Applications of SOECs in different types of energy systems

German and Danish case studies

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GERMAN AND DANISH CASE STUDIES

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Abstract

Different aspects of electrolyser integration in energy systems was investigated in order to determine the potential of using this technology in the future. First analysis examined the influence of the use of co-electrolysis for fuel production process in comparison with using steam electrolysis as a source of hydrogen that afterwards is combined with carbon dioxide. Second investigation looked into should the fuel production chain include distribution of the intermediate product syngas or distribution of the final product in form or liquid fuels. Thirdly, the potential for using combined capacities of SOEC and SOFC was investigated as it can potentially improve the profitability of the investment, but also improve the stability of the energy system by offering grid-balancing capacity when intermittent resources cannot meet the demand for electricity. Finally, five different energy systems were analysed: Danish 100% renewable scenario for 2050, smart energy system Germany 2050 and three nuclear scenarios for Germany with different shares of nuclear energy (15%, 30% and 45%) of the electricity production in order to determine the operation of electrolysers. The analysis shows that different system designs influences the feasible utilisation capacity of electrolysers and this is mainly connected with the system flexibility.

Contents

NOMENCLATURE

Abbreviation	Meaning
CCR	Carbon Capture and Recycling
CCGT	Combined cycle gas turbine
CEEP	Critical Excess Electricity Production
CHP	Combined Heat and Power
CNG	Compressed natural gas
DME	Dimethyl ether
RSOFC	Reversible Solid Oxide Fuel Cell
SOC	Solid Oxide Cell
SOEC	Solid Oxide Electrolysis Cell
SOFC	Solid Oxide Fuel Cell

1. Introduction

As the share of intermittent renewable sources is increasing it increases the demand for integration technologies that can help balancing the electricity grid in the energy system. One of these technologies could be electrolysers that can contribute to this energy system transformation as they can work as both a storage and conversion technology. The applications of electrolysers can be different in this transformation, but their ability to convert electricity from intermittent sources such as wind power and photo voltaic into chemical energy is of great value. This ability of storing electricity through various fuel types, that mankind already knows how to handle, can substitute fossil energy in a new way. Electrolysers also help grid balancing as they are utilising the fluctuating electricity and in this way both enable integration of these resources but also produce electrofuels[1] for meeting the transport demand.

The applications of electrolysers can be utilised in many sectors, but should be prioritised for the transport sector [1] due to the complexity of this sector including extremely high dependence on fossil fuels that need to be replaced with new types of liquid or gaseous fuels. There are however different types of electrolysers that can be used for fuel production and their characteristics have been assessed and reported in the previous project and publications [2]. Different fuel pathways that use solid oxide electrolysers (SOECs) for the fuel production have been researched and analysed in previously carried ForskEL project and results indicate that there is a potential of using electrolysers for fuel production and that electrofuels can be competitive with other fuel choices in the future [3–5]. All the analyses were carried out for Danish 100% renewable energy system and applications of SOECs in other types of energy systems with different system design was not investigated before. Previous work likewise did not include the reversible operation of electrolysers as fuel cells, which can be beneficial for the system as the focus of the studies was on fuel pathways and potential fuel ouputs.

Therefore, based on the previous findings this report focuses on four different aspects of SOECs integration in energy systems:

- Perspectives of using electrolysis in different energy systems configuration
- The potential of reversible operation of electrolysers as fuel cell
- Steam versus co-electrolysis for fuel production
- Distribution of syngas versus distribution of end fuel

These different aspects are important in order to explore the possibilities of using electrolysers in the energy system, to define what type of configurations are needed if electrolysers should be used for fuel production and furthermore to investigate the potential influence that electrolysers have on different types of energy systems. The operation of electrolysers in different energy system configurations is analysed to determine the potential for their integration and to determine the utilisation capacities necessary to supply the required fuel demand that is most beneficial for the energy system. Different system designs influence both the operation of the whole system but also the operation of individual components including the operation of

[1] The term "*electrofuel*" refers to fuel production by combined use of electrolysers with carbon source. If the carbon source is CO_2-emissions the term*CO_2-electrofuel* is used, and in case the carbon source is from the biomass gasification the term *bioelectrofuel* is used. Terminology is defined by Ridjan *et.al* in [28].

electrolysers. When installing the electrolyser capacity in the system and focusing on the SOEC technology it is important to consider the potential of using some of the capacity in a fuel cell mode. This can potentially improve the profitability of the investment, but also improve the stability of the energy system by offering grid-balancing capacity when intermittent resources cannot meet the demand for electricity. The potential for using combined capacities of SOEC and SOFC is therefore analysed in this report. The main characteristic of SOECs compared to other types of electrolysers is that they conduct oxide ions and are able to do simultaneous electrolysis of water and carbon dioxide in a process called co-electrolysis. The analysis in this report is carried out to examine the influence of the use of co-electrolysis for electrofuel production process in comparison with using steam electrolysis as a source of hydrogen that afterwards is combined with carbon dioxide. This analysis was followed by a comparison of the feasibility of the fuel production chain to distribute the intermediate product syngas or to distribute the final product in form or liquid fuels. These two aspects are important from the fuel production perspective in order to see which fuel pathways are preferable and which configuration of production chain and/or product distribution should be preferred.

These different aspects are reported in four chapters that present outputs of the analyses conducted mostly in the energy system analysis tool EnergyPLAN [6]. The reason why EnergyPLAN is chosen for the analyses of reversible operation and operation of SOEC in different energy systems is due to the need for hour-by-hour modelling. This is necessary to determine the optimal operation of the electrolyser in the system as it is possible to analyse the changes in the operation of different energy system units and to determine when should SOEC operate in SOFC mode to be able to substitute electricity production from other source. With this input output model deterministic, it is possible to analyse future systems by creating different scenarios. This was used in the analysis of electrolyser operation in different system designs where five different system configurations were simulated to determine the differences in electrolyser operation. EnergyPLAN is also a model that can simulate the whole energy system with different sectors: heat and power, transport and industry. This is not possible with most of the energy system analysis tools [7] and it helps in defining the right operation mode of electrolysers in the overall energy system. Furthermore, EnergyPLAN is developed on research basis, meaning that the model is following the need for simulating different technologies and processes in the energy system. In order to carry out different types of analyses in this report, EnergyPLAN tool was enhanced during the project, which helped more accurate simulation.

2. SOEC applications in different energy systems

Previous work carried out has investigated the role of SOECs in a Danish 100% renewable energy system for 2050 [5,8]. Due to the specificity of the Danish energy system that is characterized by a high share of wind and combined heat and power, it is important to consider the influence of SOECs in other European energy systems with different characteristics for electrolyser integration. In order to determine the influence of different system configurations on the utilisation of SOECs two scenarios for the German energy system in 2050 are compared with the Danish example. Descriptions of the energy systems will be given in further details below.

2.1. Analysed energy system scenarios

The analysed systems were the 100% renewable Danish 2050 system and two types of German energy systems: the forecasted 2050 German energy system based on the smart energy system approach (*Germany 2050*); and the 2050 German energy system with different levels of nuclear capacity installed. The scenario

with nuclear energy was chosen as this scenarios was considered in several publications [9,10], that analysed powering of electrolysers with nuclear electricity and utilisation of waste heat from nuclear power plants to maintain the operating temperature of electrolysers. As Germany has decided to continue its energy production without nuclear energy, a projection of the German energy system in 2050 was created.

2.1.1. Danish 100% renewable scenario for 2050 and German smart energy system 2050

Both Danish 100% renewable scenario and German 2050 scenario were created based on the smart energy system approach [1,11]. This approach tries to integrate different parts of the energy system in order to enable the integration of large share of intermittent renewable electricity produced from wind and PVs. The cross sector integration is important as enables the flow of intermittent electricity from for example electricity sector to heat sector by use of heat pumps for a short-term heat storage and flexibility. This way different flexible technologies enable more renewable sources in the system and offer the needed balancing and storage capacity for fluctuating electricity. The cross-sector integration is not only between electricity and heat sector (including district heating), but also involves transport sector and fuel supply in gas grid. By using different types of smart grid: electricity, heat and gas grids the system increases its flexibility. This approach is important as operation of one part of the energy system influences other parts, therefore coherent approach is needed to create the system where interactions between the sectors benefit the overall system.

The Danish 2050 100% renewable scenario is the scenario created for Coherent Energy and Environmental system analysis (CEESA) project [8]. This smart energy system scenario was created based on the reference scenario from 2010 (see Figure 1). The Danish 100% renewable energy system is the only scenario with 100% renewable energy. The smart energy system created for 2050 represents a recommendable scenario that is based on realistic predictions of achievable technological improvements. It has a high share of production based on wind and biomass used in combined heat and power (CHP), for industrial purposes and transport. The district heating share in the Danish scenario is 87% while the rest of the demand is met mostly by individual heat pumps. Installed wind capacity, both onshore and offshore are 16,099 MW. The transport demand is met by electrification and electrofuels, which are partly produced by CO_2 hydrogenation (CO_2 electrofuels) and partly by biomass hydrogenation (bio electrofuels). The share of electrification is 22%, while the rest of the transport demand is met by electrofuels. The total fuel demand for electrofuels is 32.15 TWh. Electrolysers are used for both production pathways and the total installed capacity of electrolysers in the system is 7743 MW. As it can be seen from the primary energy supply graph for year 2050 (Figure 1 and Figure 2), the Danish system is significantly smaller in comparison to the German system and the electrolysers are supplied only with intermittent renewable electricity. In order to be comparative with the German scenarios the export share was fixed to 5% of electricity consumption. However, it is very difficult to compare Danish and German system as they do have different system designs, which influences the operation of electrolysers.

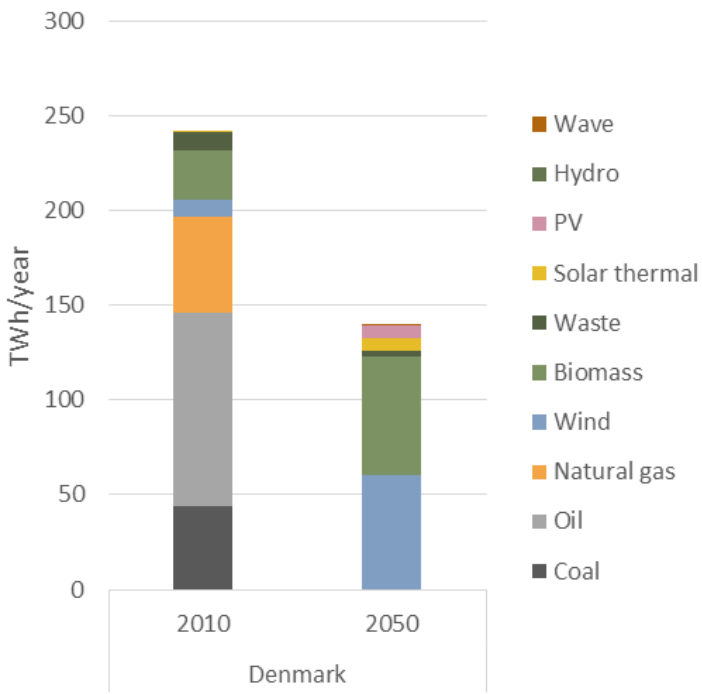


Figure 1. Primary energy supply in the Danish reference model 2010 and 100% renewable 2050 model

The German 2050 energy system is a system with a high share of intermittent renewable energy for electricity production; however natural gas remains a main energy source in power plants, boilers for heating and combined heat and power. This scenario was created as a smart energy system scenario where the use of renewable energy is maximised according to predicted potentials [12] and covering the remaining demand with natural gas. Space heating demand was reduced by 60% through heat savings in comparison with the reference model (2010) and 30% of the heat demand is covered by district heating. Installed wind capacity is 138,600 MW. The transport sector demand was met by 60% electrification (electric vehicles) and 40% electrofuels. Electrolysers were used only for transport purposes and due to the high fuel demand in Germany the capacity was 79,600 MW, which in comparison to the Danish system is just over 10 times higher. Half of the electrofuels are produced with CO_2 hydrogenation process and the other half with biomass hydrogenation process. This division is aligned with one used for Danish scenario in order to be comparative. It is important to note that it was not been possible to create 100% renewable German scenario by using these renewable energy potentials and described system characteristics. Therefore, further work is needed in order to create 100% renewable scenario for Germany, where the level of CHP in relation to power plants and district heating share could be increased further.

