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A B S T R A C T

Future renewable energy systems with high shares of variable renewable energy production must also include technologies and measures to balance these production fluctuations. This could be in the form of electricity storage, energy demand adaptation (also known as demand-side management), or sector coupling. Industry electrification couples electricity and industry sectors by replacing the fossil fuel demand with electricity demands, thus enabling further integration of renewable electricity and transitioning the hard-to-abate energy sector. The effects of electrification on 100% renewable energy systems are rarely investigated. When investigated, one 100% renewable energy system scenario is used, which is often created by the same author, actor or organisation and may result in a narrow view of the possibilities for future energy systems. This study quantifies the role of industry electrification in the context of different 100% renewable energy system scenarios created by different relevant actors, to identify how its role may differ based on the scenario investigated. It is found that direct electrification of industrial process heat demands should be favoured over, e.g., a fuel shift to hydrogen-based process systems, even when these provide more flexibility.

1. Introduction

Worldwide, there is a shift towards renewable energy sources (RES). A shift in energy consumption from traditional fossil fuels to electricity in different energy sectors, such as the transport, heating and industry sectors, is an important part of the transition towards increased use of RES [1]. The types of RES expected to see the largest expansion globally are wind turbines (WT) and photovoltaic panels (PV). However, because of the variable nature of RES, an energy system built solely on variable renewable energy sources (VRE) also requires other changes to the energy system. Consequently, future renewable energy (RE) systems with high shares of VRE production will need to also include technologies and measures to balance these production fluctuations. This could be in the form of electricity storage or energy demand adaptation, also known as demand-side management or sector coupling solutions [2]. When considering such changes in the other parts of the energy system, previous studies on the transition towards 100% RE systems have found that to achieve a low-cost and energy-efficient transition, all energy sectors should be considered to maximise the potential integration and synergies between these, also in relation to the flexibility options [3]. Considering the entire energy system when transitioning to 100% RE systems is often referred to as the Smart Energy System approach, which was first introduced by Lund et al. [4].

When investigating future RE systems, energy system scenarios and energy planning models are often used [5,6]. These have become essential tools for quantifying the consequences of changes to energy systems. Despite modelling the same physical energy system, scenarios are inevitably influenced by the authors that make them, and even minor differences in their design and goals can cause ripple effects throughout the energy system, thereby complicating their comparison. The impact of different model assumptions and methodologies across different scenarios is rarely explored in detail and the reason behind the differences is not always transparent. Added to this is the influence of the different interpreting stakeholders of a scenario. Differences in the interpreting stakeholders' prior knowledge, their stake in the given

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subject, and their involvement in the development process can lead to misconceptions or distortions of the results when using energy system scenarios [7].

In the scenarios studying energy system transitions, the industrial sector is only sparingly included and often entirely overlooked [8]. Currently, the industry sector accounts for 25.8% (2018 numbers) of the final energy consumption [9] of the 27 European Union (EU) member states. About 9% of the energy used in industry is supplied through renewables or biofuels, while approximately 47% is based on fossil fuels. The rest of the energy demand is covered by electricity, heat and non-renewable waste [10]. This relatively low share of RES within the industrial sector emphasises the need for decarbonisation and transition towards using more RES. The decarbonisation of the industry sector does, however, face some inherent challenges including costs, trade sensitivity, and long facility lifetimes; all contributing to the slow diffusion of energy decarbonisation measures. Furthermore, the heterogeneity of the industry sector, e.g. caused by the differences in production facilities over the world and the variety of products, increases the complexity of decarbonisation [11]. Increased electrification of the industrial sector could result in larger utilisation of WT and PV for industrial processes, and thereby increase the utilisation of renewables.

