600 kW wind turbines, a 48 kW electrolyser, a 10 kW FC and a 55 kW hydrogen combustion engine [8]. The Faeroese island of Nolsoy along with other partners in the North Atlantic Hydrogen Association is equally considering wind-hydrogen hybrid systems. The Danish village Vestenskov on the island of Lolland is introducing hydrogen systems, though not with the close wind links as in the cases of Utsira and Nolsoy. Future hydrogen city concepts can also be found, like H_2PIA [9] in Denmark including urban planning and architecture with the aim of minimising energy needs. However, these are further from actual implementation.

The FC technology is, however, not the only option when integrating renewable energy into heating systems and thus introducing flexibility for the integration of large amounts of fluctuating renewable energy sources. Integration technologies such as heat pumps (HP), electric boilers, MW size and micro FC-CHP, battery electric vehicles and hydrogen FC vehicles have previously been studied at the system level, with the aim of locating the least-cost technologies for the integration of wind [10]. Compared to larger CHP plants based on FC technologies in micro CHP is less feasible and less efficient, because such FCs can replace gas and steam turbines [11-13]. However this may not be the case when micro FC-CHP is compared to other individual house heating system. In this paper, renewable energy systems with wind power are also in focus, but here, the aim is to analyse different technologies suitable for individual house heating.

Heating systems such as micro FC-CHP cannot be evaluated in a stand-alone situation but have to be analysed as part of an energy system. The aim of this analysis is to compare different alternatives for individual heating in renewable energy systems with 50 per cent wind power. The comparison is made in terms of fuel efficiency; the ability to reduce excess production; the impact on electricity trade; socio-economic and business-economic costs. A comparative analysis is made of a scenario including individual heating based on natural gas; wood pellet boilers; micro FC-CHP operated on natural gas, or hydrogen from electrolysers as well as geothermal and air to water HPs. Two types of HPs are included in order to consider the fact that not all dwellings have access to the same heat source. Biogas in individual boilers and biogas for micro FC-CHPs for individual house heating are also included as sub alternatives. District heating systems with local CHP plants replacing individual heating systems are not included in the analyses.

2 Methodology

In the methodology, two fundamentally different energy systems are defined in which the heating systems are compared using by use of energy system analysis modelling. The energy system analysis model is described in the following sections as well as the assumptions concerning technologies and fuels, etc. The performed technical analysis of the effect on fuel efficiency etc. is described; as are the electricity market exchange analysis and the socio-economic feasibility study. A method for making recommendations for new public regulation schemes reflecting these findings is also elaborated.

2.1 The EnergyPLAN energy system analysis model

When the integration of fluctuating energy sources is a matter of concern, the analyses of heating systems require detailed hour-by-hour simulations of the whole energy system with emphasis on excess electricity production. Such analyses can be done by use of the EnergyPLAN model. This is a general energy system analysis tool designed for the analysis of regional or national energy systems. It is an input-output model, which uses data on capacities and efficiencies of the components in the energy system and the availability of fuels and renewable energy inputs. Hour-by-hour, the model calculates how the electricity and heat demands of the complete system will be met under the given constraints and technical or market regulation strategies. The model has libraries of e.g. hourly wind power distributions based on actual historical productions from Danish wind turbines. As a result of the calculation, detailed knowledge is created of the production of the different components.

The EnergyPLAN model has previously been used in a number of energy system analysis activities, including expert committee work for the Danish Authorities [14] and the design of 100 per cent renewable energy systems [15-17]. The present version 7.2 of the model including documentation is available for download [18].

When using this model, a three-step energy system methodology can be applied. Technical energy system analyses can reveal the fuel efficiency of the system as well as its ability to use excess production from e.g. wind power, from a purely technical perspective. In the technical regulation strategy of these analyses, CHP plants are operated to produce as little as possible by the use of boilers under conditions with high wind power productions. By using heat storage, the production at condensation mode power plants (PP) is minimised and replaced with CHP production. In these analyses, the electric interconnections to the neighbouring countries are not used, i.e. the system is modelled as a closed energy system. Such energy system analyses enable a coherent technical comparison of the fuel efficiency and the ability of the systems analysed to reduce the excess production from wind power.

Fuel cost and variable operation and maintenance costs (O&M) are included in a market electricity exchange analysis, using electric interconnections to neighbouring countries. This analysis can reveal the costs and earnings of exports, imports and bottlenecks from implementing the heating systems; some of which use or produce electricity.

The total socio-economic costs of the eating systems are compared in terms of fuel consumption, etc., from the energy system analyses and combining these results with fuel and fuel handling costs as well as CO_2 quota costs, investment costs, lifetimes and fixed and variable O&M costs.

2.2 Definition of energy systems

The purpose of the energy system analysis is to examine the impacts of different house heating options. Such analyses should reveal how the integration of wind power is impacted by the choice of technology. In its nature, such analysis depends on the energy system in question. The share of wind power is especially important as well as other production units with limitations or restrictions, such as e.g. distributed CHP plants. Here, a “Business as usual” (BAU) energy system from the Danish Energy Authority’s projection of the Danish energy system to year 2030 is used as the reference [19].

The reference has a high share of CHP, which is not the case in most countries. A Non-CHP reference has thus also been defined, simply by replacing all CHP in the reference by heat production from boilers and electricity production from PP. This defines the two reference systems which are listed in table 1. In the analyses, wind power share is 50 per cent leading to an excess electricity production of 1.66 TWh/year (approx. 7 per cent of the wind power production). The data in table 1 represents the results of the energy system analyses using the technical regulation strategy described above.

In the model, different limitations on the components can be defined. Here, the analyses assume that PP and CHP can change production from one hour to the next in order to compensate for fluctuations in wind power. A minimum capacity limit of 450 MW has been defined in order to secure the supply of ancillary services (voltage and frequency). Such limitation represents a system with central power plants, such as the Danish system in which 5-6 PP units are always above technical minimum production.

TWh/year	CHP-system (BAU 2030 CHP)	Non-CHP-system (BAU 2030 Non-CHP)
Key figures:		
Electricity demand	49.00	49.00
District heating demand	39.18	39.18
Excess electricity production	1.66	1.66
Fuels		
Coal	12.47	18.46
Oil	114.66	128.85
Natural gas	77.98	84.67
Biomass	36.36	23.38
Primary Energy Supply		
Onshore and offshore wind power	24.49	24.49
Fuel for power plants (PP)	13.62	45.60
Fuel for CHP	40.68	-
Fuel for district heating boilers	19.00	41.59
Fuel for households	22.57	22.57
Fuel for industry	53.66	53.66
Fuel for transport	69.20	69.20
Fuel for refinery etc.	22.74	22.74
Total	265.96	279.85

Table 1, The two reference energy systems.

2.3 Analysed heating systems and assumptions

The heating systems analysed are compared to a scenario in which the heat demand is met by individual natural gas boilers. Wood pellet boilers are included in the analyses, as these are used more and more frequently in Denmark. The coefficient of performance (COP) is the heat / electricity factor in HP. Here, the COP is defined as the annual average and includes a peak electric boiler for the geothermal HP. The micro FC-CHP is assumed to have a heat capacity equal to half of the peak heat demand. In the very few situations in which the FC-CHP cannot meet the demand, a fuel boiler is activated. In all alternatives, central heating with a heat storage capacity corresponding to one day of average heat demand is assumed to be installed. Such storage enables the utilisation of the flexibility of HP and micro FC-CHP. The efficiencies of the units are listed in table 2.

A 3.2 and 2.6 COP are used for geothermal and air/water HP, respectively [20]. Current commercially available electrolysers have a 60 per cent electricity to fuel efficiency. However, an efficiency of more than 80 per cent may be possible and is used in the sensitivity analysis here in combination with a 10 per cent thermal efficiency. Hydrogen storage may eventually achieve efficiencies between 88 and 95 per cent. [21-24]. 5 per cent losses are assumed in hydrogen storage and in inverters, which results in a total efficiency of electricity to fuel at households of 72 per cent. The micro CHP units consist of solid oxide FCs or polymers exchange membrane FCs. Both electric and thermal efficiencies are 45 per cent in the analysis, when operated on hydrogen. When operated on natural gas or biogas, an additional loss is included for the reforming process; hence 30 per cent electric and 60 per cent thermal efficiencies are estimated to be possible. The efficiencies are higher for other applications than the micro FC-CHP included here, such as, for instance, MW size distributed FC-CHP. In the sensitivity analysis, the efficiencies of micro FC-CHP are raised to 60 per cent for electricity and 30 per cent for heat.

	Heat	Electricity	COP	Hydrogen
Individual Technologies:				
Boiler (natural gas, biogas and hydrogen)	1.00	-	-	-
Boiler (wood pellets)	0.85	-	-	-
Geothermal HP	-	-	3.20	-
Air/water HP	-	-	2.60	-
Micro FC-CHP (natural gas/biogas incl. reformer)	0.60	0.30	-	-
Micro FC-CHP (hydrogen)	0.45	0.45	-	-
System Technologies:				
Power plant (PP)	-	0.52	-	-
CHP plant	0.50	0.41	-	-
Electrolysers	0.10	-	-	0.72

Table 2, Efficiencies of technologies in the analyses

The heating systems are analysed in the case of supplying 300,000 individual houses. Each of these houses has an annual heat demand of 15,000 kWh, equal to a total of 4.5 TWh. Typical Danish hour distribution and duration curves have been used for the heat demand, as illustrated in fig. 1. For each house, the peak heat demand is approx. 4.5 kW. Out of the annual 15,000 kWh, 3,750 kWh is hot water and 11,250 kWh is heating. A sensitivity analysis is conducted in which houses are insulated and the heat demand is decreased by 50 per cent, leading to a total annual heat demand of 9,375 kWh and a peak demand of 1.5 kW.

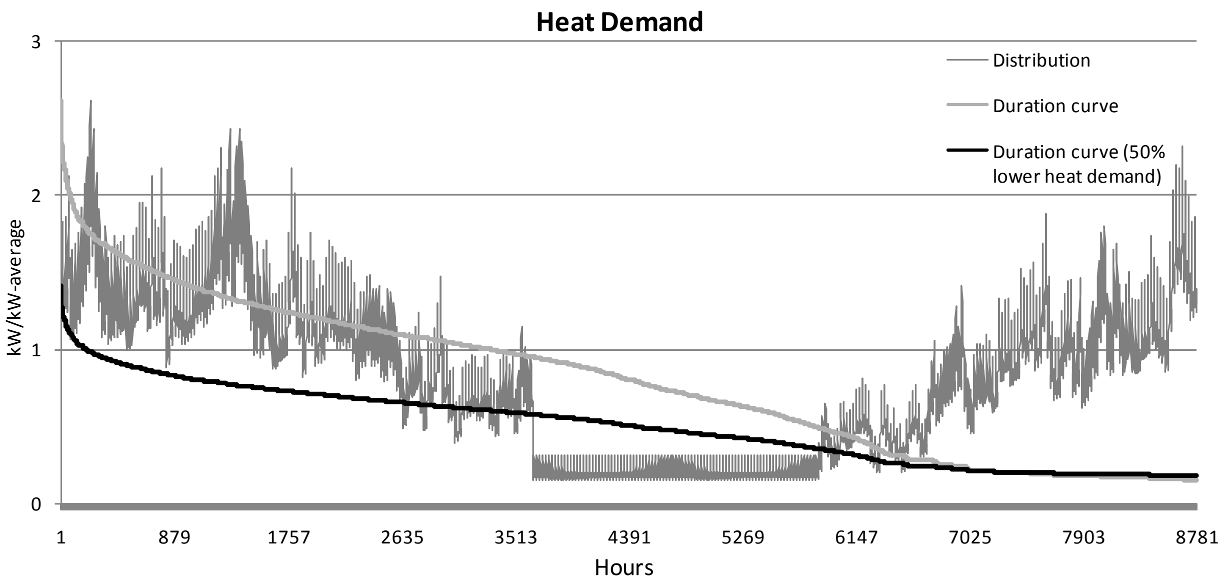

Fig. 1, Distribution and duration curves of the heat demand in individual houses.

2.4 Technology costs

Investments and O&M costs excluding taxes and levies are listed in table 3. The total annual costs are found using a socio-economic interest rate of 3 per cent. The costs of natural gas and wood pellet boilers, air/water and geothermal HP are based on current commercially available units [20]. Boilers for biogas are assumed to have the same costs as natural gas boilers. For geothermal HP, 60 per cent of the initial investment is assumed to have a lifetime of 15 years and 40 per cent has a lifetime of 40 years [20]. For FC, electrolysers and hydrogen storage cost estimates are long-term, i.e. after 2020 [20]. The costs of the micro FC-CHP are based on future mass productions of between 10.000 and 100.000 units. The costs of 1.5 kW natural gas and hydrogen FC-CHP units are 6,660 € and 6,000 €, respectively, including a peak load boiler. Here, these cost are adapted to 1 kW and 2 kW by assuming that the marginal extra capacity is 1,000 €/kW. The potential replacement or increase of PP is assessed both technically and economically in a sensitivity analysis, and the cost of PP is included in table 3.

	Construction Costs €/unit	Lifetime Year	Annual Cost (3%) €/year	Operation and main. €/year	Ref.
Individual technologies					
Boiler (natural gas/biogas)	4,000	15	200	535	[20]
Boiler (wood pellets)	6,660	15	370	928	[20]
Geothermal HP	13,330	15/40	107	1,008	[20]
Air/water HP	6,670	15	107	665	[20]
Micro FC-CHP 1 kW_e/ 2 kW_{th} (natural gas/biogas)	6,160	15	333	849	[20]
Micro FC-CHP 2 kW_e/ 2 kW_{th} (hydrogen)	6,500	15	267	811	[20]
System Technologies					
Electrolyser per 10 kW (min. 5 MWh)	2,500	20	50	218	[10]
Hydrogen storage per 0.33 MWh (min. 5 MWh)	19	25	0.2	1.3	[26]
Steam turbine Power Plant					
Advanced coal per 1 kW (min. 400 MW)	1,200	30	24	85	[26]

Table 3, Investment, operation and maintenance costs of the technologies in the analyses.

In the feasibility study, three different sets of future fuel prices are related to oil prices. This is based on the assumption that oil prices will not be constantly high or low but will continue to fluctuate. The base line fuel costs correspond to the current prices in the spring/summer of 2008, equivalent to an oil price of 120 $/bbl. The lower price level is based on the assumptions recommended by the Danish Energy Authority from February 2008 [25]. For wood pellets, though, the price level expected by the Danish Energy Authority is used for the base line, and the current price is at the lower level. The high fuel price level is calculated by adding the difference between the lower and the current fuel price level in the base assumptions, see table 4.

€/GJ	Crude Oil	Coal	Natural Gas / Biogas	Fuel Oil	Wood pellets
62 $/bbl	6.8	1.8	4.2	4.8	6.5
120 $/bbl	13.2	3.3	8.2	9.2	8.0
178 $/bbl	19.5	4.8	12.1	13.7	9.5

Table 4, Three fuel cost scenarios dependent on oil price.

€/GJ	Coal	Natural Gas	Fuel Oil	Wood pellets	Biogas
Central PP and CHP	0.1	0.4	0.2		
Distributed CHP, district heating boilers		1.0	1.9		
Individual households		2.6		5.9	(as Ngas)

Table 5, Fuel transport and handling costs.

The cost of biogas is assumed to follow the costs of natural gas. This is, however, hardly the case, since the costs depend on the local possibilities of producing biogas. Please note that the biomass-based fuels are also assumed to fluctuate in the analyses presented in this paper. The current coal price is 150 $/ton hard coal, equivalent to approx. 3.3 €/GJ. Natural gas prices are based on crude oil prices by assuming a 62 per cent relation to the oil price. For fuel oil, the relation is 70 per cent. The fuel transport and handling costs used and listed in table 5 are from the Danish Energy Authority [25]. The handling costs of biogas are assumed to correspond to the level of natural gas, while keeping in mind that this is also dependent on local conditions.

For the electricity market exchange analyses, long-term electricity costs are required. The analyses are performed of the Nordic electricity exchange market, Nord Pool. Here, the long-term electricity prices recommended by the Danish Energy Authority are used [25]. The average price is expected to be 49 €/MWh, which is used here in combination with the hour-by-hour fluctuations on the Nordic electricity market in 2005. CO_2 quotas are assumed to affect the prices with a constant input of 9 €/MWh; thus, the price of 40 €/MWh is expected to fluctuate. In this analysis, each type of plant produces according to its business-economic marginal costs including handling costs and taxes. In the results, taxes are excluded, representing socio-economic costs.

The socio-economic feasibility study does not include externalities connected to environmental effects or health etc. The CO_2 quota costs are included; however, this does not reflect the externality costs of the emissions. CO_2 quota costs are currently approx. 26 €/ton. In accordance with the recommendations of the Danish Energy Authority, a long-term price of 23.3 €/ton is used here, although this level may prove conservative in a future with stricter emission reduction targets.

The current Danish taxes and levies (2008) are used in a business-economic feasibility study with current public regulation. In this study, an interest rate of 6 per cent is applied. The aggregated levies are currently 7.6 €/GJ of natural gas and 0.086 €/KWh of electricity. Subsequently, a new public regulation scheme is recommended on the basis of the socio-economic feasibility study.

3 Results

The results are grouped according the analyses conducted; i.e. a technical analysis of the alternatives; an electricity market exchange analysis; a feasibility study and a series of sensitivity analyses. Subsequently, adequate public regulation measures are proposed in order to create business-economic conditions which support the socio-economic feasibility identified in the analyses.

3.1 System fuel efficiency of individual house heating alternatives

The fuel efficiency and the excess electricity production of the alternatives are described in detail for the analyses of the BAU 2030 CHP system. Subsequently, the energy system analyses of the Non-CHP system are described. The heat demand for the population of 300,000 houses is supplied from boilers involving 4.5 TWh of natural gas/biogas or 5.3 TWh of wood pellets, as illustrated in fig. 2. Such house heating does not influence the electricity supply or the excess electricity production, which is 1.66 TWh/year.

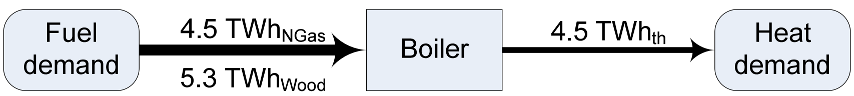

Fig. 2, Annual natural gas, biogas or wood pellet consumption of supplying
300,000 houses with heat from individual boilers.

In fig. 3, the energy conversion with geothermal HP is illustrated. Combined with peak load electric boilers, the HPs require 1.41 TWh of electricity to meet demand. During some hours, electricity consumption can be met by excess electricity production. Here, the excess production is reduced by 0.36 TWh from the 1.66 TWh in the reference energy system. During other hours, the increased electricity demand has to be produced either by CHP or PP. When additional electricity is produced by CHP plants, more boiler heat production is replaced in the CHP district heating systems and, consequently, the marginal extra fuel consumption is relatively low. In total, the annual extra fuel demand is 1.48 TWh, most of which is used in the condensing PP. In a sensitivity analysis, all wind power is removed, and thus, fuel consumption is increased for all electricity consumed in HP.

The results for air/water HP resemble the results for geothermal HP. The electricity demand is 1.73 TWh and the total fuel demand is 1.87 TWh. Electricity from PP, CHP and reduced excess electricity are now 0.53, 0.79 and 0.42 TWh, respectively.

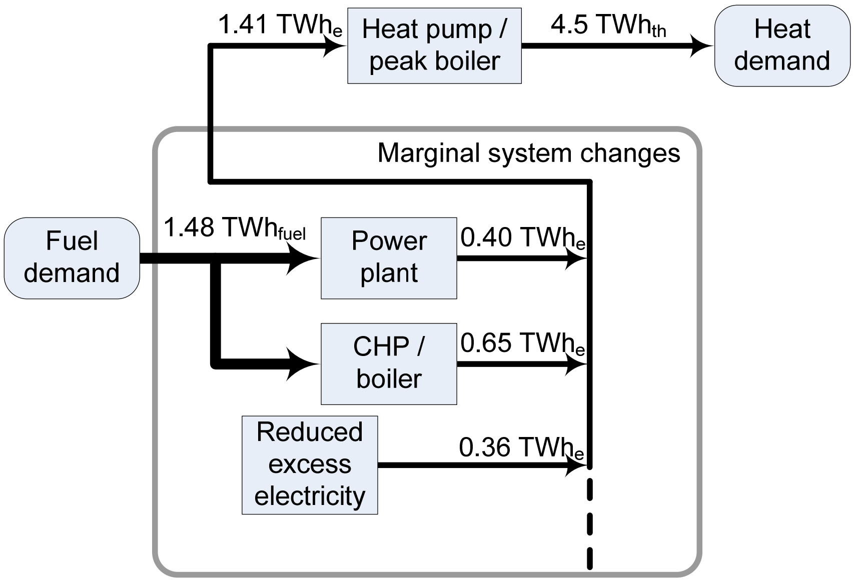

Fig. 3, Annual fuel consumption of supplying 300,000 houses with heat from individual geothermal HP incl. electric peak load boiler in the BAU 2030 CHP energy system.

In fig. 4, the energy conversion with micro FC-CHP based on either natural gas or biogas is illustrated. In this case, 7.37 TWh of gas is consumed in order to meet the heat demand of 4.5 TWh. However, 2.14 TWh of electricity is also produced. The excess production is raised by 0.39 TWh and the remaining electricity is saved at CHP and PP. At CHP plants, the reduced production leads to a change in the heat production, which is then met by peak load boilers. This leads to relatively small marginal fuel savings in the BAU 2030 CHP system. In total, 2.63 TWh of fuel is saved in the energy system. The net result is 4.73 TWh, which is a minor increase compared to the 4.5 TWh used in gas boilers. If biogas is used in the micro FC-CHP shown in fig. 4, the net fuel consumption is the same; but the use of biogas is 7.37 TWh and the net saving of natural gas is 2.18 TWh.

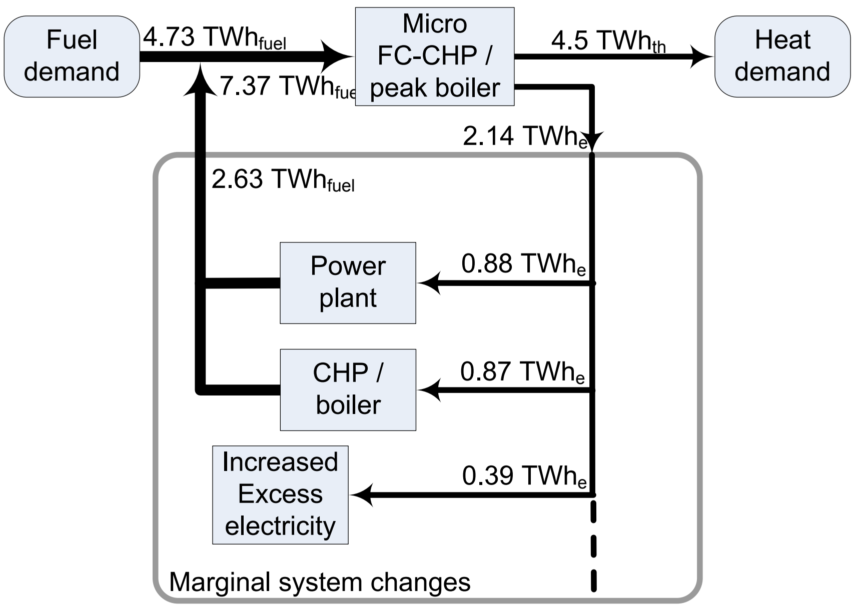

Fig. 4, Annual fuel consumption of supplying 300,000 houses with heat from individual micro FC-CHP based on natural gas or biogas in the BAU 2030 CHP energy system.

In fig. 5, the energy conversion with hydrogen micro FC-CHPs is illustrated. Electricity production is higher because of higher efficiencies. On the other hand, a substantial amount of electricity is needed for hydrogen production in electrolysers. The higher electricity demand decreases the excess production by 1.21 TWh. This decrease is a net reduction. In most situations, the electrolysers use the excess electricity production. However, in other cases, the micro FC-CHP will increase the excess electricity production. 8.02 TWh of electricity has to be provided to the electrolysers from an increased production of CHP and PP, leading to a fuel consumption of 12.89 TWh.

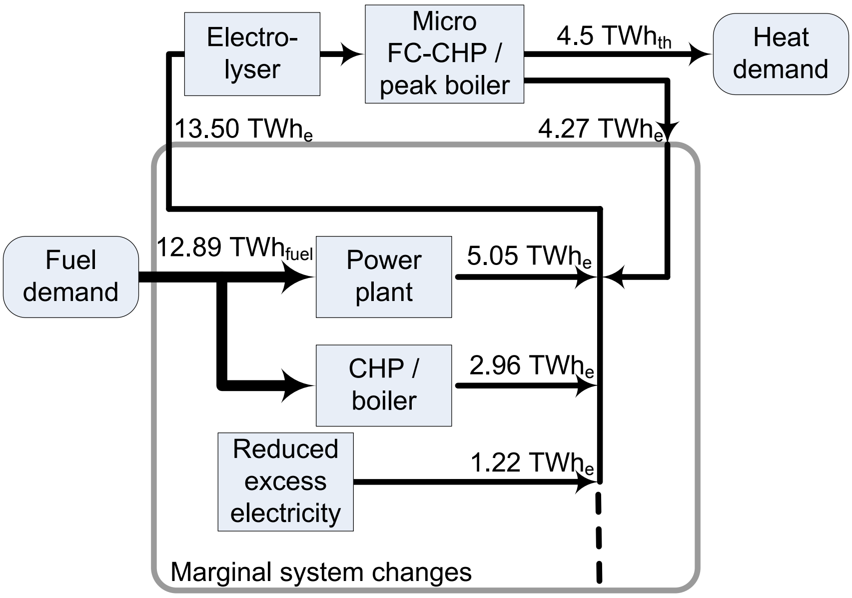

Fig. 5, Annual fuel consumption of supplying 300,000 houses with heat from individual micro FC-CHP based on hydrogen in the BAU 2030 CHP energy system.

CHP plants play an important role in the analyses of the alternatives in the BAU 2030 CHP system. The alternatives are also analysed in a system without CHP, also with 50 per cent wind. In such a case, the fuel consumption generated by the production of electricity for the heat pumps becomes higher and the micro FC-CHP systems improve, since more fuel is saved at PP.

In fig. 6 and 7, the resulting fuel consumption of the heating systems in the energy system with and without CHP plants is shown. In both cases, HPs have by far the lowest fuel consumption and the hydrogen micro FC-CHP has the highest. The fuel consumption of natural gas-based micro FC-CHP is 0.23 TWh higher than the natural gas boiler in the BAU 2030 CHP system and 0.5 TWh lower than in the BAU 2030 Non-CHP system. The oil savings achieved in the HP and electrolyser alternatives are related to an increased CHP production, which provides an extra electricity demand replacing oil-based boiler district heating production. In both energy systems, micro FC-CHP provide a displacement of coal-based PP. While this displacement results in savings in the micro FC-CHP based on natural gas or biogas, it creates net increases in the system based on hydrogen, because of the heavy increase in electricity demand.

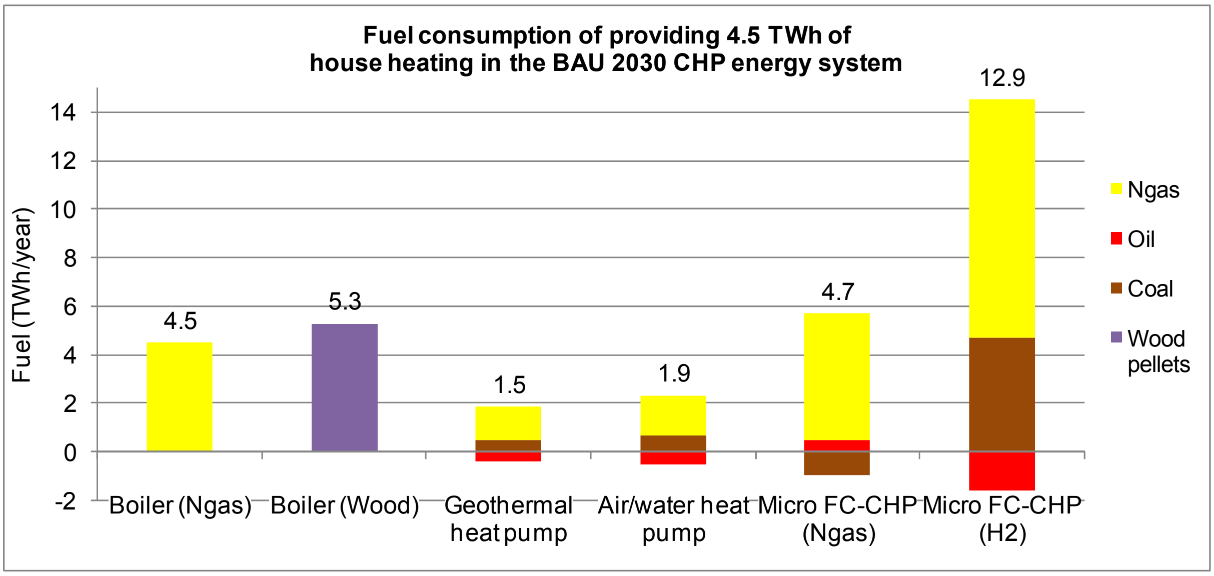

Fig. 6, Total annual fuel consumption of supplying 300,000
houses with heat in the CHP energy system.

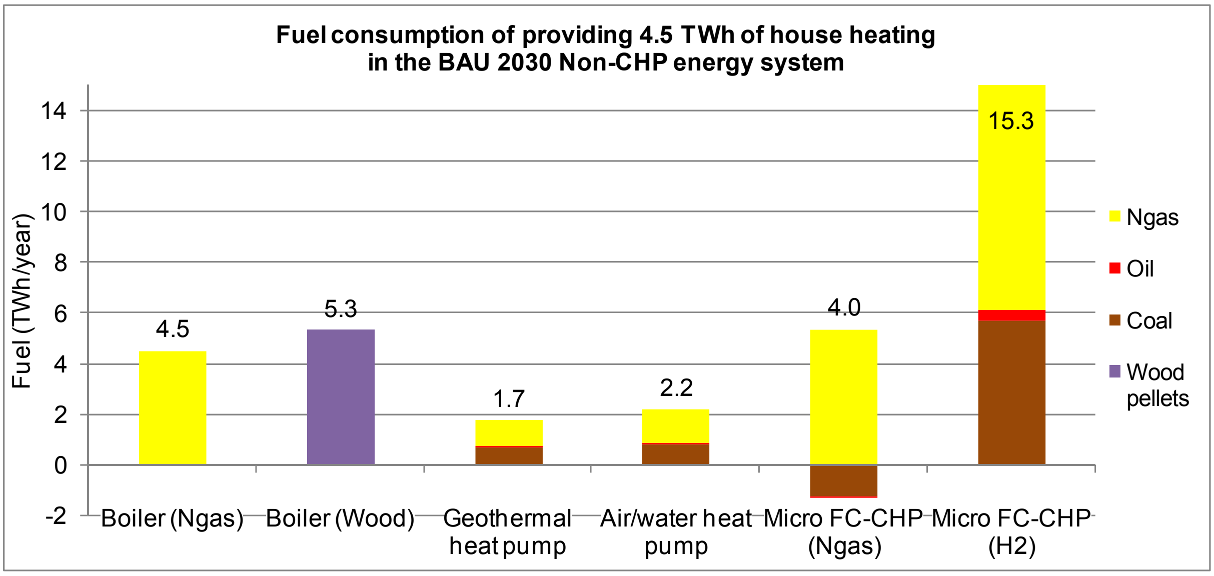

Fig. 7, Total annual fuel consumption of supplying 300,000
houses with heat in the Non-CHP energy system.

In fig. 8, the CO_2 emissions resulting from the individual heating supply of 300,000 households are illustrated for the heating systems analysed. Except for the case of wood pellet boilers, the HP systems have the lowest CO_2 emissions, even though these systems involve an increase in the coal consumption, while the natural gas micro FC-CHP system involves a decrease. The electrolyser systems have the highest emissions. The natural gas micro FC-CHP in the Non-CHP energy system leads to lower emissions than those in the CHP system, because they replace more coal-based PP.

When comparing the technical systems, the HP has the lowest CO_2 emissions, since biogas and wood pellets could also be used in the fuel supply for the production of electricity for HP. An example of CO_2 opportunity costs of the wood boiler is also illustrated in fig. 8. Wood pellets used in boilers are CO_2 neutral. However, the 5.3 TWh of wood could also replace coal in large central CHP and PPs, which in all alternatives could reduce CO_2 emissions by approx. 1.8 Mton. If 5.3 TWh wood pellets are used for supplying electricity for HP, this enables a heat supply for at least 850,000 households, while maintaining a CO_2 neutral heat supply. Several other opportunity costs can be defined which are not listed here.

If the aim is to reduce CO_2 emissions, the most fuel-efficient system should be implemented in individual households, and fuels, either fossil or biomass-based, should be used to replace other fuels in the system.

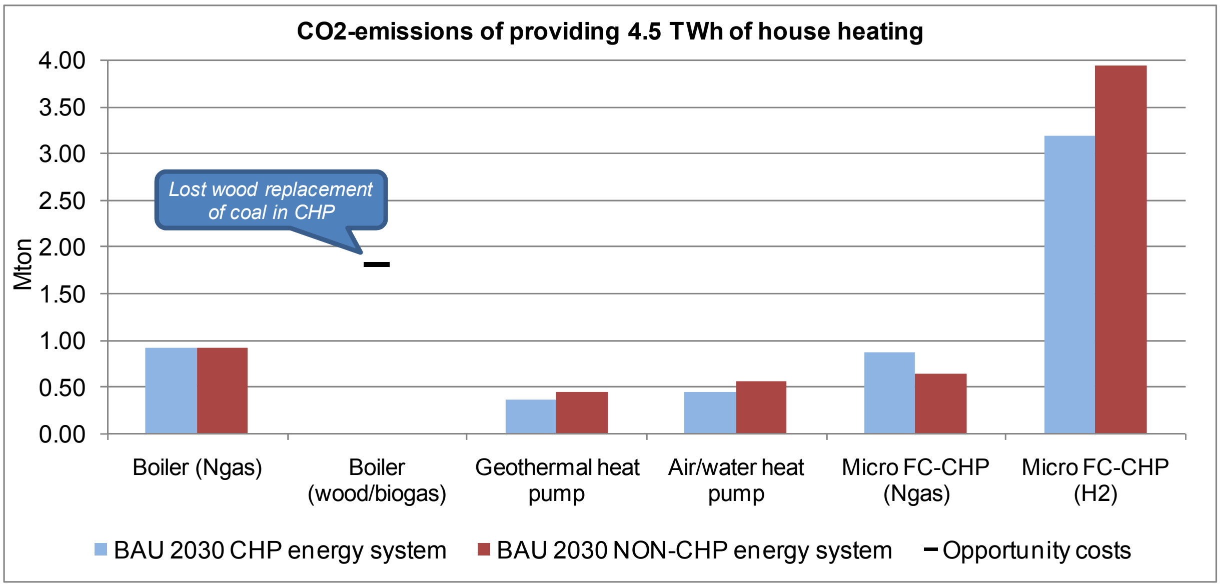

Fig. 8, CO_2 emissions of supplying 300,000 houses with heat in the two reference energy systems and including an example of opportunity costs.

3.2 Socio-economic feasibility study and market exchange analyses

The total annual cost of supplying 300,000 individual houses with heat is illustrated in fig. 9 in the BUA 2030 CHP system, on the basis of the energy system analyses presented above. The total annual costs include investments, fuel, fuel handling, O&M and CO_2 quotas. The base line fuel costs are used, i.e. the current level.

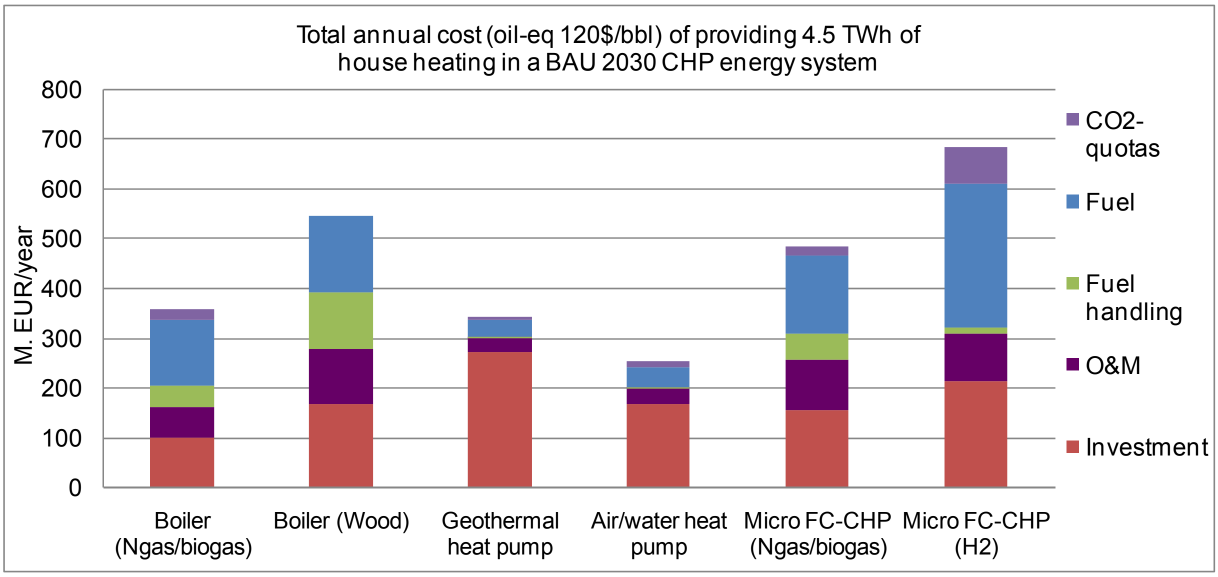

Fig. 9, Socio-economic costs of supplying 300,000 houses in the CHP energy system.

The air/water HP system has the lowest costs, while the geothermal HP carries marginally lower costs than the gas boiler. The hydrogen micro FC-CHP system is by far the least feasible. The geothermal HP has the lowest fuel costs and the largest investment costs, while the gas boiler carries high variable costs. In fig. 9, the results are shown for the alternatives analysed in relation to the CHP system. The general picture is the same in the Non-CHP system.

3.3 Electricity market exchange analysis

In this analysis, the components in the system aim at optimising the electricity and heat production. The ranking of the systems, both in terms of fuel efficiency and socio-economics, does not change. This is mainly due to the fact that the regulation used in the technical energy system analyses of HP, micro FC-CHP and electrolysers described above to a large extent reflect the marginal electricity production costs. The main difference is the possibility to trade. Furthermore, due to the technological limitations of the individual household heating solutions, a market-economic optimisation of the electricity trade cannot change the operation of the units much in comparison with the results of the technical energy system analyses.

While the HP system increases the import and decreases the export, the micro FC-CHP alternative has the opposite effect. The HP system enables the use of electricity at times with low prices, while the electricity sold from micro FC-CHP does not improve the costs enough compared to the alternative heating systems analysed.