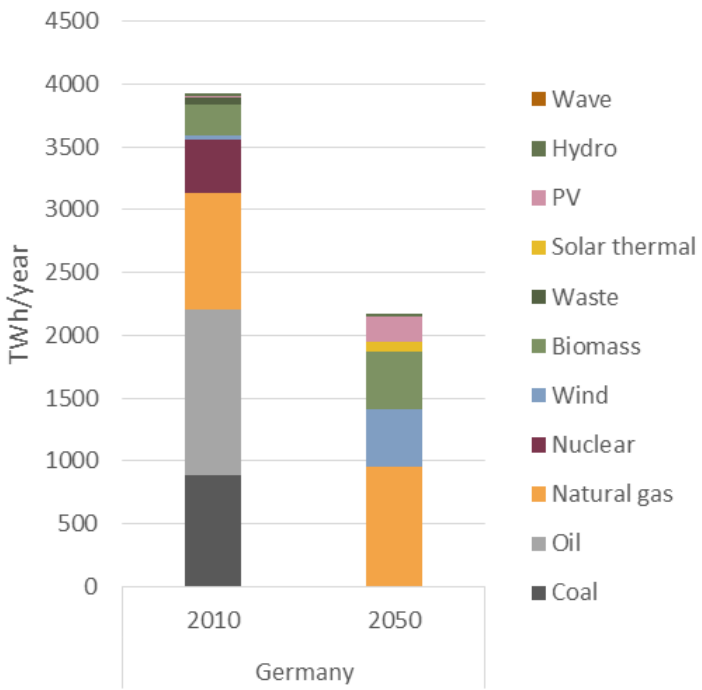


Figure 2. Primary energy supply in German reference 2010 model and smart energy system 2050 model

2.1.2. German scenarios with nuclear energy

Three extra scenarios for Germany were analysed in order to show how does nuclear energy in the system influence the operation of electrolysers. These scenarios were created just for the purpose of the analysis as it is known that Germany has decided to close down their nuclear power plants and restricted the future investments in nuclear energy.

In the nuclear scenario for Germany, three sub-scenarios were analysed in order to determine the influence of different shares of nuclear energy (15%, 30% and 45%) of the electricity production on the electrolyser operation for the fuel production. The installed capacity and primary energy supply of uranium are outlined in Table 1. The efficiency used for nuclear power plant is 33%, meaning that for every TWh of electricity produced from nuclear energy it is expected that 3 TWh of uranium is used.

In order to be comparative, all German scenarios, including the smart energy Germany 2050, have the same transport demand, the same levels of electricity export and same primary energy supply for solar thermal, PV, hydro and offshore wind. The variables that were modified were: onshore wind capacities, thermal capacity, electrolyser capacity and nuclear capacity.

Table 1. Installed nuclear capacity, annual production and primary energy supply of uranium for German nuclear scenarios and reference 2010

	Nuclear capacity (GW)	Annual production (TWh/year)	Primary energy supply of uranium (TWh/year)
Germany 2010	20	140.5	421.1
Nuclear – 15%	22	151.1	453.7
Nuclear – 30%	44	302.2	907.5
Nuclear – 45%	66	453.3	1361.2

Figure 3. illustrates primary energy supply for different German scenarios and it can be seen that the increase in nuclear capacity in the system reduces the use of natural gas and wind production. This is also a result of keeping the same export of 5% of the electricity consumption, meaning that the wind capacities were adjusted to maintain the same export of electricity. Furthermore, the capacity of installed electrolysers did not differ as it was connected to the utilisation capacity. Meaning that for the same utilisation the same capacity was in all scenarios. Even with the same capacity installed different optimal utilisation capacities occur with different share of nuclear energy in the electricity production.

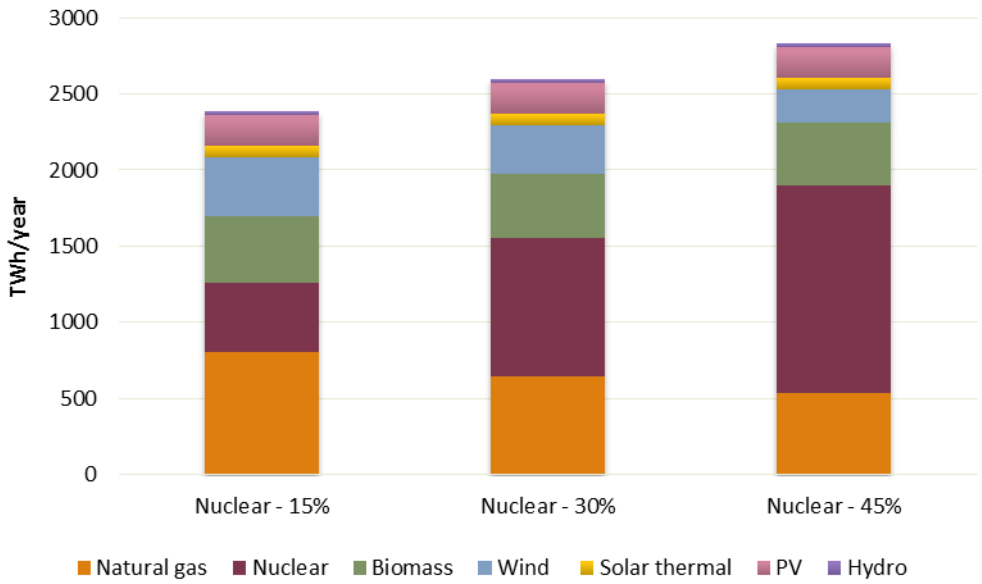


Figure 3. German scenarios with differing nuclear production and their primary energy supply

2.2. Comparative analysis on optimal utilisation capacity of electrolysers

The utilisation capacity is defined as the average operating capacity divided by the maximum operating capacity. The optimal utilisation capacity is defined as the utilisation capacity at which the primary energy supply and the system costs are the lowest. The optimal utilisation capacity changes depending on the energy system design therefore analysis included all the German scenarios and the scenario for 100% renewable Denmark. Every scenario has a tipping point of total system costs and points where production/consumption increases or decreases.

Analysis steps for all scenarios in order to find optimum utilisation capacity for electrolysers:

1. •Calculating the needed electrolyser capacity for set of different utilisation capacities (10-100%)
2. •Adjusting the nuclear capacity in the system to fit 15, 30 or 45% share of the electricity production (in case of scenarios with nuclear energy)
3. •Adjusting the wind capacity in the system to fit the fixed export of 5% of the consumption
4. •Running the technical simulation to get the most fuel efficient system operation

The *Step 1* included calculating the needed electrolyser capacity for different utilisation capacities of electrolyser ranging from 10 to 100%. The actual (maximum) installed capacity in the system is calculated for all steps by keeping the same average operation. The *Step 2* was applied only for the scenarios with nuclear energy, where the nuclear capacity was adjusted so it has a certain share of electricity production. The *Step 3* included adjusting (lowering or increasing) the onshore wind capacity in the system so that the export always equals to 5% of the total electricity consumption. The *Step 4* was basically running the technical simulation in order to get results of primary energy supply in the system (specifically wind, biomass and natural gas) and total system costs.

2.2.1. Danish and German scenario for 2050

In case of the German 2050 scenario, this includes both biomass, natural gas consumption and wind production, while in the Danish scenario it includes only wind and biomass. Figure 4 shows the changes in primary energy supply with different electrolyser utilisation capacities for the Danish 100% renewable scenario 2050. We can see that with the increase in the utilisation capacity the wind production is decreasing and the biomass consumption is increasing. This is due to the fact that the electrolyser demand for electricity does not correspond to the wind production profile and the more stable production of electricity from combined heat and power starts and use of biomass is increased. Similar system reaction happens for the German 2050 model, where the natural gas use in power plants increases while the wind production decreases (see Figure 5).

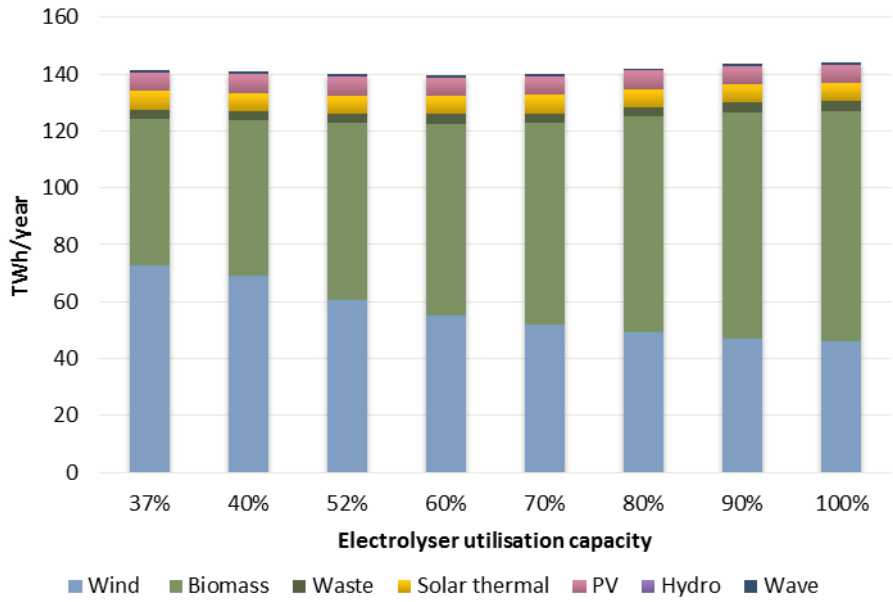


Figure 4. Changes in primary energy supply with different electrolyser utilisation capacities – 100% renewable Denmark 2050

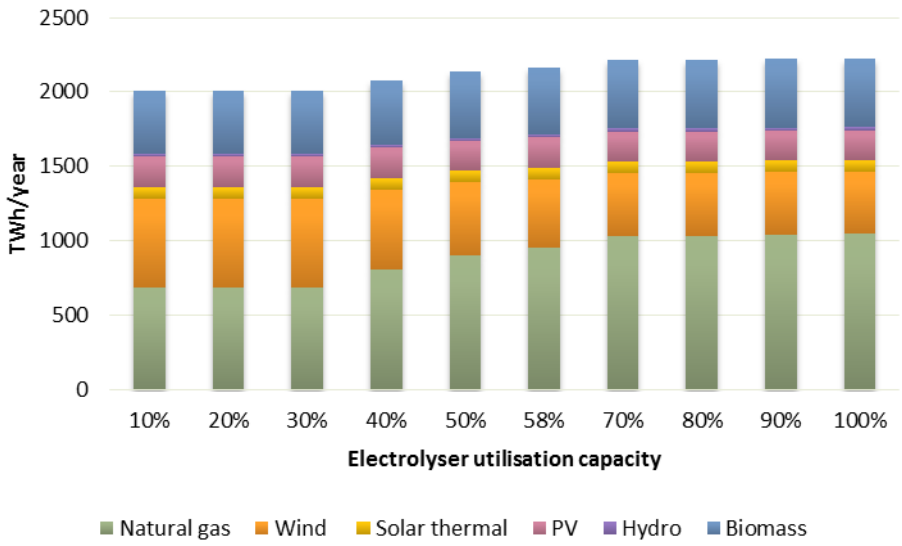


Figure 5. Changes in primary energy supply with different electrolyser utilisation capacities – smart energy Germany 2050

The analysis indicates (Figure 6) that the Danish 100% renewable energy system shows higher utilisation of electrolysers in comparison with the German smart energy system 2050 (see Figure 7). The optimal utilisation capacity in the Danish system according to the lowest costs is at 70% while in German scenario is 30%. This is due to the system design. In the optimal utilisation capacity in German system gives the system operation with 5% share of CHP and 14% of power plants in the electricity production, while the Danish system in the optimal utilisation has 15% of CHP and 4% of power plants in the electricity production. Danish system has higher share of combined heat and power that offers more flexibility in the system with wind power, than power plants do. As the electrolyser utilisation increases the operating regime of electrolysers changes, meaning the higher the utilisation capacity the more constant the operation. The more constant operation does not favour wind production pattern and there is a need to produce electricity from other plants in the system.