In the electrolyser micro FC-CHP system, the resulting fuel consumption is considerably lower; the import is increased significantly, and the export is reduced. This hydrogen-based system uses significant amounts of wind power as well as imported electricity and produces electricity from micro FC-CHPs. As a result, the net electricity costs increase the total costs to a level similar to the case of wood pellet boilers.

The socio-economic feasibility of the alternatives in the market exchange analysis of the CHP energy system is illustrated in fig. 10. The same analysis has been conducted in the Non-CHP system. Such analyses do not change the relation between the alternatives.

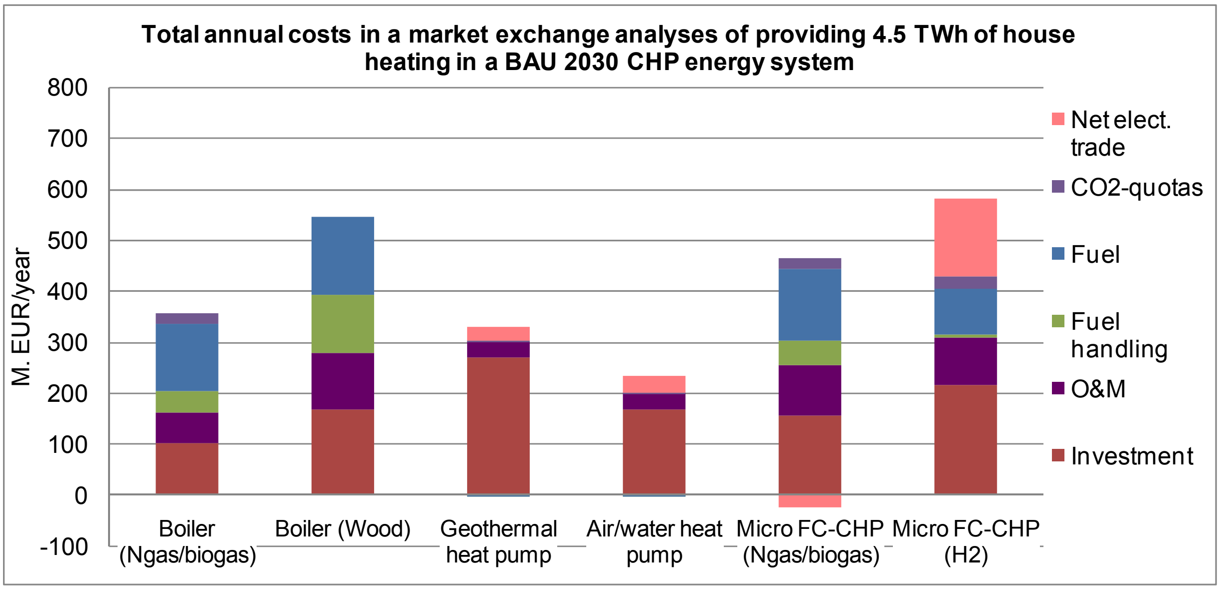

Fig. 10, Socio-economic costs of supplying 300,000 houses with heat
in an electricity market exchange analysis of the CHP energy system.

3.4 Technical and economic sensitivity analysis

In fig. 11, the feasibility study is conducted with low fuel prices, equivalent to an oil price of 62 $/bbl. The low fuel prices make the gas boilers marginally more feasible than the geothermal HP. Although the cost of the electrolyser alternative is reduced, the system is still unfeasible. The use of high fuel prices does not change the socio-economic conclusion presented in fig. 8.

The COP of both HP systems have to be lowered by approx. one in order to make gas boilers more feasible. A lower efficiency than 100 per cent for the gas boiler would increase fuel costs. If heat storage time is in-creased from an average of one day to five days, the fuel efficiency of the HP systems is improved by 0.2 TWh and excess production is reduced by 0.1 TWh. The micro FC-CHP systems only achieve minor improvements to.

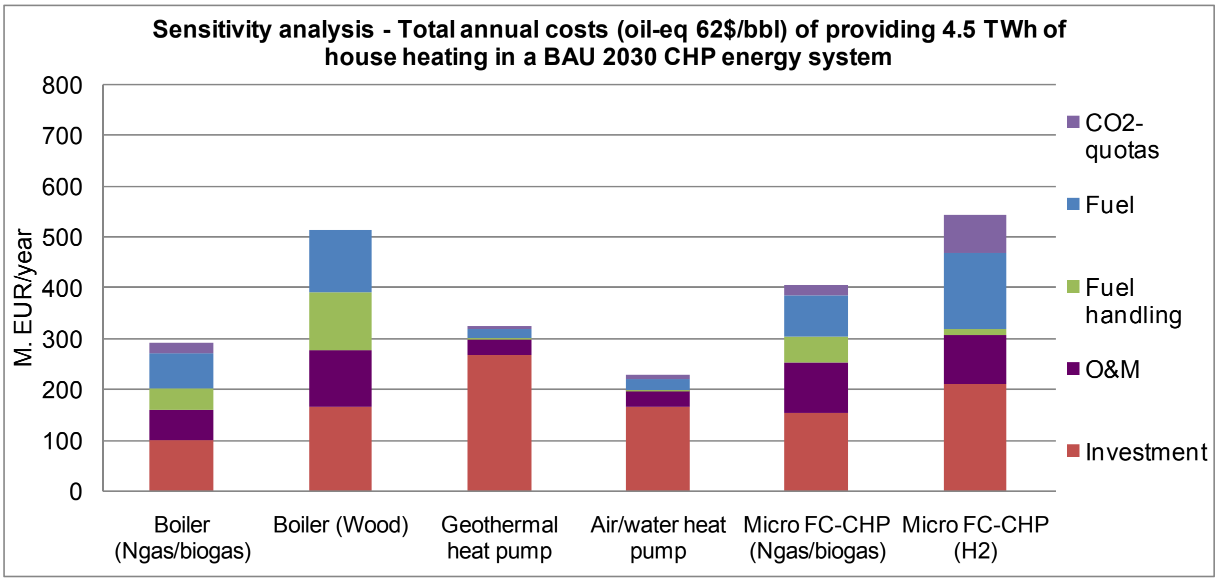

Fig. 11, Sensitivity analysis showing the total annual costs (low fuel prices) of supplying 300,000 houses with heat.

A situation in which micro FC-CHP have significantly higher electricity efficiency at 60 per cent and 90 per cent total efficiency has been analysed. These systems reduce coal PP and increase the use of natural gas more than the FC-CHP systems analysed above. The electricity production from micro FC-CHP is doubled. Half of this production takes place at times when the demand is met; thus, the excess electricity production is also doubled. In the electricity market exchange analyses, the total costs are now marginally lower than those of geo-thermal HP. However, this is heavily dependent on payments from forced export. The electrolyser micro FC-CHP alternative is still the least feasible solution. More efficient micro FC-CHPs do not significantly improve the fuel efficiency or the socio-economic feasibility, in this sensitivity analysis.

When using waste from electrolysers, fuel consumptions decrease by 2.5 to 3.0 TWh/year, as illustrated in fig. 12. The fuel consumption is still higher than in all other systems analysed, as are the socio-economic costs; even though low fuel prices are used and no additional costs are included in the analysis of the systems. The annual costs are still higher than 500 M€/year when utilising the waste heat from electrolysers in the CHP energy system.

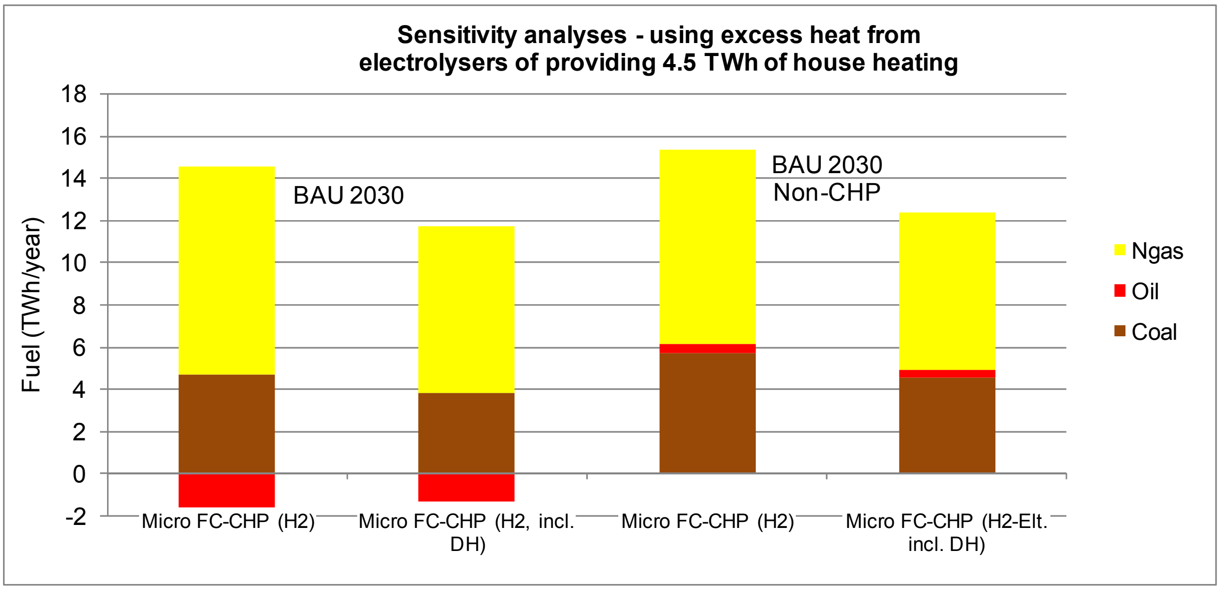

Fig. 12, Fuel consumption of supplying 300,000 houses with heat in the hydrogen micro FC-CHP alternative. The columns show two different energy systems with and without the utilisation of waste heat from the electrolysers, but both with 50 per cent wind.

The production at HP and micro FC-CHP systems affects electricity produced elsewhere in the energy system. This may, in the long-term, affect the installed capacity. Here, this displaced or increased capacity is included in a feasibility study. As mentioned, HPs are used in situations with high shares of wind power and heat demand; micro FC-CHP is used in situations with electricity and heat demand, and the electrolysers are used in situations with high shares of wind. All the operation strategies use heat storage and hydrogen storage. These characteristics imply a potential for reducing the PP capacity in the long term. In fig. 13, two effects on the installed capacity are illustrated: the annual average change in operating PP (Δ PP) and the maximum potential effect on the installed capacity (Max pot. PP). The average values (Δ PP) use the flexibility of the different technologies in the energy system analysis. The electricity-consuming alternatives are operated at times with high shares of wind power production and low electricity demand, and less at times with low or no wind power and high electricity demand. The operation of the micro FC-CHP is placed during hours with PP production, whenever possible.

The HP alternatives increase the operation hours of the PP capacity by between 100 and 150 MW. In the extreme situation assuming that all HPs are operating at the same time with a COP lowered by 1, the maximum effect on PP capacity is between 600 and 850 MW. For the micro FC-CHP, the maximum capacity saved is between 300 and 600 MW for the 1 and 2 kW units. In case of the hydrogen-based FC-CHP, the electrolysers may contribute with a negative effect of 3,000 MW, and thus, as the worst case, net results could be 2,400 MW installed PP. On average, the extra capacity used in the micro FC-CHP electrolyser system is up to 900 MW.

Assuming that the alternatives have an effect on the PP installed in the long term, this can be included in the feasibility analyses, based on the costs of PP listed in table 3. The result only changes in one case. If the geothermal HPs could provide the maximum potential increase of the PP capacity, the gas boiler would be marginally more feasible. However, this is not likely to happen, since it would imply that all HPs installed were operated simultaneously; that the COP was very low, and that the heat storage was not used in these hours. Furthermore, it would require that they were all operated at times with high electricity demand, instead of times with high shares of wind and low electricity demand.

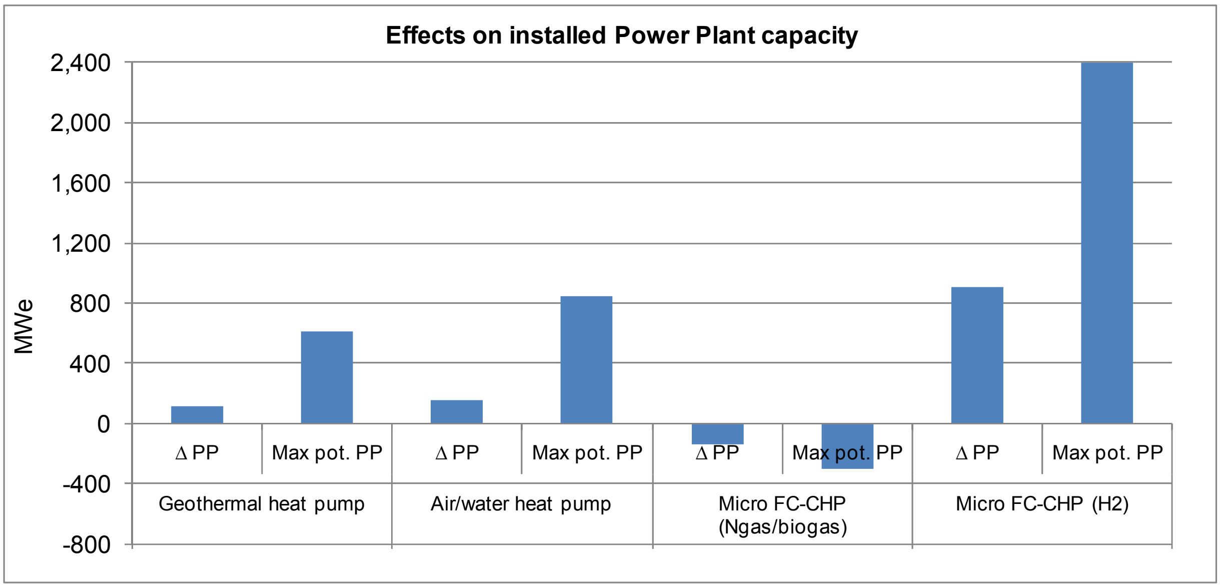

Fig. 13, The effects of different technologies on the installed power plant capacity in the two energy systems analysed. The average effect (Δ PP) and the maximum potential effect are both illustrated.

With a 50 per cent lower heat demand, a changed distribution and half the capacities described above is used and the investment and O&M costs are assumed to be 10 per cent lower for all systems. In fig. 14, the total annual cost of such a scenario is illustrated. The geothermal HP has the lowest fuel consumption, but the gas boiler can now compete with the geothermal HP.

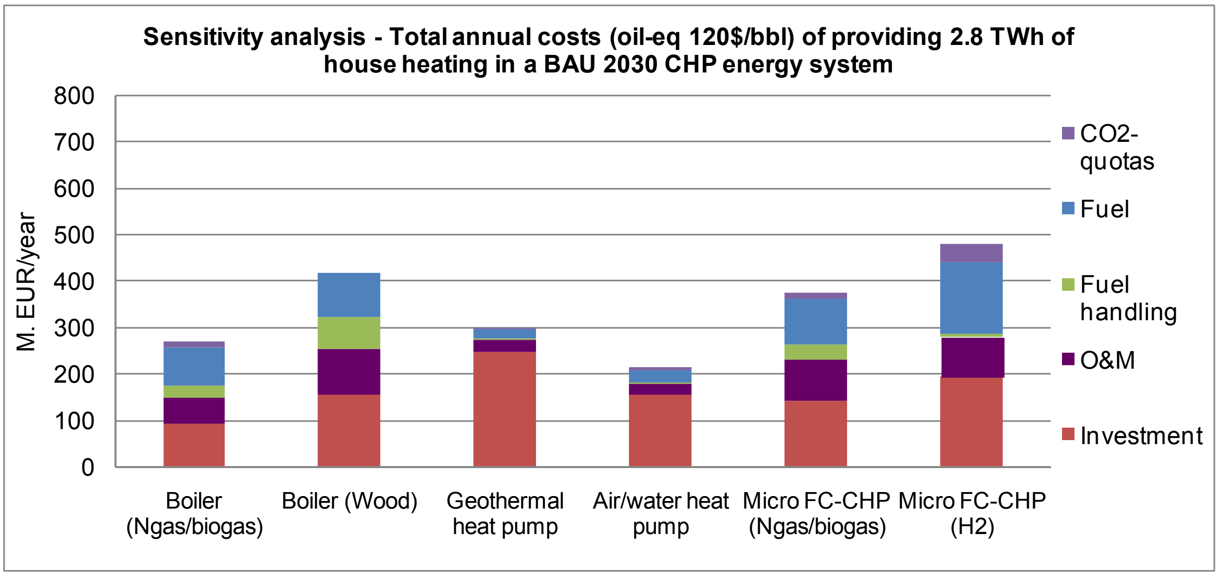

Fig. 14, Sensitivity analyses of the CHP energy system with reduced heat demand and changed heat demand distribution. The columns show total annual costs of the technologies when supplying 300,000 housed with heat.

In order to make a comparison of the alternatives without any fuel "free" excess electricity, the alternatives have been modelled in a system with no wind power. This makes the gas boiler marginally more feasible than the geothermal HP, as illustrated in fig. 15.

If we consider the extreme situation that 1) the electricity consumption is “free”, i.e. that e.g. wind turbines have been installed and paid for, even though the demand was not present, and 2) that the HP and electrolysers are able to adjust perfectly to the wind power production, the excess electricity production is reduced significantly more by the electrolysers than by the HP systems. However, we have to consider the fact that the capacity of the HP systems is much lower than the capacity of the electrolysers, and that the electricity demand varies. The geothermal HPs use 1.41 TWh; the air/water HPs use 1.73 TWh, while the electrolysers require 13.5 TWh. “Free” electricity from wind turbines would hardly be the case in practise; however, if this was the case, the technologies required in order to use this electricity would be competing and we would have to consider with which technology we are able to displace the largest amount of fuel. In this situation, HPs constitute the most fuel-efficient technology.

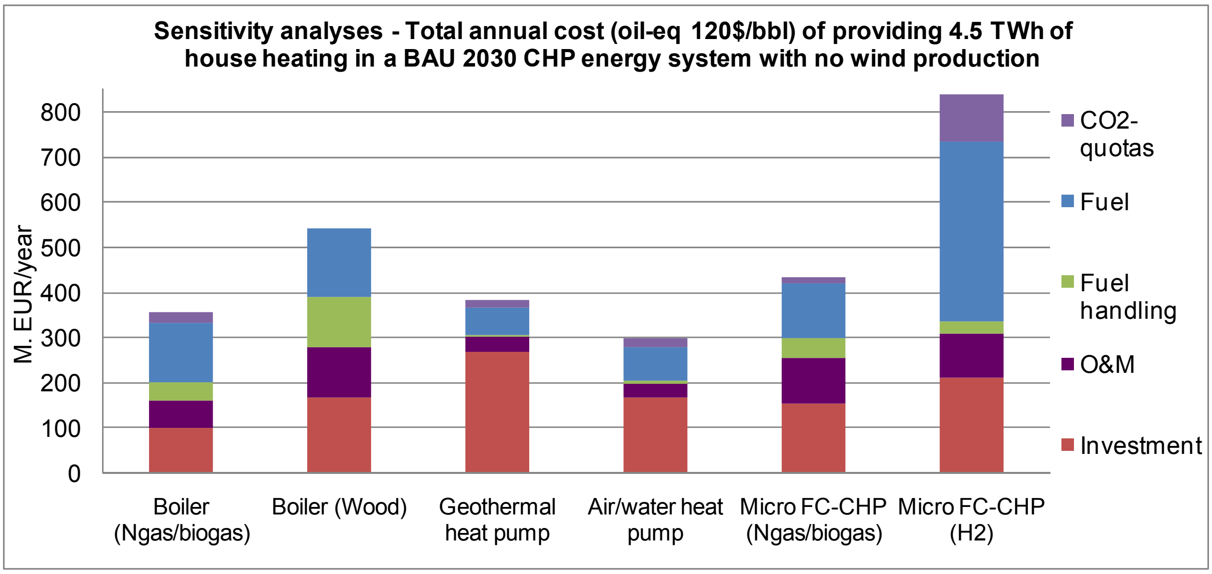

Fig. 15, Sensitivity analyses of the CHP energy system with no wind power. The columns show the total annual costs of supplying 300,000 houses with heat.

The long-term goal of some producers of micro FC-CHP is to reduce the investment costs to the price of the gas boiler; this would lower the cost to 430 M€/year. However, in order to obtain the same total socio-economic costs as gas boilers, the O&M costs of micro FC-CHP would also have to be reduced to the level of those of gas boilers. This would lower the socio-economic costs of micro FC-CHP to a level which, more or less, would balance with that of gas boilers in the Non-CHP energy system. In the CHP energy system, the ranking of the technologies does not change.

3.5 Evaluation of feasibility and a new public regulation scheme

Both HP systems have marginally lower socio-economic costs than gas boilers and lower costs than wood boilers and the two micro FC-CHP alternatives. In the feasibility studies, we did not include the fossil fuel opportunity costs of using limited resources, such as natural gas in boilers only producing heat, instead of in CHP plants producing both heat and power.

The geothermal HPs have the lowest CO_2 emissions. Here, we assume that the alternatives analysed have opportunity costs. A CO_2 emission could be allocated to the use of wood or biogas in boilers. As an example, wood boilers can reduce emissions by around 900 Mt CO_2, when compared to natural gas boilers. If wood is used in CHP plants instead, it can replace approx. 1,800 Mt CO_2 from coal. By using wood in boilers instead of in CHP plants, a CO_2 opportunity cost of around 900 Mt tons CO_2 can be defined. The situation is similar for natural gas boilers, which could allocate CO_2 emission, including lost CO_2 opportunity costs, by not using natural gas in CHP plants; thus, also replacing coal CHP.

The HP systems analysed for 300,000 households have the following advantages, when compared with the micro FC-CHP and boiler alternatives:

a) The lowest socio-economic costs; although in the case of the geothermal HP, these costs are only marginally better than those related to natural gas boilers.

b) For geothermal HP, 40 to 50 per cent CO_2 emissions compared to natural gas boilers, approx. 80 per cent of the emissions from natural gas micro FC-CHP, and 10 per cent of the emissions from hydrogen micro FC-CHP.

c) They have future possibilities for further reducing fuel use and CO_2 emissions by introducing larger heat storages. The socio-economic value of this has not been quantified here.

d) Compared with other fossil fuel alternatives, HPs reduce the dependence on fossil fuels by 30 to 40 per cent. The socio-economic value of this has not been quantified here.

e) Compared with other fossil fuel alternatives, HPs decrease the emissions to air from the conversion of fuels. The socio-economic value of externalities connected to environmental effects or health, etc., has not been quantified here.

The socio-economic evaluation of the results concludes that the HP systems have the largest advantages and that geothermal HPs provide the most fuel-efficient solution with the highest reduction in CO_2 emissions.

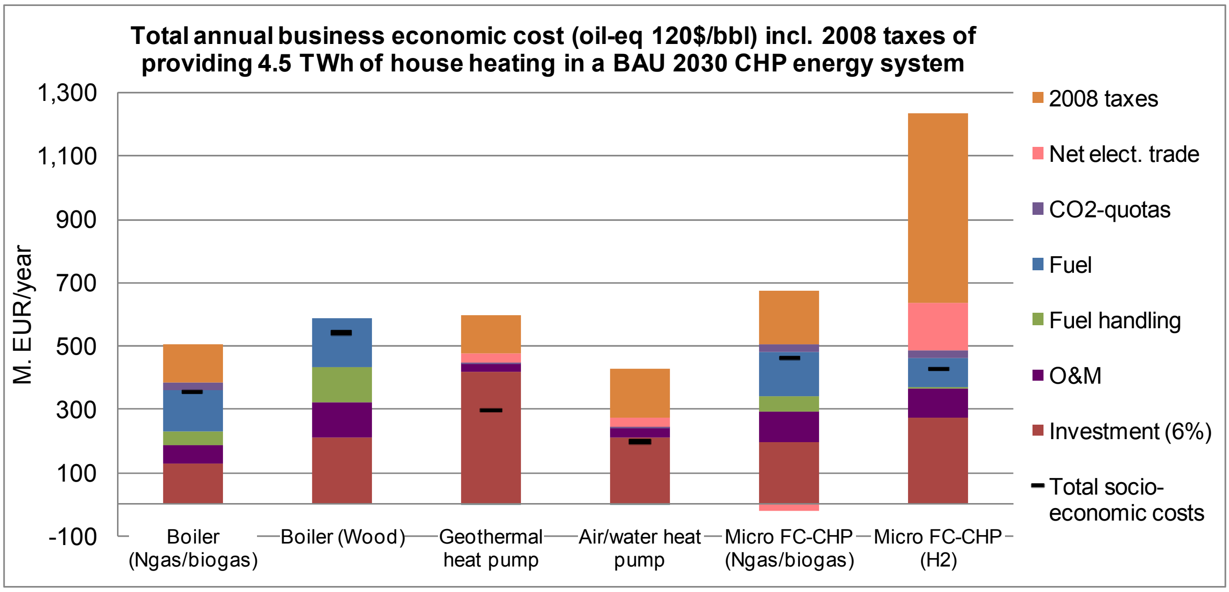

Fig. 16, Total annual business-economic costs of the CHP energy system supplying 300,000 houses with heat, including Danish 2008 fuel and electricity taxes. The socio-economic costs of the systems are also illustrated for comparison.

In fig. 16, current Danish taxes and levies (2008) are included in the evaluation made in the market exchange analyses previously presented. Under present market and taxation conditions, the geothermal HP cannot compete with neither natural gas nor wood boilers. This inability to compete is due to these factors:

a) The geothermal HP carries the highest investment costs of the alternatives, which make this investment very risk sensitive.

b) The geothermal HP has a high investment share in pipes with a very long technical lifetime. This makes heavy demands on the financial system. It requires an incentive to make long-term investments and the opportunity to take out loans for 30 years for these heating systems, as is the case for investments in house improvements.

c) In the Danish tax system, the HP alternative has a higher taxation of "fuel used" than the other alternatives, as described in section 2.4. Wood for boilers has no taxation.

When considering the current taxation, HPs are taxed much higher per Unit of fuel used than natural gas boilers. In table 6, the taxes per KWh for HP have been converted into taxes per MJ fuel, using the results from section 3.1. The large difference between the fuel taxes linked to boilers and those linked to the HP system is based on the fact that, for HP, the tax is levied on electricity, whereas the tax of natural gas boilers is levied on fuel. If, for instance, the HP system had been 20 per cent less efficient, the tax per MJ fuel would have been 20 per cent lower. As a consequence, there is no reward for the fuel efficiency of the HP system. Also there is no tax on biomass fuels which re even less efficient than gas boilers.

	Geothermal HP	Air/water HP	Ngas boiler	Wood boiler
2008 taxation	0.086 €/KWh	0.086 €/KWh	0.0076 €/MJ	-
2008 Taxation related to fuel efficiency	0.023 €/MJ	0.022 €/MJ	0.0076 €/MJ	-
New taxation rewarding fuel efficiency (first step)	0.028 €/KWh (0.0076 €/MJ)	0.028 €/KWh (0.0076 €/MJ)	0.0076 €/MJ	-

Table 6, Present taxation, taxation connected to fuel efficiency and suggestions for the first step of a new taxation for the HP and boiler heating systems.

The present tax system causes at least four problems. First, it promotes wood and natural gas boilers, even though HP systems carry lower socio-economic costs. Secondly, it results in socio-economic allocation losses, as there is a high taxation on renewable energy if it is wind power, but no taxation if it is, for instance, imported biomass. Moreover, taxation at the electricity use levels gives no direct incentive to reduce fuel use for electricity production. Thus, the tax system for individual house heating does not in general support the development of fuel-efficient energy systems, when these use electricity. The last problem mentioned here is the fact that there is no scarcity and CO_2 tax on the "inefficiency opportunity costs" created by using limited resources, like natural gas and wood in boilers, instead of more efficient CHP systems.

A new public regulation scheme should solve these problems and thus give incentives to install socio-economically feasible and fuel-efficient systems as well as systems with low CO_2 emissions. As the first step, a tax reform should have the same fuel tax level for HP as for natural gas boilers, as listed in table 6. This step is called a minimum step, since it does not involve any extra payment to the HP system as a compensation for its ability to integrate more wind power into the energy system or any tax on the opportunity cost of the fuel use and CO_2 emissions of using boilers instead of CHP. These two factors should be included in the second step.

In the first step, no tax on wood for wood boilers is included, and the tax on electricity used in HP is reduced to a third of the present level. In order to ensure that only fuel-efficient systems are installed, such low taxation on HP should only be given to licensed systems. A licensed system could have the following characteristics:

1. The HP system should supply 100 per cent of the heat and hot water demand not supplied by other renewable heating solutions.
2. A metering system should monitor the COP on an hourly basis and calculate the average COP monthly. The monthly tax is calculated as fuel taxation linked to the average fuel use of the month. This means that very efficient HP systems will have a lower taxation than less efficient HP systems.
3. If the HP owner purchases a share in a wind turbine, the production amount and profile of the share will be known. The owner of the HP should, therefore, pay zero tax in periods when the wind turbine share produces electricity. The remaining time, the taxation is calculated according to 2.

The business-economic results of implementing the first step of such a taxation system are illustrated in fig. 17. The first step in such a reform promotes a better accordance between socio-economic costs and market costs, and more HP systems should be installed due to such a reform.

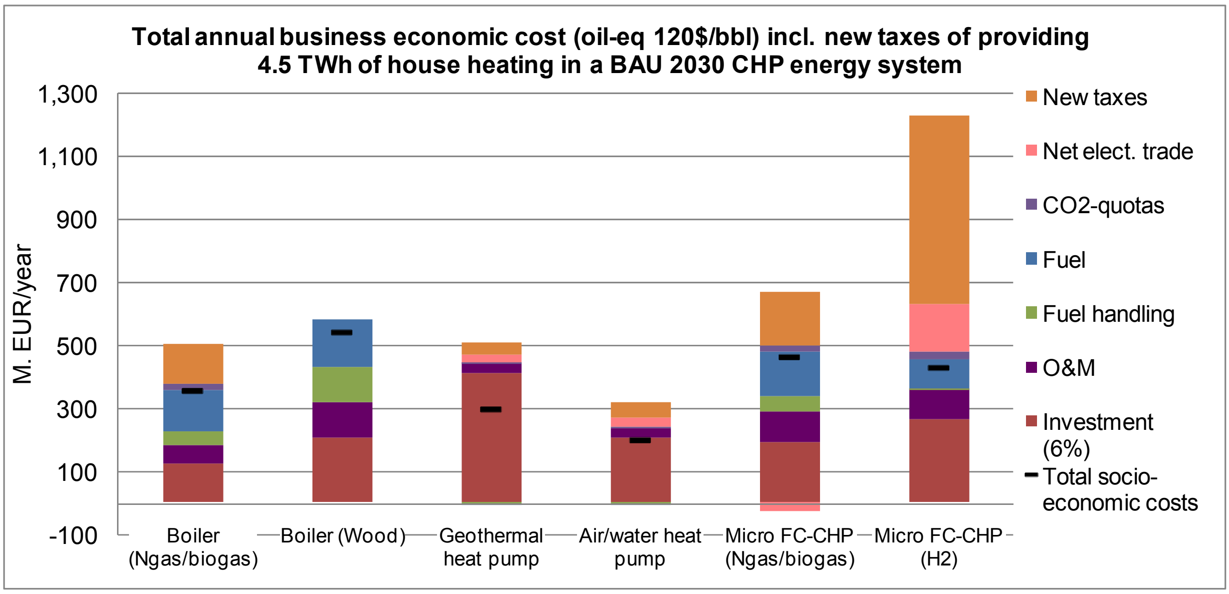

Fig. 17, Total business-economic costs of supplying 300,000 houses with heat, including the first step in a tax reform. The socio-economic costs of the system are also illustrated for comparison.

In the second step of a tax reform, the fuel use and CO_2-emission opportunity costs should be included in order to increase the tax on natural gas and biomass used in boilers. The first stage should be implemented as soon as possible and the second step should be decided in Parliament. It is suggested that the second step is implemented e.g. five years from now. Hence, this could introduce a reward and an incentive to an efficient use of natural gas and biomass is in the tax system.

4 Conclusion

The geothermal and air/water HP have the lowest fuel consumption and lowest CO_2-emissions of the individual heating systems analysed as well as the lowest costs, based on the current fuel prices (equivalent to 120$/bbl). While the micro FC-CHP based on natural gas reduces CO_2 emissions, because it displaces coal in the energy systems, it is not more fuel-efficient or cost-effective than natural gas boilers. The micro FC-CHP can, however, almost compete with the natural gas boilers, when the investments as well as the operation and maintenance costs of these are reduced to an expense similar to that of boilers. Wood pellet boilers are not feasible in comparison with other technologies analysed.

In the energy systems analysed here, the micro FC-CHPs replace coal PP with natural gas or biogas. However, in the long term, this may not be a good solution in renewable energy systems which depend on a gas supply. When evaluating the use of renewable resources, such as biogas or wood pellets, in terms of their reduction of CO_2 emissions, these should be used in the electricity and heat production at CHP plants to supply e.g. electricity for HP, rather than in household boilers or the micro FC-CHP systems analysed here.

If fuel prices are lowered to half of the current level in the spring/summer 2008 or if the heat demand is reduced by 50 per cent, the natural gas or biogas boilers carry lower socio-economic costs than the geothermal HP. Fuel prices, however, are likely to continue to fluctuate, and thus, the HPs represent a solution with low variable costs in all fuel price scenarios.

In future renewable energy systems, the fuel efficiency of the technologies is important, as well as the efficient integration of intermittent resources, such as wind power. It is important to ensure that the HPs are operated with high COP and at times with low electricity demands and high wind power production. However, even if this is not the case, HP are feasible systems.

In systems with high shares of wind power, electrolysers are often referred to as technologies required in order to integrate wind power and use “free” excess electricity. Although the electrolysers can decrease the excess electricity production, more efficient alternatives can be found, such as the HPs analysed here. Electrolysers combined with micro FC-CHP are not fuel or cost-efficient in energy systems with a 50 per cent wind power share, as analysed here.

At present, the public regulation supports natural gas and wood boiler systems. This results in socio-economic losses, a high usage of fossil fuels and high CO_2 emissions. In order to eliminate these disadvantages of the present taxation system, energy taxation should be changed in order to levy the same fuel tax on HP and natural gas boilers for a given heat production. A system is proposed in which fuel efficiency is rewarded and opportunity costs are included.

5 Acknowledgements

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Appendix VI

Comparative analyses of seven technologies to facilitate the integration of fluctuating renewable energy sources

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Abstract

In this paper, an analysis of seven different technologies is presented. The technologies integrate fluctuating renewable energy sources (RES) such as wind power production into the electricity supply and the Danish energy system is used as a case. Comprehensive hour-by-hour energy system analyses are conducted of a complete system meeting electricity, heat and transport demands, and including RES, power plants, and combined heat and power production (CHP) for district heating and transport technologies. In conclusion, the most fuel-efficient and least-cost technologies are identified through energy system and feasibility analyses. Large-scale heat pumps prove to be especially promising as they efficiently reduce the production of excess electricity. Flexible electricity demand and electric boilers are low-cost solutions, but their improvement of fuel efficiency is rather limited. Battery electric vehicles constitute the most promising transport integration technology compared to hydrogen fuel cell vehicles. The costs of integrating RES with electrolysers for hydrogen fuel cell vehicles, CHP and micro fuel cell CHP are reduced significantly with more than 50 per cent RES.

Keywords – Energy storage, distributed generation, micro CHP, renewable energy planning, wind power, electrolysers, micro CHP, fuel cells, flexible electricity demand, heat pumps, hydrogen

1 Introduction

Wind power and combined heat and power production (CHP) are essential components of the implementation of European Climate Change Response objectives. Recently, these objectives have gained increased attention. According to the agreement from January 2007, 20 per cent of European primary energy demand shall come from renewable energy sources in 2020. A further expansion of both wind and CHP technologies is intended in the upcoming decades in the EU [1-5]. Meanwhile, wind turbines depend on wind and CHP depends on heat demand. As a consequence, electricity production may exceed demand at some hours.

The challenges of balancing consumer demands with fluctuating renewable energy sources, such as wind power, are well known and have been analysed mainly with a focus on stand-alone systems and the integration of fuel cells and hydrogen systems [6-10].

At the energy system level, Denmark is one of the leading countries in terms of implementing the combination of CHP, energy conservation and wind power. Because of the active Danish energy policy pursued, the primary energy supply (PES) of the country has been kept at a constant level for more than 30

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years [11]. In 2007, more than 50 per cent of the Danish electricity demand was produced by CHP plants and 20 per cent by wind power.

Already now, the integration of wind turbines and CHP causes challenges to the Danish electricity supply in terms of excess electricity production during some hours. Excess electricity production combined with bottlenecks in the transmission lines to the neighbouring countries during certain hours have substantial influence on the market prices. The Danish case can reveal problems and solutions which may be faced by other energy systems in the coming years, as the European initiatives to promote CHP and renewable energy are implemented.

Previous studies have analysed how wind power can be better integrated into the electricity supply through the investment in flexible technologies, such as heat pumps and heat storage capacities, including small CHP units in the balancing of supply and demand and in the supply of ancillary services [12-17]. These flexible technologies and, potentially, electrolysers are important in future renewable energy systems such as analysed in [5;18-20]. Studies indicate that transmission lines reduce operation cost [21]; however, other analyses show that investments in flexibility are less costly than investments in larger transmission lines [15;16;22]. In the Danish case, a wind power share of more than 50 per cent is achievable, provided that the energy system consists of more flexible and integrated technologies, without significant changes in transmission lines [23]. Compressed air energy storage (CAES) and underground storage have also been analysed [13;24]. These analyses show that CAES is an unfeasible alternative, while boilers at CHP plants prove to have a higher feasibility. Flexible demands and the integration of energy supply for transport, via electric vehicles in vehicle to grid (V2G) solutions and hydrogen, have been included in other analyses {Kempton, 2005 230 /id;Mathiesen, 2008 318 /id;Lund, 2006 208 /id;Salgi, 2008 389 /id;Marie Münster, 2007 228 /id;Lund, 2008 435 /id}.

In this paper, emphasis is put on the comparison of seven flexible technologies for the integration of wind power production. The analysis is based on the methodology described in [30], with special attention given to efficient electrolysers. The seven integration technologies are electric boilers (EB), heat pumps (HP), electrolysers with local CHP (ELT/CHP), electrolysers with micro CHP (ELT/micro), hydrogen fuel cell vehicles (HFCV), battery electric vehicles (BEV), and flexible electricity demand (5%FLEX). The different integration technologies are analysed and compared in terms of their ability to integrate RES and their fuel efficiency in scenarios with a share of intermittent renewable energy sources (RES) varying from 0 to 100 per cent. Subsequently, the costs of the integration technologies are compared in terms of their ability to improve fuel efficiency.

2 Methodology

In this section, the methodology of performing such analyses is described. The section introduces an energy system analysis model as well as the assumptions and regulation strategies applied to the technical energy system analyses of the potentials of the RES integration technologies. The seven integration technologies, their capacities, efficiencies and costs are described below.