In German case, the power plants will take over and their operation will increase as the wind operation decreases, while combined heat and power is slowly increasing its production due to the low level of district heating share in the heating sector of 30%. This is also due to the export that is adjusted to be 5% of the electricity consumption; therefore, the electricity production is adjusted to not exceed this level. In Danish case on the other hand, CHP will take over the wind reduction and the high demand for district heating which has 87% of share, while power plants will increase the production when the heat demand is met. This influences the optimal utilisation capacity as the Danish system can absorb more wind in the system even when electrolysers cannot use the fluctuating electricity, as other flexible technologies in the system (CHP with district heating network and heat pumps) can utilise this electricity. The difference in the total system costs reflect the difference in electrolyser capacity installed in the different utilisation points, different wind capacity installed and associated fuel costs for biomass and natural gas.

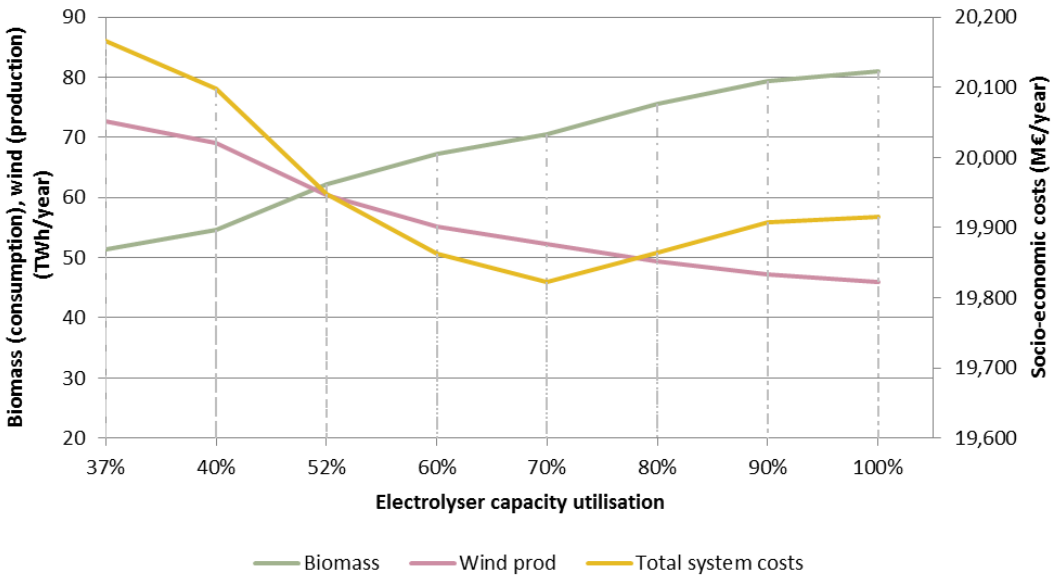


Figure 6. Illustration of utilisation capacity of electrolysers in the Danish 100% renewable scenario 2050

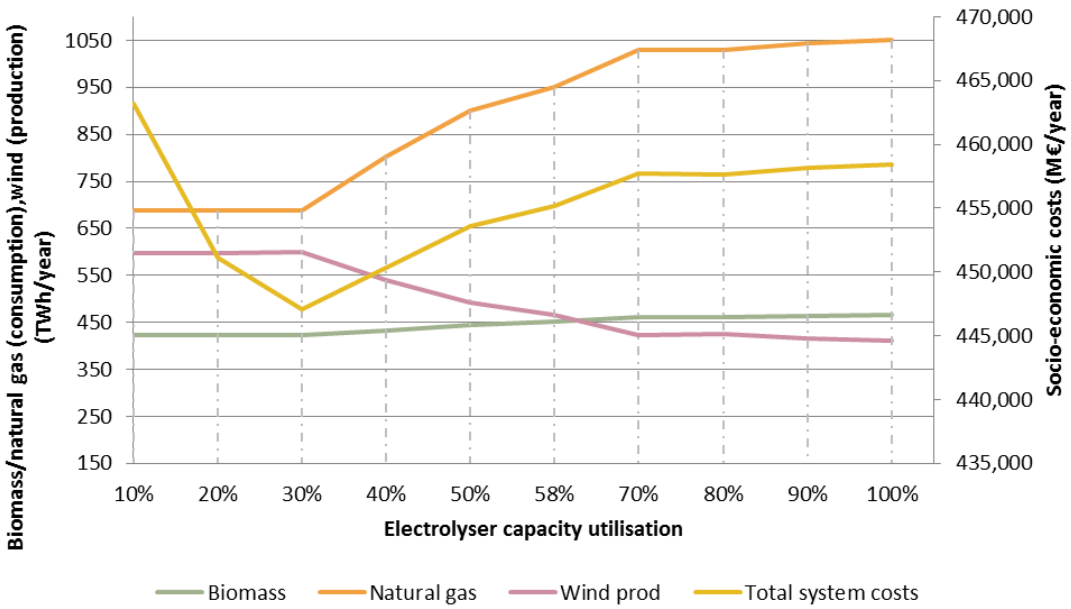
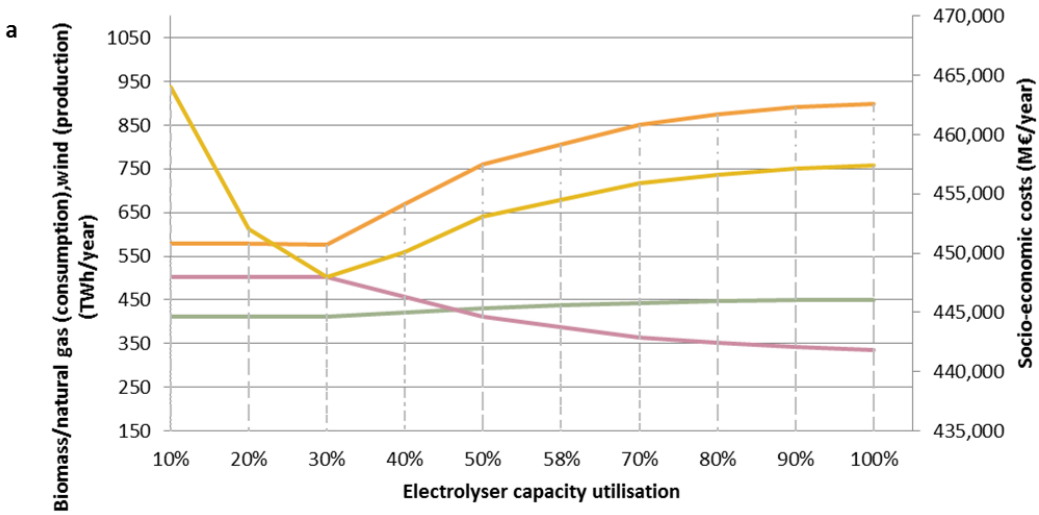


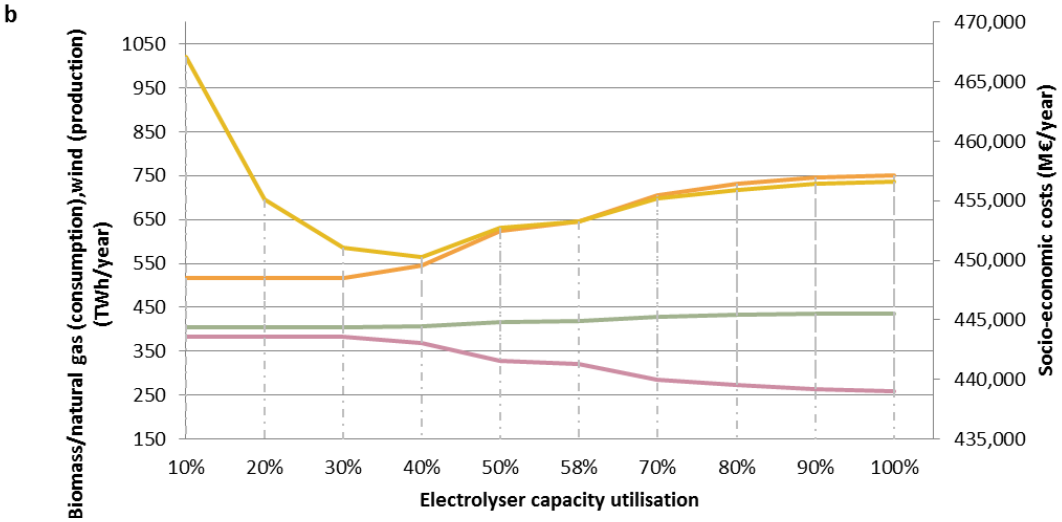
Figure 7. Illustration of utilisation capacity of electrolysers in German smart energy 2050 scenario

2.2.2. German scenarios with different nuclear energy share

Three German scenarios are analysed in which the nuclear capacity was changed in order to simulate 15, 30 and 45% of nuclear share in electricity production. It is interesting to see how the share of nuclear energy in the energy system influences the utilisation of electrolysers. The analysis shows that an increase of nuclear capacity in the system, increases the utilisation rate of electrolysers, lowers the capacity of wind in the system, but at the same time reduces the use of natural gas (see Figure 8). This is expected since nuclear power plants operate at base load meaning that they restrict a high integration of wind in the system, the lower the fluctuating wind in the system is the lower is the need for high electrolyser capacity as the operation regime of electrolysers as more constant fits the nuclear plant operation. The costs are the lowest

just before or just at when the natural gas costs starts increasing due to the operation of power plants that need to cover the electricity demand that is not met by reducing the wind in the system.