2.1 Energy system analysis model

A detailed energy system analysis is conducted by use of the freeware model EnergyPLAN [31]. The model is an input/output model that performs annual analyses in steps of one hour. Inputs are demands, capacities of the technologies included, demand distributions, and fluctuating RES distribution. A number of technologies can be included enabling the reconstruction of all elements of an energy system and allowing the analyses of integration technologies, such as the one conducted in this paper.

The model makes it possible to use different regulation strategies putting emphasis on heat and power supply, import/export, and excess electricity production and using the different components included in the energy system analysed. Outputs are energy balances, resulting annual productions, fuel consumption, and import/exports.

The model provides the possibility of including restrictions caused by the delivery of ancillary services to secure grid stability. Hence, it is possible to have a minimum capacity running during all hours and/or a percentage running from a certain type of plants required to secure voltage and frequency in the electricity supply [15].

As part of this work, the EnergyPLAN model has been modified to improve the utilization of hydrogen storage and the electric boiler. The model has been used in several technical and socio-economic studies of energy systems. Most recently, it was used in the construction of a vision for the energy system in 2030 and 2050 for the Danish Society of Engineers [5;19;32;33]. The model can be applied to technical as well as electricity market exchange analysis and socio-economic feasibility studies. In this paper, technical energy system analyses are performed in order to identify the potential of the technologies in relation to the increasing amounts of RES in the system. The results of such technical analyses are used for identifying least-cost integration technologies.

2.2 The reference energy system

In this paper, the Danish Energy Authority's (DEA) business-as-usual 2030 energy system is used as the reference. This system is a projection of demands and generation capacities from 2005 to 2030 [34]. The main characteristics of this system are listed in the first column in Table 1 (DEA 2030). Thorough analyses of this reference energy system were performed in connection with the design of renewable energy systems in [5;33]. This was done in order to assure the consistency between the energy system model defined in EnergyPLAN and the energy system projection of the DEA. In the reference, the electricity demand is expected to be 49.0 TWh in 2030. The district heating demand is 39.2 TWh out of a total household heating demand of 52.4 TWh. The heating demand of the CHP units is low quality heat, and e.g. steam for processing is treated separately as a fuel input for industry. When the old units expire, existing large coal-fired power plants (PP) and CHP steam turbines are replaced by new plants, which use biomass or natural gas-fired combined cycle CHP units. In 2030, heat storage capacities are assumed to be equal to the existing level. According to the DEA, the total production from wind turbines is expected to be 14.9 TWh in 2030. In this paper, biomass is kept at a constant level in all analyses and RES is defined as intermittent electricity production from wind power. Compared to the energy system of today, the electricity demand and the transport demand are higher, while the heating demand is the approx. the same. The reference 2030 energy system is described in further detail in [33;34].

This system projected by the DEA is characterised as a system that could develop with stable 2005 market conditions and rather low long-term 2030 fuel prices (35$/bbl), as recommended by the IEA in October 2004. In the recent business-as-usual projection by the DEA from July 2008, the level of the primary energy supply is the same, when applying the latest IEA recommendations (62$/bbl). The fuel prices used by the DEA for the projection until 2030, used here as the reference energy system, have no direct connection to the results. The reason for this is that if prices rose to a level at which the DEA would expect energy savings, this would already be reflected in the energy system analyses with very high amounts of RES in relation to the electricity demand. In a system with lower electricity and heat demands, the capacities of the seven integration technologies would affect the integration of wind into the system differently. In a sensitivity analysis, the capacities of the seven integration technologies are doubled. In this paper, technical energy system analyses are performed which do not take into account the marginal electricity costs of using different fuels. However, the technical energy system analyses take into consideration the most efficient use of the components, such as PP, CHP boilers, etc., by applying different regulation strategies to the energy system; thus minimising the total fuel consumption, see section 2.3.

In Fig. 1, some of the main components of the reference energy system are illustrated in a very simplified version, as they are represented in the EnergyPLAN model. The system consists of electricity and power supplies, transport, and five power and heat-producing units; i.e. RES, conventional centralised coal and natural gas-fuelled PP and CHP plants, locally distributed CHP plants, and oil-based boilers. Furthermore, the CHP plants have heat storages equal to approx. one day of heat consumption, like the CHP plants of today.

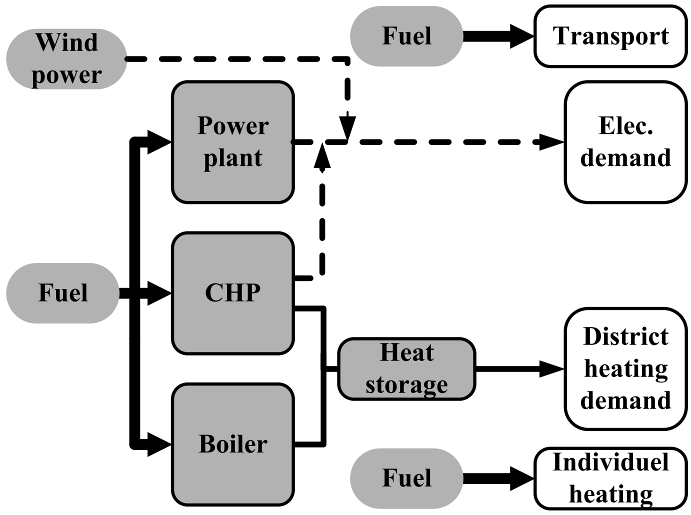

Fig. 1, Very simplified model of the reference energy system.

2.3 Energy system analysis methodology

The potential of introducing the seven integration technologies into the reference energy system is analysed by varying the amount of RES from 0 to 100 per cent of the electricity demand in technical energy system analyses.

The technical energy system analyses are conducted for a period of one year taking into consideration demands and RES production during all hours. The ability of the reference energy system to integrate fluctuating RES is defined by applying two different regulation strategies: 1) the capability of the system to avoid excess electricity production and 2) the ability of the system to reduce fuel consumption and thus improve fuel efficiency. The methodology applied to these analyses is presented here:

Hour-by-hour the electricity production from RES is prioritised as well as the production of electricity at CHP plants, industrial CHP or micro CHP. The remaining electricity demand is met by PP and the remaining district heating demand is met by boilers. By utilising extra capacity at the CHP plants combined with heat storages, the production at the condensation plants is minimised and replaced by CHP production. At times when the demand is lower than the production from CHP and RES, the electricity production is minimised mainly by use of heat pumps at CHP plants or by introducing electrolysers or other flexible technologies available.

This constitutes an *open energy system* in which the technologies are utilised with the aim of supplying demands in the system. The measures introduced to secure the balance between the supply from CHP and RES and the electricity demand described may NOT be sufficient to reduce electricity production, and thus forced electricity export will be the result. This type of technical energy system analyses enables the investigation of the flexibility of the seven integration technologies, focussing directly on the effect on excess electricity production, i.e. regulation strategy 1) of the two types of energy system analyses.

Such analysis is presented by showing the reference energy system's ability to integrate fluctuating RES. In Fig. 2, the x axis illustrates the wind turbine production between 0 and 50 TWh, equal to a variation from 0 to 100 per cent of the demand (49 TWh) in excess electricity diagrams in an *open energy system* [35]. The y axis illustrates the excess electricity production in TWh. The less ascending curve illustrates a better integration of RES. In Fig. 2, a situation without CHP plants regulating according the electricity demand is illustrated. The purpose of this is to show that the first step which must be taken is to introduce CHP and boiler regulation with heat storages. This can significantly reduce the excess electricity production with low investments in thermal storages and also reduce the production at PP by utilising the extra capacity of the CHP plants. In Fig. 2, a total of nine energy system analyses have been conducted hour-by-hour for a year for both types of CHP regulation. For each of the seven integration technologies, these nine energy system analyses are performed, see section 3.

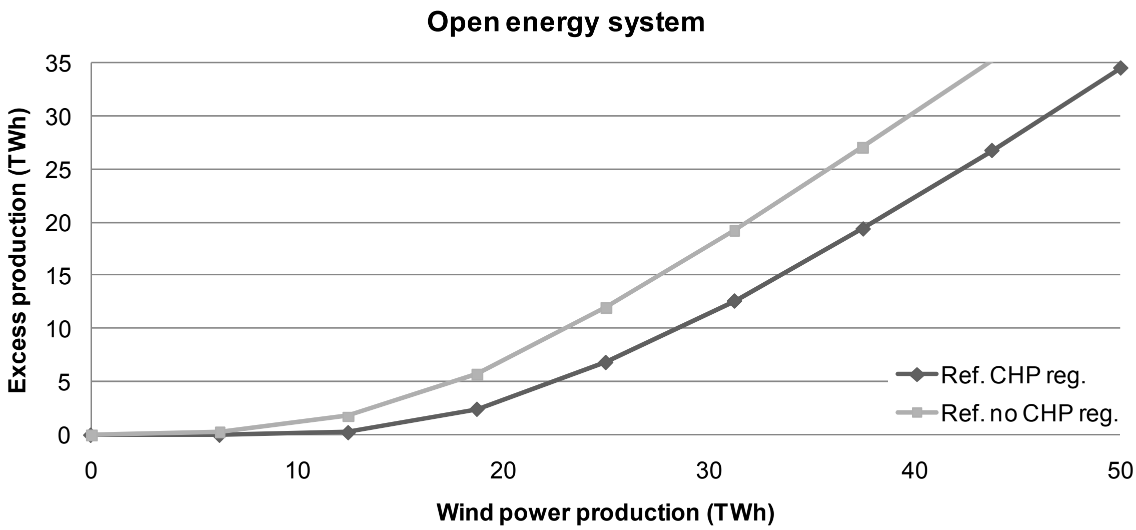

Fig. 2, Wind power production and excess electricity production in an open energy system analysis of the reference energy system with and without the regulation of CHP plants.

The second of the two types of energy system analyses, i.e. regulation strategy 2), builds on the first analyses. However, here any excess electricity production is converted or avoided; first, by replacing CHP production by boilers in the district heating systems and, secondly, by stopping wind turbines. The import/export is of course zero, as it is a closed system. All excess electricity production is converted or avoided and the entire primary energy supply (PES) excl. the RES of the system is presented.

The result of such analyses represents a *closed energy system* and is illustrated in Fig. 3.The x axis shows the wind production and the y axis illustrates the PES excl. the RES of the entire energy system. The less PES excl. the RES, the more flexible and fuel-efficient is the energy system. In Fig. 3, the same two analysis systems with and without heat storage are presented. Again, it can be seen that the first step is to introduce heat storage in order to increase the production potential of CHP plants at times with a low share of RES, instead of using boilers to supply heat at times with a high RES share. The heat storage also increases the opportunity to replace the production of PP with CHP if the capacity is available. Again, a total of nine energy system analyses have been conducted hour-by-hour for a year for both types of CHP regulation. These nine energy system analyses have been performed for each of the seven integration technologies analysed in this paper, see section 3. The advantage of presenting PES excl. the RES instead of PES incl. the RES is the fact that such results can reveal the ability of a technology to utilise RES, such as wind power, to efficiently replace fuels in PP, CHP, boilers and internal combustion engines.

The main characteristics of the reference energy system with no RES, the open reference system with 25 TWh RES, and the closed reference system with 25TWh RES, respectively, are shown in the three columns to the right in Table 1. In the reference energy system with no RES, the net export is 0. In the reference system with 25 TWh RES in the *open energy system* analysis 6.8 TWh excess electricity is produced. In the reference system with 25 TWh RES in the *closed energy system* analysis, the forced export is removed, partly because the system is able to use boilers and CHP plants and thus avoid the problem of heat-bound electricity production, and partly by stopping the turbines. Only 20.9 TWh of the wind power is utilised, indicating that the system is not equipped to handle 25 TWh of wind power. The purpose of the analysis of the seven integration technologies is to identify good options to improve the ability of the energy systems to efficiently integrate RES.

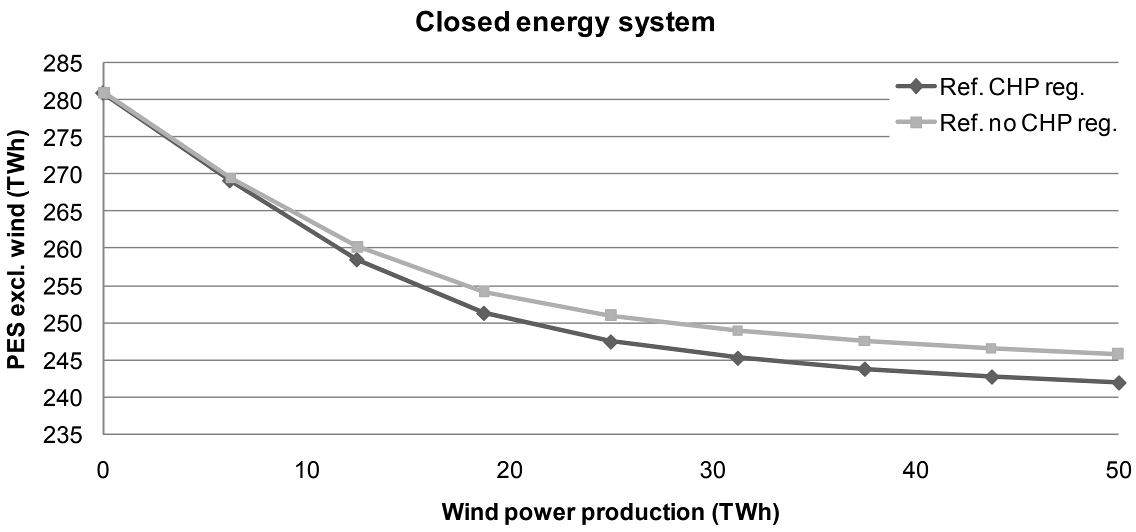

Fig. 3, Primary energy supply (PES) in a closed energy system analysis of the reference energy system with and without the regulation of CHP plants.

The analyses are conducted with the following restrictions in order to secure the delivery of ancillary services and achieve grid stability (voltage and frequency). At least 30 per cent of the power or as a minimum 450 MW (at any hour) must come from power production units capable of supplying ancillary services, such as central PP and CHP. At least 450 MW running capacity in central power stations must be available at any moment. The distributed generation from RES and small decentralised CHP units is not capable of supplying ancillary services in order to achieve grid stability in the analyses conducted here. The small decentralised CHP units are, however, included in the load balancing made according to the heat and power demand and the hourly production from RES, as described above. At present, Denmark has two separate electricity grids, which are planned to connect in 2010. In the analyses here, the Danish energy system is treated as a one point system, i.e. no internal bottlenecks in Denmark are assumed. The seven integration technologies analysed are assumed to be distributed throughout the energy system, as wind power and CHP plants are today. A distributed system to handle the fluctuating production from RES or CHP is recommended in [12], where the spatial location of different technologies are investigated in transmission grid analyses. Distributed RES and distributed integration technologies are also recommended by the Danish TSO Energinet.dk [36]. It is not the aim to recommend the precise optimal location for the integration of RES in this paper. However, it is the aim to provide information on which technologies are fuel efficient and able to integrate RES.

The reference energy system defined above is used for varying wind power. Off-shore wind power is assumed to be installed with a load factor of 44 per cent and spread out throughout the energy system, such as recommended in official Danish off-shore wind turbine location plans and by the Danish TSO Energinet.dk [36]. In a sensitivity analysis, land-based wind turbines are analysed using a load factor of 28 per cent. The concrete modelling of wind in the EnergyPLAN model is based on actual wind power production distribution data, but modified to have a larger load factor [31].

		DEA 2030 (market)	Reference no RES (technical)	Reference 25 TWh RES (open technical)	Reference 25 TWh RES (closed technical)
Input:					
Electricity demand	TWh/y	49.0	49.0	49.0	49.0
District heating demand	TWh/y	39.2	39.2	39.2	39.2
Ind. boiler heat demand	TWh/y	19.7	19.7	19.7	19.7
Industry incl. service and refining	TWh/y	53.7	53.7	53.7	53.7
Transport (incl. aviation & shipping)	TWh/y	69.2	69.2	69.2	69.2
North Sea (oil extraction)	TWh/y	22.7	22.7	22.7	22.7
Primary energy supply					
Wind power	TWh/y	14.9	0.0	25.0	(25.0) 20.9
Biomass	TWh/y	36.4	36.4	36.4	36.4
Coal	TWh/y	20.4	26.8	16.0	14.4
Oil	TWh/y	112.0	111.7	115.4	116.0
Natural gas	TWh/y	95.4	106.0	84.1	80.8
Total PES	TWh/y	279.2	280.9	276.9	268.5
Total PES excl. wind power (RES)	TWh/y	264.3	280.9	251.9	247.6
Key figures					
Net export/Excess electricity production	TWh/y	5.7	0	6.8	0
Av. eff. local CHP (elect./heat)	%	41 / 50	41 / 50	41 / 50	41 / 50
Av. eff. central CHP (elect./heat)	%	41 / 50	41 / 50	41 / 50	41 / 50
Av. eff. power plants	%	52	52	52	52
Total excl. import/export of elect.	TWh/y	269.7	280.9	263.7	263.5
Power plant of demand	%	28	49	25	21
District heat boilers of demand	%	27	22	47	50
Power plant capacity	MW	8,000	8,000	8,000	8,000
- hereof extraction power plant	MW	2,000	2,000	2,000	2,000
Local CHP capacity	MW	1,350	1,350	1,350	1,350

Table 1, The main characteristics of the reference energy system defined by the Danish Energy Authority (DEA 2030) and the reference energy systems used in the technical analyses in a closed and an open system, respectively.

2.4 Technologies for integrating fluctuating intermittent energy sources

In the energy system analyses, the end-demands for electricity, heat and transport are the same in all cases, but the technologies introduced provide the energy system with more flexibility. The technologies are explored in the alternatives described below. The principle relations between the different components in the seven alternatives are shown in Fig. 4 to Fig. 7.

Alternative 1 – Electric boilers (EB): EBs are used in CHP units after the production of the units has been reduced by use of fuel boilers at times with excess electricity production. EBs can replace fuel boilers in order to further reduce excess electricity production and fuel consumption.

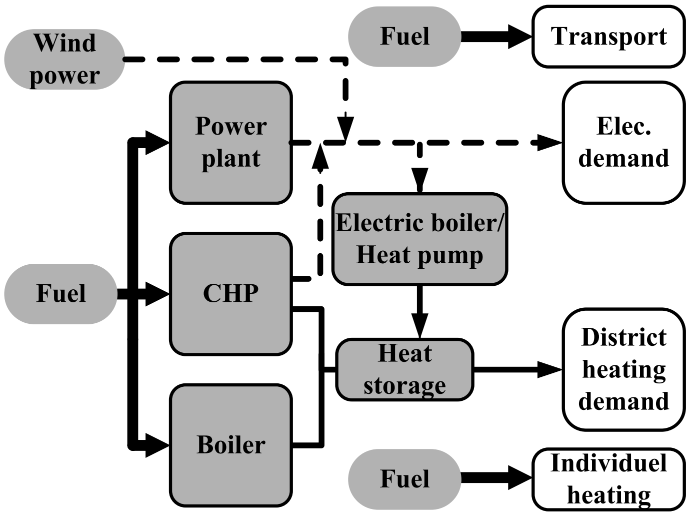

Fig. 4, The electric boiler and the heat pump energy systems.

Alternative 2 - Heat pumps (HP): Large-scale HPs are used in CHP units with the purpose of replacing heat production from CHP and fuel boilers. Consequently, the excess electricity produced at times with high productions of wind power and heat-dependent CHP is decreased. The production of CHP units is decreased and, at the same time, the electricity consumption of the HP can utilise wind power production. Individual heat pumps are analysed in a sensitivity analysis.

Alternative 3 – Electrolysers/CHP (ELT/CHP): ELTs produce hydrogen for the CHP plants at times with excess electricity production. Waste heat from the process is utilised in the district heating system. The hydrogen storage is used in order to enable electricity consumption at times with a high wind power production. No fixed amount of hydrogen is required; thus, the electrolysers only produce at times with excess electricity production.

Alternative 4 – Electrolysers/micro CHP (ELT/micro): Here, natural gas boilers in individual houses are replaced with micro hydrogen fuel cell CHP units. Like in alternative 3, ELTs produce hydrogen at times with high wind power production, utilising the hydrogen storage. The micro CHP needs a fixed amount of hydrogen, which means that the electrolysers in some situations may produce when there is no or little wind production. The ELT units are decentralised and the waste heat is utilised to replace natural gas boilers. The flexibility of the electricity production of the micro CHP units is limited by the heat demand and heat storage of one average day. The micro CHP units are able to meet half of the peak heat demand. The rest of the heat demand, i.e. approx. 5 per cent of the total annual demand, must be met by boilers. Whenever possible, the micro CHP units produce at times when the PP would otherwise produce electricity, in order to increase the fuel efficiency of the system.

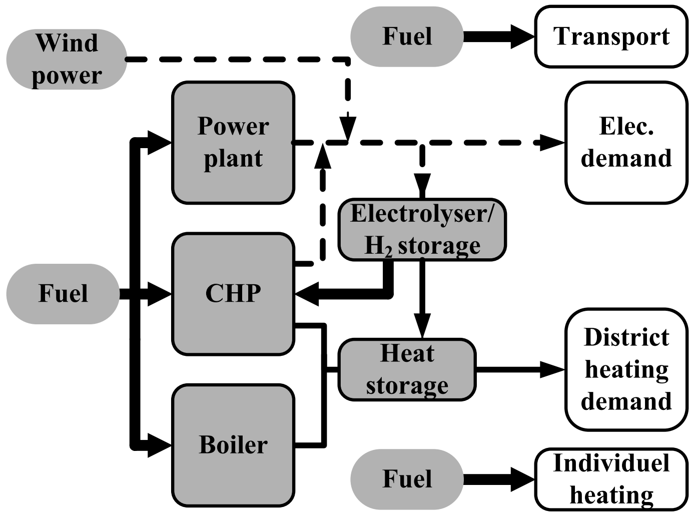

Fig. 5, The electrolyser CHP energy system.

Alternative 5 – Hydrogen fuel cell vehicles (HFCV): Here, HFCV have replaced petrol-driven internal combustion engine vehicles (ICE). The hydrogen demand for transport is distributed according to driving habits and the number of parked vehicles at a certain time. As in the case of alternative 4, the hydrogen demand is fixed; the hydrogen storage is utilised in order to place electricity consumption at times with wind production, and waste heat is utilised to replace natural gas boilers.

Alternative 6 – Battery electric vehicles (BEV): V2G BEV have replaced ICE and the demand is distributed according to driving habits and the same amount of parked vehicles as for HFCV. Like in the hydrogen alternatives, the BEV are charged at times with high wind power production when possible. Similar to the alternatives in which hydrogen is used in CHPs, the BEV are capable of discharging the batteries at times when the electricity demand is otherwise met by PP. A dump charge vehicle has been included in a sensitivity analysis only taking into account the transport demand with no discharge available.

Alternative 7 – Flexible electricity demand (5%FLEX): 5 per cent of the electricity demand is flexible within one day and can be moved according to the wind power and CHP productions in order to achieve better fuel efficiency and decrease the electricity produced by PP.

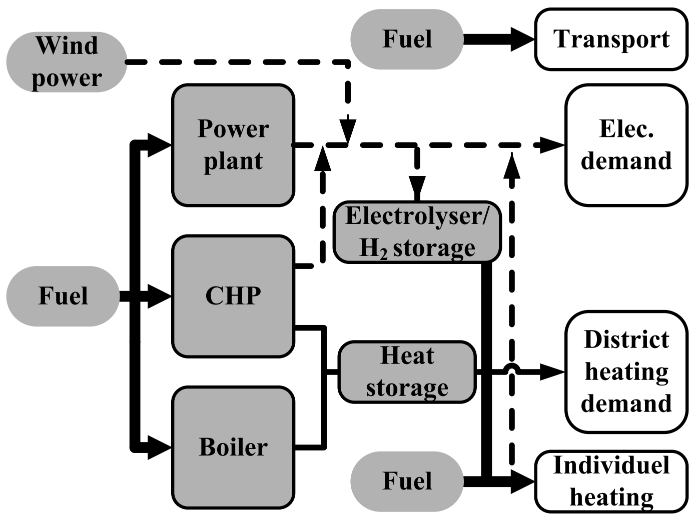

Fig. 6, The electrolyser micro CHP energy system.

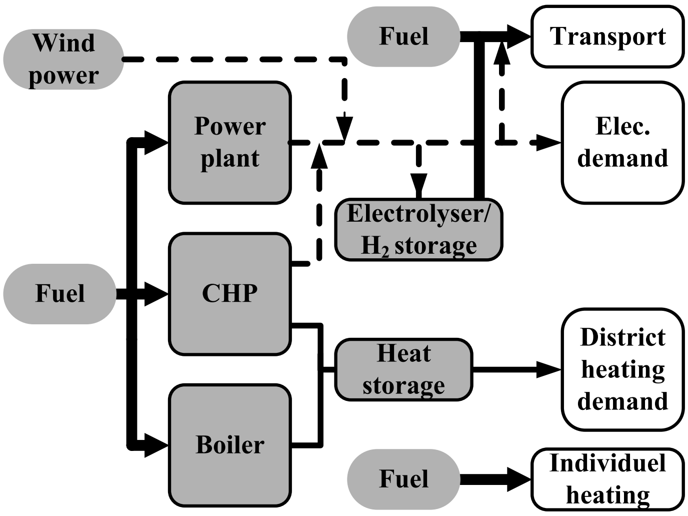

Fig. 7, The hydrogen fuel cell vehicle and the battery electric vehicle energy systems.

2.5 Capacities, efficiencies and costs of the integration technologies

In this section, the capacities, efficiencies and cost estimates of the integration technologies analysed are presented. The alternative technologies are analysed with comparable capacities, which are listed in Table 2. For technologies used in combination with CHP, an electricity demand of 450 MW has been added, i.e. alternatives 1-4. For the transport technologies of alternatives 5 and 6, the 450 MW effect has been used for identifying the number of vehicles. The flexible demand alternative is comparable to the other alternatives in the sense that the amount of flexible electricity corresponds to a decrease in the peak electricity demand by 450 MW.

Alternatives	Capacities		Efficiencies %			Costs M€		Lifetime (years)	O&M costs/y	Total cost M€/y	Ref.
			el.	th.	fuel						
1 EB	450	MWe	-	100	-	0.13	/MWe	20	0%	4.0	-
2 HP	450	MWe	-	350	-	2.52	/MWe	20	0.2%	78.1	[37]
3 ELT/CHP											
Electrol.	450	MWe	95	10	80	0.25	/MWe	20	2%	9.9	[37]
H2 storage	300	GWh	-	-	95	0.06	/GWh	25	0%	1.0	[37]
4 ELT/micro											
Electrol.	450	MWe	95	10	80	0.25	/MWe	20	2%	9.9	[37]
H2 storage	300	GWh	-	-	95	0.06	/GWh	25	0%	1.0	[37]
Micro CHP	61	MWe	45	45	-	1.87	/MWe	20	6%	14.5	[33]
5 HFCV											
Electrol.	97	MWe	95	10	80	0.25	/MWe	20	2%	2.1	[37]
H2 storage	77	GWh	-	-	95	0.06	/GWh	25	0%	0.3	[37]
Vehicles	450	MWe	-	-	45	0.53	/MWe	15	0%	19.9	[33]
6 BEV	450	MWe	95	-	90	1.20	/MWe	15	0%	45.2	[33]
7 5%FLEX	450 2.45	MWe TWh	-	-	-	20	/TWh	20	1%	3.8	[33]

Table 2, Capacities, efficiencies and costs of the alternatives.

In alternative 3, 250 MWe of the ELT are placed at central CHP plants, and 200 MWe at decentralised CHP units. The hydrogen storages for CHP plants, micro CHP and HFCV can store more than one month of hydrogen production from the ELT. The capacity of the ELT for HFCV corresponds to 25 per cent average operation time, as does the ELT for the micro CHP.

The V2G capability of the *BEV* alternative is limited in such way that only 70 per cent of the parked vehicles are grid-connected. Moreover, it is limited by the batteries which can store a quantity equivalent to six hours of driving at full capacity. The discharge capacity is limited to the ratio of grid connected parked vehicles and half of the loading capacity (225 MW) to take into account potential limitations of electricity supply from low voltage grids.

The efficiencies of the technologies in the reference energy system are mainly taken from publications from the Danish Energy Authority and the Danish Association of Engineers [33;37]. ELTs are commercially available with approx. 60 per cent electricity to fuel efficiency, but 80 per cent efficiency may eventually be possible. The efficiencies of hydrogen storage devices are between 88 and 95 per cent. [38-41]. Here, 80 per cent electricity to fuel efficiency and 10 per cent thermal efficiency are used. 5 per cent losses are assumed in the hydrogen storage and in inverters. The micro CHP units consist of solid oxide fuel cells. Both the electric and thermal efficiencies are 45 per cent in the analysis here, although efficiencies may eventually be higher for other applications than micro CHP. However, technologies such as MW-scale SOFC CHP are not analysed here.

Today, efficiencies of 60 per cent for vehicles under optimal conditions can also be achieved in fuel cell systems and efficiencies of more than 50 per cent are considered possible taking into account losses due to mass, drag, friction, drive train and electricity consumption for other services than the electric engine, such as lights, cooling, etc. This is also the case when losses related to differences in standard driving patterns are taken into account [42-44]. Here, an efficiency of *HFCV* of 45 per cent from a European driving cycle study is used [44]. These vehicles replace ICE with an average efficiency of 22 per cent in 2030. For *BEV*, an efficiency of 90 per cent is assumed and 5 per cent losses in inverters both in charging and discharging to the grid. The maximum capacity of the *HFCV* is 32 kW and 16 kW for *BEV*. *HFCV* can replace 0.6 per cent of the vehicle fleet assuming 2.5 million vehicles in 2030 and a total drive train capacity of 450 MW. With equivalent assumptions for *BEV*, 1.1 per cent vehicles can be replaced. Using a future efficiency of existing vehicles of 22 per cent, the total amount of petrol saved has been calculated in the case of both transport alternatives.

When considering the potential heat sources, a 3.5 coefficient of performance (COP) of *HP* is used as an annual average. The COP constitutes the electricity to heat ratio of *HP*. It is assumed that large-scale *HPs* are only able to supply 50 per cent of the heat demand at any given hour, because the output temperatures may prove lower than required in some periods. This is due to the fact that the *HPs* run independently of the CHP and thus have a lower value heat source. In the model, boilers or CHP units must supply the rest of the heat demand. This COP and limitation may, however, prove rather conservative as *HP* combined with heat from flue gas, intercoolers or waste heat from gas engines and turbines can increase the COP. Already today, the COP has proven to be higher. In the future, the COP is expected to be above 4, also for *HP* running independently of the CHP and supplied by a low value heat source [37;45].

The efficiencies and costs of technologies in 2030 derive from [33;37;44] with the adjustments described in the following. The costs of *EB* are based on initial Danish experiences. For larger *EB* between 8-15 MWe, the costs are 530,000-800,000 €. Smaller *EB* systems are considered too expensive. The cost of grid connection is between 260,000 and 1,000,000 € depending on location and local connection possibilities. The costs are estimated to be 66,000 €/MWe *EB* and 66,000 €/MW grid connection. For the micro CHP, the costs in Table 1 represent units installed in households and include a peak load boiler. Here the marginal costs of investing in micro CHP instead of individual natural gas fuel boilers are applied. The costs of these boilers are 0.25 M€/MWth, the life time is 20 years, and operation and maintenance (O&M) costs are 3 per cent, corresponding to total annual costs of 4.7 M€.

The costs of *HFCV* are 60 per cent higher than those of a normal vehicle [44]. The costs of *BEV* are 80 per cent higher, excl. the costs of V2G technology. The significance of this is included in the sensitivity analysis. The costs of a regular vehicle are approx. 10,500 € [33]. In the analyses, the marginal costs of investing in a *BEV* or *HFCV* instead of a regular vehicle are used. The *ELT* costs are estimated to be 0.18 M€/MW in 2030 [37]. Here, 66,000 €/MW grid connection costs are added to the costs of *ELT*. The grid connection costs are included in the *HP* cost estimate used [37].

The costs of flexible demand are rather difficult to determine. Here, the costs presented in [33] are used; thus, costs are estimated to be 67 M€ for 10 per cent flexible demand or 3.3 TWh with a lifetime of 20 years and 1 per cent for O&M. In the analysis here, this is equivalent to 20 M€/TWh flexible electricity demand. The DEA has assessed the potential flexibility at approx. 600 MW[46]. Flexibility could be implemented by introducing mandatory requirements for new meter installations in industry or households and thus lowering the additional costs. When applying flexible demand and looking at the potential reductions in peak electricity demand, the potential savings in investments in PP capacity result in larger savings than the costs listed here. These capacity savings are not included in the analyses. Flexible demand may, however, be introduced in other ways than by improving the meters of households and companies. Here, the flexible electricity demand is 5 per cent within one-day. However, the technologies installed may provide flexibility over a longer period of time.

In Table 2, the total annual costs of the different technologies are calculated on the basis of capacity, investment costs, lifetime and O&M costs. A real interest rate of 3 per cent is used and a 6 per cent rate is used in the sensitivity analysis. The costs of the technologies are used for identifying the least-cost alternatives reducing the fuel consumption, i.e. identified in the technical energy system analyses.

For transport technologies, marginal costs are used, assuming that it is possible to choose between regular vehicles and the alternative. Also for *ELT/micro* marginal costs are used; the costs listed in Table 2 include a boiler and the alternative is a natural gas boiler. The costs of the other alternatives are additional costs, since these alternatives cannot totally replace other technologies.

3 Results

In this section, the results of the analyses are presented. A total of 126 energy system analyses have been conducted hour-by-hour for a period corresponding to one year with due consideration given to the methodology described above. In these analyses, RES have varied from 0 to 50 TWh in open and closed energy systems, and for all seven alternatives, 36 energy system analyses were conducted for the reference energy system presented in Fig. 2 and Fig. 3.

The results of these energy system analyses of the alternatives are presented in diagrams depicting the marginal changes in relation to the reference energy system. A negative marginal effect in the diagrams indicates that the alternative is more flexible and/or more efficient than the reference energy system.

First, the results of the energy system analyses of the integration technologies with 25 TWh RES (50 per cent wind production of the electricity demand) are presented. Secondly, the results of varying RES shares are presented. The potential improvement in the total fuel efficiency using the integration technologies is analysed and the results of this analysis are used for identifying the least-cost alternatives for the integration of RES. In addition, several sensitivity analyses have been conducted, which are also presented below.

3.1 Effects of alternatives with 25 TWh wind power production

First, the marginal effects at 25 TWh wind power production are presented. The *ELT/CHP* has the best abilities to utilise the excess electricity production, see Fig. 8. It can integrate almost 2 TWh more wind power than the reference. The *HP*, *EB* and *BEV* can each provide more than 1 TWh reductions in excess production. The *ELT/micro* contributes with a lower improvement. The *HFCV* and the *5%FLEX* have almost no effect on reducing the excess electricity production compared to the ability of the reference.

The *HP* is by far the most fuel-efficient technology, see Fig. 9. In comparison with the reference, at an annual wind power production of 25 TWh, *HP* can reduce the fuel consumption by 7 TWh; thereby reducing the total fuel consumption excl. RES from 248 TWh to 241 TWh. *BEV* can reduce the fuel consumption by approx. 1.5 TWh. *ELT/CHP*, *ELT/micro* and *HFCV* result in the lowest fuel savings.

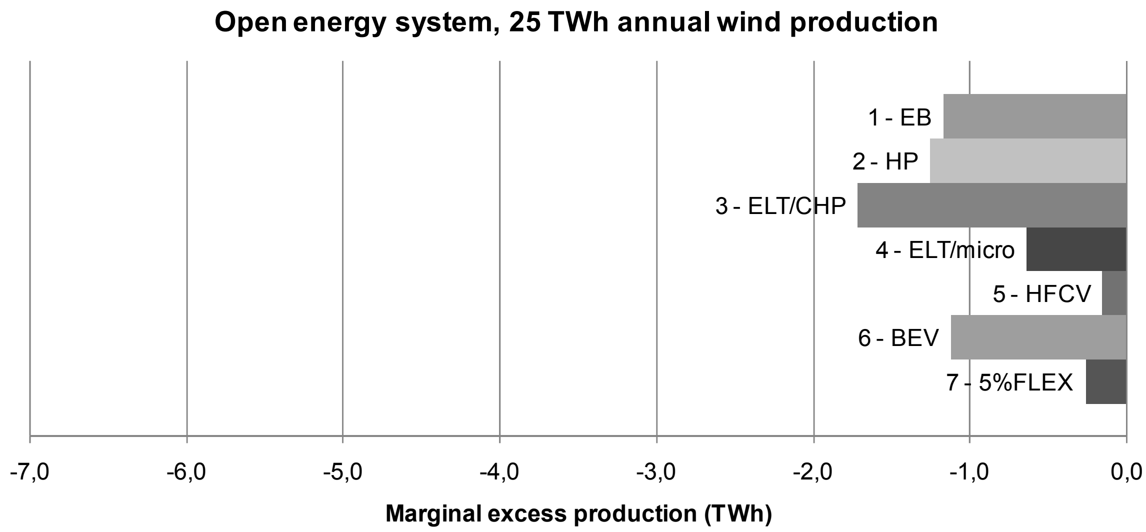

Fig. 8, The marginal excess electricity production at 25 TWh wind power production in an open energy system in relation to the reference with 25 TWh wind power.

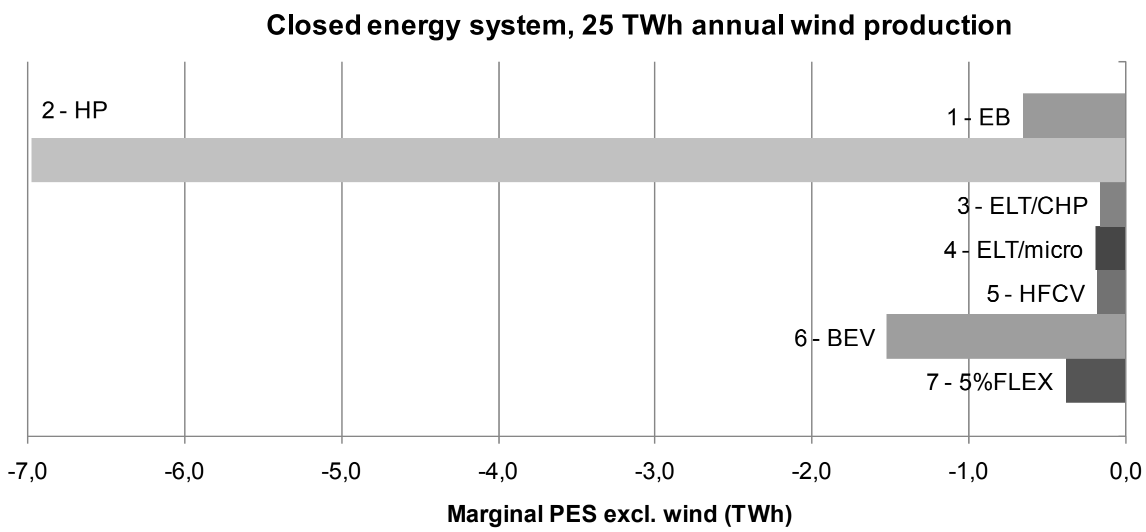

Fig. 9, The marginal fuel savings at 25 TWh wind power in a closed energy system in relation to the reference with 25 TWh wind power.

3.2 Effects of alternatives with varying annual shares of wind power

The marginal effects with an annual wind power production varying from 0 to 50 TWh are presented in Fig. 10 and Fig. 11. Again, negative effects in the diagrams represent better wind integration abilities than those of the reference energy system. In Fig. 10, it is evident that the seven alternatives have rather different abilities to integrate wind power although comparable capacities are introduced. *ELT*/CHP has the best ability to integrate excess electricity production, while *HP*, *EB* and *BEV* have similar effects until a share of 30 TWh wind power production is reached. *ELT/micro*, *HFCV* and *5%FLEX* have almost no effect on reducing excess electricity production.

In Fig. 11, the results are presented as marginal effects on PES excl. RES in relation to the reference energy system. *HFCV*, *ELT*/*micro*, *ELT*/*CHP* and *5%FLEX* add almost no fuel efficiency to the energy system no matter how much wind is introduced. With less than 6 and 12 TWh of wind power production, respectively, *HFCV* and

ELT/micro increase PES excl. RES. *HP* and *BEV* improve the fuel efficiency of the energy system in combination with any amount of wind power.

In the energy system analyses, *HP* proves to have the best performance. It can reduce excess electricity as well as fuel consumption in all wind production scenarios. Like *HP*, *EB* is rather good at integrating excess wind; however, the fuel savings are rather low. If not implemented correctly, *EB* may even result in increased fuel consumption. For transport, *BEV* is the best alternative both in terms of wind integration and fuel efficiency. *ELT/micro* and *HFCV* have a fixed annual hydrogen demand. This significantly limits the possibility of these systems of producing hydrogen at times with high excess electricity production. Furthermore, it results in low fuel savings due to the fact that hydrogen must sometimes be produced at PP. For *ELT/micro*, an additional problem is the fact that the production of electricity displaces CHP production elsewhere in the system; thus, district heating has to be produced by fuel boilers.

ELT/CHP has higher fuel savings than the other electrolyser alternatives, because it is able to place production at times with excess electricity and is not dependent on a fixed demand for hydrogen. Although *ELT/CHP* has good abilities to reduce excess production, the fuel savings are rather limited compared to other alternatives analysed. *5%FLEX* gives both low reductions in excess production and fuel savings. This is connected to the typical electricity demand distributed and the capacity of the flexible demand; hence, there is a limit to how much can be moved from peak demand to low demand hours.

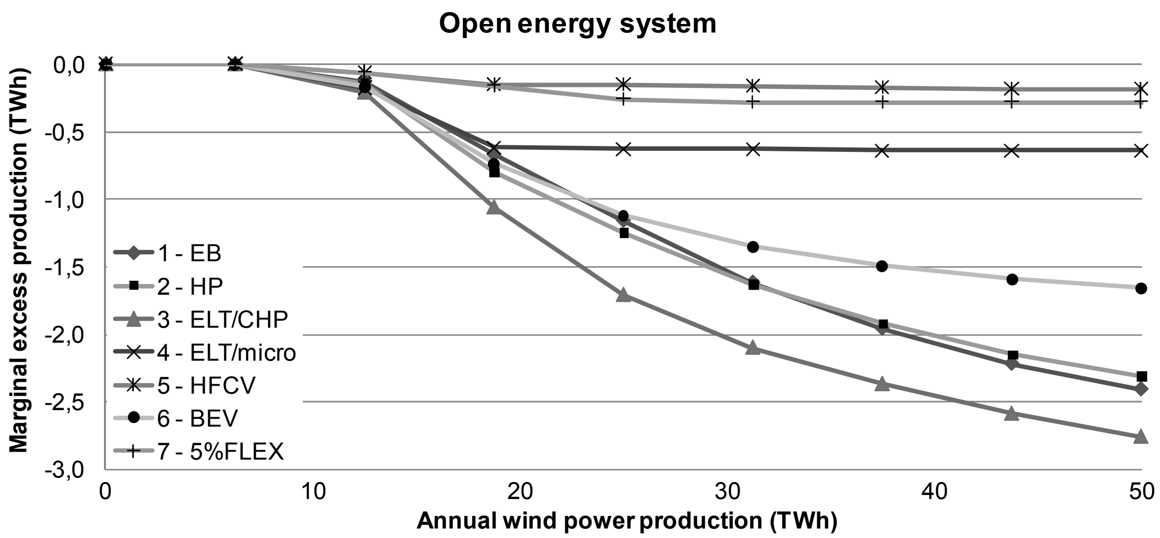

Fig. 10, Marginal excess electricity production at varying annual wind power production in an open energy system seen in relation to the reference with varying annual wind power.

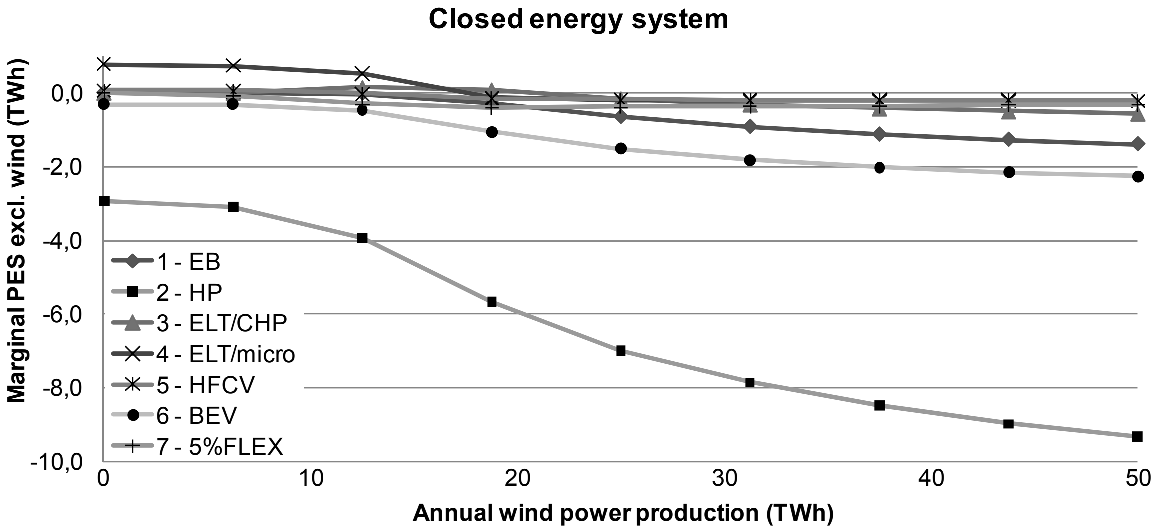

Fig. 11, Marginal fuel savings with varying annual wind power production in a closed energy system seen in relation to the reference with varying wind power.

3.3 Least-cost wind power integration technologies

The analyses have revealed different potentials of integration technologies with comparable capacities. The costs of the technologies, however, vary significantly. In Table 2, the costs of the technologies analysed are presented. Here, the total annual costs and the ability of each of the seven alternatives to increase the fuel efficiency of the energy system over a year are compared.

In Table 2, the costs in M€/TWh fuel saved are illustrated at 25 TWh wind power production, corresponding to 50 per cent of the electricity consumption in the reference energy system. As illustrated in Fig. 12, EB, *5%FLEX, HP* and *BEV* have significantly lower fuel saving costs than the other alternatives at 25 TWh wind power production. The *HFCV* alternative has the highest costs per TWh fuel saved.

In Fig. 13, the total annual costs of fuel savings from 0 to 50 TWh wind power production are illustrated. It is evident that *EB*, *HP*, *5%FLEX* and *BEV* have similar low fuel saving costs when wind production is above 20 TWh. However, HP has rather low fuel saving costs even with no wind production. *ELT/micro* has rather high costs no matter how much wind is introduced into the energy system. The fuel saving costs of *HFCV* are rather constant at approx. 50 M€/TWh. However, these fuel savings can only be achieved with an annual wind power production above approx. 20 TWh. When wind power production exceeds 25 TWh, *ELT/CHP* improves as the wind power share increases further.

EB, *HP, 5%FLEX* and *BEV* may all have rather low costs per TWh fuel saved, but their effects on fuel savings differ to a great extent. Although *HP* and *BEV* have the highest total annual investment costs, they also provide the largest fuel savings in all scenarios. Therefore, they should be the first options to implement if a fuel-efficient and cost-effective integration of wind power is the main objective.

The investments in integration technologies can be compared to fuel costs. In May 2008, oil prices were more than 120 $/bbl and coal prices were more than 150 $/ton. For oil, 100 $/bbl is equivalent to 39 M€/TWh, which is included for comparison in Fig. 12 and Fig. 13. *ELT/CHP* and *HFCV* have larger fuel saving costs than 39 M€/TWh in all the scenarios analysed.

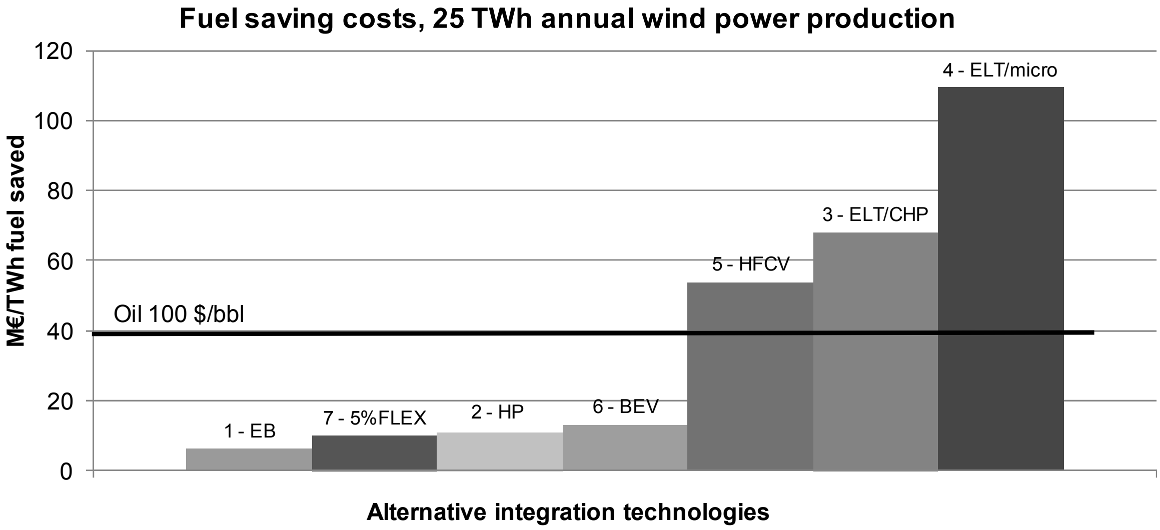

Fig. 12, The total annual costs of saving 1 TWh fuel at 25 TWh wind production for the seven alternatives.

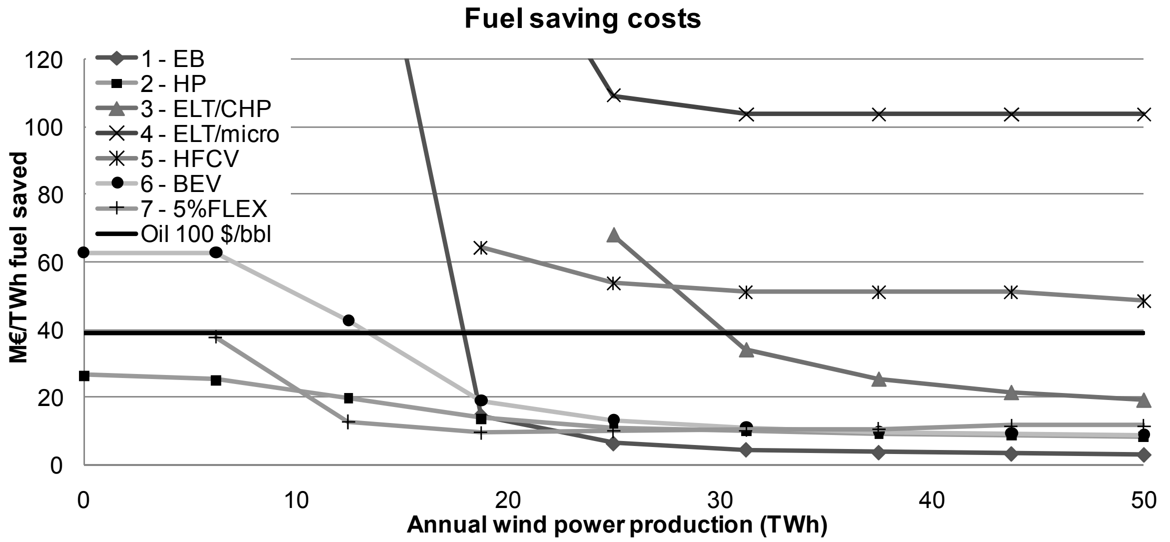

Fig. 13, The total annual costs of saving 1 TWh fuel from 0 to 50 TWh wind power production. Situations with increased fuel consumption or costs above 120 M€/TWh are not included.

3.4 Sensitivity analyses

In order to test the reliability of the results, a series of sensitivity analyses have been performed. In a sensitivity analysis for *EB*, another regulation strategy has been analysed using *EB* before replacing the CHP with boilers. The regulation strategy used in the analysis above is defined as the best of the two regulation strategies.

For *HP*, the COP used may prove rather conservative and the share of delivered heat at any given hour is limited to 50 per cent due to limitations of the heat source. With a 20 per cent share of heat delivered from *HP*, fuel savings are 0.3-0.5 TWh lower and the effect on the excess electricity production remains in the same range. If the COP is 2.5, fuel savings are reduced by between 1.5 and 3 TWh. *HP* fuel saving costs start at 55 M€/TWh with this COP and with more than 10 TWh of wind power production, it is lower than the oil price. An analysis of individual heat pumps applying a COP of 3 and analysing 450 MWe reveals that such a solution reduces excess production and fuel savings to approx. 60 per cent of those of a large-scale heat pump. Assuming that these pumps cost the double of the large-scale heat pumps listed here, the cost saving curve is similar to the HP in Fig. 13, starting at 50 M€/TWh and ending at 27 M€/TWh. Hence, such a solution also has rather low costs.

Half of the fuel savings of *ELT/micro* and *ELT/CHP* results from the production of heat by electrolysers. If the heat is not utilised, the fuel saving costs of these alternatives would double. For *HFCV*, almost all fuel savings stem from the replacement of regular vehicles. Thus, the heat production of electrolysers is not significant for the results of this alternative. The same picture can be seen if the electrolyser efficiency is lowered to 70 per cent. Again, half of the efficiency gains are lost in *ELT/CHP* and *ELT/micro*, while *HFCV* is less affected, because the efficiency gains stem from the replacement of regular vehicles. For *ELT/CHP*, no fixed amount of hydrogen is required and the 450 MWe electrolysers are given by the premises of the comparative analysis, i.e. comparing 450 MWe integration technologies. This enables *ELT/CHP* to perform better than other electrolyser alternatives, also in the sensitivity analysis. The 300 GWh storage is applied, since a larger storage does not improve the alternative and given the fact that this storage size does not influence the economy of the system significantly. Larger heat storage in households in *ELT/micro* does not improve the fuel efficiency significantly, either.

ELT/micro and *HFCV* have been modelled with 25 per cent operation of electrolysers. An analysis of 50 per cent running time decreases the electrolyser capacity and thus the costs. This has almost no effect on the fuel savings of *HFCV*, again because they replace other vehicles. For *ELT/micro*, though, more than 35 TWh wind power production is required to gain fuel savings and fuel saving costs are increased significantly.

In the V2G *BEV* alternative, the vehicles are able to discharge to the grid in situations with PP production. If this was not the case, the maximum fuel saved would be 0.5 TWh and not 2.2 TWh, as illustrated in fig. 11. This would increase the fuel saving costs of *BEV* to between 40 and 62 M€/TWh, at all times more than 8 M€/TWh lower than the costs of *HFCV*. The V2G technology is a part of the *BEV* alternative but is not included in the costs. If the costs of 5%FLEX are added, the conclusions do not change.

5%FLEX is analysed by applying a one-day flexible demand. With one-week flexible demand or more, fuel savings would almost double. This would lower the costs; however, the fuel savings of *5%FLEX* are still moderate compared to those of the other alternatives.

Halving the investment costs of the integration technologies does not change the relative relation between the alternatives and does not make *ELT/micro* competitive with the oil price. If the investment costs of *HFCV* and *BEV* were halved, there would be a net saving compared to regular vehicles.

With double investment costs, *5%FLEX*, *HP* and *EB* are still defined as the least-cost alternatives. In this situation, 5*%FLEX, HP, EB, BEV* and *ELT/CHP* have lower costs than the oil equivalent at above approx. 10.0 TWh, 12.5 TWh, 19 TWh, 28 TWh and 44 TWh wind power production, respectively. The remaining alternatives have much higher fuel saving costs.

In the case that the costs of *ELT/micro* can be reduced to the price of a natural gas boiler, fuel saving costs are approx. 3 M€/TWh more than *HFCV*. Thus, *ELT/micro* is still one of the integration technologies with the highest costs, because it is rather inefficient.

For all alternatives, doubling the capacity gives an additional reduction in PES of approx. 70-110 per cent in comparison with the savings identified above. For the alternatives in which no savings were present with low amounts of fuel, the additional fuel consumption increases. For electrolyser alternatives, these analyses confirm that a certain amount of wind power production needs to be present in order to enable fuel savings. Otherwise, increased fuel usage will be the result. In Fig. 14, the fuel saving costs achieved by doubling the capacities of the integration technologies are illustrated. Doubling the capacities does not change the results and neither does a 6 per cent interest rate instead of the 3 per cent used.

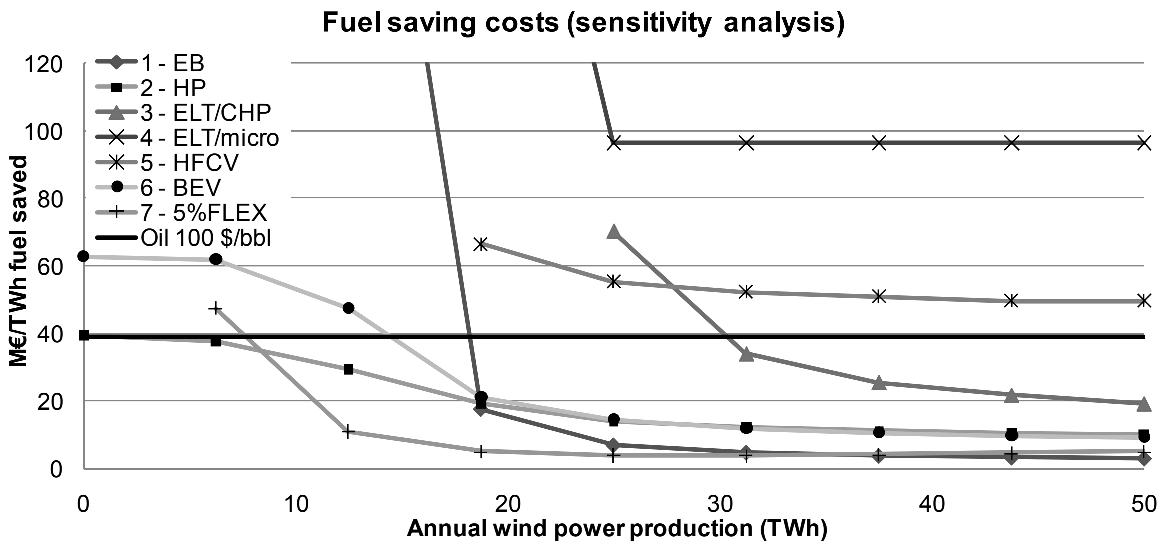

Fig. 14, Sensitivity analysis of doubling the capacities of the integration technologies. Total annual costs of saving 1 TWh fuel from 0 to 50 TWh wind power production. Situations with increased fuel consumption or costs above 120 M€/TWh are not included.

A sensitivity analysis has been conducted of the potential future situation in which other components than the central plants, such as wind turbines and local CHP etc., provide ancillary services. In this type of system, excess electricity production is more than halved and, thus, the energy system is able to integrate more excess electricity production and reduce the fuel consumption with the technologies already installed.

This changes the effects of the seven integration technologies. In general, more than 25 TWh of wind power production (50 per cent of the electricity demand) must be present before the excess electricity problems become severe enough for the integration technologies to have an effect. The most effective technologies reducing excess electricity production are *HP*, *ELT/CHP* and *EB*. *ELT/micro* has the same effects as previously seen, while the effects of *HFCV* and *5%FLEX* improve. The ability of *BEV* to reduce excess electricity production is reduced.

The total PES at the starting point is lower, because the reference energy system in itself becomes more flexible. However, the *HP* still results in fuel savings no matter the share of wind power produced in the energy system. The alternatives have a better ability to reduce the fuel consumption than previously, with more than 25 TWh wind power production, except for *BEV*. In Fig. 15, the fuel saving costs in this situation are illustrated. The alternatives with electrolysers are more competitive in this sensitivity analysis with wind power production at more than 25 TWh and are less sensitive to not using waste heat from electrolysers. However, *ELT/CHP* and *ELT/micro* are still very sensitive to lower electrolyser efficiencies.

When combining the integration technologies, the effects on the fuel consumptions accumulate to a large extent. However, this depends on whether the technology in question is dependent on wind power production in order to provide fuel savings, or will provide fuel savings in any case. The effect on the excess electricity production is gradually smaller when the integration technologies are combined.

For land-based wind turbines, the same production requires almost the double installed capacity. The costs of these are, however, also about half the costs of off-shore wind turbines. A sensitivity analysis is conducted with land-based turbines with a 28 per cent load factor. The distribution of wind power production has much larger peaks, and thus, fluctuations are heavier. This does not change the results of the analyses significantly; although the fuel savings of *5%FLEX* improve by a factor 2 to 3, *HP* and *BEV* still have much higher fuel savings.

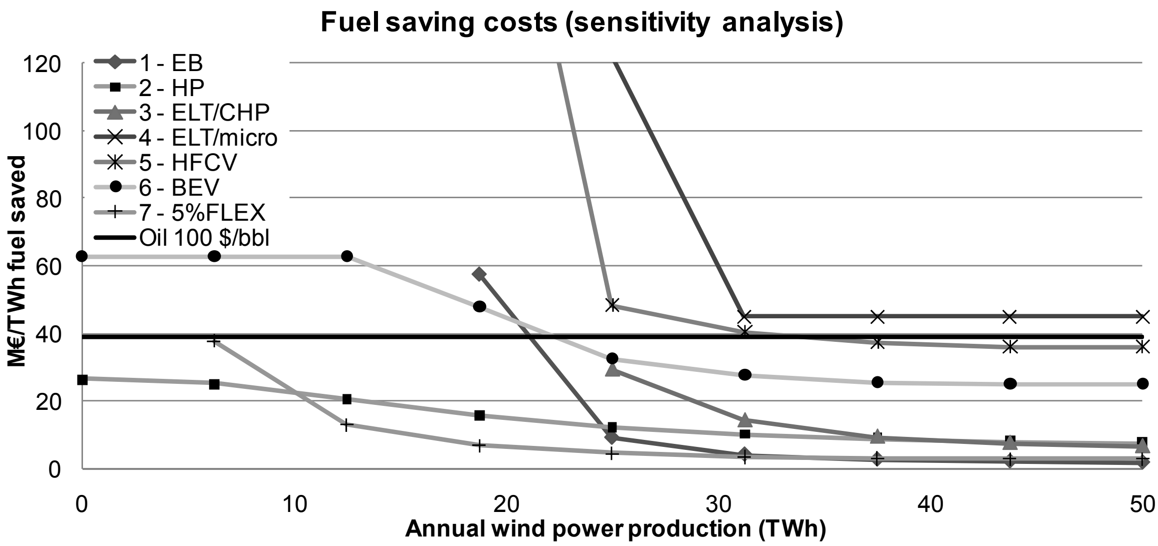

Fig. 15, Sensitivity analysis with more technologies able to provide ancillary services. The total annual costs of saving 1 TWh fuel from 0 to 50 TWh wind power production. Situations with increased fuel consumption or costs above 120 M€/TWh are not included.

4 Conclusions

Seven different integration technologies have been analysed in terms of their ability to improve the balance between demand and supply in a sustainable energy system with a high penetration of CHP and fluctuating RES. The Danish energy system has been used as the case, providing a fuel-efficient energy system with high amounts of wind power production and CHP plants already installed; measures which other countries and regions also plan to implement in the future.

The seven technologies have been evaluated in terms of their ability to integrate fluctuating wind power production, their influence on the system fuel efficiency, and their annual costs in relation to fuel savings.

Heat pumps have good abilities to integrate RES and constitute by far the most fuel efficient solution. Electrolysers which produce without depending on a fixed demand for hydrogen for CHP plants are able to integrate RES better, but are, on the other hand, rather inefficient at utilising RES compared to other technologies. Electrolysers with a fixed annual production rate are unable to place all the production of hydrogen at times with high amounts of wind power, and are thus even more inefficient.

Heat pumps and flexible demand are the most promising technologies in respect of costs. These technologies should be implemented first. Electric boilers also have rather low costs, but only with a RES share above 40 per cent of the electricity demand. Heat pumps make up a good investment even with lower amounts of wind power than those expected for the future. This makes it a low-cost technology in years with less wind, whereas other technologies will not be feasible in years with low amounts of wind power production. The electric boiler can result in increased fuel consumption if it is not implemented correctly into the energy system and is not feasible in years with low wind power production. Flexible demand has rather low fuel saving cost, even though the technology analysis made here only covers one day and does not include potential savings in the power plant capacities. For both electric boilers and flexible demand, an extra installed capacity does not improve fuel savings much compared to heat pumps. This indicates that the heat pumps are more important than these technologies in terms of reducing excess electricity and, at the same time, increasing fuel efficiency at low costs.

For transport battery electric vehicles, fuel and cost-effective solutions both comprise a vehicle to grid solution and a dump charge solution compared to the hydrogen fuel cell vehicles.

With more than 40-50 per cent of the electricity demand produced by wind turbines, the costs of integrating RES with electrolysers for hydrogen fuel cell vehicles, CHP plants and micro CHPs are reduced. However, if the aim is fuel-efficient and low-cost integration of RES, the other technologies mentioned should be implemented first. The results of using electrolysers are very sensitive to the efficiency of these and to the use of waste heat, except for the hydrogen fuel cell vehicles if these replace regular internal combustion engine vehicles.

Although these analyses conclude that other technologies should be implemented first, the electrolyser technologies may prove important in 100 per cent renewable energy systems with large amounts of intermittent renewable energy and in which biomass is a limited resource [5].

These results are based on technical energy system analyses. The investment costs, O&M costs and the lifetime of the technologies and solutions are most sensitive to the efficiencies used and, thus, the results are rather robust against changing fuel prices.

The first step in the integration of wind power production is to use CHP plants with heat storages and boilers and to move CHP production to times with low wind power production. If technologies are developed to change the current centralised ancillary service design using only large centralised power stations, the excess electricity production is significantly reduced. Thus, the regulation ability of CHP plants and a decentralised ancillary service supply are more important than integration technologies in terms of reducing excess electricity production efficiently.

5 Acknowledgements

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Appendix VII

Long term perspective for balancing fluctuating renewable energy sources

Fuel cells for balancing fluctuating renewable energy sources

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Contents

7 Technology Description

7.1 Introduction

CHP plants have proven to have good and efficient abilities to integrate fluctuating energy sources. The expansion of CHP systems is important to increase the overall fuel efficiencies in both energy systems with high amounts of fluctuating wind power and in systems with low amounts of fluctuating wind power. The efficiencies of the CHP plants themselves can be improved significantly by means of fuel cell technologies. These can improve the overall fuel efficiency further and reduce the environmental impacts connected to the production of energy. In these cells chemical energy is converted directly into electricity instead of traditional technologies where the energy content in fuels is converted into thermal energy, then mechanical energy and then electricity.

Although several types of fuel cells are currently being developed and demonstrated, for large stationary appliances or micro-CHP one kind of fuel cell is especially promising because of its high efficiency and fuel flexibility, solid oxide fuel cells (SOFC). Other kinds for fuel cells are more suitable for mobile or smaller distributed generation. The most promising fuel cells within these applications are proton exchange membrane fuel cells (PEMFC), because of their rather simple design and quick start-up.

For the task of integration of wind power and other fluctuating renewable energy sources the different fuel cells have different capabilities. Fuel cells, like other technologies, cannot be seen as an isolated improvement, but has to be assessed within the energy system surrounding it. In this section the advantages and disadvantages of using fuel cells for balancing fluctuating renewable energy sources is assessed.

7.2 Fuel cell characteristics, efficiencies and applications

All fuel cells have in common that the core consists of a cell with an electrolyte and two electrodes, the anode and the cathode. In Figure 1-1 the reactions in different fuel cells is illustrated. In the cell the hydrogen and oxygen is converted to water producing electricity and heat. The conversion of hydrogen takes places in a chemical process, where the catalytic active electrodes convert hydrogen into positive ions and oxygen into negative ions. The precise reactions depend on the type of fuel cell. The ions cross the electrolyte and form water and possibly CO_2 depending on the fuel and fuel cell. Only protons can cross the electrolyte creating a voltage difference between the anode and the cathode in the cell. This voltage difference can create the current in a fuel cell system. [1]

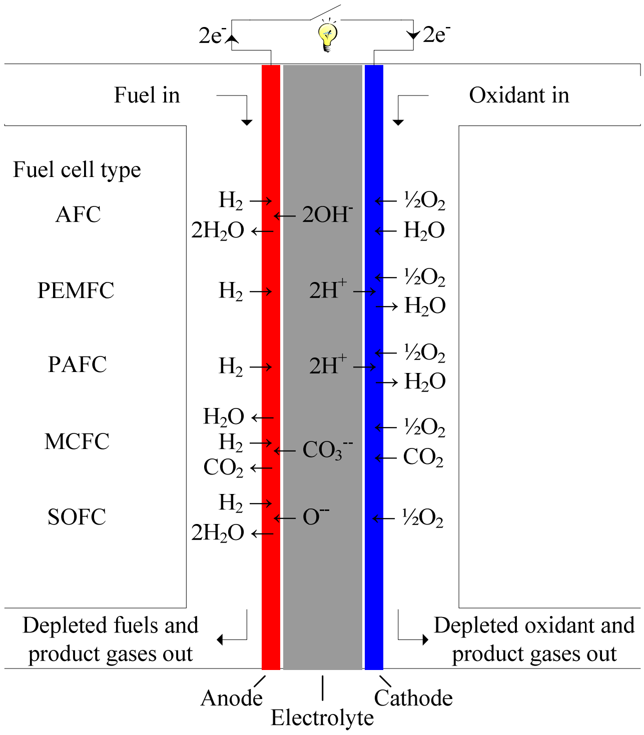

Figure 7-1: Schematics of different fuel cell types.

7.2.1 Fuel cell types

In Table 7-2 the characteristics of the five main types of fuel cells are listed. Although some fuel cells are mainly considered for mobile and others for stationary use, this is not at all determined yet. The different characteristics of the fuel cells however, make certain potential applications more probable than others. The fuel cells are named after their electrolyte which also determines its operating temperature.

Fuel cells	**AFC**	**PEMFC**	**PAFC**	**MCFC**	**SOFC**
Name (electrolyte)	**Alkaline**	**Polymer**	**Phosphoric acid**	**Molten carbonate**	**Solid oxide**
Operating temp.	<120 ºC	70-120 ºC	150-200 ºC	550-650 ºC	500-1000 ºC
Fuel(s)	Perfectly pure H_2	Pure H_2 or CH_3OH	Pure H_2	H_2, CO, NH_3, hydrocarbons	H_2, CO, NH_3, hydrocarbons
Intolerant to	CO, CO_2, S	CO, S, NH_3	CO, S, NH_3	S	S
Future electric efficiency %	40	40	40	60*	60*
Potential area of use	Space, military	Mobile units, micro-CHP	Smaller CHP units	Larger CHP units	Small & large CHP units

Table 7-2: Characteristics of the five main types of fuel cells and potential areas of use. [1-4].
** 75% electricity efficiency can be achieved when combined with gas turbines.*

For the *low temperature fuel cells* the advantages are mainly that the cells are compact, light weight and have a quick start-up potential. This combined with the fact that the efficiency can not compete with other power producing technologies, makes the most promising application transport and mobile applications where they can compete with the efficiencies of the existing technologies. For stationary appliances other technologies already have better efficiencies today.

Phosphoric acid fuel cells (PAFC) are widely used today as emergency power and stand-alone units in hospitals, schools and hotels. They have been commercially available since 1992 but the costs are still about three times higher than other comparable alternatives. The main problems are that they are dependent on noble metals for the electrodes and that the efficiencies are not much better than other technologies.

Alkaline fuel cells (AFC) are highly reliable and compact, but no widespread commercial use is expected, because of the cost of the extensive gas purification needs. CO_2 in ambient air has to be completely removed via scrubbing and if hydrogen is derived from fossil fuels it also needs to be purified.

There are different variants of PEMFC available. These cells are characterised by a rather simple design and fast start-up. The conventional PEMFC at 80 ºC is easily poisoned by small amounts of CO. Higher temperature PEMFCs are being developed in which gaseous water is used. These cells are rather promising. Even though they still contain platinum which makes them more expensive, the amount has been reduced significantly. The system is simpler than the conventional cells because of fewer problems with water management, cooling etc. These higher temperature PEMFC are more tolerant to CO, which makes the fuel processing simpler. Another variant of PEM is the direct methanol fuel cell (DMFC) which uses methanol directly without prior external reforming. These are mainly considered for small portable devices such as mobile phones, computers etc.

For *high temperature fuel cells* the two main advantages are the higher efficiencies and the fuel flexibility. Other advantages include that the high operating temperatures allow internal reforming or direct conversion, which enables a rather simple system design. Also they consist of rather cheap materials and do not contain noble metals.

In molten carbonate fuel cells (MCFC) it is necessary to add CO_2 with ambient air on the cathode side. Also the molten carbonate is heavily corrosive, which is the main problem in these cells today. Research is still being conducted to improve the cells mainly for larger CHP and power plants.

Solid oxide fuel cells (SOFC) seem to be more promising as they have already proven rather long lifetimes and efficiencies. The main challenge for further improvement is to replace some of the ceramics with lower cost metals as the ceramics are rather expensive to produce. This is why efforts are being made to reduce the temperature to around 550 ºC in order enable the use of metal-supported SOFCs. At the moment the temperature has been reduces from 1.000 ºC to 700 ºC. Another challenge for the cells is temperature gradients in start-up and shot-down which require matching thermal expansion characteristics. This problem is also reduced with lower operating temperatures.

Overall the higher temperature PEMFCs and high temperature SOFCs are the most promising for the mobile and stationary appliances. These two technologies are elaborated in the following sections.

7.2.2 Fuel supply

To a large extent, the balance of plant equipment for all types of fuel cells is the same. One major exception is that the low temperature requires fuel pre-reforming into hydrogen whereas the high temperature fuel cells can reform natural gas and other fuels internally or use these directly in the conversion. These fuel processes are connected to losses which are not taken into account for the lower temperature fuel cells in Table 7-2 since these efficiencies are derived when using hydrogen in the fuel cells. For high temperature fuel cells hydrocarbon based fuels may have even higher efficiencies than indicated in the table.

Since hydrogen is not readily available it has to be procured by electrolyses or reforming of hydrocarbons. The maximum electricity-to-hydrogen efficiency in electrolysis is 84,5% no matter which technology is used. In the future electrolysis may be based on reversed or reversible PEMFCs or SOFCs. Various losses such as the system energy usage, activation losses and leakages will however occur. The electricity-to-hydrogen efficiency of commercially available electrolysers can be up to 73% today. [5-7]

For fuels reforming the theoretical achievable efficiencies vary from fuel to fuel. Methanol has the highest potential efficiency, 96%, which, in combination with rather mild reforming conditions, is considered promising [8]. Other fuels such as natural gas and ethanol also have rather high potential efficiencies and have the advantages that the infrastructure is already widely spread. Hydrogen and methanol have unsolved problems concerning infrastructure such as storage. The most promising energy carriers concerning weight and volume are methanol and ethanol.

The fuels also have to be clean for the substances which the fuel cells are intolerant to. All cells have to be fitted with a de-sulpheriser and the lower temperature cells also have to have CO, CO_2 and NH_3 removed, depending on the type of cell. The intolerances of the fuel cell are listed in Table 7-2.

In the SOFCs the electrolyte allows oxygen to pass from cathode to anode. In the PEMFCs hydrogen passes from anode to cathode. For the SOFCs this means that a wide range of fuels including natural gas, biogas, ethanol, diesel, LPG, methanol etc. can be used without the requirement to reform the fuel completely into hydrogen and CO_2 prior being processed in the fuel cell [9].

7.2.3 Efficiencies, start-up times and regulation abilities

It requires a stack of cells to deliver direct current at high voltage. In a stack individual cells are connected in series divided by interconnectors. The interconnector is a bipolar metal plate that distributes the electricity produced. To form a power unit, the fuel cell has to be fitted with an appropriate support system and research is still being done to improve the fuel cell systems, for example different heat recovery systems for the fuel supply. The fuel processing system requires reforming and the supply system has to deliver fuel and air under the right conditions, i.e. temperature, pressure, moisture and mix. The fuel supply and reforming systems are the major challenges for fuel cells on the system level.

After the electricity production in the fuel cell an inverter has to change the current from DC to AC which also is connected to losses. Other power electronics can give the fuel cells the same abilities as other traditional power supply units concerning grid stability. [1]

The high temperature fuel cells can be used in combined cycle systems, potentially improving the electricity efficiency from 60% up to 75% by adding gas turbines. Both PEMFC and SOFC can be used as CHP units. The total efficiency of both micro-CHP and larger CHP based on fuel cells can potentially reach 90%. These CHP-systems can function in the same manner as some of the existing CHP-systems i.e. be connected to the natural gas grid and combined with heat storage. In Figure 1-3 the conceptual design of a solid oxide fuel cell is illustrated. If hydrogen is used, an electrolysor or fuel reformer has to produce this prior the usage in the plant.

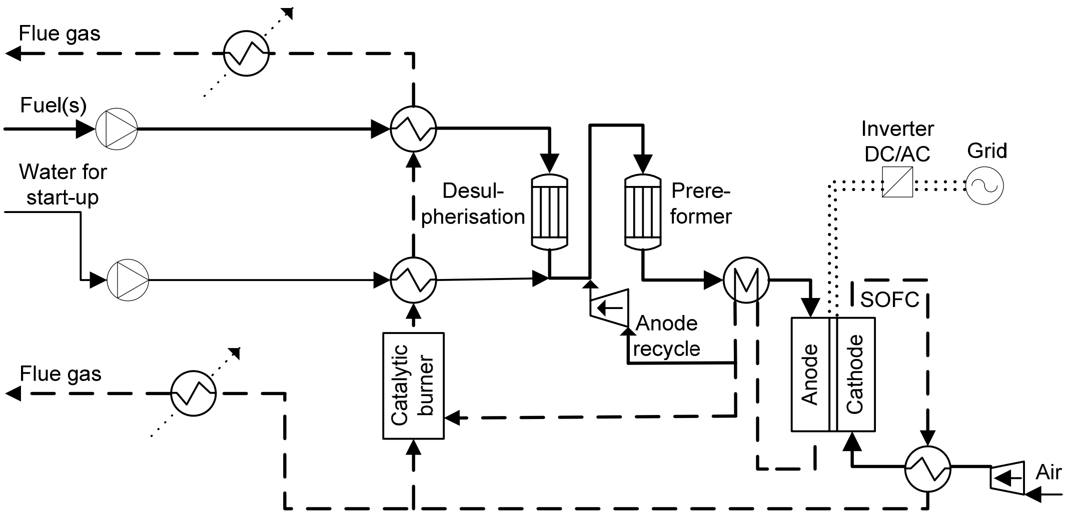

Figure 7-3: Conceptual design of a solid oxide fuel cell combined with a gas turbine.