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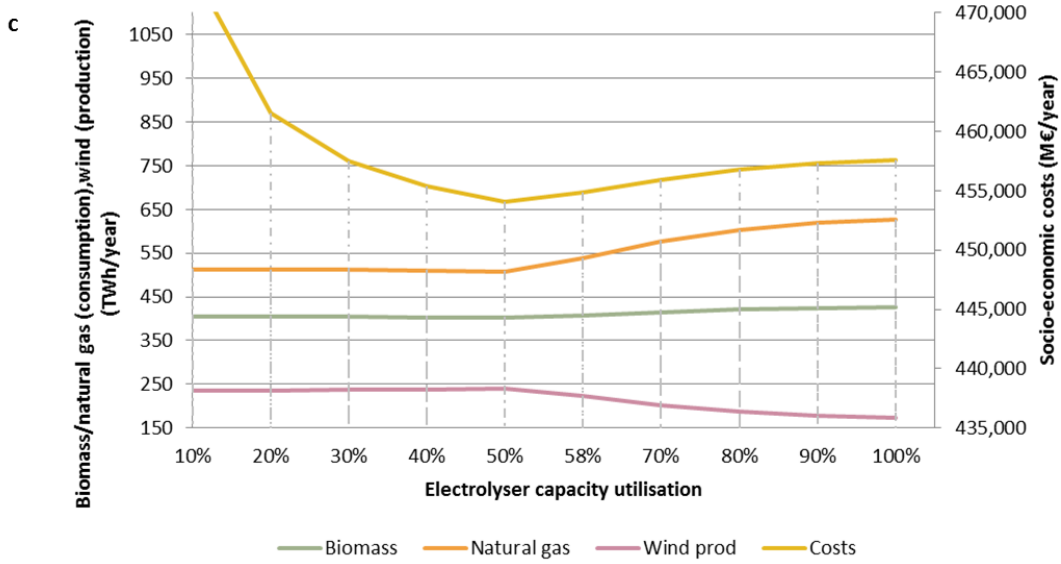

Figure 8. Illustration of utilisation capacities of electrolysers in a) German nuclear system with 15% share of nuclear energy, b) German nuclear system with 30% share of nuclear energy, d) German nuclear system with 45% share of nuclear energy of electricity production

Figure 9 illustrates the cost comparison between the four German scenarios. It is apparent from the figure that the costs are firstly reducing with increased utilisation capacity but in the span of 30-50%, they start increasing again depending on the optimal utilisation capacity. This figure just illustrates the cost component of the different scenarios and it is visible that the higher utilisation of electrolysers is the closer the costs are between the scenarios. This is related to the wind capacity installed and fuel costs, in this case mainly natural gas costs.

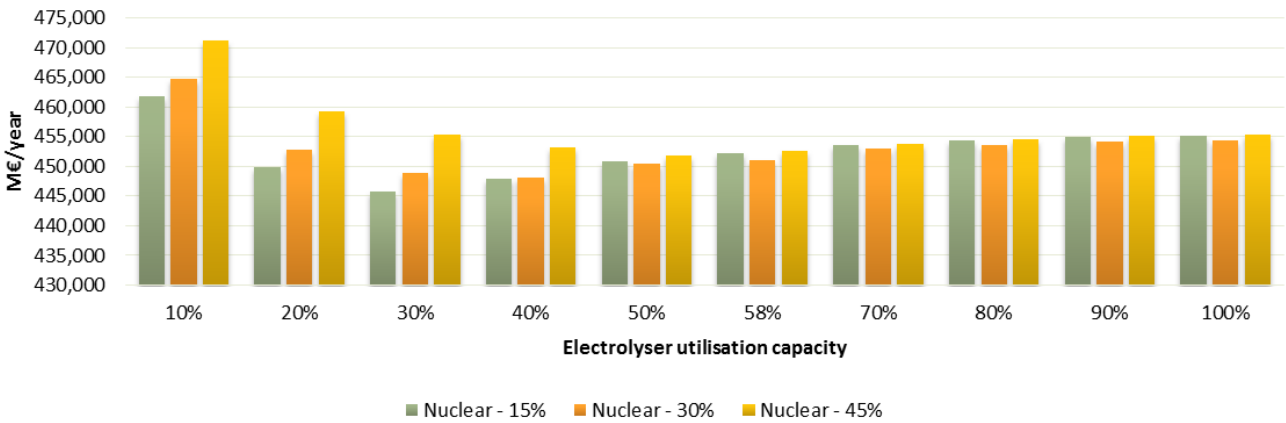

Figure 9. System cost comparison for all German scenarios

2.3. Sensitivity analysis

The first sensitivity analysis was conducted to investigate the influence of price changes of natural gas, biomass and uranium on total system costs. The prices were varied from ±25 and ±50% as it is outlined in Table 2. As can be seen in Figure 10 and Figure 11, the costs oscillations are not exceeding ±2.5% difference compared to the reference scenario and assigned fuel costs.

Table 2. Input data for sensitivity analysis for different fuel prices

	Price	Uranium	Natural gas	Biomass
Reference	€/GJ	1.75	12.2	7.86
-50%	€/GJ	0.88	6.10	3.93
-25%	€/GJ	1.31	9.15	5.90
25%	€/GJ	2.19	15.25	9.83
50%	€/GJ	2.63	18.30	11.79

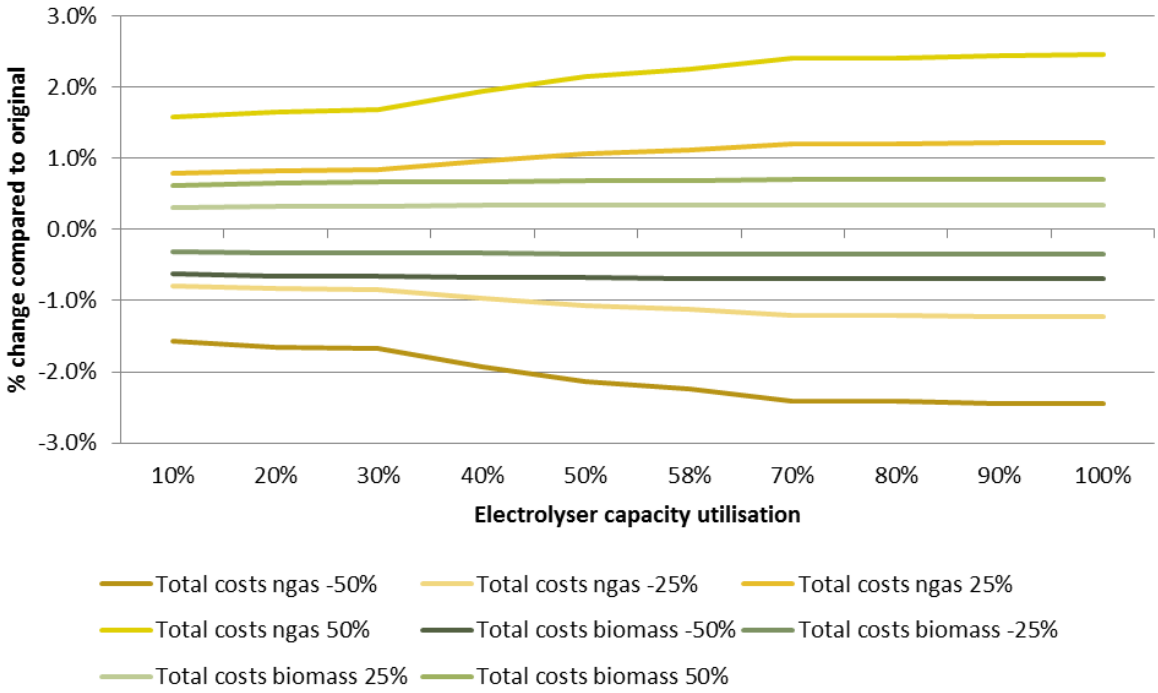

Figure 10. Influence of changes in natural gas (yellow) and biomass (green) prices on total system costs (excluding vehicle costs) in a German smart energy 2050

It can be seen from the graphs that the total system costs (excluding vehicle costs) is most sensitive towards changes in natural gas prices while the applied changes in the prices of uranium do not give significant oscillations. Moreover, as the scenarios that use nuclear energy have reduced consumption of natural gas and biomass in comparison to German smart energy 2050, the influence of changes in natural gas and biomass prices is lower (see Figure 11).

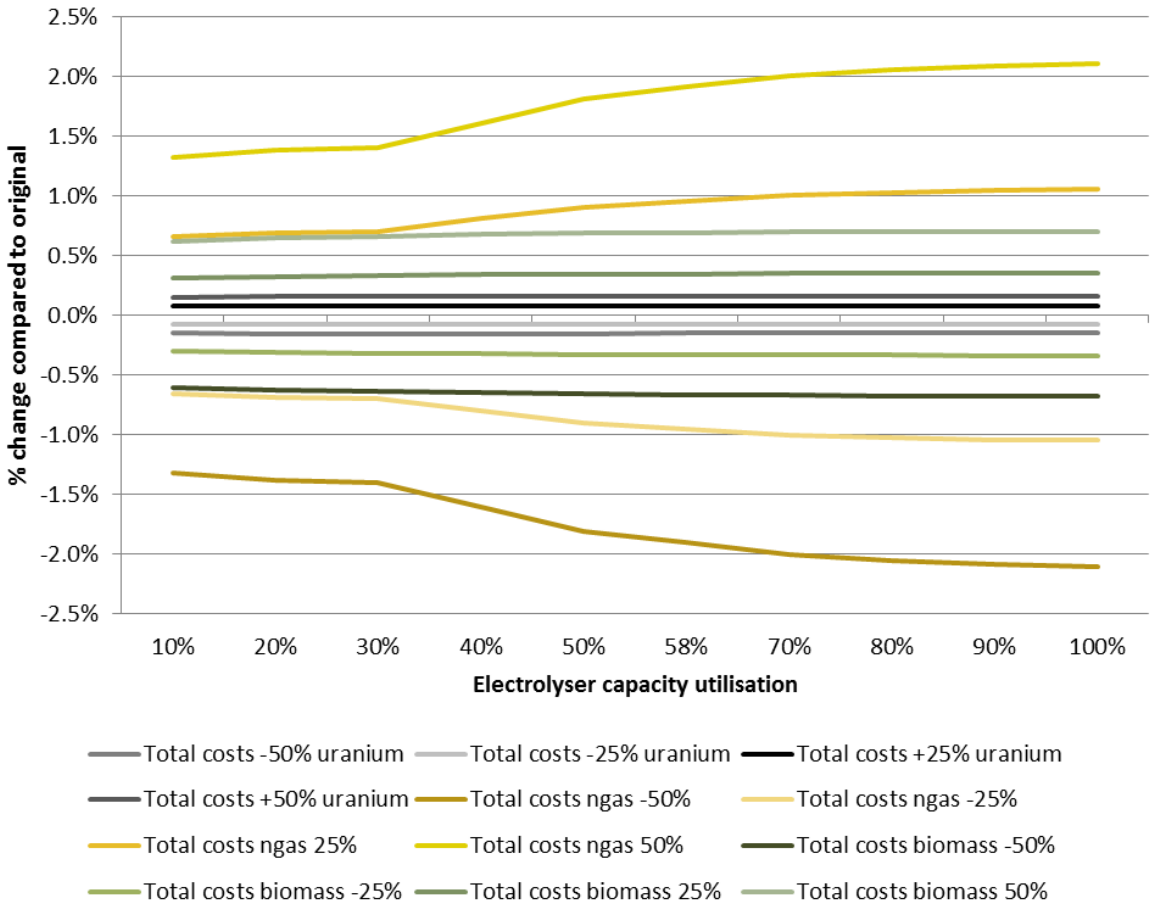

Figure 11. Influence of changes in natural gas (yellow), biomass (green) and uranium (grey) prices on total system costs (excluding vehicle costs) in a German scenario with 15% share of nuclear energy in electricity production

Another sensitivity analysis with changes in the wind investment prices was conducted to investigate the influence of investment changes on the total system costs (excluding vehicle costs). The investment costs were for onshore wind as this was the capacity that was altered in modelling for different utilisation of electrolysers (see Table 3). It can be seen from the Figure 12 that the highest oscillations in total system costs due to the changes in wind investments are up until 30% of the electrolyser utilisation capacity and it is reduced afterwards. This is connected to the reduction in wind capacity as with the higher utilisation capacity of electrolysers the less wind is in the German system. Overall, the range of changes in comparison to the reference scenario is between 1-3%.

Table 3. Input data for sensitivity analysis for different investments in wind turbines

	Investments (M€/MW$_e$)	Lifetime (years)	Operation and maintenance (% of investment)
50% increase	1.73	25	2
25% increase	1.44	25	2
Reference	1.15	25	2
25% decrease	0.86	25	2
50% decrease	0.58	25	2

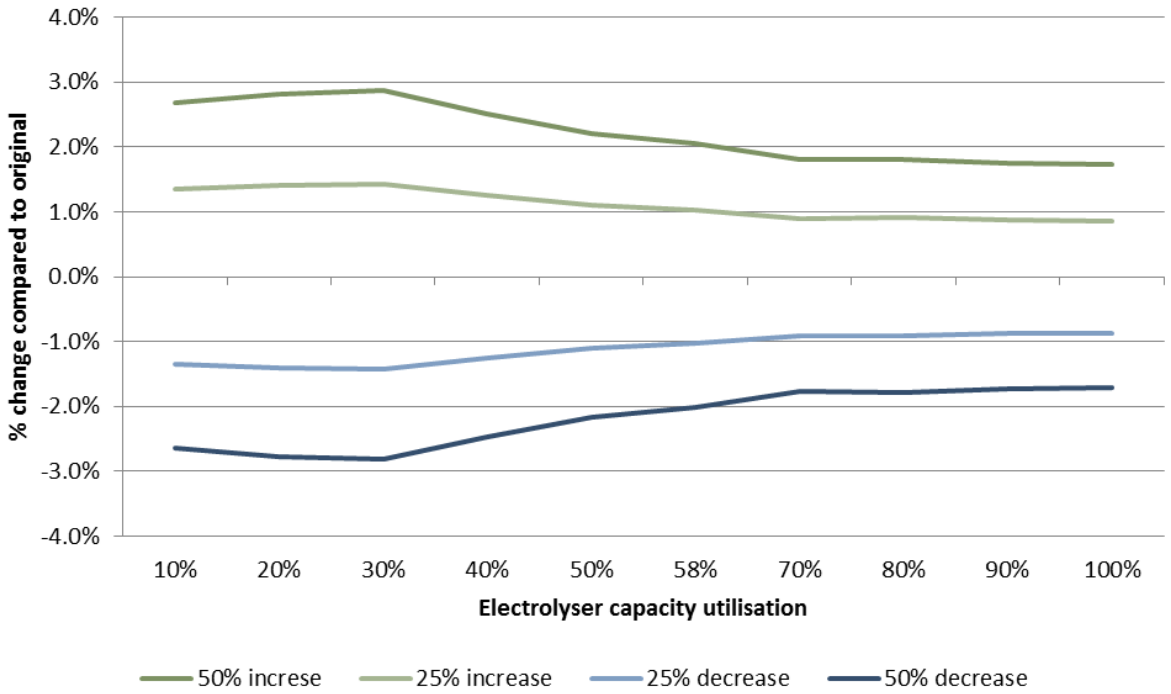

Figure 12. Influence of changes in wind investment prices on total system costs (excluding vehicle costs) in a smart energy Germany 2050

2.4. Alkaline versus SOECs

Alkaline electrolysers have been commercially available for many years and represent an option for production of electrofuels already today. In comparison with alkaline, SOECs are still not commercialized but their development and demonstration is progressing [13]. Alkaline electrolysers will be more expensive than SOECs as they use noble materials for electrodes while SOEC use ceramics, however as the SOECs are not commercially available this assumption is based on cost predictions. Furthermore, the commercially available alkaline electrolysers have lower efficiencies than the expected efficiencies for SOECs and therefore it is important to compare the use of these two types of electrolysers for fuel production. The data used for this analysis is presented in Table 4 and is based on [2].

Table 4. Investment costs and efficiencies for SOEC and alkaline in the analysis

	Investments (M€/MW)	Lifetime (years)	Operation and maintenance (% of investment)	Efficiency-$_{LHV}$ (%)
SOEC	0.28	15	3	73
Alkaline	0.87	27.5	4	63.7

The results indicate that the energy system cost differences between using alkaline electrolysis for producing hydrogen for electrofuels instead of SOECs is negligible (see Figure 13). The total system cost difference is approximately 2% due to lower efficiencies of the process and increasing investment costs. The cost difference from the costs associated only with transport (as the electrolysers are used for transport fuel productions) were analysed in [14] which reports that using alkaline instead of SOECs could result in 9% higher costs. This shows that alkaline should not be disregarded if the commercialization of SOECs is postponed after 2020 in order to introduce electrofuels as a production process in the system.

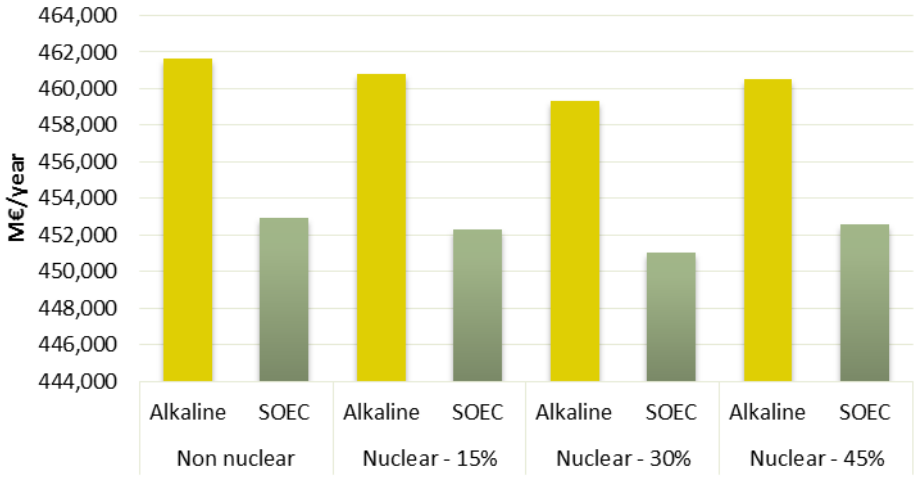

Figure 13. Comparison of alkaline versus SOEC electrolysis on the total investment costs

3. The capacities of combined SOEC/SOFC units for grid balancing

The solid oxide cells (SOCs) are capable of operating in reversible mode, meaning they can operate as both electrolyser and fuel cell. This benefits both the energy system and the profitability of the projects that use this technology. When operating in reversible mode, the device is called reversible solid oxide fuel cell (RSOFC) [15]. When operating in electrolysis mode (SOEC) the RSOFC is converting water to hydrogen or water and carbon dioxide to syngas by use of an electricity source. In the fuel cell mode (SOFC) the device is generating electricity by converting fuels such as hydrogen or hydrocarbons.

When installing the electrolyser capacity in the system it is important to consider the potential of using some of the capacity in a fuel cell mode. This can offer economic benefit of having one investment that can both produce fuels, but also produce electricity at times and thereby improve the stability of the energy system by offering the grid balancing capacity when intermittent resources cannot meet the demand for electricity. The reversible mode of operation was discussed, modelled and tested in several publications [16–18]. The potential for using combined capacities of SOEC and SOFC is therefore analysed in this report. In order to determine the potential operation hours for combined SOEC/SOFC mode, it is necessary to conduct hour-by-hour analysis of an energy system. SOEC mode is used for production of liquid/gaseous fuels for the transport sector, while the potential of SOFC operation is based on substitution of CHP combined cycle gas turbines (CCGT) as they both convert fuels into electricity.

By using the scenario of 100% renewable Denmark 2050, with an installed SOEC capacity of 7741 MW (*100% RES DK*) and 4445 MW of CHP. It was investigated when reversible operation of SOEC/SOFC in fuel cell mode can substitute CCGT in combined heat and power plants and what the economic benefits are for this mode of operation. Firstly, it was important to determine how do installed electrolysers operate in relation to CHP. This hour-by-hour analysis showed that electrolyser and the CHP are operating 4602 hours at the same time, of which 3837 hours the electrolyser is operating while the CHP is idle and only 345 hours the electrolyser is idle and the CHP is operating. This happens in relation to off-shore wind production; while off-shore wind production is high the CHP is idle and electrolysers are operating and producing fuel, while during the low off-shore wind production the electrolysers are idle and CHP is operating. As the electrolysers are technically regulated to minimize the critical excess electricity production, this operation is understandable.

3.1. Maximum theoretical potential for SOFC operation

In order to investigate the potential of fuel cell mode to substitute operation of CHP, we need to define first the maximum theoretical potential of SOFC operation. The maximum theoretical potential of SOFC is determined by hourly operation of SOEC and unutilised capacity in this mode. Figure 14 illustrates the operation of SOEC during the third week of January. The unutilised SOEC capacity can be determined by subtracting the hourly utilised capacity from the installed capacity. For example, in the first hour of the presented week, the unutilised capacity is 6207 MW. To determine the maximum theoretical SOFC potential, the unutilised SOEC capacity needs to be multiplied with the efficiency of SOFC mode. It is expected that in 2050 the efficiency of SOFC technology will be $60\%_{LHV}$ [19] and therefore the maximum operation capacity in the first hour is 3724 MW. On an annual basis, the maximum theoretical SOFC production is 20.4 TWh.

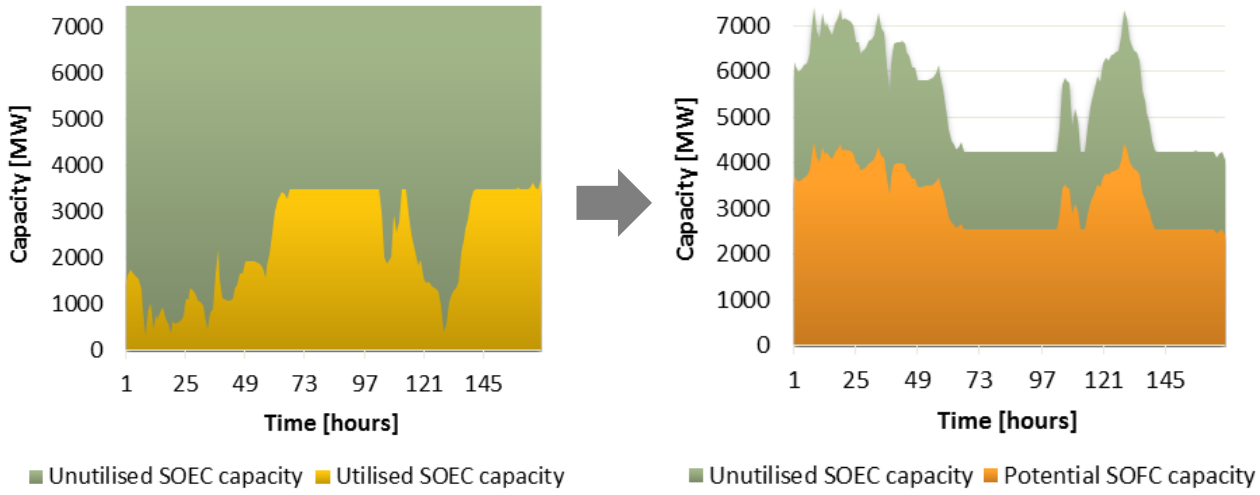

Figure 14. Theoretical maximum capacity for SOFC operation in combined SOEC/SOFC units

3.2. Substitution of CCGT with SOFC

The next step is to determine how much CCGT capacity can be substituted by SOFC operation. This will depend on not only the SOFC capacity available to substitute CCGT but also on the electricity demand. The potential of how much of the capacity can be substituted by SOFC is can be calculated by equation (1): subtracting the theoretical SOFC production from capacity of CCGT and divided by the CCGT capacity. This is an example for first hour in this specific week.

$$P_{SOFC} = \left(1 - \frac{4445MW - 3724.72MW}{4445MW}\right) = 84\% \quad (1)$$

This example for the first hour of this week can be seen from Figure 15, where SOFC can substitute 84% of CCGT capacity (difference of yellow and orange surface).