For fuel cells such as PEMFC and SOFCs up- and downscaling does not interfere with the efficiency. Power density of the fuel cells however can be affected, if the support systems or the power electronics are less scalable.

PEMFCs have very fast start-up because of the rather low operating temperatures. High temperature PEMFCs may even prove to have the shortest start-up time of the two because of less problems with liquid H_2O. This on the other hand is a challenge for SOFCs because these have more problems with temperature gradients than PEMFCs. The SOFCs are several hours to start-up because of their high operating temperature and the temperature gradients. These problems however can be reduced by fitting the cells with start-up burners, or as a more promising alternative, keeping them at a high temperature by operating them periodically and with insulation [10]. SOFCs can be operated on low amounts of fuel and producing very little electricity but keeping the temperature at the right operation level.

When in operation both types of fuel cells have very fast regulation abilities, enabling them to have properties similar to batteries. Fuel cells also have good part load efficiencies. Full load and part load performance prediction for integrated SOFC This, in combination with the rather low heat production and good regulation abilities, enables them to be a flexible market player.

7.3 Calculations of fuel cells wind balancing abilities

The characteristics of fuel cells give the technology a strong potential to be combined with large amount of fluctuating renewable energy. Analysis shows that high temperature fuel cells, such as SOFC are better than conventional power plants with high amounts of wind turbines.

If fuel cells are able to remove the necessity to have running capacity available at all times and can ensure grid stability, this can enable more wind power to be integrated efficiently and also increase the flexibility of the energy system [11]. However this requires that the cells are constructed so that they can regulate from 0-100% of the capacity that the system is constructed with fast start-up and shut-down and also is fitted with additional power electronics. It also requires that wind turbines or technologies on the demand side are able to deliver grid stability. These requirements are already being made for new wind turbines. The high temperature SOFCs have proven god regulation abilities. By insulating the SOFC and adapting the operation in situations with prolonged stand still it may be possible to have fast start-up [10].

Based on the methodology in [12] the official reference energy system in Energy Strategy 2025 [13] for Denmark in 2030 has been analysed with increasing amounts of wind and with SOFCs with the abilities mentioned above. The analysis is conducted in the EnergyPLAN model hour-by-hour. The energy system's ability to integrate fluctuating renewable energy sources is illustrated in two different diagrams. One diagram shows the annual excess electricity production (in TWh) as a function of the renewable energy input in an open energy system. The less excess electricity production the better capacity of energy system to integrate fluctuating renewable energy sources. The other diagram shows the resulting fuel consumption (in TWh) in a closed energy system excluding the primary fuel consumption from renewable energy sources, in this case wind power. The less fuel consumption the better the system is to use the wind production efficiently. In the closed system the following strategy for handling surplus wind production is used: first the CHP production is replaced by boilers in the district heating systems, next the excess electricity production is utilised for electric heating and finally wind turbines are stopped. In both diagrams the production from wind turbines varies between 0 and 50 TWh equal to a variation from 0 to 100 per cent of the electricity demand in the reference.

The analysis of the reference energy system has been made with the following restrictions in ancillary services in order to achieve grid stability: At least 30 percent of the power or as a minimum 450 MW (at any hour) must come from power production units capable of supplying grid stability such as central power stations and CHP units. At least 450 MW running capacity in large power plants must be available at any moment. Distributed generation from renewable energy sources and small decentralised CHP units are not capable of supplying ancillary services.

In the same energy system SOFC CHP plants are introduced. To illustrate the full potential of the SOFCs all CHP and power plants are replaced with the fuel cells. For smaller SOFC CHP plants the electricity efficiency is 56% and the thermal efficiency is 34%. In larger SOFC CHP and power plants the efficiencies are assumed to be 66% for electricity and 24% for heat. These efficiencies are considered achievable in 2015 [14].

The analysis is conducted on the reference energy system and an energy system where the CHP and power plants have been replaced by SOFCs. The energy system with the SOFCs is also analysed without the restrictions mentioned above, which these fuel cells potentially can enable in the future. In Figure 7-4 the excess electricity production from 0 to 100 percent of the electricity consumption is illustrated. The energy system where the SOFCs can enable less restrictions has by far the best abilities to integrate wind energy. This is mainly due to the shift in the electric and thermal efficiencies, thus lowering the heat controlled power production at the CHP plants.

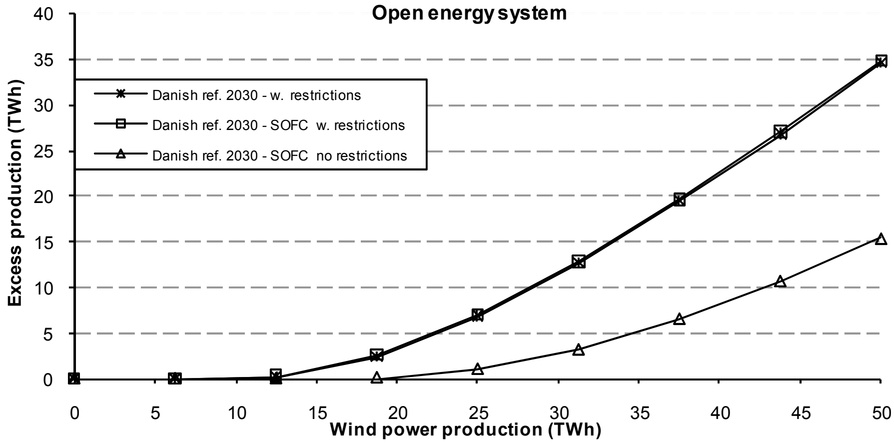

Figure 7-4: Excess electricity production.

In Figure 7-5 the primary energy consumption excluding wind power is illustrated for increased wind power production. The SOFC energy systems are significantly better at reducing the fuel consumption, because of their higher electric efficiencies. If the potential for very fast regulation abilities is achieved, the fuel consumption can be even lower, especially for wind production above 50 percent of the annual electricity demand in this reference.

The analysis here illustrate that the introduction of SOFCs will reduce the fuel consumption. If the SOFCs also have better regulation abilities, the integration of wind power can also be improved.

If the Danish reference for 2030 is analysed without CHP plants, i.e. the heat demand is meet by boilers and electric heating, the energy system with no CHP plants is a bit better at reducing the excess electricity production. This is due to the fact, that there is no heat bound electricity production. As expected though this energy system, without CHP, proves to be very inefficient because of inefficient heat and power production.

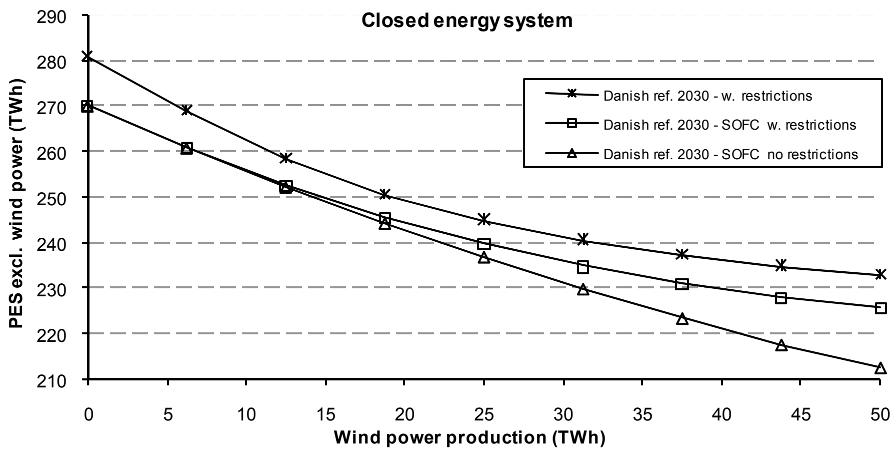

Figure 7-5: Primary energy consumption (PES) excl. wind power.

7.4 Assessment of fuel cells

In the perspective of using fuel cells for integration of fluctuating renewable energy the SOFCs are the most promising. These cells have the advantage of significantly higher electricity efficiency than competing technologies and fuel flexibility. Fuel cells in general also have the advantage of fast regulation abilities combined with excellent part-load efficiencies. Additionally scaling the cells from W to kW to MW is possible and does not influence the efficiencies of the cells. The feasibility of the scaling however depends on the market at hand and the fuel cells characteristics.

Wind integration can also be preformed with other types of fuel cells than the SOFCs such as PEMFC in micro-CHP. These however have the disadvantage that the efficiency is lower and require pure hydrogen. PEMFCs have advantages for mobile applications replacing internal combustion engines and batteries were feasible. For mobile applications the PEMFCs have the advantages that they can compete with internal combustion engines with fast start-up, fast regulation abilities and better efficiencies. In comparison with batteries fuel cells have the advantage that they have higher energy densities and can be refilled instantly, however the storage problems have yet to be solved. As storage and energy carriers methanol and ethanol are the most promising in regards to mass and volume. These can be used directly in SOFCs but have to be reformed for use in PEMFC.

New technologies that can provide energy system flexibility, such as SOFCs, heat pumps and heat storage technologies are more important than storing electricity as hydrogen via electrolysis in energy systems with high amounts of wind [12]. Unnecessary energy conversions should be avoided. However in future energy systems with wind providing more than 50% of the electricity and with the best measures for improving flexibility have already been taken, making fuels via electrolysis is one of the alternatives to integrate more renewable energy. Creating the road map to a 100% renewable energy systems require difficult choices between balancing fluctuating renewable with hydrogen production or electric cars, and on the other hand using biomass and bio fuels [15]. Fuel cells can have an important role in these future energy systems.

7.5 Investment cost

At the moment most types of fuel cells are at a development stage where only demonstration plants are being produced. The cost of fuel cells is still several thousand dollars pr. kW effect. Both PEMFC and SOFC, which are considered to be the most promising cells, are expected to be competitive with other competing technologies within the next 10 years. The goal for the US Department of Energy (DOE) is that the prices of stationary application for SOFCs should be

400$/kW before 2015 also for SOFC systems combined with gas turbines. The system should have 40.000 hours of durability. Reaching these cost reduction estimates require that the obstacles outlined above are dealt with. The cost for stationary SOFCs may prove closer to 1.000 $/kW [16]. If the durability can be lower the costs can also be lower and SOFCs are also considered for mobile application. For PEMFC for transportation the goal for DOE in 2015 is 30$/kW in 2015 with a durability of 5.000 hours [17]. The costs for other applications and for the other mentioned fuel cells are expected to be higher, though these may have other advantages [1].

It should also be mentioned that the maintenance cost can prove to be rather high in comparison with other technologies, especially concerning fuel cells for stationary appliances. The fuel cells them selves require little daily attention and can in principle be run automatically. However the stacks of cells in stationary appliances have to be changed periodically because of cell-degradation. Today this is connected to rather high cost because of the ceramics used. As these get thinner or replaced by other materials in future third generation metal-supported cells the maintenance costs may be reduced.

For PEMFC the main problems concerning cost may not be the cells themselves, but the storage and reforming systems. For SOFCs the infrastructure and storage problems and cost are significantly lower because of the internal reforming of hydrocarbons. When using the PEMFCs for mobile or stationary appliances the cost for new infrastructure and for reforming of fuels into hydrogen have to be added.

7.6 Environmental impacts

The environmental impacts of a fuel cell in operation are minute in comparison with other technologies. The global warming potential and emissions of CO_2 is directly linked to the fuel used in the cells. When using fossil fuels such as natural gas in SOFCs the CO_2 emissions pr. kWh are however lower than the traditional gas turbines, because of higher efficiencies.

Other emissions such as sulphur, NO_x and CO are expected to be very low, because of the fuel pre-treatment, higher efficiencies and direct chemical conversion. Sulpher has to be removed from the fuels so SO_x is not a problem like it is in combustion technologies. The sulphur emissions are virtually nonexistent. The NO_x emissions are also significantly lower and these emissions are connected only to the catalytic burner using unused fuel from the fuel cell for heat in the fuel supply system. The emission of CO is rather low for all cells, as it is used as a fuel in the higher temperature cells, and is poison and hence removed for the low temperature cells. There may be emissions of unused hydrocarbons, but this can be reduced in the system design. No non methane volatile organic compounds or NMVOC and particles are emitted from the cells. Also the cells are very quiet with almost no sound in operation.

Apart from the environmental impacts and resource consumptions in the operation of fuel cells impacts in a life cycle perspective is also important to investigate. Here one of the two most promising fuel cells, the SOFC, is investigated in a life cycle perspective. The primary energy consumption for the production the fuel cell is used as an indicator of the environmental impacts and resource consumptions. The development within the field of SOFCs has commenced from first generation electrolyte-supported cells, to second generation anode-supported cells. These are less costly to produce and also have less internal resistance [10]. The third generation metal-supported cells are now being developed and will continue on this course, making the cells more efficient.

In Figure 3-1 the distribution of primary energy consumption for the production of materials and manufacturing of a first generation cell and system is illustrated. The dataset used in Figure 3-1 is based on a planar 1 kW SOFC from Karakoussis, 2001 [18] which can be considered as the first estimate of the likely environmental burdens connected to SOFCs. For this type of fuel cell the main part of the energy consumption is connected to production of materials. The production of chromium alloy used in the interconnecter and the production of steel used for heat exchangers, air and fuel supply etc. are the two most important factors in the production stage of this fuel cells life cycle.

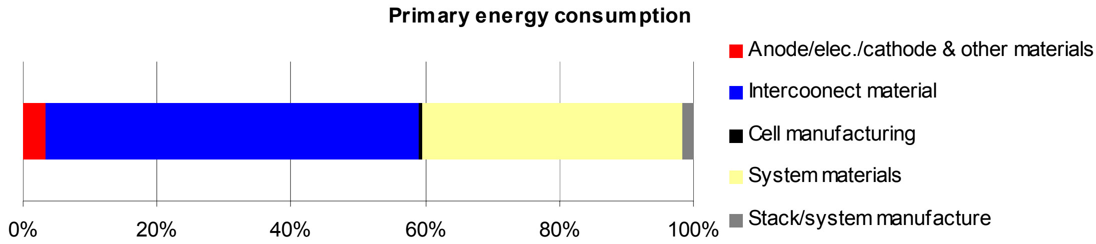

Figure 7-6: Distribution of primary energy for materials and manufacture of cell and system forming a fuel cell. The data is based on a 1 kW planer SOFC.

When the cells develop towards the third generation cells the relative contribution from the anode/electrolyte/cathode will diminish as these parts will become thinner and be supported by the interconnector. The interconnector may also become thinner as the cells develop, thus the system surrounding the cells themselves will become more and more important. The energy consumption to manufacture of the anode, cathode and electrolyte has been assessed using the energy consumption for aluminium production pr. mass in the cell analysed here. At this time, no exact data about the production of these materials in the cell itself have been acquired because of commercial confidentiality. Doubling the energy usage for manufacturing the anode, cathode and electrolyte has proved only to increase the total energy requirement for materials and manufacturing by 1.6 per cent. This is due to the interconnector made from chromium-alloy and the steel for the system which by far have the largest energy consumption in the cells themselves [18].

The production of the anode, cathode and electrolyte is not likely to be connected with larger energy consumption in the future and only contribute marginally to the total energy consumption in the production of the fuel cells. In addition to the cells, the system surrounding the cells is also connected to energy consumption. The system constitutes for approximately 40 percent of the energy consumption in this cell and also here the material production has a significant contribution.

The processes used in Karakoussis, 2001 are not optimised for mass production. As an example, the anode and cathodes are not co-sintered, thus increasing the energy demand in the data used here. Furthermore, no recycling of the materials in the system has been assumed, which can prove important for lowering the energy consumption for the production of materials for this fuel cell.

The power density of this fuel cell is 0.2 W/cm2 and it has an operating temperature of 900°C. The power density of the fuel cell, i.e. the capacity of the individual cell pr. cm^2, is rather important pr. capacity for the amount of material and energy used for producing a fuel cell. The power density is expected to exceed 0.5 W/cm^2 [10], which means that the energy consumption for producing a 1 kW fuel cell would decrease 40 percent. At this point in time 0.48 W/cm^2 has been performed in electrolyte-supported cells, and experimental second generation cells have performed 0.8 W/cm^2 [10]. Third generation interconnector metal-supported cells are still on the experimental stage. However, these are expected to increase the power densities even more. The running temperature is lowered to 550-650°C as oppose to 900-1.000°C in the first generation cells. This will lower the internal resistance. The power density will increase from the first generation cell analysed here and subsequently the overall energy consumption for producing 1 kW SOFC will decrease.

In Figure 7-7 the energy consumption pr. kW capacity for producing the SOFCs and traditional power producing units is illustrated. Two SOFCs is illustrated. One with a power density of 0.2 W/cm^2 and another SOFC, where the same data are used, but is scaled for an improved power density of 0.5 W/cm^2. The SOFCs are compared to the primary energy consumption for the production of a large coal fired power plant and for three sizes of gas turbine power plants, all of which represent today's technologies. For these power plants existing data from the EcoInvent database has been used. The EcoInvent database is one of the most comprehensive and up-to-date life cycle inventory databases available. The 2.500 processes, products, and services in the database are applicable in a European context [19-22]. This database contains data gathered in 2004 for processes, products, and services in the year 2000 and was constructed from several Swiss databases covering both data for Switzerland and for Europe.

The primary energy consumption for SOFC in the production stage is already more efficient than large coal fired power plants as power density higher than 0.5 W/cm^2 has been achieved. The lifespan however is still a problem and require further development. The coal fired power

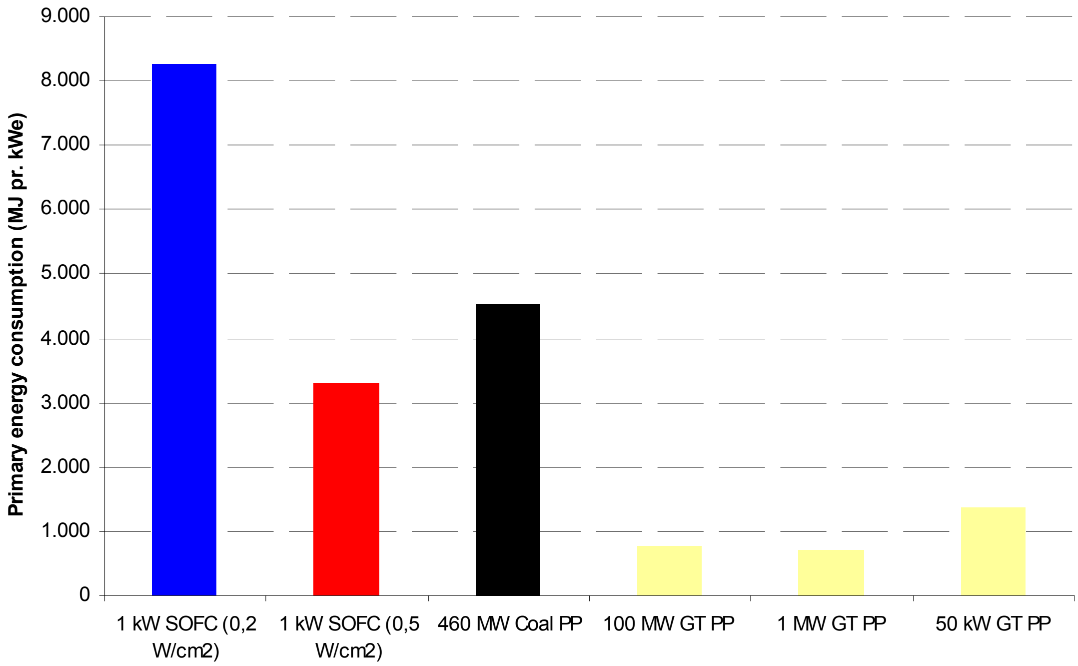

Figure 7-8: Primary energy consumption connected to the production of power producing unit pr. kWe.

plants are connected to large energy consumption pr. kW because of large amounts of steel. The gas turbines are still less energy consuming to produce than SOFCs. The SOFC would have to reach a power density of 1 W/cm^2 and reuse at least one third of the interconnector and system material to be comparable to gas turbines in the production stage.

The most important part of traditional power producing environmental impact is in the operation of the plant. These environmental impacts are global warming, acidification, smog and eutrophication. For fuel cells the main part of acidification, smog and eutrophication is likely to be in the manufacturing stage of the fuel cell [18]. The main part of the contribution to global warming is in the operation phase if based on fossil fuels. If the operation of the fuel cell is based on biofuels the main contribution will also be in the manufacturing stage.

The environmental impacts in the operation of the SOFC are a lot smaller than for traditional power plants. The impacts in the manufacture and materials for the fuel cell are relatively more important, compared to traditional combustion technology because the emissions in the operation phase are smaller in the fuel cell. In Figure 7-9 the manufacture of a fuel cell is compared to other power plants, and it is evident, that the SOFC is already close to other technologies. When taking the manufacture and operation of the SOFC into consideration, the environmental impacts can potentially be reduced significantly when the cells are developed enough to replace other traditional combustion technologies.

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Appendix VIII

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Integrated transport and renewable energy systems

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Abstract

No single technology can solve the problem of ever increasing CO_2 emissions from transport. Here, a coherent effort to integrate transport into energy planning is proposed, using multiple means promoting sustainable transport. It is concluded that a 100 per cent renewable energy transport system is possible but is connected to significant challenges in the path towards it. Biomass is a limited resource and it is important to avoid effecting the production of food. The integration of the transport with the energy system is crucial as is a multi-pronged strategy. Short term solutions have to consider the long term goal. In a short term proposal for 2030 it is concluded that it is possible both to reduce CO_2 emissions substantially and, at the same time, gain economic benefits. Biofuels are not able to solve the problems within the transport sector but play an important role in combination with other technologies.

Keywords: Sustainable mobility; Renewable energy system; Biofuel; Bioethanol; Energy system analysis

1. Introduction

The global focus on the resource consumptions of transport is increasing these years due to two main factors. First, when considering renewable energy and CO_2 emissions, electricity and heating have traditionally been the only focus. As more and more countries have implemented changes in these sectors, the focus on transport has been intensified. Secondly, transport gains increasing international attention due to its large oil dependency of approximately 95 per cent globally. In almost all regions worldwide, the oil demand is increasing and the transport sector's share of the total oil demand is increasing even faster, with a share of approximately 50 per cent at the moment (IEA, 2004). This, in combination with other international geopolitical tensions, has led to substantially increasing oil prices over the last years, with prices above US$50 a barrel since January 2005 and recently above 100 US$ a barrel. In Denmark, the above-mentioned issues are even more evident. Danish energy policies have been successful within electricity and heating where political focus has produced actions and initiatives, i.e. the CO_2 emissions have been declining and the fraction of oil is low in these sectors (Lund, 2000). In the transport sector, however, this is not the case.

The IPCC (Intergovernmental Panel on Climate Change) report from 2007 has increased the focus on renewable energy. In 2003, the European Union was 98 per cent dependent on oil for transport. Recently, the EU countries agreed that 20–30 per cent of their primary energy supply (PES) shall be covered by renewable energy in 2020. 10 per cent of the fuels for transport must be biofuels in 2020. The directive on biofuels from 2003 has set specific targets for the transport sector in the EU member countries (EC, 2003). However, the target of 2 per cent biofuels in 2005 was not reached. In a European Commission strategy on biofuels from 2006, emphasis is put on second generation biofuel production for the substitution of oil products (Commission of the European Communities, 2006). Worldwide, the focus on biofuels has increased recent years. However, biofuels alone will not be able to solve the problems of the transport sector. The biomass resource is limited.

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Furthermore, the problems of blind promotion of biofuels are documented by increasing food prices worldwide. It is, therefore, crucial to promote efforts involving other technologies, nationally as well internationally. Schemes should ensure independency and that energy crops are produced sustainability.

In national energy plans, transport has historically been ignored. Focus is on savings and improved efficiency within electricity and heating. This has also been the case of Danish Energy Plans (Lund, 2000). However, in January 2007, the Danish government suggested a share of 30 per cent renewable energy in 2025 and 10 per cent biofuels in 2020. Other countries have also adapted efforts to promote biofuels in recent years.

Denmark has managed to stabilise PES, which is the same as before the first oil crises in the 70s. The share of oil is much smaller today and 20 per cent of the electricity is wind power. 15 per cent of PES is from renewable energy including biomass and waste. Moreover, energy savings and efficiency improvement have constituted an important part of the policy leading to that 50 per cent of the electricity production originates from CHP (Combined Heat and Power). This has only been possible due to an active energy policy (Lund, 2000).

In the same period, the quantity of oil for transport in Denmark has been steadily increasing, since the active energy policy has traditionally excluded transport. The energy consumption of transport has risen by 60 per cent from 135 PJ in 1972 to 216 PJ in 2005. It is expected to be 249 PJ in 2030 if no new policies are implemented. This development is symptomatic of the lack of focus on transport. While the consumption and production of electricity and heat have been part of policy-making, the increasing fuel consumption in the transport sector has swallowed part of the efficiency gains. In Fig. 1, PES and the transport part of the energy consumption are illustrated for 1972–2005 and for a reference scenario for 2030. If no further actions are taken the path to a sustainable development will be harder and harder to find.

If the aim is to increase the share of renewable energy in Denmark as such, the transport sector is one of the most important sectors to include in combination with other flexible technologies for energy systems (Blarke and Lund, in press; Clark and Rifkin, 2006; Hvelplund, 2006; Lund, 2000; Mathiesen and Lund, 2005; Salgi and Lund, 2008; Sørensen et al., 2004). In other sectors, measures have already been taken to reach this aim. In most analyses of the implementation of transport technologies, though, the various technologies—such as bioethanol, battery electric vehicles, hybrid vehicles, hydrogen vehicles or public transport—are investigated individually. A narrow focus on one technology is not sufficient, as no single technology can point the way to a sustainable development of the transport sector.

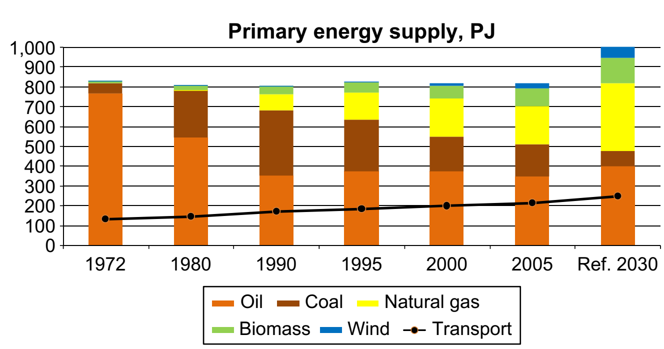

Fig. 1. The Danish primary energy supply and fuel supply for transport from 1972 to 2005 and the reference scenario for 2030.

In the Danish energy system, coherent studies of electrical, battery, biomass and fuel cell technologies show that the integration of transport technologies into the energy system can give economic benefits of the combined system and decrease fuel consumption and CO_2 emissions. This integration also increases the energy system's ability to integrate fluctuating renewable energy sources such as wind power. (Lund and Münster, 2006b).

The design of 100 per cent renewable energy systems has to meet especially two major challenges. One challenge is to integrate a high share of intermittent resources into the energy system, especially the electricity supply (Lund, 2003, 2005, 2006; Lund and Clark, 2002; Lund and Mathiesen, 2007; Lund and Münster, 2003, 2006a; Lund and Ostergaard, 2000; Moller, 2006; Ostergaard, 2003). The other is to include transportation (Lund and Münster, 2006b). In this paper proposals are made to help meet both challenges.

Transport's energy consumption must be analysed with the energy system surrounding it and a multi-pronged proposal is necessary in order to achieve a sufficient impact. When integrating transport with renewable energy systems, only coherent analyses of the energy system can reveal whether the measures to increase the renewable energy share of the transport sector are successful. This is the focus of the analyses in this paper. An energy system is proposed for 2030 with 50 per cent renewable energy and a 100 per cent renewable energy system is proposed for 2050.

2. Methodology

In October 2006, the Danish Prime minister announced that the long-term target for Denmark is 100 per cent independence of fossil fuels and nuclear power. In December 2006, the Danish Association of Engineers (IDA) proposed a plan to achieve such targets in 2050. This paper is based on the results of the IDA Energy Plan 2030. This Energy Plan was the result of the "Energy Year 2006" project, in which 1600 participants in more than 40 seminars discussed and designed a future energy system in Denmark. The framework of these efforts is based on three overall targets:

- To maintain security of energy supply
- To cut CO_2 emissions by 50 per cent by year 2030 compared to the 1990 level
- To create employment and to raise export in the energy industry by a factor 4

The process of designing a future sustainable energy system involved both a creative phase with inputs from a number of experts, and a detailed technical and economic analysis phase. The detailed energy system analysis and the feasibility studies of the overall energy plan were carried out by researchers at Aalborg University, using the energy system analysis model EnergyPLAN (Lund, 2007). In the technical and economic analysis phase, feed-back on each individual proposal was given. In a forward and back process, each proposal was assessed for a coherent energy system in the IDA Energy Plan. This process made it possible to combine the best expert knowledge with an evaluation of the ability of each proposal to fit into the overall system. Furthermore, it enabled the formulation of an energy system proposal which is technically innovative, energy-efficient in terms of supply and economically feasible Lund and Mathiesen (2007).

The seminars forming the inputs were divided into seven themes which led to proposals on how each theme could contribute to the three overall targets. One of these themes was transport and mobility. The contributions from the themes involved energy demand side management and energy efficiency within households, industry and transportation. Improved energy conversion technologies with high temperature fuel cells such as SOFCs (Solid oxide fuel cells) and renewable energy sources such as photo voltaic, wind and wave power were included. All proposals were described in relation the 2030 ‘‘business as usual’’ reference from the Danish Energy Authority (DEA) (Danish Ministry of Transport and Energy, 2005). These descriptions include technical consequences as well as investment and operation and maintenance costs (Lund and Mathiesen, 2006).

The results are detailed energy system designs and energy balances for two energy target years. For 2050, a 100 per cent renewable energy system is proposed and analysed technically. For 2030, a 50 per cent renewable energy system is proposed, emphasising the first important steps on the way. For the first step until 2030, the results include detailed economic feasibility studies and electricity exchange analyses.

This paper presents the methodology and results of a multipronged proposal for integrating transport in a 100 per cent renewable energy system.

2.1. Analysis methodology

In a parallel process, all proposals were analysed technically in an overall energy system analysis by use of the computer model EnergyPLAN (Lund, 2007). The model enables the analysis of annual energy supply and demand in hour by hour calculations of the system. Its focus is regulation strategies for the integration of large quantities of intermittent renewable energy sources and CHP. In the model, it is possible to conduct detailed technical energy system analysis as well as economic feasibility studies and exchange analyses on international electricity markets. In the process of analysing the IDA Energy Plan, the model was improved and expanded to version 7.0. In particular, the analyses of different transport technologies and elements of the economic analyses were improved.

The DEAs’ ‘‘business as usual’’ reference for the Danish energy system of 2030 was re-calculated by use of the EnergyPLAN model. Consequently, a common understanding of the reference was established. Subsequent to the forward and back process, all proposals were simulated technically in the model and more proposals were made, improving the energy system imbalances initially caused by the proposals. Following this, the economic feasibility of the energy system was assessed. In this analysis, all production units run on the basis of a business-economic optimisation, i.e. including taxes and prices on the international electricity market. On the basis of the analysis, flexible energy systems were designed with good abilities to balance the electricity supply and demand and to exchange electricity on the international markets.

The economic evaluation of the consequences for Danish society does not include taxes; however when plants sell to the markets, taxes are included to simulate the existing market conditions. It is based on assumed fuel costs equal to an oil price of \$68/barrel with sensitivity analysis of \$40 and \$96/barrel (Lund and Mathiesen, 2006). The investment and operation costs are based on Danish technology data (Energistyrelsen, Elkraft System and eltra, 2005), if available, and if not, based on the input from the involved experts. An interest rate of 3 per cent is used in the analysis with a sensitivity analysis of 6 per cent. The environmental costs are not included, apart from CO_2 trade prices of €20/ton with sensitivity analysis of €40/ton.

Each individual proposal was analysed technically and a feasibility study was conducted. Since many of the proposals are not independent in nature, such analysis was conducted for each proposal, both in the reference ‘‘business as usual’’ system as well as in the alternative system. In this paper, the proposals of transport and mobility are described thoroughly and the economic consequences of the transport proposals are presented. The technical energy systems analyses and the exchange analysis on international electricity markets are presented in Lund and Mathiesen (2007).

2.2. Implementation of proposal for a sustainable transport development

In the IDA Energy Plan, a wide range of measures has been proposed and analysed. The measures are different from other suggestions related to transport policy because the plan involves a wide range of technologies and includes both the demand and supply side. Also, it differs from other analyses as its measures have been analysed both in the context of the surrounding energy system and in relation to economics. The following proposals for Denmark are part of the transport theme:

- Passenger transport demand in vehicles, trains and bicycles is stabilised at the 2004 level in 2030.
- The rate of increase in passenger transport demand for air transport is limited to 30 per cent instead of 50 per cent in the period from 2004 to 2030.
- 20 per cent road transport is transferred to trains, ships and bicycles in 2030:

- 5 per cent of goods transport is transferred from roads to trains and 5 per cent to ships
- 5 per cent of passenger transport is transferred to trains and 5 per cent to bicycles.

– 30 per cent more energy efficiency in the transport sector compared to the reference situation in 2030 with stable passenger transport at the 2004 level and with a lower increase in air transport.
– 20 per cent biofuels and 20 per cent battery electric vehicles in road transport.

Initiatives within all means of transport have to be taken in order to stabilise the total passenger transport demand and achieve the transfers between types of transport and a more efficient transport sector mentioned above. In the sections below, the proposals are operationalised by means of the following considerations and are implemented in steps. The consequences of each proposal and step are listed in Table 1.

2.2.1. Constant passenger transport (step 1)

The total passenger transport demand in vehicles and trains is constant from 2004 to 2030. When implemented in the IDA Energy Plan, passenger transport is considered to be petrol-based road transport and the total train transport in 2004. In comparison with the reference, road passenger transport is reduced by 13 per cent in 2030. In train transport, the stabilisation at the 2004 level prevents train passenger transport from falling as projected. The economic costs of retaining the needs for passenger transport at the 2004 level are regarded as neutral, but require the restructuring of taxes and levies. With revenue-neutral restructuring of taxes from taxation of vehicle purchasing to a kilometre levy the passenger transport in vehicles can be reduced by up to 15 per cent. With this measure, passenger transport is kept at a constant in 2030 at the level of 2004 (Lund and Mathiesen, 2006).

2.2.2. No measures on the development of goods transport (step 1)

There is virtually no transport of goods by train in the reference, so train transport is considered to be passenger transport. Regarding the road and sea transport of goods, the rate of increase is retained assuming that all diesel-based vehicle and ship transport is related to goods.

2.2.3. Reduced air transport increase (step 1)

The fuel consumption for international and domestic aviation rises by 50 per cent from 2004 to 2030 in the DEA reference. This increase is limited to 30 per cent in this proposal. To achieve the reduced rate of increase in aviation, international policies are required. Fuels for air transport are levy-free because of international conventions as opposed to fuels for vehicles and trains. Putting levy on fuels for aviation is an example that could guarantee a fair competition between the different types of transport and limit the growth in air transport. Another example of an international measure is to implement levy on aviation for the economic costs connected to global warming, i.e. on CO_2 emissions and emissions of other substances with a global warming effect. These substances are particles that condense water vapour, ozone and cirrus clouds. In the EU, aviation is expected to increase by 4 per cent annually in the period from 2008 to 2012 if no interventions are implemented. The European Commission has estimated that this increase can be halved (Wit et al., 2005). However, it requires that air transport, like other energy consuming sectors, is integrated into the European CO_2 quota regulation.

Table 1
Fuel consumption in the transport sector and implementation of the proposals in the IDA Energy Plan 2030

Means of transport	2004	% Increase	Ref. 2030	% Reduction	Step 1	Step 2	Step 3	Step 4
	PJ		PJ		PJ	PJ	PJ	PJ
Road	161.17	19	192.22	7	178.70	142.96	131.91	106.34
Diesel	*72.25*	24	*89.78*	0	*89.78*	*71.91*	*71.91*	*59.13*
Petrol	*88.92*	15	*102.44*	13	*88.92*	*71.05*	*56.84*	*22.78*
Bioethanol	*0.00*		*0.00*		*0.00*			*21.27*
Electricity	*0.00*		*0.00*		*0.00*		*3.16*	*3.16*
Railroad	3.82	−6	3.60	10	3.23	5.61	5.61	5.61
Diesel	*2.74*	0	*2.73*	56	*1.21*	*1.21*	*1.21*	*1.21*
Electricity	*1.08*	−19	*0.87*	−132	*2.02*	*4.40*	*4.40*	*4.40*
Domestic, JP4	1.36	48	2.02	12	1.77	1.77	1.77	1.77
Internat., JP4	30.84	48	45.68	12	40.09	40.09	40.09	40.09
Shipping	5.01	−3	4.84	0	4.84	5.73	5.73	5.73
Fuel oil	*1.82*	0	*1.82*	0	*1.82*	*1.82*	*1.82*	*1.82*
Diesel	*3.19*	−5	*3.02*	0	*3.02*	*3.91*	*3.91*	*3.91*
Defence	1.66	0	1.66	0	1.66	1.66	1.66	1.66
Bicycle	0.00	–	0.00	–	0.00	0.00	0.00	0.00
Sum	203.87	–	250.03	8	230.30	197.83	186.78	161.21

Italic values represent sub-values.

The increase in the international air transport from Denmark has been 2 per cent annually since 1990. In the DEAs reference for 2030, the annual growth in the international air transport is expected to be 1.5 per cent. A more moderate increase in air transport implicates that the annual increase is reduced to 1 per cent. It is estimated that this can be achieved by implementing a separate trading scheme within aviation for CO_2 emissions and the other mentioned substances that have a global warming effect. For every unit of global warming effect of CO_2 that the plane emits, the other substances have between two and five time's units of global warming effects. The economic costs of the limited rate of increase in aviation are estimated to be revenue-neutral.

2.2.4. Passenger transport to public transport and bicycles (step 2)

The proposal of transferring 20 per cent of road transport to trains, ships and bicycle is calculated on the basis of an environment scenario in a report with future scenarios for transport in Denmark. In this scenario, the focal point is mobility and reductions in CO_2 emissions achieved by transferring road transport to public transport (Nielsen et al., 2006). In total, 5 per cent of the passenger transport on roads is transferred to trains and 5 per cent is transferred to bicycles. The conditions for more bicycles are ideal because Denmark is rather flat. The primary rail track network is electrified and expanded. Also commuter trains, light rail and metros are expanded. The changes in train fuel consumption caused by the electrified primary rail track network are estimated on the basis of specifications of the rail transport from The National Rail Authority (Lund and Mathiesen, 2006). In the analyses here, passenger transport is five times more energy-efficient in trains compared to average vehicles in 2030. Today, this relation is one to three because of the large quantity of diesel trains (Lund and Mathiesen, 2006).

In total, 5 per cent of transport of goods is transferred to trains and 5 per cent to ships. The freight of goods via rail is ten times more energy-efficient compared to heavy vehicle and lorries already today (Lund and Mathiesen, 2006). This relation is used for transferring the freight of goods to rail transport. Sea transport of goods is also ten times more energy-efficient.

In the analyses, both the transport of passengers and of goods is transferred to electric trains. The increased amount of passengers and goods in trains and the electrified primary rail track network entails a reduction in the diesel consumption from 2.74 PJ to 1.21 PJ. The electricity consumption, on the other hand, is increased from 1.08 PJ to 2.02 PJ. Both the consumption of petrol and of diesel is reduced by 17.87 PJ. The use of diesel for shipping is increased by 0.89 PJ.

With the suggested investments, the transfer of, in total, 20 per cent of all road transport can be achieved (Lund and Mathiesen, 2006). The required investments in more and better national and local rail track networks, commuter trains, light rail, metros, upgrading of tracks for higher speed trains, better infrastructure for freight of goods etc. are estimated by the authors of (Nielsen et al., 2006) to be DKK 200 billion (€27 billion). Furthermore, DKK 3 billion is required for investments in bicycle infrastructure and park and ride facilities for bicycles and vehicles. A detailed list of the investments in Danish rail track network is available in (Lund and Mathiesen, 2006; Nielsen et al., 2006). The investments will reduce the journey time between the regions in Denmark significantly.

The lifetime of the investments in public transport is estimated to be 100 years for the course of the tracks. This applies to 50 per cent of the investment. The rest is estimated to have a 30-year lifetime. With a economic interest rate of 3 per cent, the annual depreciation is DKK 8.38 billion (€1.12 billion). In effect, the market share of both public transport and transport of goods via rail is doubled from the level today (Lund and Mathiesen, 2006) which is equal to the transfer of 20 per cent of the road transport in the IDA Energy Plan 2030.

This transfer from vehicles to public transport and goods transport via rail entails less road congestion and less fuel consumption. A conservative estimate of the value of this congestion is used in the analyses here. Already in 2004, the economic costs of congestion in the Copenhagen area alone was estimated to be DKK 5.7 billion (€0.76 billion). The difference in annual costs is thus DKK 2.69 billion (€0.36 billion) which is used in the analyses here as an investment of DKK 53 billion with a lifetime of 30 years.

2.2.5. Transfer of road transport to battery electric vehicles (step 3)

In addition to the proposals above, 20 per cent of the remaining passenger transport is transferred to battery electric vehicles (BEV). Today, the fuel efficiency of the BEV is 75 per cent and the internal combustion engine vehicle efficiency (ICE) is 18 per cent. In 2030, the BEV efficiency will be 90 per cent from grid. If the development of ICE continues, the efficiency will be 20 per cent or 17.9 km/L petrol in 2030, which is an improvement of 15 per cent compared to today (Lund and Mathiesen, 2006). In the calculations, it is assumed that the number of passengers in vehicles is the same as today in 2030 and that only petrol ICE is replaced. If 20 per cent of the passenger transport is transferred, 3.16 PJ electricity is consumed to replace 20 per cent of 71.05 PJ. Please note that if the energy efficiency of an average vehicle is 20 per cent or 17.9 km/L in 2030, then the corresponding energy efficiency of BEV at 90 per cent is 80.7 km/L or 8.1 km/kWh.

The economic costs of BEV are 80 per cent higher than those of ICE. This implies that the lithium battery is not replaced in the 15-year lifetime of the vehicle, but not that there will be a substantial development and streamlining in the production of BEV (Lund and Mathiesen, 2006). The economic costs of an average vehicle are 80,000 DKK. A replacement of 20 per cent of the vehicle fleet will increase the annual economic costs of cars by 16 per cent from the current DKK 13 billion invested in vehicles annually in the reference. Extra annual costs of DKK 2 billion (€0.27 billion) are thus connected to a 20 per cent replacement with BEV. An extra investment of DKK 25.6 billion (€3.41 billion) is related to the replacement with BEV, which is estimated to have a lifetime of 15 years. The charging of vehicles is assumed to be flexible in the periods when the vehicles are parked. These periods are estimated by the use of driving patterns (Lund, 2007), assuming that only 70 per cent of the vehicles are grid-connected.

2.2.6. Better energy efficiency in the transport sector (step 4)

The IDA Energy Plan 2030 proposal of a 30 per cent more efficient transport sector. This is related to the proposals of keeping the level of passenger transport at the 2004 level and introducing a lower rate of increase in air transport, i.e. after implementing step 1. It is achieved partly by transferring road transport to rail and replacing ICE with BEV, i.e. steps 2 and 3. The 231 PJ used in the transport sector has to be reduced to 162 PJ which implicates an improvement of the energy efficiency of road transport based on liquid fuels by 25 per cent to achieve the same passenger transport. The fuel consumption of vehicles using liquid fuels has to be reduced to 106 PJ.

New vehicles in 2005 drove 15.6 km/L on average (Danmark Statistik, 2005). In 2030, vehicles will be 15 per cent more efficient without any additional international measures to improve the energy efficiency, i.e. 17.9 km/L. This is applied as an average in 2030 for ICE. An energy efficiency improvement of 30 per cent in passenger vehicles and heavy vehicles and lorries on liquid fuels could be achieved by transferring petrol vehicles to diesel vehicles, by promoting hybrid vehicles or potentially by promoting fuel cell vehicles. It could also be induced by gradually increasing the international demands efficiency of new vehicles. Here, half of the energy efficiency is covered by diesel vehicles and half by petrol vehicles.

This energy efficiency improvement is principally socioeconomically revenue-neutral. This is partly because ordinary passenger vehicles with an efficiency of 23 km/L can already be purchased which is 30 per cent more efficient than the 17.9 km/L in the reference, and partly because the energy efficiency of heavy vehicles is already being improved. In the analyses here, 1 per cent of the passenger vehicles are replaced with hybrid vehicles and 1 per cent are replaced with fuel cell vehicles, in total 40,000 vehicles. The economic investment costs of hybrid vehicles are approximately 20 per cent higher and, for fuel cell vehicles, 100 per cent higher than average vehicles in 2030 (Lund and Mathiesen, 2006).

Here, the calculations include an extra investment cost of 20 per cent of 20,000 vehicles in 2030, corresponding to approximately DKK 320 million (€43 million). The 20,000 fuel cell vehicles are implemented with extra investment costs of DKK 1.6 billion (€213 million). Both types of vehicles are assumed to have a lifetime of 15 years in 2030. In total, these amount to extra annual investment costs of DKK 160 million (€21 million), corresponding to 1 per cent of the total annual investment in vehicles in the reference.

The consumption of fuels is assumed improved to reach the goal of a total annual consumption of 106 PJ by the means mentioned above. The same relation between petrol and diesel are assumed from step 3 to step 4. The implementation of the improvements mentioned above requires that an average passenger vehicle drives 22.5 km/L in 2030.

2.2.7. Biofuels for road transport (step 4)

The share of bioethanol is 20 per cent of the total fuel consumption of road transport in the IDA Energy Plan. This corresponds to 21.16 PJ bioethanol. Here, this is implemented with 30 per cent vehicles using at least 85 per cent bioethanol. Extra costs of 10 per cent are connected to these vehicles. 30 per cent of the vehicles mainly using bioethanol correspond to approximately 470,000 vehicles, equivalent to DKK 3.74 billion (€0.5 billion). With a lifetime of 15 years, this is an annual investment of DKK 300 million (€40 million) at an interest rate of 3 per cent. This corresponds to approximately 2 per cent of the total annual investment in vehicles in the reference. The remaining bioethanol is utilised in the rest of the vehicle fleet.

The biomass consumption and costs of producing bioethanol are estimated with a 2006 IBUS plant (Integrated Biomass Utilisation System) (Lund and Mathiesen, 2006). The energy input is 2,320 TJ of straw, 36 GWh electricity and 497 TJ of steam/heat. This can be converted into 948 TJ of bioethanol, 1064 TJ of biofuel and 38 tons of animal feed (molasses 70 per cent dry matter). The heating value of the animal feed can be estimated to be equal to 295 TJ of biomass, which, in the calculation here, is related to the utilised amount of biomass for the processes. The plant is placed in the proximity of an existing extraction power plant that uses biomass as supplementary fuel. The plant can produce the steam and heat required at a marginal efficiency of 167 per cent. The biomass needed in the process is calculated as the marginal fuel, equal to 931 TJ biomass subtracting the biomass needed to produce the extra steam/heat, equal to 298 TJ. The net biomass for the process is thus 1,259 TJ to produce 948 TJ of bioethanol, adding an electricity demand of 36 GWh.

The investment costs of this IBUS plant are DKK 590 - million (€79 million) and operation and annual maintenance costs of approximately DKK 30 million (€4 million). The lifetime of the plant is 20 years. In addition to these costs, the costs of enzymes have to be estimated. This is rather complicated as no enzymes are available on the market. Based on estimates from an enzyme producer, the costs are 0.95 DKK/L (€0.13/L) in 2006. In 2030, the costs are estimated to be 0.16 DKK/L. Using the lower heating value of 21 MJ/L equal to DKK 43 million annually in 2006 or approximately DKK 7 million (€0.9 million) in 2030. (Lund and Mathiesen, 2006).

The future plants in 2015–2030 will presumably not produce more bioethanol but plants will be more effective using less heat and electricity and thus involving less investment costs for the same production. It is estimated that 20 per cent less steam/heat and 30 per cent less electricity is required. Also a 15 per cent saving in operations and maintenance is estimated. On the other hand, it cannot be expected that the steam required will be produced at a marginal efficiency of 167 per cent as there will be less condensing power production. The marginal efficiency is thus reduced to 130 per cent, corresponding to condensing power production half the time and boiler production half the time. This is equal to 497 TJ reduced by 20 per cent to 398 TJ steam/heat requiring 305 TJ of fuel. For the production of 21.16 PJ of bioethanol in

2030, this results in 28.56 PJ net biomass required and 0.56 TWh of electricity. In total, the investment costs are DKK 11 billion (€1.47 billion) with a lifetime of 20 years and operation and maintenance costs of 6 per cent. In Table 2, the results of the calculations above are listed.

2.3. Summary of transport and mobility proposals for 2030

In Table 3, step 4 from Table 1 is listed as input data on transport for the analyses conducted in the EnergyPLAN model. The proposals are divided into the types of fuels in the reference and in the IDA Energy Plan. In comparison to Table 1, 35 per cent biomass for bioethanol production has been added, i.e. the description above.

2.4. Inputs for a 100 per cent renewable transport sector

In addition to the initiatives above, further proposals are needed to enable a conversion to a 100 per cent renewable energy system in 2050. Further savings are made and the electricity and heat production is converted into a combination of intermittent renewable energy, heat pumps, electrolysers and biomass processed for high temperature fuel cells. In Lund and Mathiesen (2007) all proposal are listed. The following further proposals are put forward within transport:

- The total passenger and goods transport demand is kept constant at the 2030 level
- 50 per cent of goods transport is transferred to trains
- All remaining use of oil product within the transport sector is converted into electricity, hydrogen and biofuels

In Table 3 the fuel consumption in IDA 2030 is listed. In the proposal for 2050, 50 per cent of the diesel consumption is transferred to trains. The total consumption of fossil fuels is thus reduced from 36.78 TWh to 28.57 TWh and the electricity consumption increases by 0.82 TWh. The remaining oil consumption is parted in three and is replaced by BEV, hydrogen fuel cell vehicles and biofuels. This corresponds to 9.52 TWh oil is replaced by 2.10 TWh electricity, 9.52 TWh hydrogen and 12.86 TWh biomass. In total the fuel consumption for transport is now 20.78 TWh biomass, 9.52 TWh hydrogen and 4.78 TWh electricity with the total electricity consumption for trains increased to 1.80 TWh annually and for BEV 2.98 TWh. The hydrogen is assumed produced in electrolysers.

Table 2
Production and costs of bioethanol using the IBUS concept

	IBUS 2006	IBUS 2015–2030
Straw	2320 TJ	2320 TJ
Biomass (incl. feed)	−1359 TJ	−1359 TJ
Fuels for steam/heat	+298 TJ	+305 TJ
Net biomass	1259 TJ	1266 TJ
Bioethanol	948 TJ	948 TJ
Biomass/ethanol factor	1.30	1.35
Investment costs	590 million DKK	500 million DKK
Operation and maintenance	30 million DKK/year	25 million DKK/year
Enzyme costs	43 million DKK/year	7 million DKK/year
Electricity consumption	36 GWh	25 GWh

Table 3
Fuel consumption of transport

TWh/year	Reference 2030	IDA 2030
JP4 (for aviation)	13.25	11.63
Diesel	27.50	18.82
Petrol	28.46	6.33
Biomass for ethanol	–	7.98
Electricity	0.24	2.10
Sum	69.45	46.85

3. Results

The results of the implementation of a sustainable development within transport and economic analyses of the proposals are presented in four parts below. The results are divided into the results of the 2030 proposal, the 2050 proposal, the socio-economic results and the CO_2 emissions.

3.1. Fifty per cent renewable energy for transport in 2030

The stabilisation of the transport needs is absolutely crucial in a sustainable energy development. This proposal ensures that a large proportion that the dependency of fuels for transport is not increased and thus that the proportion of renewable energy for transport can be larger than otherwise. These initiatives require long-term planning of the urban development. The result is that the fuel for transport is 20 PJ lower and thus less oil or other fuels is needed. The efficiency improvement in the ICE vehicles is also important in this respect as it decreases the fuel dependency by 25 PJ.

The electricity consumption for transport is significantly larger than in the reference energy system. It is increased with 1.84 TWh. Annually the total electricity production from intermittent renewable energy is more than 55 per cent and approximately 40 per cent of the electricity production in CHPs is based on biomass in the proposal for a 2030 energy system. Thus the transport technologies using electricity to a large extent are using renewals. The electricity used for trains uses the main part of the electricity in the day and uses on average less than the renewable energy electricity fractions mentioned above. The BEVs are used for the integration of renewable energy. The charging is flexible and the BEV uses close to 100 per cent renewable energy.

The total biomass consumption in the 2030 system is 180 PJ (50 TWh). The DEA has assessed the potential Danish biomass resource, assuming only residual resources, to be 165 PJ in 2005. This resource can principally be increased substantially by altering the crops grown, also without a drop in the production of food. In total 417 PJ is considered possible (Lund and Mathiesen, 2006). The total consumption of biomass in the 2030 energy system is listed in Fig. 2. Energy crops such as

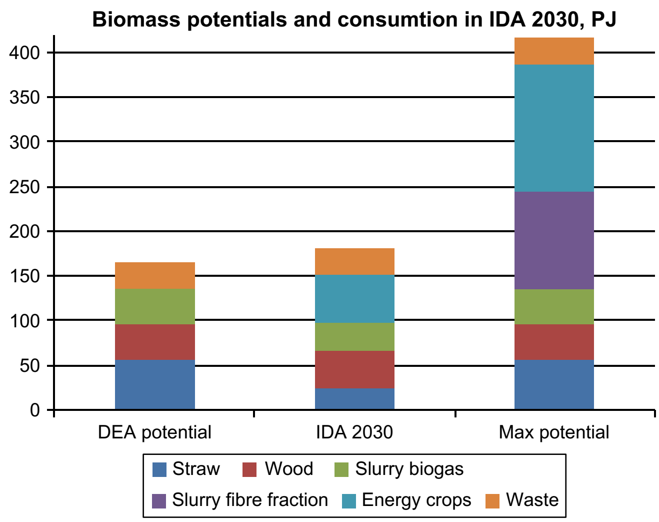

Fig. 2. Biomass potential and consumption in IDA 2030.

maize or beets can be grown without affecting agricultural output. This is possible partly because co-production of liquid biofuels, other biofuels and fodder decreases the use of farmland elsewhere, partly because fallow farmland can be utilised.

The gross biomass consumption for the production of bioethanol is 52 PJ. According to the DEA the potential for the use of straw is approximately 25 PJ considering the agricultural production. Here 27 PJ of the biomass needed for bioethanol is thus produced with energy crops. In the IDA Energy Plan 5 per cent of the farmland is converted into energy crops. The 144 PJ, which is the maximum potential from energy crops illustrated in Fig. 2, requires an altered production in 15 per cent of farmland. Up to 20 per cent is potentially possible without effecting the agricultural production (Lund and Mathiesen, 2006). The net consumption of biomass for bioethanol is 29 PJ. The remaining biomass consumption in Fig. 2 is for industry, electricity and heating. In the proposed energy system for 2030 it has been assured that the biomass resources are available for the transfer to a 50 per cent renewable energy system, including 20 per cent biofuels in the transport sector.

Overall the results of the technical analyses of the energy system integrating the transport sector will enable that approximately 50 per cent of the transport demand to be covered by renewable energy in 2030. In total 20 per cent of all fuels for transport is renewable energy.

3.2. One hundred per cent renewable energy for transport in 2050

The 2050 energy system is entirely based upon renewable energy. In the 2050 the transport sector plays an even more important part in the integration of intermittent renewable energy. Especially the use of electricity for transport is an important part of the energy system as it makes it possible to relocate electricity consumption and simultaneously replaces rather inefficient technologies.

The increase in the proportion of biofuels for transport in the 2050 system requires one or more of the following initiatives. A larger proportion of the potential straw resources has to be utilised, more energy crops has to be grown or technologies has to be developed in order to utilise the fibre fraction in slurry. The gross biomass demand for bioethanol production is 190 PJ. The increased demand of bioethanol is dependent upon the change from natural gas to biomass at fuel cell CHPs.

Although within the transport sector this is technically possible, the exact design of the surrounding 100 per cent renewable energy system requires further research. This total conversion to renewals requires further analysis of the balance between wind and biomass (Lund and Mathiesen, 2007). The one requires rather large investments in wind and electrolyser capacity, the other requires rather large proportions of biomass.

3.3. Economic feasibility studies

The results of the economic feasibility studies include an analysis of the total energy system as well as assessments of each individual proposal for the 50 per cent renewable energy system for 2030. Demands and productions, fuel consumptions and CO_2 emissions are analysed for both the 2030 energy system and for the 100 per cent renewable energy system proposal.

The overall results of the economic feasibility studies show that the energy system proposed for 2030 in the IDA Energy Plan gives a net benefit of DKK 15 billion annually (€2 billion) in comparison with the reference energy system, when considering average fuel and CO_2-qouta prices. When analysing the electricity exchange of the two systems, the results are that the systems are equally able to benefit from the exchange with approximately DKK 500 million annually with varying fuel prices (€67 million). The sensitivity analysis includes doubling the investment costs and doubling the interest

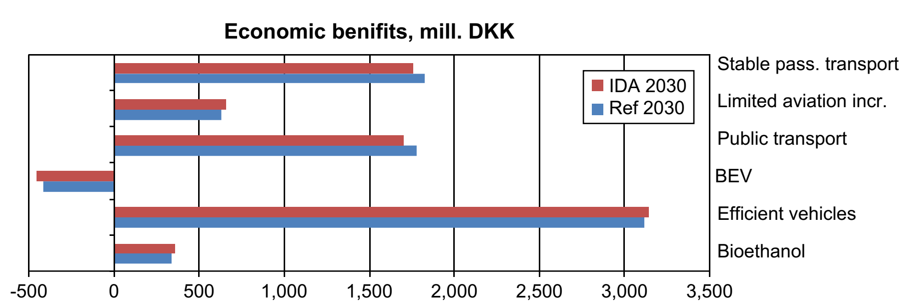

Fig. 3. The economic benefits of the proposals in the 50 per cent renewable energy system and in the DEA reference for 2030.

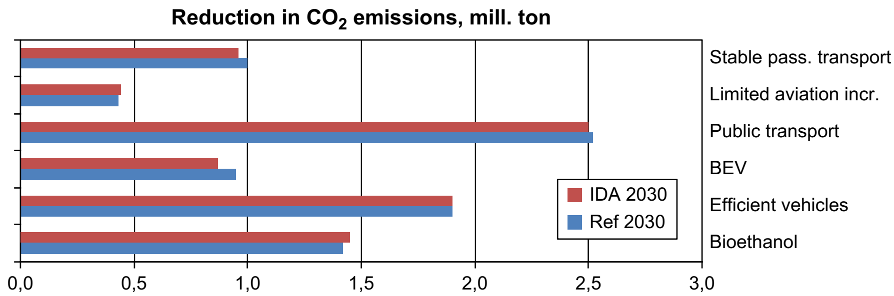

Fig. 4. The reductions in CO_2 emissions of the proposals in the 50 per cent renewable energy system and in the DEA reference for 2030.

rate to 6 per cent. The result is that the costs of the two energy systems balance. The proposals have been analysed individually. Within transport the net benefit of the proposals is approximately DKK 7 billion (€ 0.9 billion), see Fig. 3.

The proposals have been analysed both in the 2030 system proposed in the IDA Energy Plan and in the reference for 2030. The conclusion is that the proposals have a net socio-economic benefit in both systems. The condition for the benefits of the limited growth of road and air transport and the better efficiency in vehicles is that the costs are revenue-neutral. Even if this proposal is connected to some costs, the benefits for society are rather high as is will decrease the dependency of fuels. The benefits of public transport are connected to the fuel savings and the improved mobility in society. The socio-economic benefits connected to mobility may be even higher than estimated in the analyses, as the estimates used for congestion are rather conservative. BEVs are connected to economic costs, but are necessary in the long term for transferring to a 100 per cent renewable energy system. BEVs improves the efficiency in transport and reduces the CO_2 emissions as well as enable integration intermittent renewals. Bioethanol has a net benefit and is crucial as it decreases the oil dependency. The biomass recourse is limited though and has to be combined with other solutions.

3.4. Transport fuel supply and CO_2 emissions

The fuel consumption for transport is reduced significantly. In total the electricity and fuel consumption for transport is reduced from 250 PJ to 161 PJ in 2030. In the 100 renewable energy system the total consumption is 126 PJ. This enables that the transport sector can be based on 100 per cent renewable energy. In Fig. 4 the reductions in CO_2 emissions of each proposal is illustrated for 2030. The total CO_2 emission reduction is approximately 8 million tons, corresponding to approximately half of the reference CO_2 emissions connected to transport.

4. Conclusion

The conversion of the transport sector to 100 per cent renewable energy is possible, but is connecting to an extremely challenging process before reaching such a goal. Locating solutions that integrates transport and energy systems is crucial, as it enables utilising more intermittent renewable energy in both the transport and the electricity and heating sectors. It also enables a more efficient utilisation of the biomass resources without putting strain on the biomass resource. It is only possible to propose a coherent sustainable development within transport if transport is analysed in the context of the surrounding energy system and resource potentials.

The increasing international focus on the transport sector is mainly centred upon biofuels. Biomass is, however, a limited resource that cannot introduce a sustainable path for transport on its own. If utilised without regulation biofuels will effect the food production. In the long-term planning for 100 renewable energy biofuels for transport play an important part in combination with other equally important technologies and proposals.

A 100 per cent renewable energy transport development for Denmark is possible without affecting the production of food if biofuels are combined with other technologies. These include savings and efficiency improvements, intermittent resources, electric trains and vehicles, hydrogen technologies and more. It is, however, connected to large challenges in the process towards this goal, requiring multiple measures and integrating transport with the remaining energy system. These challenges can only be meet by combining planning for this long term goal, in the shorter term solutions. The 50 per cent energy system for 2030 is a shorter term proposal that enables the transport sector to reach the long term goal. The short-term 2030 energy system enables the later process towards 100 per cent renewable energy and has substantial economic benefits.

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Appendix IX

Energy ∎ (∎∎∎∎) ∎∎∎–∎∎∎

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Energy

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Energy system analysis of 100% renewable energy systems—The case of Denmark in years 2030 and 2050

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ABSTRACT

This paper presents the methodology and results of the overall energy system analysis of a 100% renewable energy system. The input for the systems is the result of a project of the Danish Association of Engineers, in which 1600 participants during more than 40 seminars discussed and designed a model for the future energy system of Denmark. The energy system analysis methodology includes hour by hour computer simulations leading to the design of flexible energy systems with the ability to balance the electricity supply and demand. The results are detailed system designs and energy balances for two energy target years: year 2050 with 100% renewable energy from biomass and combinations of wind, wave and solar power; and year 2030 with 50% renewable energy, emphasising the first important steps on the way. The conclusion is that a 100% renewable energy supply based on domestic resources is physically possible, and that the first step towards 2030 is feasible to Danish society. However, Denmark will have to consider to which degree the country shall rely mostly on biomass resources, which will involve the reorganisation of the present use of farming areas, or mostly on wind power, which will involve a large share of hydrogen or similar energy carriers leading to certain inefficiencies in the system design.

1. Introduction

In a recent report from 2007, the United Nations' International Panel of Climate Change, IPCC, emphasises the many indicators on climate change and recommends that the world society respond to the serious problems. In the US, the European Union and China, policies have been formulated with the objective of decreasing CO_2 emissions. And in many nations around the world, policies to raise the share of renewable energy are being initiated as part of the global response to climate change [1–10]. In March 2007, the European Union defined a target of 20% renewable energy for year 2020. In Denmark, a target of 30% renewable energy for year 2025 has just been proposed by the Danish Government.

In Denmark, on the one hand, CO_2 emissions per capita have for many years been among the highest in the world on the other, an active energy policy has already led to remarkable results in the decrease of emissions [11]. For a period of 35 years, Denmark has managed to stabilise the primary energy supply, which is the same today as it was before the first oil crises in the early 70s. Furthermore, the share of oil is much smaller today. 20% of the electricity is supplied by wind power and 15% of the primary energy supply is renewable energy including biomass and waste incineration. Moreover, savings and efficiency measures have constituted an important part of the policy, leading to a situation today in which 50% of the electricity is produced by combined heat and power (CHP).

In his opening speech to the Danish Parliament in October 2006, the Prime Minister announced the long-term target of Denmark: 100% independency of fossil fuels and nuclear power. A few months later, the Danish Association of Engineers (IDA) put forward a proposal on how and when to achieve such targets. This proposal was the result of the "Energy Year 2006", in which 1600 participants during more than 40 seminars discussed and designed a model for the future energy system of Denmark, putting emphasis on energy efficiency, CO_2 reduction, and industrial development. The proposal was presented as the IDA Energy Plan 2030 (see Fig. 1).

The design of 100% renewable energy systems involves at least three major technological changes [12]: energy savings on the demand side [13,14], efficiency improvements in the energy production [15,16], and the replacement of fossil fuels by various sources of renewable energy [17,18]. Consequently, large-scale renewable energy implementation plans must include strategies for integrating renewable sources in coherent energy systems influenced by energy savings and efficiency measures [19–26].

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Fig. 1. The Danish association of Engineers' IDA Energy Plan 2030 discussion.

The design of 100% renewable energy systems has to meet especially two major challenges. One challenge is to integrate a high share of intermittent resources into the energy system, especially the electricity supply [27–34]. The other is to include the transportation sector in the strategies [35].

This paper presents the methodology and results of the overall energy system analysis of a 100% renewable energy system. The methodology includes hour by hour computer simulations leading to the design of flexible energy systems with the ability to balance the electricity supply and demand and to exchange electricity productions on the international electricity markets.

The results are detailed system designs and energy balances for two energy target years: year 2050 with 100% renewable energy from biomass and combinations of wind, wave and solar power; and year 2030 with 50% renewable energy, emphasising the first important steps on the way. For the first step until 2030, the results include detailed socio-economic feasibility studies, electricity market trade calculations, and sensitivity analyses.

2. Methodology

The methodology applied to the design of a future sustainable energy system in Denmark was the combination of a creative phase involving the inputs of a number of experts and a detailed analytical phase involving the technical and economic analyses of the overall system and feed-back on each individual proposal. In a forward and back process, each proposal was formed in such a way that it combined the best of the detailed expert knowledge with the ability of the proposal to fit well into the overall system, both in terms of technical innovation, efficient energy supply, and socio-economic feasibility.

2.1. The creative innovation process of IDA Energy year 2006

First, the IDA declared 2006 as the "Energy year" in which the organisation aimed at making specific proposals to advocate an active energy policy in Denmark.

Three targets were formulated for the future Danish energy system year 2030:

- To maintain security of energy supply.
- To cut CO_2 emissions by 50% by year 2030 compared to the 1990 level.
- To create employment and to raise export in the energy industry by a factor 4.

The target of maintaining security of supply refers to the fact that Denmark, at present, is a net exporter of energy due to the production of oil and natural gas in the North Sea. However, the reserves are expected to last for only a few more decades. Consequently, Denmark will soon either have to start importing energy or develop domestic renewable energy alternatives.

Based on such targets, the work was divided into seven themes under which the following three types of seminars was held: firstly, a status and knowledge seminar; secondly, a future scenario seminar, and, finally, a roadmap seminar. The process involved around 40 seminars with more than 1600 participants and resulted in a number of suggestions and proposals on how each theme could contribute to the national targets.

The contributions involved a long list of energy demand side management and efficiency measures within households, industry and transportation, together with a wide range of improved energy conversion technologies and renewable energy sources, putting emphasis on energy efficiency, CO_2 reduction, and industrial development. All such proposals were described in relation to a Danish year 2030 "business as usual" reference (see below). Such description involved technical consequences as well as investment and operation and maintenance costs.

2.2. Analysis methodology

In a parallel process, all proposals were analysed technically in an overall energy system analysis using the computer model

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described below. The energy system analysis was conducted in the following steps:

First, the Danish Energy Authorities' official "business as usual" scenario for year 2030 was re-calculated by use of the EnergyPLAN model, through which it was possible, on the basis of the same inputs, to come to the same conclusions regarding annual energy balances, fuel consumptions, and CO_2 emissions. Consequently, a common understanding of the reference was established.

Next, each of the proposals for year 2030 (mentioned above) was defined as a change of the reference system and a first rough alternative was calculated including all changes. Such a system leads to a number of imbalances both technically as well as economically, and, consequently, proposals of negative feasibility were reconsidered and suitable investments in flexibility were added to the system.

In the model, the operation of the system is based on a business-economic optimisation of each production unit. Such optimisation includes taxes and involves electricity prices on the international electricity market.

The socio-economic consequences for the Danish society do not include taxes. The consequences are based on the following basic assumptions:

- World market fuel costs equal an oil price of 68 \$/barrel (with a sensitivity of 40 and 96 \$/barrel).
- Investment and operation costs are based on official Danish technology data, if available, and, if not, on the input from the "Energy Year" experts.
- An interest real rate of 3% is used (with a sensitivity of 6%).
- Environmental costs are not included in the calculation, apart from CO_2 emission trade prices of 20 EUR/ton (with a sensitivity of 40 EUR/ton).

Each individual proposal was analysed technically and a feasibility study was conducted. Since many of the proposals are not independent in nature, such analysis was conducted for each proposal, both in the reference "business as usual" system as well as in the alternative system. One proposal, e.g. the insulation of houses, may be feasible in the reference but not in the alternative system, if solar thermal is applied to the same houses or improved CHP is also part of the overall strategy.

Consequently, several of the contributions and proposals had to be reconsidered and coordinated with other contributions.

2.3. The EnergyPLAN energy system analysis model

The overall energy system analysis and the feasibility studies of the project were carried out by researchers at Aalborg University using the energy system analysis model EnergyPLAN (see Fig. 2). The model has previously been used in a number of energy system analysis activities, including expert committee work for the Danish Authorities [28] and the design of 100% renewable energy systems [12]. However, during the process of analysing the IDA Energy Plan, the model was improved and expanded into the present version 7.0 in order to include all contributions in the analysis. Especially, the analyses of different transportation technologies were improved. Moreover, the modelling of socio-economic feasibility studies including exchange on international electricity markets was expanded.

The energy system analysis of the EnergyPLAN model includes hour by hour simulations of the future Danish energy supply leading to the design of flexible energy systems with the ability to balance the electricity supply and demand and to exchange electricity productions on the international electricity markets. The methodology also includes the design of suitable feasibility studies of national energy systems under conditions of fluctuating world market oil prices, CO_2 quota trade prices, and electricity market prices.

Inputs include energy demands and renewable resources. For relevant demands such as electricity and district heating and relevant sources such as wind power and solar thermal, the inputs are distributed into hour by hour values using actual distribution from historical demands and productions.

More information on the model can be found in [36,37].

The present version 7.0 of the EnergyPLAN model including input data for the analysis of the IDA Energy Plan and

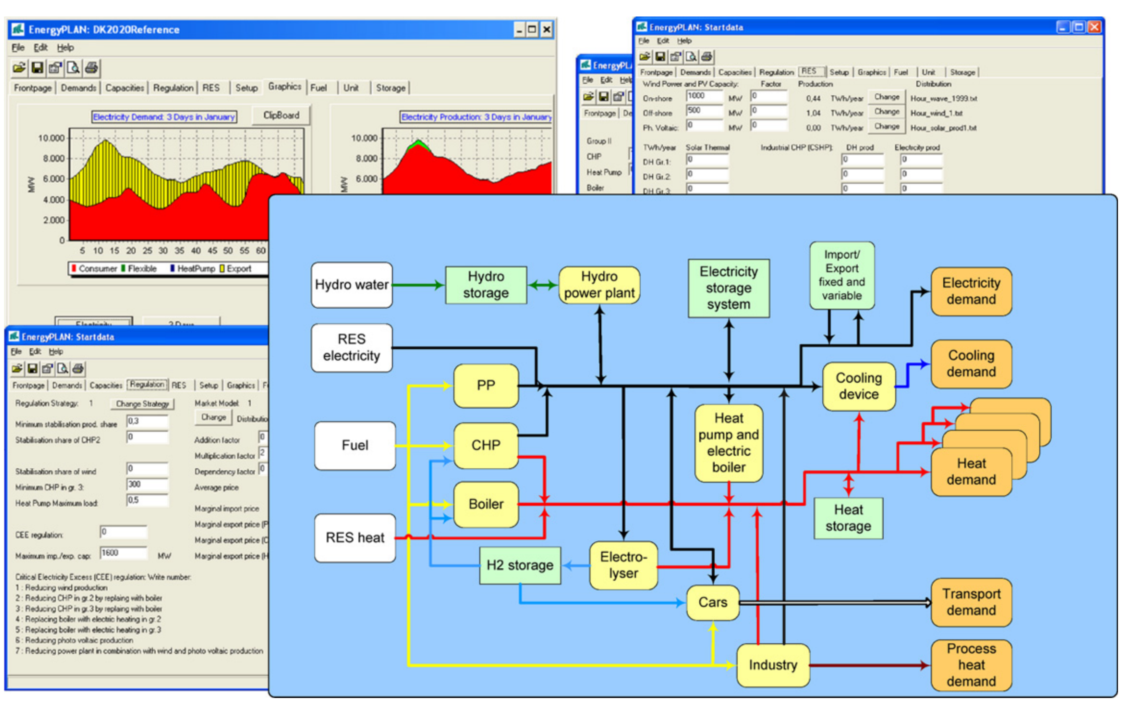

Fig. 2. Flow diagram of energy technologies in the EnergyPLAN computer model.

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documentation of the model can be downloaded freely from the home page www.EnergyPLAN.eu.

2.4. Input proposals to the IDA Energy Plan

The IDA Energy Plan is compared to both the present situation (of year 2004) and to a "business as usual" reference scenario year 2030, in which the gross energy consumption (primary energy supply) is expected to rise from 850 PJ in 2004 to 970 PJ in 2030.

The IDA Energy Plan is defined as a series of changes to the "business as usual" reference in 2030. The proposal is shown as both an alternative for year 2030 and a 100% renewable alternative for year 2050. The different energy systems include everything, also natural gas consumption on the drilling platforms in the North Sea and jet petrol for international air transportation.

After completing the forward and back process of comparison and discussion between experts and overall systems analysis, the proposals for year 2030 ended up being the following:

- Reduce space heating demand in buildings by 50%.
- Reduce fuel consumption in industry by 40%.
- Reduce electricity demand by 50% in private households and by 30% in industry.
- Supply 15% of individual and district heating demand by solar thermal.
- Increase electricity production from industrial CHP by 20%.
- Reduce fuel consumption in the North Sea by 45% through savings, CHP, and efficiency measures.
- Slow down the increase in transportation demand through tax reforms.
- Replace 20% of the road transportation by ships and trains.
- Replace 20% of fuel for road transportation by biofuels and 20% by electricity.
- Replace natural gas boilers by micro fuel cell CHP, equal to 10% of house heating.
- Replace individual house heating by district heating CHP, equal to 10%.
- Replace future power plants constructed after 2015 by fuel cell CHP plants, equal to 35–40% of the total power plants in 2030.
- Increase the total amount of biomass resources (including waste) from the present 90 to 180 PJ in 2030.
- Increase wind power from the present 3000 to 6000 MW in 2030.
- Introduce 500 MW wave power and 700 MW photovoltaic power.
- Introduce 450 MWe large heat pumps in combination with existing CHP systems and flexible electricity demand in order to integrate wind power and CHP better into the energy system.

It should be emphasised that the proposal of adding heat pumps and flexible demand was an outcome of the overall energy systems analysis process, which also pointed out that the potential of flexible production (low minimum production requirements and ability to change production fast without losing efficiency) from solid oxide fuel cell (SOFC) CHP and power plants should be exploited in the best possible way to overcome balancing problems in electricity and district heating supply.

In order to achieve a 100% renewable energy supply, the following additional initiatives prolonging the 2030 energy system were proposed by the steering committee:

- Reduce the heat demand in buildings and district heating systems by another 20%.
- Reduce the fuel demand in industry by another 20%.
- Reduce the electricity demand by another 10%.
- Stabilise the transportation demand at the 2030 level.
- Expand district heating by 10%.
- Convert micro CHP systems from natural gas to hydrogen.
- Replace oil and natural gas boilers by heat pumps and biomass boilers in individual houses.
- Replace 50% of road goods transportation by train.
- Replace the remaining fuel demand for transportation equally by electricity, biofuels and hydrogen.
- Supply 3 TWh of industrial heat production from heat pumps.
- Replace all CHP and power plants by fuel cell-based or biogas or biomass gasification.
- Supply 40% of the heating demand of individual houses by solar thermal.
- Increase wave power from 500 to 1000 MW.
- Increase PV from 700 to 1500 MW.
- The necessary wind power and/or biomasses resources were calculated as the residual resources and had to be increased as described below.

3. Results

The results are divided into the overall socio-economic feasibility study of the year 2030 system, the marginal feasibility of each individual proposal, and the energy balances, fuel consumptions, and CO_2 emissions of both years 2030 and 2050.

3.1. Overall socio-economic feasibility and export potentials

The results of the socio-economic feasibility study and the export potentials are shown in Fig. 3.