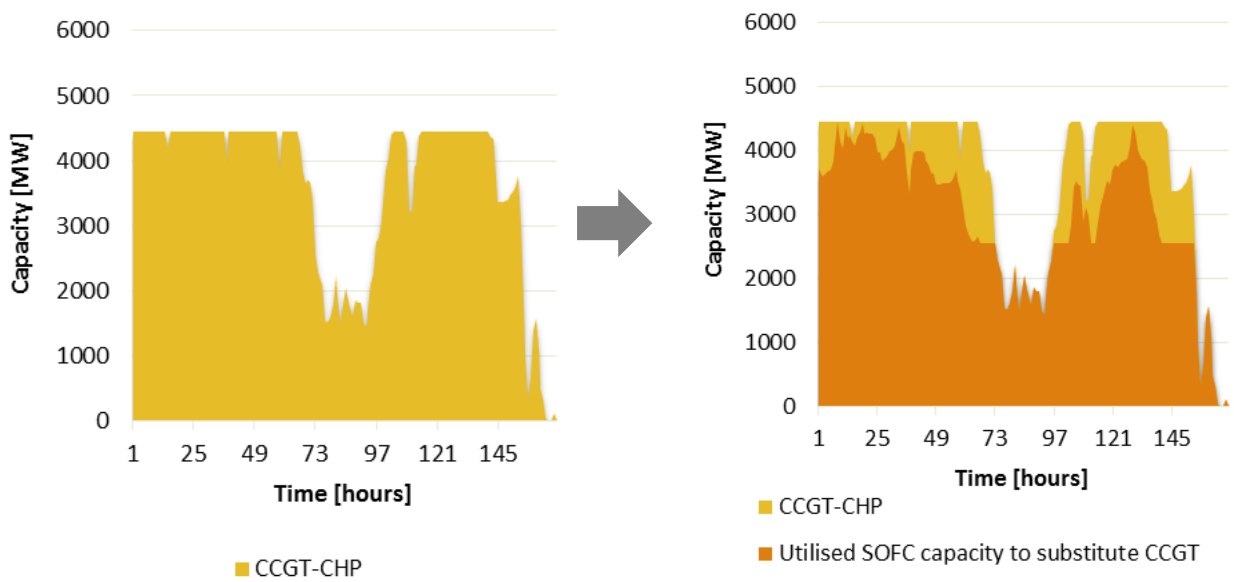

Figure 15. Substitution of CCGT by SOFC

Even though the maximum theoretical production of electricity with SOFC is 20.4 TWh per year, only 47% of this can be utilised in the system to substitute CCGT due to the hourly changes in the demand and supply (see Table 5). Interestingly, even with only 47% of the potential capacity used, it is possible to substitute almost 84% of the CCGT capacity.

Table 5. Characteristics of SOFC and CCGT in the 100% RES DK

Maximum theoretical SOFC production	Utilised SOFC capacity to substitute CCGT		CCGT production	Remaining production of CCGT
20.40 TWh/year	9.58 TWh/year	83.58 %	11.45 TWh/year	1.88 TWh/year

3.3. Economic benefits of CCGT substitution with SOFC

Economic benefits of substituting CCGT with SOFC can be calculated by comparing investment costs, operation and maintenance costs and lifetime. This calculation is a basic economic calculation and it was performed to get an overview of the investments in these technologies. The costs are calculated based on the potential of the SOFC for substituting CCGT and three cases were compared: if the investments are in CCGT, if the investments are in both CCGT and SOFC as substitute (short-term costs) and the investments in both CCGT and SOFC as substitute (long-term cost predictions). In the 100% RES DK scenario a total capacity of 4445 MW of CHP plants using CCGT are installed. They are divided with 1945 MW of small CCGT and 2500 MW of large CCGT. The maximum necessary capacity of CCGT that cannot be substituted by SOFC is 1889 MW. This is distributed according to the 100% RES DK scenario distribution to 827 MW of small and 1067 MW of large CCGT. The remaining 2556 MW is substituted by SOFC. The economic data used for this calculation is presented in Table 6.

Table 6. Economic data used for SOEC/SOFC analysis according to [19]

Technology	Investment costs [M€/MW]	Lifetime [years]	O&M costs [% of Inv.]
Small CCGT-CHP	0.79	25	2
Large CCGT-CHP	0.55	30	2.3
Small/Large SOFC-CHP (short-term)	0.8	30	6
Small/Large SOFC-CHP (long-term)	0.4	30	6

From these preliminary results in Figure 16, it can be seen that the SOFC can compete with current CCGT costs in the long-term, while the results for the short term indicate that the substitution is more costly than using CCGT. This short term result is expected as there are no large scale use of SOFCs in combined heat and power. This is purely from investment and O&M point of view. Associated fuel costs are not included in this analysis but could influence the results. Moreover, this is highly uncertain estimate of the costs as the price predictions are always subjected to changes. If it is possible to substitute high share of CCGT with SOFC with assigned costs, in the long term the use of SOFC gives the same investments as does the full operation of CCGTs. In order to determine the economic potential of SOFC, the more detailed economic assessment is needed that would include the associated fuel costs, potential taxation benefits and sensitivity analysis of predicted investment costs.

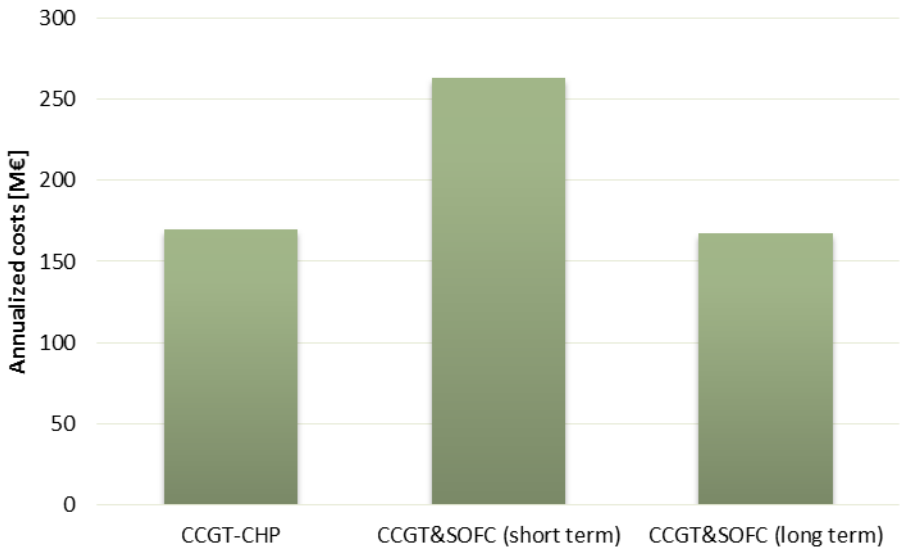

Figure 16. Annualized investment and O&M costs for CCGT today, short and long term cost prediction for scenarios with SOFC substitution of CCGT

3.4. Sensitivity analysis for wind production and distributions

The sensitivity analysis was conducted to investigate the impact of different wind productions that occur in different years, while the installed wind capacity remains constant. This type of analysis is important as the wind production can vary significantly from year to year. The 9-year period from 2005 to 2014 with historical yearly wind profiles was analysed (see Figure 17).

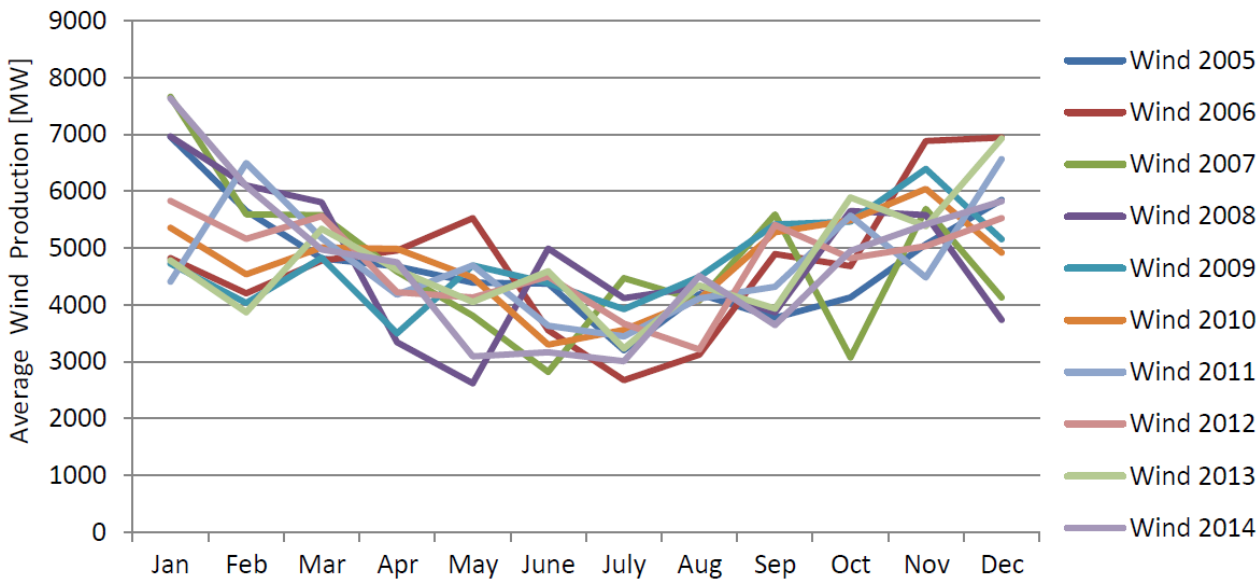

Figure 17. Average monthly wind production in Denmark for the period between 2005 and 2014

The annual wind power production profiles were downloaded from energinet.dk databases. It is important to note that this analysis does not show the different energy systems over this period of time. The system analysed is Danish 100% renewable energy system, but the different wind profiles were used in order to see what is the impact of these. The only variation were the distribution profiles, while the installed wind capacity

in the system was kept the same. The expected full load hours from the scenario is simulated by correcting the production output.

Figure 18 illustrates changes in critical excess electricity production (CEEP)[2], biomass consumption and total annual costs based on different wind productions during the period. The horizontal axis only indicates the years from which the wind profiles are taken. We can see that using different wind distributions have an influence even in the same energy system. As biomass consumption in the system is dependent on the wind production, the higher the wind production, the lower the biomass use and the same trend can be found for total annual costs which are directly connected to expenses associated with biomass consumption. This indicates that a high wind production brings economic benefits for the energy system as it replaces fuel that would otherwise be used in the system and eliminates fuel-associated expenses.

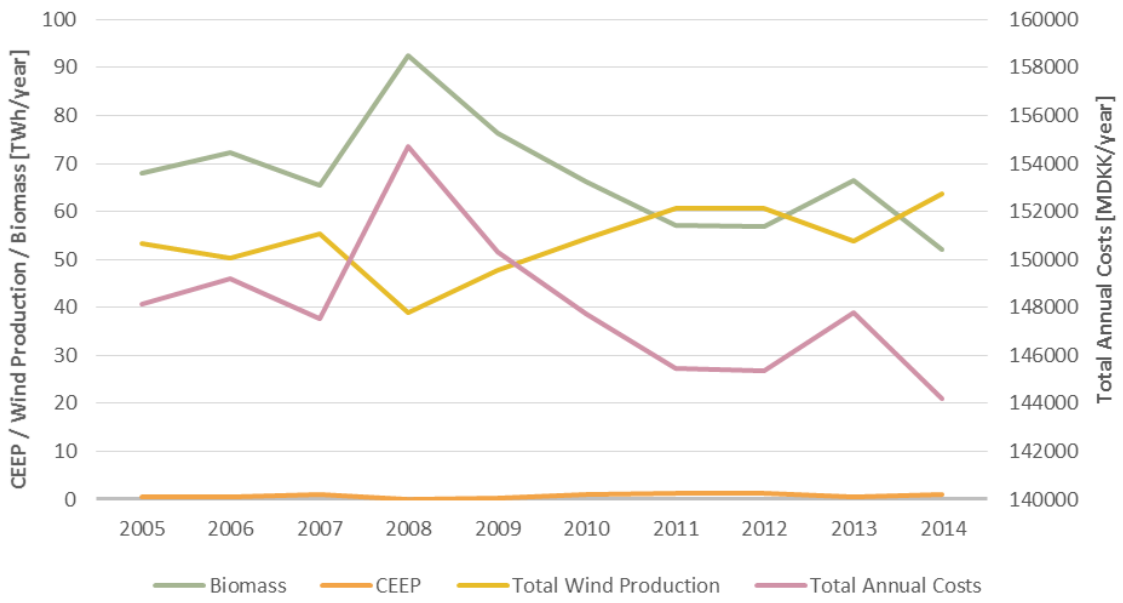

Figure 18. System operation with different wind distributions (years are indication of distribution year) in 100% renewable Denmark model

Looking into how this is reflected on the potential of SOFC to substitute CCGT, it is visible from Figure 19 that the CHP electricity production is changing according to the wind production. The maximum CHP electricity production (15.31 TWh/year) occurred in 2008 when the wind production was the lowest, while the minimum CHP electricity production (4.85 TWh/year) was in 2014, which was a windy year. With increase in wind production, the combined SOEC/SOFC can substitute higher share of CCGT. Depending on the wind production, the combined SOEC/SOFC can substitute between 73.7 % (2008) and 96 % (2014) of the CCGT capacity. On average, combined SOEC/SOFC can substitute ~84% of CCGT capacity, as the average wind production is 53.89 TWh/year.

[2] CEEP is the difference between the total electricity production and the demand, it also represents the amount of electricity that cannot be exported (if there is not enough transmission capacity).

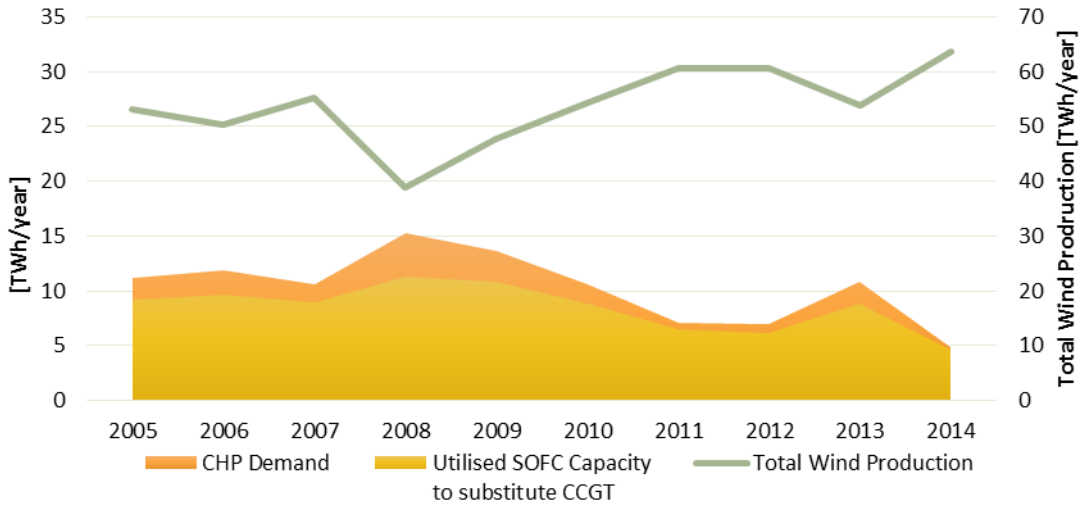

Figure 19. Sensitivity analysis with different wind production from 2005-2014 and substituted CCGT operation with SOFC in 100% renewable Denmark model

The second sensitivity analysis was conducted for the same period in which the installed wind capacity and production is kept the same, while the wind distributions are changed according to the different distribution profiles throughout the years (2005-2014). As shown in Figure 20, there are no significant variations in the biomass use or total annual costs in this analysis. The analysis shows that different wind distributions have no significant impact on operating hours of SOEC/SOFC in fuel cell mode if the wind production and capacity remains the same.

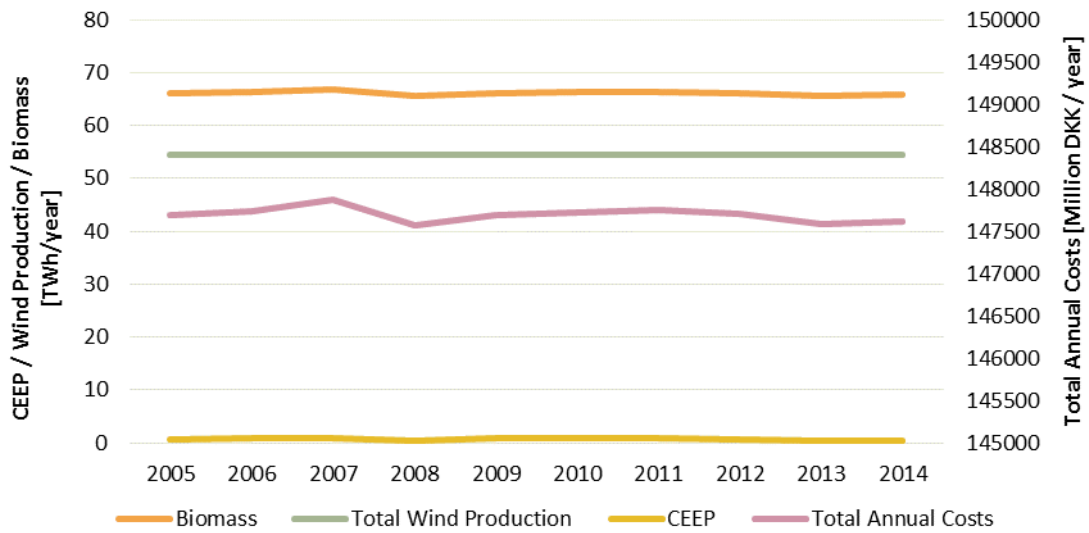

Figure 20. Main system characteristics for the period of 2005 to 2014 with different wind profiles and the same wind production in 100% renewable Denmark model

As there is no variation in wind production, the CHP production is only changing slightly between 10.1 and 11 TWh/year. Together with the fact that the fuel demand is not changed the electrolysers are operating the same as in the 100% RES DK scenario, meaning that the potential SOFC capacity that can be used remains the same. The combined SOEC/SOFC can substitute between 82 % and 83.5 % of the CCGT capacity. Thus, it

can be concluded that a different wind distribution over the year has no greater impact on the operating hours of a combined SOEC/SOFC in the fuel cell mode.

4. Steam electrolysis versus co-electrolysis for fuel production

The three fuel production pathways that were identified in the previous ForskEL project [5]: biomass hydrogenation (*bioelectrofuel*), CO_2 hydrogenation and co-electrolysis (*CO_2 electrofuels*) were further analysed and reported in a series of publications [3,4,9,20]. The liquid or gaseous fuel produced from these pathways are to be used for the freight transport as the personal transportation and public transportation has a priority to be electrified. Moreover, freight transport has a demand for high dense fuels due to the long distance transportation and these modes of transport cannot be electrified due to these specific demands. In order to completely eliminate the biomass from transport fuel production, *CO_2 electrofuel pathways* can be used. In these pathways the carbon source is coming from CO_2 emissions from stationary sources or in the future potentially from air capturing [21].

The discussion about steam electrolysis versus co-electrolysis for fuel production is of interest in case of CO_2 based fuels. Two fuel pathways can produce these fuels: CO_2 hydrogenation or co-electrolysis. These two pathways are compared in order to get indications regarding which pathway would be preferable for the fuel production in future energy systems.

The *CO_2 hydrogenation pathway* is based on combining carbon dioxide from a stationary source with hydrogen from steam electrolysis to form syngas, which is further converted to methanol/DME, or upgraded to methane. The efficiency of the water electrolysis used in this analysis is $73\%_{LHV}$. The *co-electrolysis pathway* operates in the same principle as the CO_2 hydrogenation pathway, but it is a combined process of water and CO_2 electrolysis. The process output is syngas that is later converted into a desired fuel. The efficiency of the co-electrolysis used in this analysis is $77\%_{LHV}$. The efficiencies are adapted from [2] and additional losses are included.

These two pathways are compared based on an energy consumption of 100 PJ of fuel output. Two electrofuel outputs are analysed; liquid output (methanol/DME) and gaseous output (methane). The energy consumption is calculated based on stoichiometric equations of the reactions occurring in these processes. Using the stoichiometric approach simplifies the reaction that happens in reality. This way of calculating does have limitations and uncertainties. The alteration of energy densities in the energy balance could influence the results, moreover, this analysis does not include the potential synergies of the process that can occur in reality and nor is every conversion losses that might occur in the process included. However, additional losses are added for chemical synthesis and temporarily fuel storage to better reflect the reality. No bioenergy input is required in these pathways as they recycle the CO_2 emissions from the power and heat sector or industrial processes.

The analysis carried out indicates that there are no decisive differences between these two pathways for the same fuel outputs (see Figure 21). Methane as a fuel output has a better overall efficiency (biomass demand + electricity demand) than methanol because of the ratio between hydrogen needed per fuel output.