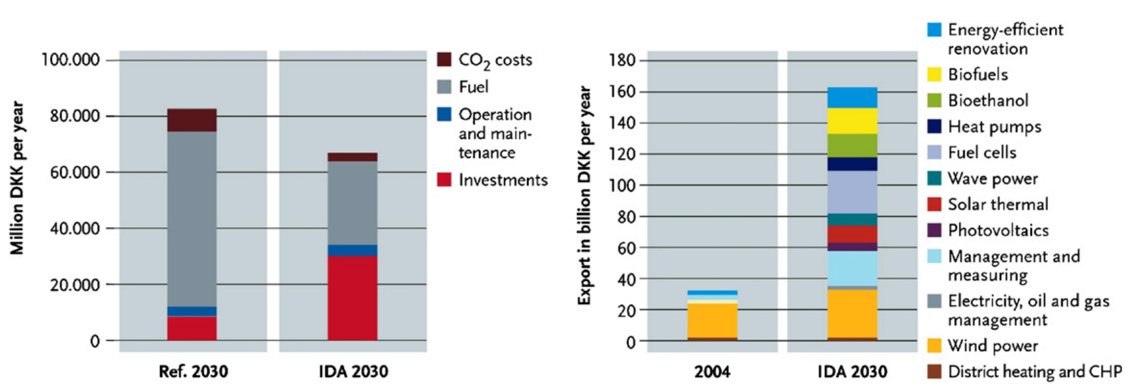

Fig. 3. Economic costs and business potential of the IDA Energy Plan 2030.

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The bars to the left illustrate the economic costs related to Denmark's energy consumption and production in the reference and in the IDA Energy Plan 2030. To the right, the business potential of the IDA Energy Plan 2030 is shown, calculated as expected exports in 2030, compared to 2004.

The socio-economic feasibility is calculated as annual costs including fuel and operation and annual investment costs based on a certain lifetime and interest rate. The feasibility study has been carried out with three different oil prices (as mentioned above) and the IDA Energy Plan 2030 is compared with the

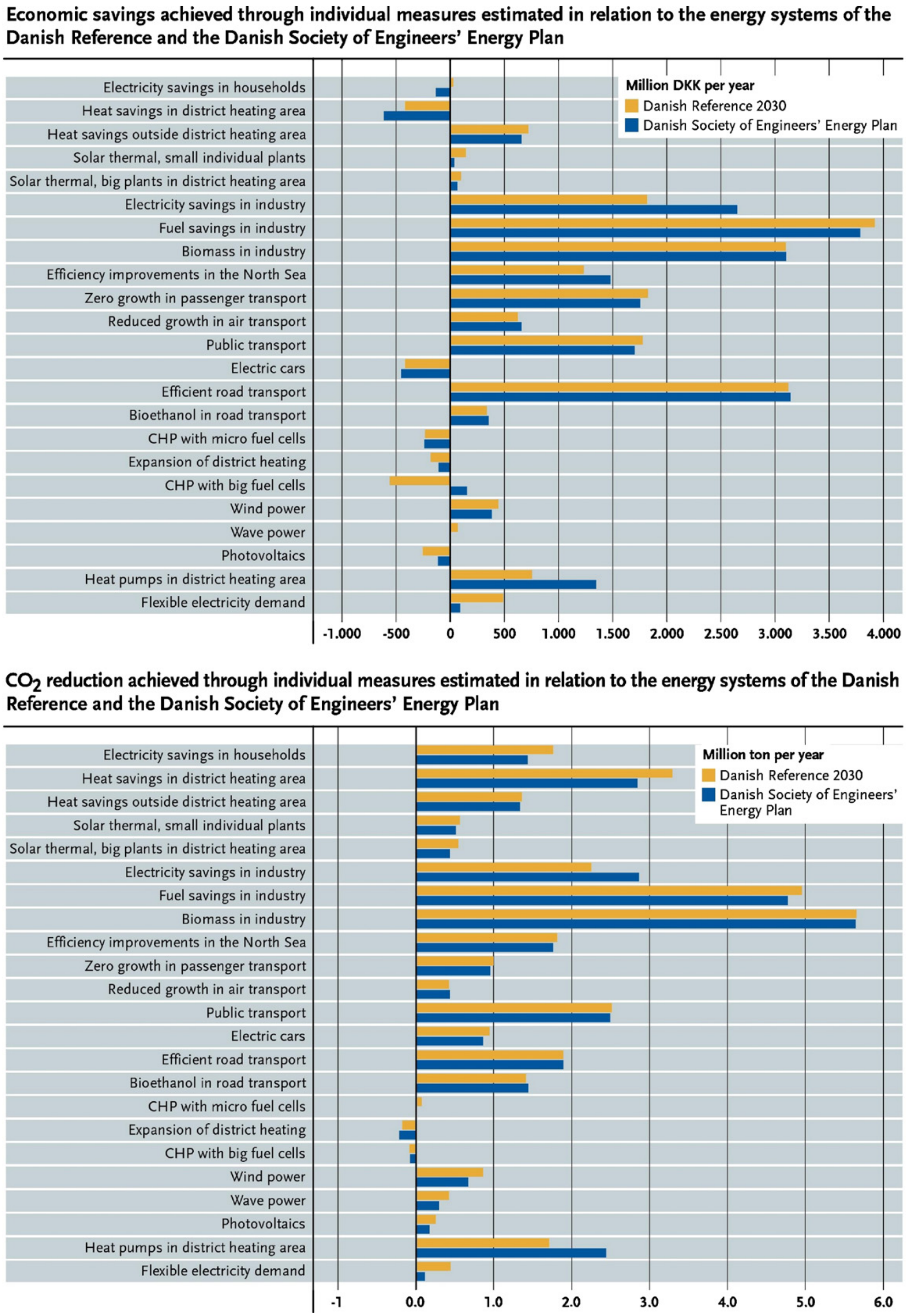

Fig. 4. Feasibility and CO_2 emission reduction of each of the individual proposals.

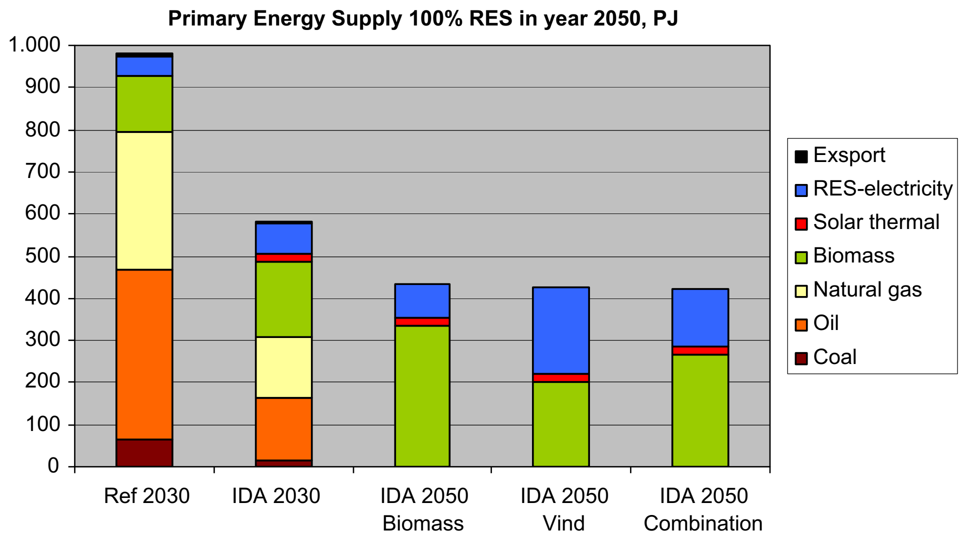

Fig. 5. Primary energy supply for 3 versions of the 100% renewable energy system compared to the reference and the IDA proposal for year 2030.

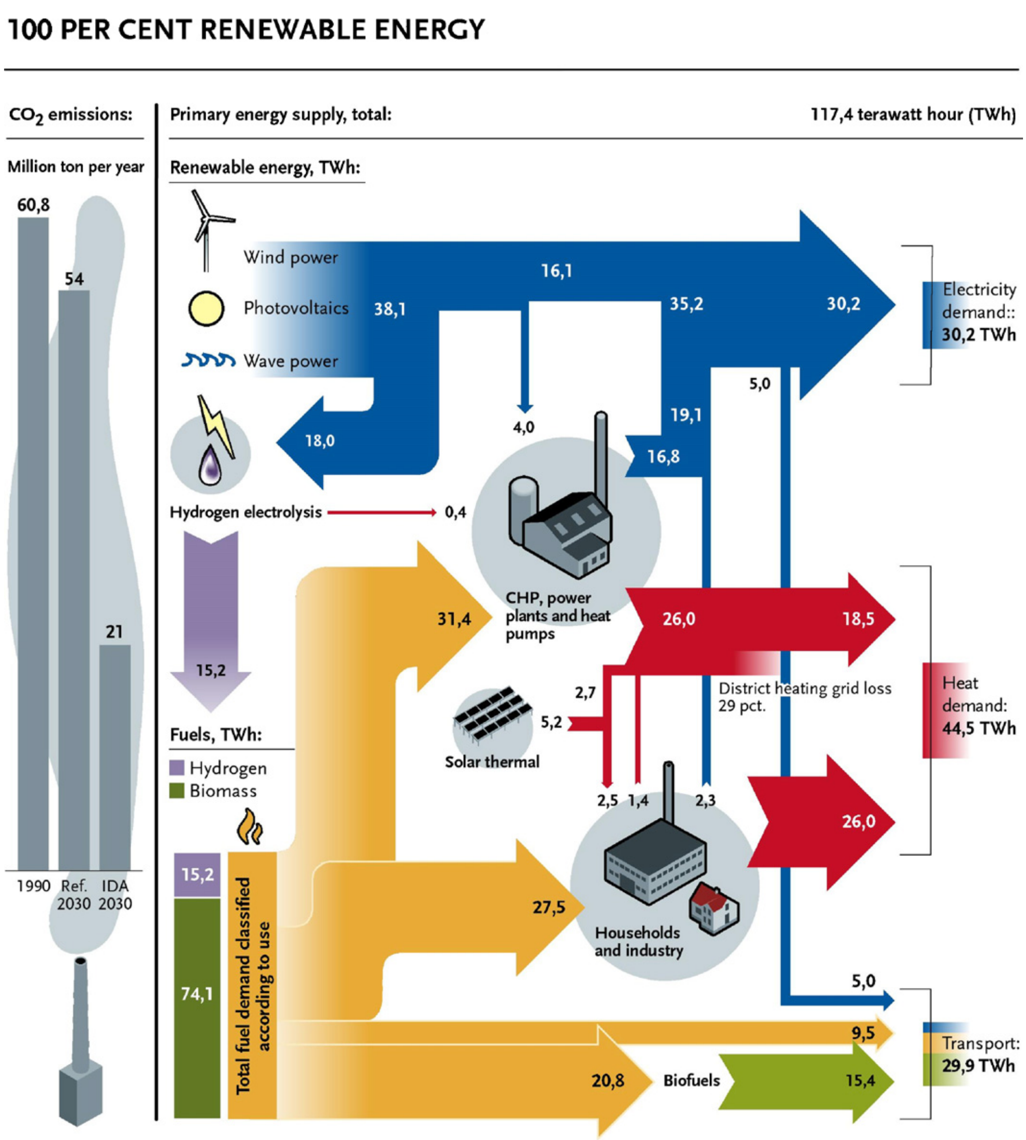

Fig. 6. Flow diagram of the 100% renewable energy system.

reference under the assumption that the average oil price is applicable 40% of the time, while the low and high oil prices are applicable each 30% of the time.

Compared to the reference, the IDA alternative converts fuel costs into investment costs and has lower total annual costs. Such a shift is very sensitive to two factors: One is the interest rate and the other is the estimation of the magnitude of the total investment costs. Consequently, sensitivity analyses have been made: One in which the interest rate has been raised from 3 to 6%, and another in which all investment costs have been raised by 50%. In both cases, the IDA alternative is competitive to the reference.

The export potentials have been estimated on the basis of the Danish development of wind turbine manufacturing and are to be considered a very rough estimate. However, the estimate provides valuable information on both the different relevant technologies and the magnitude of the total potential.

3.2. *Marginal feasibility of each proposal*

The socio-economic feasibility and the CO_2 emissions of each proposal are shown in Fig. 4. All proposals have been evaluated marginally in both the reference system and the alternative system. As can be seen, the forward and back process has led to the identification of proposals with predominantly positive feasibility. However, some proposals with negative feasibility have been included in the overall plan for other reasons. Some have good export potentials. Others are important in order to be able to reach the final target of 100% renewable energy in the next step. Still others have important environmental benefits.

3.3. *100% renewable energy system*

The 100% renewable energy system for year 2050 has been calculated in more than one version.

First, all the proposals mentioned above were simply implemented, which led to a primary energy supply consisting of 19 PJ solar thermal, 23 PJ electricity from renewable energy sources (wind, wave and photovoltaic) and 333 PJ biomass fuels. In such a scenario, wind power is equal to the figure of year 2030, i.e. 6000 MW installed capacity.

However, a figure of 333 PJ of biomass fuels may be too high. According to the latest official estimate, Denmark has approximately 165 PJ of residual biomass resources including waste. Residual resources comprise straw, which is not needed for animal purposes, together with biogas from manure, organic waste and waste from wood industries. However, the potential of biomass fuels from the change of crops is huge. E.g. Denmark grows a lot of wheat, which can be replaced by other crops such as corn, leading to a much higher biomass production while still maintaining the same outputs for food. Such reorganisation of the farming areas together with a few other options may lead to a total biomass fuel potential as high as 400 PJ.

On the basis of the first version of the 100% renewable energy scenario, it was analysed how much the need for biomass fuels would decrease if more wind power was added. If wind power is raised from 6000 to 15,000 MW, then a rise in electricity to 200 PJ will lead to a decrease in biomass fuel consumptions to 200 PJ. It should, however, be emphasised that such replacement leads to a huge demand for hydrogen as an energy carrier, which results in considerable efficiency losses.

The analyses ended up proposing a compromise with 10,000 MW wind power and 270 PJ biomass fuels. All three versions are shown in Fig. 5. The energy flow of the system is illustrated in Fig. 6.

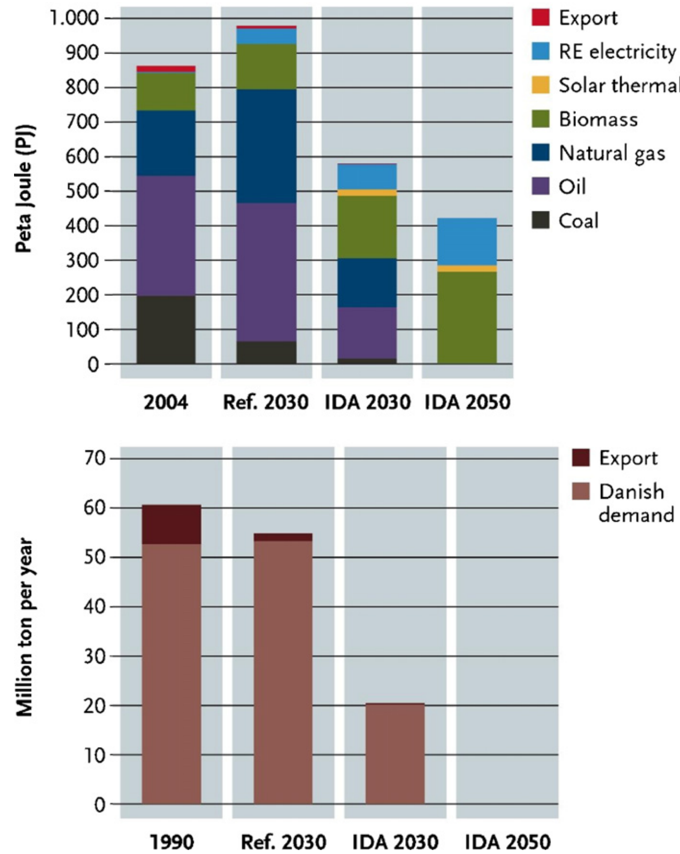

Fig. 7. Primary energy supply and CO_2 emissions. CO_2 emissions are divided into domestic electricity demand and electricity net exports.

3.4. *Primary energy supply and CO_2 emissions*

The primary energy supply and the consequences related to CO_2 emissions are shown in Fig. 7.

The primary energy supply is expected to increase from approximately 800 PJ in 2004 to nearly 1000 PJ in the "business as usual" reference. If the proposed IDA Energy Plan is implemented, the primary energy supply will fall to below 600 PJ and CO_2 emissions will decrease by 60% compared to year 1990.

If the 100% renewable energy system proposed for year 2050 is implemented, the primary energy supply will fall to approximately 400 PJ and the CO_2 emission will, in principle, be equal to zero. However, it should be mentioned that Denmark will still contribute to greenhouse gas emissions from gases other than CO_2. In total, the Danish greenhouse gas emissions will decrease by approximately 80%.

4. Conclusion

From a Danish case point of view, the conclusion is that a 100% renewable energy supply based on domestic resources is physically possible, and that the first step towards 2030 is feasible to Danish society. However, Denmark will have to consider to which degree the country shall rely mostly on biomass resources, which will involve the present use of farming areas, or mostly on wind power, which will involve a large share of hydrogen or similar energy carriers leading to certain inefficiencies in the system design.

From a methodology point of view, the conclusion is that the design of future 100% renewable energy systems is a very complex process. On the one hand, a broad variety of measures must be combined in order to reach the target, and, on the other hand, each individual measure has to be evaluated and coordinated with the new overall system. Here, such a process has been achieved by the combination of a creative phase involving the inputs of a number of experts and a detailed analysis phase with technical and economic analyses of the overall system, giving feed-back on the individual proposals. In a forward and back process, each proposal was formed so that it combined the best of the detailed expert knowledge with the ability of the proposal to fit well into the overall system, both in terms of technical innovation, efficient energy supply and socio-economic feasibility.

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Appendix X

Uncertainties related to the identification of the marginal energy technology in consequential life cycle assessments

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Abstract

In life cycle assessments, the use of consequential LCA methodology is becoming increasingly common. In this paper, current and recommended approaches and practices of identifying marginal electricity and heat technologies for consequential LCAs are challenged. Here, the identification of marginal energy technologies is examined from three angles: The marginal electricity technology is identified in historical and potential future energy systems. The methods of identifying and using marginal electricity and heat technologies in key LCA studies are analysed. Finally, the differences in applying energy system analysis and assuming one marginal technology are illustrated, using waste incineration as a case. It can be recommended to use fundamentally different affected technologies and identify these in several possible and fundamentally different future scenarios; thus assessing their long-term perspectives. If possible, the affected technologies should also be identified based on energy system analyses considering the technical characteristics of the technologies involved. Some results in this paper may be applicable to other affected technologies than energy; however, the general validity is not investigated in this paper.

Keywords: Consequential life cycle inventory analysis, methodology, modelling, waste incineration, energy system analyses

1 Introduction

In recent years, Life Cycle Assessments (LCA) methodologies have developed towards an analysis of environmental consequences of changes. The development started in the late 1990s [1-5] and has led to a distinction between two types of LCA studies: attributional versus consequential. This terminological distinction was formally adopted in 2001 at a workshop on life cycle inventory data (LCI) for electricity [6]. Some regard the attributional LCA approach as rather retrospective in its definition of system boundaries. The aim of the consequential approach is to model the environmental consequences of a change and it is often characterised as prospective, since it has a different definition of system boundaries and considers the elements affected. As pointed out in Ekvall et al (2005) [7], though, both attributional and consequential LCA may be used for decision-making; thus, the attributional methodology is not retrospective in the sense that it concerns the past.

The main purpose of conducting LCA studies is to convey a coherent and holistic support for decision-making affecting the environment [8;9]. In this respect, consequential LCA studies do not require the same kind of data which attributional studies do. Consequential studies involve an analysis of the possible future consequences of decisions made today. While this distinction has led to a new methodological development, the

LCI data as such are still mainly based on historical data, although some efforts are being made to include technological development into LCI data [10].

Consequential LCA is commonly used today and is described thoroughly in Ekvall & Weidema (2004) [11] in terms of system boundaries, allocation and data selection. The methodology often includes the markets affected by decisions and when identifying these markets, the methodology recommends that the analyses are simplified by defining the main affected marginal technology. Hence, it is possible to analyse the environmental consequences of new products. The long-term marginal technology for electricity generation has changed from coal power plants (PP) to natural gas (Ngas) in the Danish and Nordic electricity system [1;12;13]. The question is whether it is possible and sufficient to identify one marginal technology in order to analyse environmental impacts, considering the fact that most LCAs are long term and may affect more than one technology?

2 Methodology

The aim of this paper is to study the uncertainties and simplifications involved in "state-of-the-art" consequential LCA methodology and make recommendations for improvements. The object of study of this paper is electricity and heat production. Electricity production was one of the key drivers of the development of the consequential methodology [1-6].

In order to identify uncertainties in the methodology, three fundamentally different analyses are conducted. The first two analyses focus on capacities, i.e. as recommended in the methodology; whereas the third analysis considers the operation of installed capacities. The methodology is analysed from three angles:

- Application of the consequential LCA methodology at different specific points in time, contemporary and historical, in order to identify the marginal electricity technology
- Review of the specific "state-of-the-art" practice in LCA studies in order to identify the marginal electricity and heat technologies
- Case study of the affected electricity and heat technologies for LCA studies including waste incineration in ten specific energy system analyses

In the first analysis, the consequential methodology is applied to different points in time. The aim is to identify the marginal electricity technology of LCA studies in e.g. 1976 or 1980, and subsequently, elaborate on the actual events that occurred. In this part, projections with possible future marginal technologies presented in recent publications are also examined. Finally, the ability of the methodology to identify the marginal technology under the terms set up in the methodology is evaluated.

In the second analysis, the practice of several recent LCA studies is analysed. Recent studies are chosen in order to enable an examination of studies that follow consequential LCA methodology. In the review of the LCA studies, the type of marginal technologies, the sensitivity analyses, and the arguments used for the choices made are identified. Also the characteristics of the changes in the electricity demand, which represent the main reason for identifying the marginal technology, are examined. In the review, both marginal electricity and heat technologies are included and the importance of the energy supply to the conclusions of the studies is examined.

In the third analysis, energy system analyses are conducted of different uses of waste incineration. This case is chosen because waste is often included in LCA studies either in studies of waste management [14-16] or as part of the product life cycle. It is not the aim to establish new default values for the affected technologies with changes in incineration. The aim of this case study is to analyse different geographical locations of waste incineration and different temporal uses of waste for incineration in different future energy scenarios and thus illustrate the complexity of the system. Here, it is possible to determine whether the current identification of one marginal technology is coherent with the results based on energy system modelling. Please note that only one model is used in these analyses and, like for LCA, different methodologies apply to different energy system analysis tools.

In the next section, the consequential LCA methodology for identifying marginal technologies is described, and in the following sections the three analyses described above are performed. In the last section, the overall conclusions are presented and the recommendations for future LCA studies are given.

3 Identifying marginal technologies

A consequential LCA study is basically concerned with identifying the cause and effect relationship between possible decisions and their environmental impacts. It has a different approach to system boundaries than attributional LCA and because it analyses the markets affected in the life cycle. In order to identify the marginal technologies on a certain market, a series of changes must be identified which can be approximated to only have infinitely small effects. According to the methodology, this precondition makes it possible to simplify the studied changes, which either increase or decrease the production capacity. The marginal technology is identified as the product affected by a decision made. Hence, LCA practitioners can identify the environmental consequences of e.g. changes in electricity demand. [11]

The first step of the assessment is concerned with the temporal scope which, among others, is concerned with the short-term and long-term effects of decisions [1;11]. A short-term study may have a temporal scope of typically 5 years [13]. The long-term study supports decisions which have a longer perspective depending on the lifetime of the item assessed.

Short-term effects are e.g. electricity production and hour-by-hour operation. Long-term effects create short-term effects on the operation as well as effects on the installed capacities.

According to the methodology, the first line of simplification is to simply include either short-term or long-term effects. LCA studies most often support long-term decisions, or decisions made on the basis of short-term LCA decision support contribute to the accumulated trend of the market and have effects on investments made in the long term. This argument enables the second simplification, which suggests that the system dynamics in the operation of the marginal capacities are ignored, and that the long-term marginal technology should simply be used [11]. In the case of electricity, this means that the dynamics of the operation of the energy system can be ignored and that one long-term marginal technology can be identified by comparing the costs of different technologies.

The next step in the methodology is to identify the properties, position and relevant market segment of the products in question. The identification of properties and market segment makes it possible to define the competing products on the markets affected. [11]

The general market trend is important in the third step. If the demand is decreasing at a higher rate than investments in the replacement of the existing capacity, the marginal technology, which is most likely to be phased out, is the technology with the highest short-term costs. With a lower decrease in demand than the replacement rate or with an increase in demand, the new capacity installed is most likely the technology with the lowest long-term costs. It should be noted that, according to the methodology, if the item studied changes the trend of the market it cannot be considered a marginal change. Thus, the LCA should model the environmental consequences by use of other methods, i.e. find other methods to identify the affected technologies.

The marginal technology is among the technologies on the market capable of responding to changes in demand, which is analysed in the fourth step. Since some technologies cannot be adjusted, technical properties exclude them both as short-term and long-term marginal technologies, according to the methodology. Besides technical constraints, natural, political and market-related constraints also exist. These constraints include limits of natural resources, emission limits, quotas, etc. An example of a non-adjustable technology is wind power, in the logic of the methodology. Wind power operation cannot respond to changes in demand, and it has natural constraints as its potential is limited from one region to another; thus, wind cannot be considered the marginal technology neither in short-term nor long-term LCA studies. Another example of constraints is CO_2 quotas. If e.g. the quota system changes the marginal technology may change. Such a change is difficult to model; hence, the methodology recommends that the LCA is simplified in the sense that constraints are treated as fixed entities, i.e. the constraints do not change even in LCA studies intended for long-term decision support. This enables the identification of the marginal technology in the fifth step [11].

In this paper, instead of defining fixed constraints, which are dependent and fixed at the point in time when the analysis is made, we do not exclude any technologies because of contemporary uses of technologies, market conditions or political focuses.

With these methodological considerations about the temporal scope, markets and constraints etc. in mind, we define a series of new terms in order to be able to distinguish between different types of marginal technologies that can be identified. The term "simple marginal technology" covers the technology either able or unable to adjust its operation to the demand on an hour-by-hour basis. The simple marginal technology can be all types of e.g. electricity-producing technologies such as PP and wind power. The simple marginal could also be old-fashioned combined heat and power (CHP), with no heat storage capacity, where the electricity production is totally dependent upon the heat demand. The term "dynamic marginal technology" refers to the technology affected, which is able to adjust its operation to the demand on an hour-by-hour basis, similar to the methodology for identifying marginal technology for consequential LCA taking into account the different constraints described above. The term "complex marginal technology/technologies" refers to the set of technologies able to meet the demand on an hour-by-hour basis, i.e. which takes into account the mix of capacities in the system dynamics using system modelling and changes in demand e.g. night and day. The types of marginal technologies are defined in table 1.

In the next three sections, the methodology described above is examined through three fundamentally different analyses.

Type of marginal technology	Definition
Simple marginal technology	The marginal technology unable and able to adjust operation to meet demand hour-by hour, i.e. one technology out of all potential technologies.
Dynamic marginal technology:	The marginal technology able to adjust operation to meet the demand hour-by-hour, i.e. one technology of a subset of the simple marginal technologies.
Complex marginal technology(ies):	The set of marginal technologies able to meet the demand hour-by-hour found by system modelling, i.e. a set of technologies out of all potential technologies.

Table 1, Definition of three types of affected technologies in consequential LCA

4 The historical and future marginal electricity in the consequential approach

Here, it is analysed how the expected and actual marginal electricity technologies have developed in Denmark. Consequential LCA and the terms defined above are applied to historical and contemporary circumstances in order to evaluate the ability of consequential LCA to identify marginal technologies.

Two key types of data sources are used. The first data set consists of publications describing the long-term development of the Danish energy system, i.e. demands, capacities, costs, etc. The publications include both official governmental energy plans and energy plans from various organisations. These enable the identification of simple and dynamic expected long-term marginal electricity technologies by applying the approach defined above. They include a reference energy system projection and most publications also present plans or policies for changes and a projection of the energy system with these changes. This enables the identification of both a *reference* and a *planned* marginal technology.

The second data set is statistics of historical developments of the energy system, i.e. production, demand, capacities, etc. [17]. With such data, the *actual* marginal technology is identified according to the consequential LCA methodology.

The question is which marginal technology would have been expected, if we made an LCA at any given point in time from 1976 until now? In Table 2, the results of such analyses using publications from 1976 to 2006 are presented. Some may argue that a market for electricity did not exist before 1999, when the short-term trade on the Nordic electricity market (Nord Pool) was introduced for the Nordic electricity market. Before, the Danish PP were consumer-owned, and the main aim was to lower the long-term production costs. This was by no means the case. The terms for investments in new capacity may have been different then, but the players involved under the previous regulation also had incentives to make least-cost long-term investments. Thus, it is possible to identify a marginal technology, according to consequential methodology.

The publications used are made with changing motivations over time including elements like balance of payment, security of supply, employment, export, regional development, environment, etc. Only elements relevant to the consequential approach are included here. All publications refer to economic feasibility studies, which form the basis for the results presented in table 2 and the use of the consequential methodology. The causal relation between increase/decrease in demand, and thus the reference and the planned marginal technologies identified, are subject to the policies proposed in the policy publications. Similarly, the actual marginal technologies identified in statistics are subject to the actual events and to how policies were implemented. It should be noted that a table similar to table 2 could be constructed for marginal heat technologies.

Period / type of publication	Ref. / planned demand	**Ref. marginal tech. simple / dynamic**	Main new capacity planned	**Planned marginal tech. simple / dynamic**	Actual demand / until year	Actual main phased out capacity	**Actual marginal tech. simple / dynamic**
1975-1995 Gov. [18]	Steep / heavy incr.	**Oil PP**	Nuclear PP	**Nuclear PP / coal PP**	Incr. / 1980	Oil PP	**Coal PP**
1975-1995 NGO [19]	Incr. / small incr.	**Oil PP**	Ngas CHP	**Ngas CHP / Ngas PP**			
1981-2000 Gov. [20]	Incr. / small incr.	**Coal PP**	Nuclear PP	**Nuclear PP / coal PP**	Incr. / 1990	Oil PP	**Coal CHP / coal PP**
1981-2000 NGO [21]	Incr. / heavy decr.	**Coal PP**	Ngas CHP	**Coal PP**			
1988-2030 Gov. [22]	Incr. / small incr.	**Coal PP**	Ngas CHP	**Ngas CHP / coal PP**	Small incr. / 2000	Coal PP	**Wind power / (-)**
1988-2005 Gov. [23]	Incr. / small incr.	**Coal PP**	Ngas CHP	**Ngas CHP Ngas PP**			
1996-2030 Gov. [24]	Small incr. / decr.	**Coal CHP / Coal PP**	Biomass CHP	**Biomass CHP / (Hydro power)**			
2003-2017 Gov. [25]	Small incr. / -	**Ngas PP**	-	**-**	Small incr. / 2005	Coal PP	**(Ngas CHP)**
2005-2025 Gov. [26]	Small incr. / -	**Ngas CHP / Ngas CHP**	-	**-**	?	?	**?**
Price level: 1. Low	Small incr. / -	**Wind power / Ngas CHP**	-	**-**			
2. Base 3. High	Small incr. / -	**Wind power / Biomass CHP**	-	**-**			
2004-2030 NGO [27;28]	Small incr. / steep decr.	**Wind power / Biomass CHP**	Wind power	**Coal PP**			

Table 2, Review of simple and dynamic marginal electricity technologies in publications on the Danish energy system from 1976 to 2006. The trend of the electricity demand is identified in both a reference and a planned energy system. This enables the identification of a simple and a dynamic marginal technology in both the reference energy system and the planned energy system. The main new capacity installed may be different from the marginal technology. In order to emphasise this distinction, the main new capacities planned are also listed in the table. Similarly, the actual trend, the actual marginal technologies and the actual main changes in the installed capacity are listed on the basis of Energy Statistics from the Danish Energy Authority [17]. The marginal technologies that could constitute the input to consequential LCA are listed in bold, i.e. the expected reference, the planned and the actual simple and dynamic marginal electricity technologies. The dashes indicate that the publication does not include a planned energy system, and thus only the reference is included.

4.1 Historical marginal electricity technologies

The official Danish energy policy from 1976 [18] concluded that nuclear PP had the lowest long-term costs and the lowest marginal production costs compared to coal/oil PP. The aim of the publication was to promote nuclear PP because the electricity demand was expected to increase steeply and to reduce oil dependency, which was almost 100 % at the time. The policy was to lower the rate of increase in demand from a steep increase to a heavy increase. No comparison was made with Ngas PP or CHP and renewable energy was regarded utopia. In the reference projection, the electricity production from oil PP and coal PP was expected to increase, and the largest increase was expected for oil PP, like in the past. Thus, oil PP can be regarded as both the simple and dynamic marginal technology in the reference. It was recognized that nuclear PP requires other plants able to regulate up and down in combination with an extended use of electric heating. In this planned energy system, nuclear PP is the simple marginal technology and coal PP is the dynamic marginal technology.

An alternative energy policy [19] presented by two organizations in 1976 used the same reference energy system as the official policy publication. The aim was to show that an energy system could be constructed without nuclear PP and this system would be at least as feasible as the one proposed in the official policy. Instead of nuclear PP, a heavy expansion of central and decentralised CHP based on Ngas was proposed as well as larger electricity savings than in the official energy policy. Some regulation of production would take place at CHP plants with heat storage, but extra PP capacity was also needed. The main fuel in the PP was coal; however, the main new capacity installed in the alternative policy was Ngas PP, which is considered the dynamic marginal in accordance with the LCA methodology.

In 1981, the next official energy policy was published [20]. The expected increase in the electricity demand was only half the size of that projected in the first official publication. Since 1976, higher electricity levies had lowered the rate of increase in demand, which had also slowed down the increase in oil dependency. In the long term, though, nuclear PP was still regarded as the technology with the lowest long-term costs. In the years from 1976 to 1981, instead of oil, coal had now become the main fuel for PP. The use of coal was planned to increase further, until nuclear PP would be needed in 1993, according to the publication.

In 1983, another alternative energy policy was published [21] proposing a heavy decrease in electricity demand. Oil boilers were replaced by heat from CHP and oil for transport was substituted with other fuels. At the same time, coal PP was replaced by electricity from Ngas CHP and renewable energy. According to the LCA methodology, the decreasing electricity demand implicates that coal PP is identified as both the simple and the dynamic marginal technology, because of a heavy decreasing trend in the market.

The actual development until 1990 was not reflected in the publications presented until then. In the first period, mainly coal PP was installed, but in the 1980s, coal CHP was the main new capacity installed. The actual dynamic marginal electricity in the period from 1976 until 1990 was coal PP. Coal CHP can be regarded as the simple marginal technology from the mid-1980s, as coal CHP has the lowest long-term cost of the technologies installed in the period.

In the next official energy policy from 1990 [22], an expansion of decentralised Ngas CHP was most feasible but wind also played an important role. The overall energy consumption was planned to decrease, but the electricity demand was still expected to increase moderately. Coal PP was planned to assist the integration of fluctuations from wind power and heat-bound CHP and can be regarded as the planned dynamic marginal technology. The simple marginal technology in the publication is Ngas-based CHP, being the main and cheapest capacity proposed. In 1993, a follow-up to this publication [23] boosted the initiatives to meet the goals of the plan and new Ngas PP should now meet the unexpected increases in electricity demand.

The policy from 1996 [24] built on previous policies and had higher shares of renewable energy, CHP and energy savings. In the reference system in the publication, coal CHP and PP are expected to be the simple and dynamic marginal technology, respectively. In the proposed energy system, an increase in demand was expected until 2005, after which the demand was expected to decline slowly until 2030. The main new capacity proposed was biomass CHP, and wind power was also important. Assuming that the decrease in demand is slower than the replacement of existing capacity, biomass CHP is the simple marginal and Norwegian hydro is proposed as the means for regulation, i.e. the dynamic marginal technology. The actual increase in demand in the 1990s was larger than expected, which resulted in a follow-up policy with better conditions for wind power. As a result, more than the increased demand was covered by wind power. The dynamic marginal technology is the installed capacity able to meet the demand on an hour-by-hour basis; however, no additional capacity of this type was installed in this period. The actual developments in installed capacity exceeded the policy from 1996 regarding decentralised CHP and especially wind power which was the simple marginal technology. From 1990 until 2000, the demand increased, but the installed coal PP and CHP capacities were actually reduced. Until 2003, the developments from the 1990s continued. In addition, the re-regulation of the electricity market in 1999 included new ownerships and changes in the way electricity was traded.

The marginal electricity technologies have been identified for periods which we can compare with statistical data. In the next section, we elaborate on the identification of the current long-term marginal electricity technology.

4.2 Future marginal electricity technologies

In 2003 and 2005, two official energy policies were published [25;26]. Focus changed from aiming at achieving lowest long-term costs for society to generating lowest costs for the commercial market players, which were considered to be equal to the lowest long-term costs for society. The main purpose was to describe the development with the given market structures as business-as-usual projections. The projection from 2003 had low fuel prices equivalent to 29$/bbl oil, while projections from 2005 included three different CO_2 quota prices and three different fuel prices at 20, 28 and 50$/bbl. According to the projection from 2003, Ngas PP is the simple and dynamic marginal technology [25]. In 2005, all projections identify wind power as the technology with the lowest long-term costs from year 2020, except in the situation with very low fuel and CO_2 prices [26]. With lower fuel prices than approx. 30$/bbl, the dynamic marginal technology installed is Ngas CHP. With the highest fuel and CO_2 quota prices, the dynamic marginal is biomass CHP. In both of these publications, CHP plants are regarded as a flexible technology, i.e. a dynamic marginal, which can use heat storage in order to meet heat demands and which can be stopped when wind power production is high [25;26]. Biomass is not regarded as a constrained fuel in these publications and the increased use of this fuel is not dependent upon the obligations set up for power companies. A new projection with a long-term price of 50$/bbl from January 2007 confirmed that the simple marginal is wind power and that the dynamic marginal is biomass CHP [29].

In January 2008, the conclusion changed [30]. The expected wind turbine costs were doubled from previous publications. Material costs did also increase for other technologies, but this increase was not included in the projection. The publication uses long-term fuel prices of approx. 60$/bbl; the demand is expected to increase and the simple and dynamic marginal technology is now Ngas CHP because of the changed preconditions. Fuel prices are now more than 120$/bbl, which will change the feasibility of technologies again.

An alternative energy policy from 2006 is included in table 2 [27;28], in which a number of new production technologies were proposed. A steep decrease in demand was proposed and the planned marginal fuel is coal. The main new capacity installed is wind power. Following the consequential approach, the simple and dynamic marginal technology is coal PP, as this is the main marginal technology phased out. Flexible technologies are proposed in order to avoid situations with forced export and to make the energy system fuel-efficient. These are flexible demands, large heat pumps and electric vehicles which would be the planned marginal, if the trend of the demand was planned to increase. These technologies were also proposed in the official publications from 1996 [24].

In 2005, decentralised Ngas CHP plants installed in the 1990s were forced to participate on the electricity markets instead of producing electricity following the heat demand. This means that the existing installed capacity was used for electricity demand balancing. These units already had the hardware required in the form of heat storage capacity resulting in more than 1,400 MW extra “installed” capacity participating in the adaption to both wind power production and electricity demand on the electricity market. The full potential is approx. 2,200 MW. In table 2, the actual marginal technology, Ngas CHP, is given in brackets, because it represents a change of utilisation and not new hardware installed, as explained above.

4.3 The causes of discrepancies

In most publications, a simple and dynamic marginal technology can be identified in both the reference and the proposed energy systems. One has to keep in mind the fact that the marginal technology is dependent on the trend of demand and the lowest long-term costs. Thus, the main new capacity planned in the publications described may not be the marginal technology. In the ten publications, the expected simple and dynamic marginal technologies change between many different technologies.

All publications are influenced by the situation in society and the international context at the given point in time. As a present example, the CO_2 quota market attempts to internalise the costs of reducing emissions, and fossil fuel and biomass prices fluctuate heavily.

In the reference projections, the marginal technologies change between seven technologies from oil PP to wind power. In the policies, the planned marginal technologies change between five different technologies from nuclear to biomass. The actual marginal technology found in statistical data changes from coal PP to coal and Ngas CHP and wind power. Apart from the fact that the future is difficult to predict, there are four main reasons for discrepancies between the reference, the planned and the actual marginal technologies seen in a historical perspective:

1. The objectives described in the publications change over time and, thus, the feasibility of a concrete technology depends on the objective. This implies that feasibility also depends on the answer to the question “feasible for whom?”
2. Not all plans and policies presented in the publications are implemented or the policies may turn out not to have the planned effect.
3. Focus is placed on a specific selection of technologies in the publications and not on modified uses or potential future technologies, e.g. the exclusion of Ngas CHP and renewable energy in the first official energy policy. Another example is the fact that CHP units have often been regarded as inflexible, but they have now changed from a simple marginal technology to a dynamic marginal technology as they have entered the electricity market.
4. The long-term and short-term investment costs are heavily influenced by the expected lifetime, investments costs, operation and maintenance costs and fuel costs of the technologies in question. Typically, only one or a few fuel price scenarios are included. Also the price scenarios are typically rather low. Another example is CO_2 quota prices, which have only been used from 2003. This has had significant impacts on the feasibility of investments, and is especially visible in the differences in marginal technologies presented in the governmental publications from 2003 and 2005.

All four reasons affect the expected investments or the decommissioning of capacity. The analysis indicates that the methodology of consequential LCA used for identifying the marginal technology may be too simplified and is disputable. In the case of electricity analysed here, it is not possible unambiguously to determine the marginal electricity technology. By applying consequential LCA, at least five different types of capacities can be identified as the marginal electricity technology in the next 10-20 years. This indicates that consequential LCA studies should include several simple marginal technologies that are fundamentally different, i.e. can be both fossil and renewable technologies and which do not necessarily have dynamic operational properties. Several fundamentally different scenarios for the marginal technology should be taken in to account. This will enable the LCA study to avoid the problems mentioned above, namely changes in objectives and changes in the implementation. This would also provide a broader view on fuel and emission costs and on which technologies to include.

5 Reviewing marginal electricity in "state-of-the-art" consequential LCA studies

Here, a review of ten LCA studies, performed within the last five years and all applying the methodology of consequential LCA, is presented. Not all studies use the term "consequential"; nonetheless, in all cases, the consequences of a change are modelled and the marginal energy technology is identified. Two criteria have been applied in order to select the studies: 1. the study is change-oriented, and 2. energy is an important factor for the results. The studies have been identified via article databases and the project database of the Danish Environmental Protection Agency. For the purpose of this paper, the majority of important studies performed are believed to be included; however, some may unintentionally have been left out. The overall aim of the review is to assess the method of identification of marginal energy technologies included in consequential LCAs on the basis of seven questions:

1. What is used as the marginal technology?
2. Are sensitivity analyses performed of the marginal energy technology, and if so, which marginal technology is used in these?
3. What is the reasoning behind the choice of the marginal technology?
4. Is the marginal energy technology identified as a short-term or a long-term marginal?
5. Is the trend of the energy demand used in the identification as required by the methodology?
6. How important is energy for the results?
7. Is the identification of the marginal energy technology consistent with the five-step procedure of consequential LCA, i.e. as presented in above?

Both electricity and heat are included in this review, as the affected heat technology is also important in these LCAs. The ten LCAs apply to the Nordic countries; reflected by the technology choices listed in Table 3. The sum of crosses is eleven for electricity due to the fact that one study identifies more than one marginal technology. The results of the review are outlined in detail in appendix A. For electricity, the marginal technology is mainly identified as either coal CHP or Ngas CHP, whereas the results for heat are more varied. In the majority of the studies reviewed, a long-term time horizon of 10-20 years is used. This approach is consistent with the methodology [1].

Technology	Main scenario Electricity	Main scenario Heat	Sensitivity analysis Electricity	Sensitivity analysis Heat
Coal CHP	xxx	x	x	x
Coal	xx			
Ngas CHP	xxx	xxx	xx	xx
Ngas	x		x	xx
Mix of coal CHP and Ngas CHP		x		
Forest residues (biomass)		x		
Complex marginal (mix of different fuel types)	x	x		
Central CHP plants		x		
Site-specific (average - not marginal)	x	x		

Table 3, Identified marginal technologies for electricity and heat production in the ten reviewed studies.

The marginal electricity technology has been identified by applying different approaches which, in many cases, are synonymous with referring to other publications in which the marginal technology has been identified or discussed. Three of the studied LCAs [16;31;32] refer to Weidema et al. (1999) [1] for the identification of the marginal electricity technology; however, these also discuss the difficulties related to this identification processes, e.g. the role of market constraints. Marginal heat technologies are identified as well. The 5-step procedure is followed more or less, though the market trend and the change in energy demand are only briefly discussed or not touched upon. The three LCAs all identify a dynamic marginal technology.

Two of the reviewed LCAs [33;34] refer to Weidema (2003) [13] for the identification of the marginal. One LCA [35] refers to a critical review and one LCA [36] refers to the marginal as being the least efficient and most polluting option. Behnke (2006) [12] is referred to in one study [37] and, finally, one LCA [38] does not present any arguments for the choice of the marginal. None of the six LCAs mention the market trend or the change in energy demand. Four studies identify a dynamic marginal technology and two a simple marginal technology.

The nine reviewed LCAs share the approach of identifying a simple or dynamic marginal technology, i.e. one single technology as defined above. The tenth LCA study [39] differs by using energy system analysis for the identification of the marginal technology and thus defines it as a mix of different technologies. However, the energy system analysis used was performed in connection with another study. The result of this review indicates that identifying the marginal technology is one of the more difficult tasks when performing an LCA, and may often be given a low priority due to the time-consuming gathering of data for the inventory.

As mentioned, the marginal electricity technology is identified primarily as Ngas CHP or coal CHP. The arguments for defining Ngas CHP as the marginal technology are mainly based on the Kyoto protocol, indirectly constraining the use of coal due to CO_2 emissions, and defining Ngas as the cheapest alternative. The arguments for choosing coal CHP as the marginal technology are either the fact that coal is the most polluting technology resulting in the decommission of old coal CHP, or the fact that coal CHP is often the cheapest solution when new capacity is built. In some studies, wind is also mentioned as a potential marginal electricity technology, but is disregarded as it is constrained by wind speed and not market demand, i.e. not a dynamic marginal technology. The results for the heat marginal are more varied due to the distribution of district heating to small local nets, as opposed to electricity.

All the assessed studies conclude that energy is important for the outcome of the LCA, thus the identification of the marginal technology becomes essential. Since knowledge about the market trends and the affected marginal technology is required, some uncertainties may appear due to the difficulties related to foreseeing the development of the market. One way of accommodating to these uncertainties is by performing a sensitivity analysis identifying the consequences of using another marginal electricity technology. This is done in half of the reviewed studies. In two of these studies, the overall conclusions are sustained, but some results change. In the remaining studies, the ranking of the scenarios change. Especially, in studies comparing recycling to incineration, the marginal technology is important, as it is much more environmentally beneficial to substitute coal than Ngas technologies. It is therefore highly recommended to perform a sensitivity analysis.

Based on this review, it can be concluded that different marginal technologies are identified on the basis of varying arguments. Only a few studies take into account whether the demand for electricity and heat is increasing or decreasing compared to the overall demand. In most studies, this issue is not mentioned. Most studies identify a simple or dynamic marginal technology. Only one study applies an approach in which the marginal is defined as a complex set of technologies. This approach is further analysed in the next section. Finally, the outcome of the sensitivity analyses in the reviewed LCA studies showed the importance of performing sensitivity analyses identifying the consequences of using another marginal technology.

6 Case study of the affected electricity and heat technologies with changes in waste incineration

In the previous two sections, the main focus was placed on the capacity installed or decommissioned due to long-term changes in the demand and the properties of these technologies. In this section, the effects of production and capacity changes in future energy systems are analysed. Hereby, we find the short-term complex marginal technology/technologies seen in a long-term perspective. Furthermore, the consequences of not using energy system analysis for identifying marginal energy technologies are illustrated.

A case is analysed in which an additional amount of waste is incinerated, i.e. 3.6 PJ, corresponding to an increase of approx. 10% of the current amount incinerated in Denmark. This is an important scenario to include in consequential LCA studies of e.g. waste incineration vs. recycling. Here, the identification of a set of marginal technologies is analysed in relation to future energy systems with the aim of showing the complexity of the affected technologies.

Ten different scenarios are analysed by use of the EnergyPLAN model, which has been applied to a number of energy system analysis, including expert committee work for the Danish authorities; the design of 100 per cent renewable energy systems; analyses of technologies for handling fluctuating renewable energy and waste [28;40-43]. It conducts hour-by-hour analyses of different electricity, heat and transport technologies fulfilling the demands, which are given as hourly distributions through a year. The model simulates the energy system and marginal Danish technologies, as well as exchanges on the Nordic electricity market. In this case study, an analytical market optimisation of the operation of the different types of technologies is performed, based on the short-term marginal production costs of each technology. The model together with documentation and references to research can be downloaded from [44]. Please note that system boundaries are also important when performing energy system analyses, as is the case of LCA studies.

In the case study, three parameters are changed in order to illustrate their importance to the identification of the marginal energy technology with increased waste incineration; i.e. the surrounding energy system; the geographical location of the waste incineration, and the distribution in time.

When making support for decisions with long-term consequences for the energy system, it is important to develop scenarios of the future energy system and its components. The energy system analysis in this case study is conducted of two possible Danish energy systems in 2030: a business-as-usual system (BAU) with a higher energy demand than today, and an energy system with a lower energy demand than today and with 45% renewable energy (RE) [26;27].

The geographical location of the affected energy technologies is important when heat production or consumption is involved, when CHPs are affected, or when bottlenecks exist in the electricity transmission system. In the model, the geographical location is taken into account by dividing the energy system into three groups. The current utilisation of waste in the three groups is: district heating boilers (1.5 PJ waste), decentralised CHP plants (10.7 PJ waste) and central CHP plants (24.8 PJ waste). Each group represents areas supplied by the mentioned technologies in the energy system. PPs are placed in connection with the central CHP plants. The geographical distribution and the amount of waste are assumed to be similar to the current situation in both of the two 2030 energy systems, BAU and RE. Both today and in the BAU 2030 energy system, the total demand for district heating is 141 PJ. In the RE 2030 energy system, the district heating demand is lowered through energy savings, as is the electricity demand.

The hourly distribution of production and consumption is important in several ways. It makes a great difference whether a new demand is placed at peak demand hours or not. Furthermore, if the production can adjust to the demand, the total energy system will have a high efficiency. If, on the other hand, energy production is constant, as is the case with the incineration of waste, and this has to be integrated into a system with fluctuating energy sources such as wind, it becomes difficult to achieve the same total efficiency. The flexible incineration of waste, e.g. residual derived fuel (RDF), requires pre-treatment of the waste to enable storage. This situation is assumed in two of the scenarios analysed.

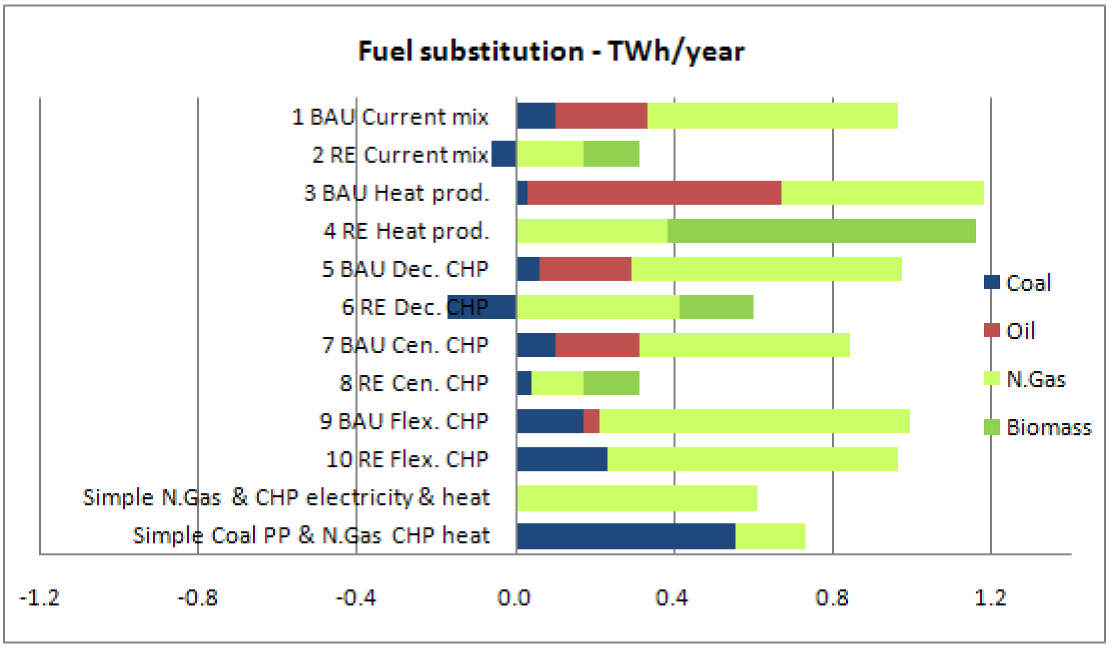

Fig. 1, Fuel substitution in the ten scenarios analyses compared to the reference energy system.

The results are presented as marginal changes from the 2030 BAU and RE references, utilising 37 PJ waste with the current distribution into district heating areas, and the current constant production. In ten scenarios, 3.6 PJ of waste are added to different district heating areas with different degrees of production flexibility. In table 4, the characteristics of the scenarios analysed are listed.

Scenario	Energy system	Geographical location	Flexibility
1	BAU	Current locations	Constant feed
2	RE	Current locations	Constant feed
3	BAU	District Heating areas	Constant feed
4	RE	District Heating areas	Constant feed
5	BAU	Decentralised CHP areas	Constant feed
6	RE	Decentralised CHP areas	Constant feed
7	BAU	Central CHP areas	Constant feed
8	RE	Central CHP areas	Constant feed
9	BAU	Current locations	Flexible feed
10	RE	Current locations	Flexible feed

Table 4, Differences between energy system scenarios

First, 3.6 PJ of waste are added with the current distribution between areas producing only heat; decentralised CHP and central CHP areas (scenarios 1 & 2). Subsequently, the waste is added first to the areas in which only heat is produced (scenarios 3 & 4); then to the decentralised CHP areas (scenarios 5 & 6), and, finally, to the central CHP areas (scenarios 7 & 8). In the last two scenarios (9 & 10), waste incineration is assumed to be used flexibly at the current geographical locations.

In fig. 1, the results of the ten analyses are presented. The results are compared with two examples of applying the consequential approach, according to the review of the energy marginal for incineration presented in the previous section. The comparison refers to one example with coal PP and heat from Ngas CHP and one with Ngas CHP. Both are calculated by use of the energy quality method.

The results reveal large variations when adding waste to different energy systems and with different locations or distributions in time. Great differences can also be found when comparing the energy system analysis to the consequential approach, in which e.g. a large amount of coal is substituted in one of the scenarios. In general, mostly Ngas is substituted together with small amounts of coal. In most cases, oil is substituted by adding waste to the BAU energy system, which replaces oil-fired boilers, whereas biomass used in boilers is substituted in the RE energy system. In general, the increased waste incineration substitutes less fuel in the RE energy system, as this system is less flexible due to its large share of wind power and due to the fact that it has much more efficient technologies, which are forced not to produce. The addition of inflexible waste incineration to an efficient and flexible energy system leads to an increased excess production of both heat and electricity. Such energy system modelling also shows CO_2 emission data as well as changes in electricity export. It is often very important to include CO_2 emissions in LCA studies; especially studies which involve energy consumption or production. The reduced CO_2 emissions when including the fossil CO_2 content of the waste vary from 0.12 to 0.20 Mt CO_2 in the BAU energy system scenarios. In the RE energy system scenarios, however, CO_2 emissions are increased. Furthermore, it is possible to analyse scenarios with different fuel prices.

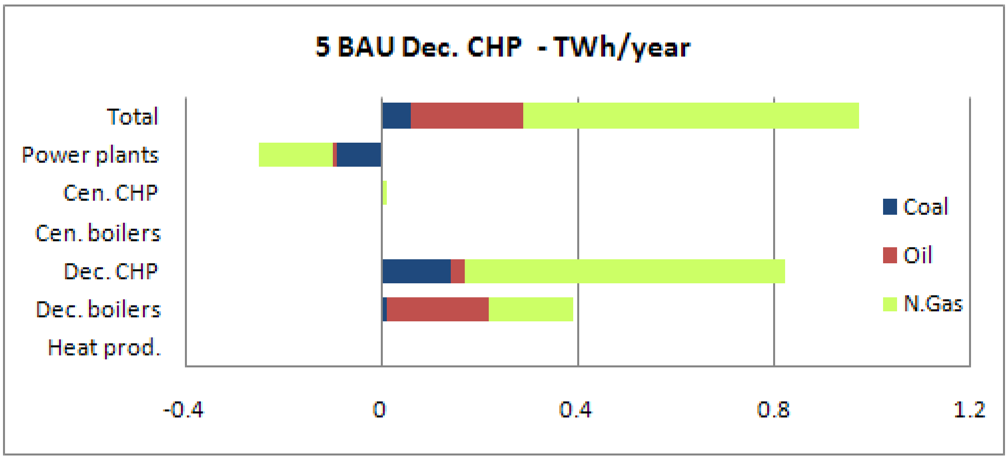

Fig. 2, Fuel substitution with 3.6 PJ waste added in the decentralised CHP areas in a 2030 business-as-usual energy system

Hourly data is available for each technology in each of the ten scenarios. In fig. 2, the scenario in which the extra waste is incinerated in a decentralised CHP area in the BAU energy system is illustrated (scenario 5). Although a net substitution of e.g. Ngas and coal takes place, an increased consumption is generated at PP, whereas fuel is substituted in the decentralised CHP area.

In fig. 3, the extra waste is added to a decentralised CHP area in the RE system. In this case, waste incineration replaces the production of Ngas-fired CHP plants and biomass boilers in decentralised CHP areas. Meanwhile, the production increases not only at PP but also in CHP plants and boilers in central areas. The short-term marginal costs of the central CHP plants are lower than the short-term marginal cost of the PP, so the CHP plants will cover the remaining electricity production until the heat demand is fulfilled. The PP will cover the remaining electricity production and the central biomass boilers will meet the heat demand in the few periods when the electricity price is too low for the CHP plants to run.

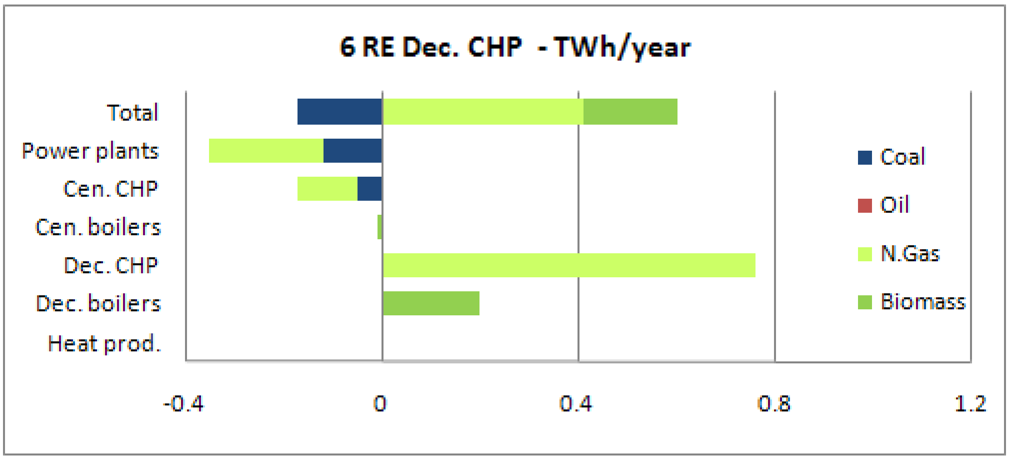

Fig. 3, Fuel substitution with 3.6 PJ waste added in the decentralised CHP areas in a 2030 renewable energy system

Boundary conditions are important in LCA studies. This is also the case of energy system analyses and must be taken adequately into account. Even though electricity trade is included in the energy system analyses here, it may be argued that, since Denmark is part of Nord Pool, the marginal technology should be identified in relation to the Nordic energy system. This means that the development taking place in the surrounding countries should also be considered. Will the countries continue on the business-as-usual path, head for a sustainable energy system with distributed renewable energy, CHP and energy savings, or a third direction? However, looking at the energy system analyses here, the exports and imports are largely unaffected in the BAU 2030 energy system. In the RE 2030 energy system, slightly more export (2%) and slightly less import (5-8%) are created due to the fact that this system has less room for inflexible waste incineration and has a more efficient electricity and heat production. Especially in the summer months in scenarios 2, 6 and 8, a larger export takes place. If taken into account, the amount of substituted fuels of the RE scenarios may generally increase slightly, while CO_2 emissions may slightly decrease. In overall terms, the increased waste incineration in both the RE and BUA 2030 systems have the largest effects on the production in Denmark, and thus, whether the surrounding areas head in one direction or another is less important than what we do with incineration in Denmark. Hence, keeping in mind the fact that most LCA studies are long-term and thus have long-term effects, changes in the Danish energy system will normally have the largest effects on the capacities installed in Denmark and thus the re-investments made in Denmark. This means that the majority of the affected technologies are placed in Denmark, and thus the identification of one single marginal technology for the entire Nordic energy system would inherently be wrong.

The complex marginal technologies can be identified as Danish marginal technologies only or can include Nordic marginal technologies, depending on the model used for the energy system analyses; but fundamentally different energy systems should always be investigated. This will enable the LCA study to take into account fundamentally different affected energy technologies and make the decision support more robust.

As an overall conclusion, the case study shows that the consequential methodology of identifying one single marginal technology is too simple, compared to results of analysing the production effects of future energy systems. In the analysis of these systems with increased waste incineration, the district heating network and the flexibility of the system have proven to be very important when determining the marginal energy technology. In all scenarios analysed, a combination of different technologies is affected and in none of the scenarios is coal PP the main affected technology. The results in fig. 1 reveal that the use of the simplistic consequential approach for the identification of only one representative marginal technology may result in very different environmental effects than when identifying the marginal technology by use of energy systems analysis. Large differences have been identified for CO_2 emissions when comparing the single marginal technology approach to the identification of complex marginal technologies here. A set of technologies are affected; thus, reinvestments are affected for a set of technologies. In these energy system analyses, waste has been used as a case; however, similar complex effects can be expected for e.g. LCA studies with changes in electricity demand or heat production.

7 Conclusions and recommendations for future LCA studies

The theoretical outline of the method for identifying marginal technologies in consequential LCA involves several simplifications that seemingly lead to an unambiguous determination of the marginal technology in many different situations. The examples in this paper, however, illustrate that the *applied* consequential LCA in reality is more difficult to conduct than it appears from the *theoretical* consequential LCA. When applied, the consequential methodology does not enable an accurate identification of the affected technology/technologies, which is the purpose of an LCA study. The practical application of the methodology is indeed individual for each practitioner and it involves the risk of making badly founded LCA decision support. In LCA studies in which energy is an important factor, the methodology is applied inconsistently and the energy system analyses in this paper reveal that the environmental impacts of the system may be very different from those anticipated. This is illustrated in the three analyses presented in this paper:

1. With consequential LCA, it is not possible to accurately determine one marginal technology for long-term decision support. The results of the historical analysis illustrate that, when applying the theoretical recommendations of consequential LCA to the identification of the future marginal electricity technology, the actual marginal technology is not identical with the one which could have been foreseen. The marginal technology varies historically. Currently, for future long-term LCA studies, the marginal technology varies between five different technologies from 2003 to 2008 in official publications from the Danish Energy Authority.

2. Practitioners of LCA use the methodology of consequential LCA inconsistently when determining marginal electricity and heat technologies. This is the case even in studies in which energy is an important factor for the results. The review of recent LCA studies reveal that these do not apply the methodology consistently and that they refer to different arguments for defining mainly coal PP or Ngas CHP as the marginal technology. In the majority of the reviewed studies, the trend of the market is not mentioned and differing arguments are used in order to identify a marginal technology. Sensitivity analyses are only performed in some of the LCA studies. Those who include sensitivity analyses find that the results are very much dependent on the marginal energy technology and, in some cases, the application of another type of marginal energy technology could change the conclusions of the LCA.

3. Identifying one single marginal technology inaccurately reflects what actually happens when the technologies are operated and interact in a complex energy system. Several technologies are affected and may thus influence the re-investment in new capacity of more than one technology.

Some technologies cannot be adjusted and, according to the methodology, technical properties can exclude technologies both as the short-term and long-term marginal technology. The marginal technology is among the technologies on the market which are able to respond to changes. Natural, political and market constraints, such as limits of natural resources, emission limits, CO_2 quotas and co-products, can also exclude some technologies according to the methodology. The analyses of the historical marginal electricity technologies, however, revealed that e.g. nuclear PP as well as wind power and CHP plants, which would normally be regarded as “constrained”, could actually, in different periods, be regarded as the capacity installed in order to meet an increased demand. This is partly due to the fact that inflexible technologies become flexible in a system when coupled with flexible technologies such as energy storage. The term “constraints” is responsible for several of the misunderstandings related to the capacity installed and the actual hour-by-hour operation. On the one hand, a general trend of demands affects the installed capacities; on the other, the characteristics of the technologies and the market design affect the way in which the system responds. No technologies should be excluded because of current market conditions, technical properties or other constraints.

In this paper, it is proposed to distinguish between three kinds of marginal technology/technologies for consequential LCA studies: The *simple* marginal technology, which is one single technology able or unable to respond to a changing demand; the *dynamic* marginal technology, which is one single technology able to respond to a changing demand; and finally, the *complex* marginal technology, which is a set of affected technologies identified by applying energy system analyses.

The technologies affected depend on the energy system in which they are analysed. The energy system analysis conducted in this paper of different uses of waste incineration illustrates that complex mixes of technologies are affected, depending on the future energy system, the location of the production plants, and the flexibility of the use of additional waste. Compared to the approach in the reviewed LCA studies, the energy system analysis revealed that several fuels and technologies are affected.

The current approach to identifying the marginal energy technology is problematic, as the marginal technology used in the consequential methodology is becoming increasingly important to the practice of LCA studies. Based on the analyses presented in this paper, it can be recommended to use the knowledge gained here to avoid that the results of future LCA studies are too sensitive to the uncertainties of changing marginal energy technologies. In order to avoid that the results of LCA studies become obsolete when the marginal technology changes, the LCA study should, as a minimum, be tested against several fundamentally different simple and dynamic technologies. Sensitivity analyses with similar technologies such as Ngas and coal should be supplemented with other types of technologies based on renewable energy, to reflect extreme situations in the analyses. LCA studies are long-term and may provide decision support for long-term investments, which makes it important to take into account fundamentally different marginal technologies, i.e. as listed in table 2.

When energy is an important part of the object studied, a complex set of marginal technologies should be identified, taking into account fundamentally different future scenarios; preferably by applying energy system analyses. In such analyses, different energy systems should be taken into account, e.g. by varying the amount of renewable energy sources and energy savings, the degree of integration between heat and power production, and different price scenarios in the energy system.

In summary, the following improvements to the current practise can be recommended: 1) Use fundamentally different affected technologies, also including production technologies which are unable to adjust to demand on an hour-by-hour basis, such as wind; 2) Use long-term perspectives by identifying affected technologies in several possible and fundamentally different future scenarios, i.e. both fossil and renewable energy technologies; and 3) Identify the affected technologies on the basis of energy system analysis taking into account the technical characteristics of the technologies and the energy system involved. If 3) is excluded from the LCA study because of resource limitations, 1) and 2) should be included as a minimum, e.g. through sensitivity analyses. Some of the results presented may be applicable to other affected technologies than energy; however, please note that the general validity is not investigated in this paper.

8 Acknowledgements

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Appendix A

LCA-Study	1. Marginal technology in LCA	2. Marginal technology in sensitivity analyses	3. The arguments for identification	4. Time horizon (short-term or long-term)	5. Characteristics of the change in energy demand	6. Importance of energy to conclusions	7. Identification of the marginal energy technology: Consistency with 5-step procedure?[1)] and type of marginal technology identified
Miljømæssige fordele og ulemper ved genvinding af plast (Environmental advantages and disadvantages of plastic recycling) Frees (2002) [31]	Site-specific electricity and heat (Danish average 1997, i.e. a mix of CHP and PP and a mix of fuels).	Marginal electricity and heat technologies based on Ngas CHP in sensitivity analysis.	Ngas and biomass will be prioritized in the future due to the Kyoto protocol. Discussed if this is realistic for heat from CHP plants as more heat from incineration may cause the closure of old coal-based PP. Also discussed whether heat from incineration plants actually substitutes heat from CHP plants since the plants compete on the same market.	Short-term (5 years) in main analysis. Long-term (time horizon not defined) in sensitivity analysis.	Only implicitly included.	Important, but overall conclusions are sustained for environmental impacts (recycling better when the marginal technology is used, incineration worse). For resource consumption, the conclusion shifts.	Does not follow the procedure in detail but refers to Weidema et al. (1999) [1] where the marginal technology for Danish electricity has been identified. Dynamic marginal technology.
Ressourcebesparelser ved affaldsbehandlingen i Danmark (Ressource savings in the waste management system in Denmark) Dall et al. (2003) [35]	Marginal electricity and heat technologies are based on Ngas CHP.	Same fuel type and technology as in the main scenario but energy yield from incineration plants reduced by 50%.	Ngas will be prioritized in the future due to the Kyoto protocol. In the future system, more peak load plants are needed due to more fluctuating energy resources. Ngas is the cheapest alternative. Biomass is a constrained resource and can thus not be the marginal technology. It is also discussed how much energy the incineration plants actually substitute as the extra heat may force the CHP plants to cool away their heat.	Long-term (10 years). In the sensitivity analysis, the time horizon is longer than 10 years. The energy system is assumed to be more efficient and contain more renewable energy => scenario with reduced (50%) energy gain from incineration.	Not mentioned.	Important, but overall conclusions are sustained (recycling better than incineration). All results are amplified in the sensitivity analysis. For food waste, the conclusion changes: now recycling is better than incineration.	Do not identify the trend in energy demand. The identification of the marginal technology is mainly based on the critical review in which the reviewers have identified a marginal technology. Dynamic marginal technology.
Systems analysis of organic waste management in Denmark. Baky & Eriksson (2003) [38]	Does not use the term "marginal", but "compensatory". Compensatory electricity and heat is coal-based CHP.	Ngas is used as the marginal technology in sensitivity analysis (the technology is not mentioned).	In the future, it will be possible to avoid power and heat based on coal condensing. Prognoses point at Ngas.	Long-term in the sensitivity analysis (time horizon not defined).	Not mentioned.	Important to electricity: the ranking of scenarios is changed. Also important to heat, but the ranking of scenarios does not change.	Do not state how the "compensatory" energy technology is identified => not consistent with 5-step procedure. Simple "marginal" technology.

LCA-Study	1. Marginal technology in LCA	2. Marginal technology in sensitivity analyses	3. The arguments for identification	4. Time horizon (short-term or long-term)	5. Characteristics of the change in energy demand	6. Importance of energy to conclusions	7. Identification of the marginal energy technology: Consistency with 5-step procedure?[1)] and type of marginal technology identified
Madaffald fra storkøkkener (Food waste from large-scale catering establishments) . Kromann et al. (2004) [36]	Substitution of electricity from incineration: coal-based technologies (mix between PP and CHP). Substitution of heat from incineration: 30% coal-based (CHP), 70% Ngas (CHP). Substitution of heat from anaerobic digestion: 100% Ngas (CHP).	No sensitivity analysis has been performed of the marginal energy technology.	The marginal energy technology is the least efficient and most polluting – the non-prioritized.	Long-term (10-15 years).	Not mentioned.	No sensitivity analysis has been performed of marginal energy technology, as it was not considered to be an uncertain parameter.	Do not identify the trend in energy demand. The main argument for identifying the marginal technology is the aim of substituting the most polluting technology. Simple marginal technology.
Life cycle assessment of energy from solid waste - part 1: general methodology and results. Finnveden et al. (2005) [16]	The marginal technology for electricity production is coal (technology not mentioned). For heat it is Ngas or forest residues (technologies not mentioned).	No sensitivity analysis performed of the marginal electricity technology. For heat one scenario uses Ngas, another scenario uses forest residues.	Different references, trends and assumptions are discussed to identify the marginal technolgy. Refer e.g. to Weidema et al. (1999) [1] who assume that hard coal is the marginal technology for European (base-load) electricity (long-term). For heat it is discussed whether forest residues (the largest share today in district heating) or Ngas (the share may increase in the future) should be identified as the marginal technology.	Long-term (decades).	The electricity demand is decreasing (if the aim is a sustainable life). The demand for district heating is increasing.	The results are sensitive to the type of fuel chosen for heat substitution, i.e. whether renewable or non-renewable fuels are substituted.	Follow the procedure more or less. Refer to different publications where the marginal technology has been identified. Dynamic marginal technology.
Miljømæssige forhold ved genanvendelse af papir og pap. Opdatering af vidensgrundlaget (Environmental impacts related to recycling of paper and cardboard. An update of the knowledge-base) Frees et al. (2005) [32]	Marginal technologies for electricity and heat are based on Ngas (CHP).	No sensitivity analysis is performed of the marginal technology but different scenarios are discussed and evaluated.	The marginal technology is the most sensitive towards changes. Assumed to be Ngas based on the submitted paper Mattson et al. (2003) [46] and Weidema et al. (1999) [1]. Periodically, the possibility exists that wind energy is part of the electricity production.	Long-term (10-20 years).	Not mentioned.	All environmental impacts come from the energy system. No sensitivity analysis (calculations) is performed of the marginal energy technology, but different scenarios are discussed and evaluated.	Do not identify the trend in energy demand. Refer to different publications for identification of the marginal technology. Dynamic marginal technology.

LCA-Study	1. Marginal technology in LCA	2. Marginal technology in sensitivity analyses	3. The arguments for identification	4. Time horizon (short-term or long-term)	5. Characteristics of the change in energy demand	6. Importance of energy to conclusions	7. Identification of the marginal energy technology: Consistency with 5-step procedure?[1)] and type of marginal technology identified
LCA of Danish fish products. New methods and insights. Thrane (2006) [34]	The marginal electricity technology is PP based on coal or Ngas (does not mention which one is used).	No sensitivity analysis performed.	In consequential LCAs, a market-based approach is used. Disregards all processes restricted by quotas or other factors (e.g. wind, as it is restricted by wind speed – not market demand).	Long-term (time horizon not defined).	Not mentioned.	Consumption of diesel oil very important, especially at the fishing stage. Electricity consumption is only of minor importance.	Do not follow the 5-step procedure but refer to the market-based approach in Weidema (2003) [13]. Dynamic marginal technology.
2nd generation bioethanol for transport: the IBUS concept. Jensen & Thyø (2007) [37]	Coal (CHP) is used as marginal electricity technology. Central CHP plants (mix of fuels) are used as marginal technology for district heating.	No sensitivity analysis has been performed of the marginal energy technology.	Refer to Behnke (2006) [12] for identification of the marginal technology for electricity production. Central CHP plants are identified as marginal technologies for heat production, but the fuel type has not been considered.	Long-term perspective (towards 2025).	Not mentioned.	Energy is important since the whole assessment is energy-related. No sensitivity analysis performed of the marginal energy technology.	Do not follow the 5-step procedure but refer to Behnke (2006) [12] for identification of the marginal electricity technology. Identification of the marginal heat technology is not discussed. Dynamic marginal technology.
Life cycle assessment of fuels for district heating: A comparison of waste incineration, biomass- and Ngas combustion. Eriksson et al. (2007) [39]	Complex marginal electricity production on the Nordic electricity market. Found by modelling the energy system in the model NELSON (dynamic optimization model). A mix of different technologies and fuels are identified (e.g. coal, Ngas, wind, oil, nuclear power and biomass).	The assessment included two scenarios – one with a low fossil fuel content in the energy mix, and one with a high content.	Coal condensing is the short-term marginal technology. Long-term marginal technologies could be nuclear power (closing down) or Ngas (building of new CHP plants). Find that the most realistic marginal technology is the complex one.	Long-term (the energy system analysis refers to a period of 50 years).	Only implicitly included.	The energy mix is important to the ranking of solutions.	Do not follow the 5-step procedure since this procedure is a simplified approach to the identification of the marginal technology. Identifies a “complex” marginal consisting of both short-term and long-term technologies by the use of a dynamic optimisation model. Complex marginal technology.
Life cycle assessment of the waste hierarchy – A Danish case study on waste paper. Schmidt et al. (2007) [33]	Marginal electricity technology is from the Danish grid. Ngas (CHP) is used as technology. This also applies to heat, although not explicitly stated.	Coal CHP is used as marginal energy technology in the sensitivity analysis.	Refer to Weidema (2003) [13] for identification of the marginal energy technology.	Not mentioned explicitly.	Not mentioned.	It is stated in the sensitivity analysis that the results of the assessment appear to be sensitive to the choice of marginal technology.	Do not follow the 5-step procedure but refer to Weidema (2003) [13] for identification of the marginal technology. Dynamic marginal technology.

1) 5-step procedure for identifying a marginal technology from Weidema et al. (1999) [1] and Ekval and Weidema (2004) [11]:
a) Time horizon, b) Process or market, c) Trend in market volume, d) Flexible technologies (unconstrained), e) Technologies actually affected

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Efficient fuel cells and electrolysers are still at the development stage. However, in future renewable energy systems, these technologies may come to play an important role. Today, most electricity, heat and transport demands are met by combustion technologies. Compared to these conventional technologies, fuel cells have the ability to significantly increase the efficiency of the system while meeting such demands. However, energy system designs can also be identified in which the fuel savings achieved are lost in technologies elsewhere in the system.

In this dissertation, fuel cells for locally distributed CHP plants are, in particular, identified as a promising application. Fuel cells should not be developed for base load operation, but for flexible regulation in renewable energy systems. Electrolysers should only be implemented in energy systems with very high shares of intermittent renewable energy and CHP or in 100 per cent renewable energy systems in which they play an important part by displacing fuels derived from biomass.