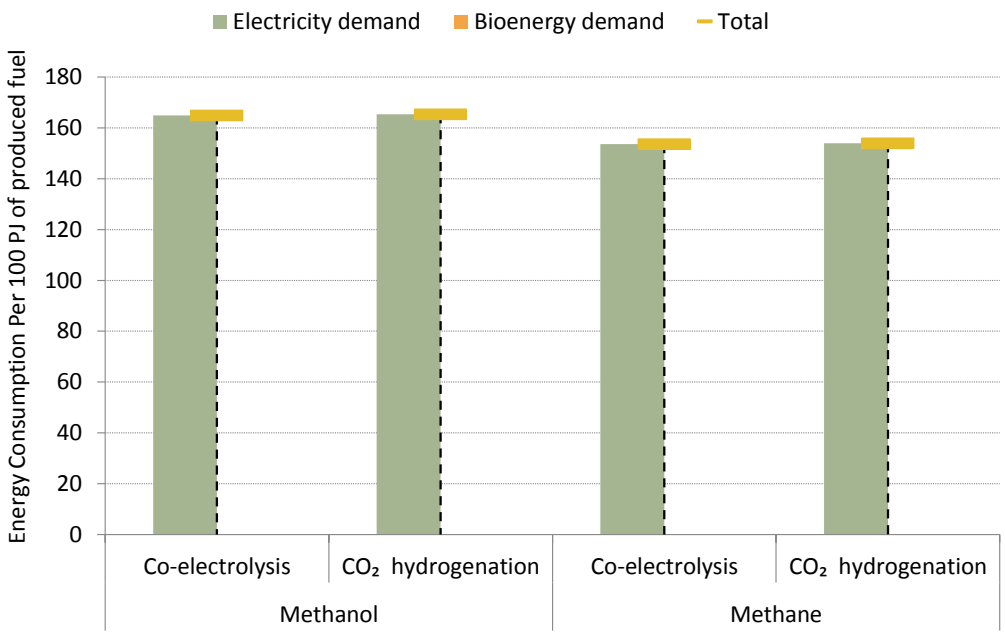

Figure 21. Comparison of energy consumption for CO_2 hydrogenation and co-electrolysis for liquid and gaseous fuel outputs

However, if we look these two fuel outputs not from the produced fuel but per met transport demand, the picture changes. In order to calculate the energy consumption per 100 Gtkm, we need to use vehicle efficiencies of dedicated vehicles for these fuels (Table 7). As the methane vehicles are less efficient than vehicles running on methanol, the picture changes (see Figure 22). Therefore, even with a slightly more efficient fuel production process the methane pathways are less efficient when it comes to meeting the transport demand.

Table 7. Specific energy consumption of vehicles used for calculating bioenergy and electricity demand for pathways

Fuel	Tank-to-wheel efficiency (MJ/km)	Load factor (t/vehicle)	Specific energy consumption (MJ/tkm)
Methanol/DME	10.8	12	0.91
Methane	12.3	12	1.02

If we focus on the technology status, the steam electrolysis is already a well-established technology and alkaline or PEM electrolysers are already commercially available, whereas the co-electrolysis used in SOEC is still under development. This gives a certain advantage to CO_2 hydrogenation pathways as it in the short-term can use commercially available electrolysers while waiting for the development of SOEC electrolysers. Eventually, the development of these technologies, the associated investment costs and the optimisation of the processes will all be decisive factors for which pathway will be preferable.

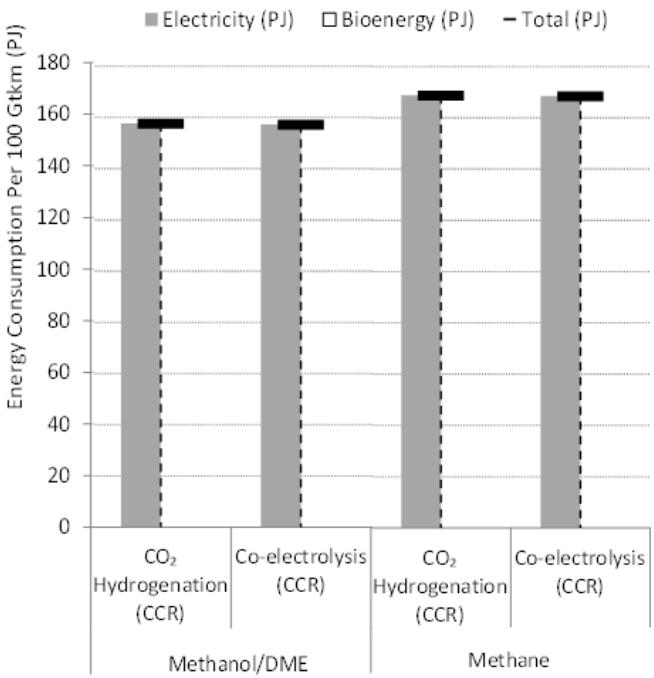

Figure 22. Energy required for pathways to provide 100Gtkm of freight transport

5. Distribution of syngas or final fuel product

Syngas is an intermediate product in the fuel production process that can be converted into any desired fuel through different fuel synthesis. Distribution of syngas as an intermediate product can be beneficial if this gas is used as a main gas in a gas network. This will enable a large storage capacity similar to what the current natural gas grid offers which also brings flexibility to the system and the gas could be converted at the user's side to the needed liquid products or upgraded to methane. On the other hand, the transportation of the final fuel product is well known. Even in cases where the fuels are methanol or DME there are certain modifications that can be done to the existing petrol or diesel fuel trucks in order to transport these fuels. This chapter looks into a comparison between syngas distribution via a natural gas grid versus further conversion of syngas into a desired fuel and the transportation of the latter.

Syngas consists of a high percentage of hydrogen and has therefore explosive potential. Syngas is a mixture of 2:1 of H_2 and CO, but it can contain carbon dioxide, methane, and smaller impurities such as chlorides, sulphur compounds, and heavier hydrocarbons. The problem with transporting syngas is due to the hydrogen and CO properties. Hydrogen can cause leakages and burns from invisible flames indicating that there is a high possibility of injuries in case of an accident. Transportation of syngas is possible in dedicated pipelines designed to manage the properties of the gas. The guideline on pipelines that transport carbon monoxide or syngas is reported in details in [22].

Transportation of syngas with its properties is not possible in the current natural gas network. In cases where hydrogen concentrations are lower than 15% there is a possibility to transport syngas in the existing natural gas network with slight modifications such as increasing the operating pressure. However, this relates exclusively to what the carbon steel natural gas pipes can handle due to the material properties. In case the grid is connected to either filling stations, gas turbines or any gas engines, the percentage of hydrogen that

can be tolerated drops to 2%. The Danish TSO, Energinet.dk, DONG, GreenHydrogen and Danish Gas Technology Centre are testing stability of natural gas pipelines for different concentrations of hydrogen [23]. In the previous tests conducted in Denmark, conclusion was that max 2% can be injected into natural gas grids if connected to CNG filling stations; max 5% if the grid is not connected to CNG filling stations, gas turbines and most gas engines; and max 10% if the grid is not connected to filling stations, gas turbines and all gas engines [24].

This implies that it is necessary to build a special pipeline network that can handle the syngas properties. Since the syngas would not play the same role as natural gas in the existing system, as this would imply that all the power plants, engines and other energy producers need to modify their devices in order to operate on syngas, establishing a completely new network should potentially be avoided since it is a money and time consuming investment. The transportation of the final fuel - in our analysis liquid methanol/DME or gaseous methane - is known and established. There are some limitations and adaptations in the case of the suggested liquid fuels. Due to the properties of methanol/DME there is a need to use either a coating or new materials for storing these fuels at the filling stations [25]. Methane can be transported in an existing natural gas network, which can be used as fuel storage. As the only fuel that is currently used in the transport sector, methane seems to be a more expensive solution than the suggested liquid fuels in terms of infrastructure modifications for transport. Compared to the expensive infrastructure for CNG stations which range from €40,000 up to €1.5 million, depending on the size and the application [26], existing petrol stations can be converted to methanol, or capacity can be added, with the cost range of €30–61,500 [27]. Designing a system without a syngas network would not imply losses in flexibility as upgrading of syngas to methane can still enable the use of natural gas in the systems with 100% renewable energy.

6. Concluding remarks

Integration of electrolysers in energy systems evolve around many aspects of which this report investigated four of them connected to electrolysers used for fuel production. The first two aspects focused on operation modes and optimal utilisation of electrolysers in the system, while the latter two focused on the preferable fuel pathways and design of fuel distribution.

The analysis looked into feasible operation of SOECs in two high renewable system smart energy Germany 2050 and Danish 100% renewable energy system. In addition, three German system with 15%, 30% and 45% nuclear energy of the electricity production were analysed to investigate the influence of nuclear energy on electrolysis operation. The results indicate that the utilisation of electrolysers is highest in the Danish 100% renewable energy system, followed by the energy system with the highest share of nuclear energy in the electricity production. This indicates that the utilisation of electrolysers changes with the system configuration and can result in a different operation regime and needed capacity in the system. For the higher utilisation capacity of electrolysers operating regime is more constant and it does not accommodate fluctuations of wind, therefore depending on the system design some systems can function with higher utilisation capacity as there is a possibility to use wind energy elsewhere in the system, while some systems do not have enough flexible technologies to do so.

The results from the sensitivity analysis considering different fuel price levels for natural gas, biomass and uranium did not show any significant changes in total system costs and the scenario with the highest share

of nuclear energy was the least sensitive to the price changes. Sensitivity analysis with different investments in wind turbines indicates that the oscillations are higher in the lower utilisation of electrolysers and they get lower as the feasible capacity is reached. This corresponds to the share of wind in the system that decreases after the feasible point. Finally, the comparison of using alkaline electrolysis instead of SOECs has indicated only 2% changes in total system costs when alkaline electrolysers are used, meaning that there are no barriers for using this type of electrolysers prior to the commercialization of SOECs. This is important as the key concern is to develop critical technologies for the electrofuel production in order to integrate these fuels in the system as soon as possible, and further improvements in technologies can always be adapted to the already established production process.

When looking into the operation of SOECs in the system it is evident that there is a space for using SOECs as fuel cells in periods when there is a need for electricity in the system. The potential of using some of the capacity as fuel cells is rather high when the capacity is used for substituting combined cycle gas turbine in CHP. Even with only half of the potential capacity for fuel cell operation almost 84% of the CCGT capacity can be substituted. By being able to have one investment that can be used for two purposes in the system is of economic benefit. Using SOFC as a substitute for CCGT in the future seems to result in the same costs as investments in CCGT today. These results indicate that there is a potential for using reversible operation of RSOFC in a Danish 100% renewable system, however further investigation is needed as economic data is highly uncertain and subjected to changes.

Three different fuel pathways can be used for fuel production that use electrolysis for converting electricity into valuable energy carriers that can be further synthesized into liquid or gaseous fuels. Two of these pathways are CO_2 hydrogenation and co-electrolysis using carbon dioxide as a source of carbon and the differences between these pathways were investigated. The analysis indicated that there are no decisive differences that can determine which pathway should be preferred in the future. However, as for the general development of electrofuels CO_2 hydrogenation has a certain advantage as it uses water/steam electrolysis for hydrogen production, which can later be merged with carbon dioxide. Therefore, already developed electrolyser technologies such as alkaline can be used for fuel production and contribute to the development and presence of electrofuels prior to the development of mature SOEC technologies. As for the design of the distribution chain of the products, the transportation of final fuel product either in liquid or gaseous form is preferable instead of transportation of syngas as mediator. This is because syngas requires a completely new pipeline infrastructure in order to be transported and due to the fact that it is not expected to play the same role as natural gas has in todays' system, there is no need for the extensive investment when final fuel can be transported.

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