Industry electrification has been investigated by various researchers. Lechtenböhmer et al. [12] found that the large increase in electricity demand caused by 100% industry electrification could result in major implications on the electricity system. Kosmadakis [13] estimates the potential for high-temperature heat pumps (HP) (>150 °C) in industries and finds that these could cover 1.5% of the industry heat demand in Europe. Bühler et al. [14] investigate the potential of HPs for electrification of the Danish industry, emphasising the potential of excess heat for HPs to supply process heat. Wiese and Baldini [15] develop an energy system analysis model of the Danish industry providing insight into the applicability of various optimisation measures in a Danish context. Bühler et al. [11] find that while the majority of the Danish industry demand (approximately 80%) can be electrified via HPs, its economic feasibility is considerably lower than the technical feasibility. The mentioned studies find various potential levels for electrification in the industry sector, but all agree that some potential exists. However, none of these studies makes a holistic energy system investigation for industry electrification regarding the flexible electricity demand.

The presented studies indicate that higher flexibility in the electricity demand enables higher utilisation of the VRE sources and that the potential for a flexible demand exists. However, the effects on 100% RE systems are rarely investigated; and when the effects are investigated, they are based only on one 100% RE system scenario, often created by the same author, actor or organisation. As a result, the studies may give a narrow view of the possibilities for future energy systems. This paper aims at quantifying the role of industry electrification including its potential for providing flexibility in different 100% RE systems created by different relevant actors. The paper also aims at determining how this role may differ based on the energy system scenario investigated, which is done by simulating different levels of industry electrification and flexibility in the energy system.

2. Methods

When investigating different energy system scenarios, it is important to clarify the specific energy system context, to increase the possibility of comparison between the scenarios. For this study, the case of Denmark is used. Denmark is often highlighted as one of the most ambitious European countries in terms of climate goals [16], committing itself to a 70% reduction in greenhouse gas emissions by the year 2030 compared with 1990 levels, and complete climate neutrality by the year 2050 [17]. Looking solely at the electricity production, 62% is produced by RES, of which 43% is from wind and 3% is from solar (2018 numbers) [18]. This relatively high share of RE in the Danish electricity production provides a better opportunity for decarbonisation through electrification of the industry, compared to other EU countries.

The Danish industrial energy consumption accounts for approximately 20% of the final energy demand [19], supplied directly with 11% renewables and biofuels, 53% fossil fuels and 35% distributed between heat, electricity and non-renewable waste [10]. This leaves significant potential for substituting fossil fuels and integrating VRE. Different levels of industry electrification are tested in three scenarios which all present different 100% RE systems for Denmark in 2050. The scenarios chosen are two scenarios developed by the Danish transmission system operator Energinet [20], the "Sustainable transition" (ST) and "Global Climate Action" (GCA) scenarios, and a scenario developed by Mathiesen et al. for and in coordination with the Danish Society of Engineers, "IDA's Energy Vision 2050" (IDA) [21]. All three scenarios are based on the long-term Danish political goal of having an energy system based on 100% RE in 2050, and all include a medium-term version of the scenario in 2035. The scenarios are, however, developed using different assumptions, methods and starting points. The focus of the present study is on the 100% RE scenarios for 2050, and as such, only the results from these are presented.

The ST and GCA scenarios have been developed using the European TYNDP2018 [22] (Ten Year Network Development Plan 2018) as a starting point for how the Danish energy system would fit into different future European energy systems. Energinet has developed these scenarios for planning future investments in infrastructure, developing market design and operation strategies, and contributing to public and political discussions. As the transmission system operator of both the electricity system and gas system in Denmark, Energinet has emphasized these parts of the energy system, although the heating, industry and transport sectors are included in the scenarios.

The IDA scenario has been developed by researchers at Aalborg University in coordination with IDA and is based on the smart energy system concept. The IDA scenario mainly distinguishes itself from the ST and GCA scenarios by aiming at supplying most of the electricity demand domestically and therefore having less transmission line capacity to other countries. The IDA scenario also includes more detailed analyses of the heating, cooling, and transport sectors. This means that the IDA scenario has major differences in these sectors, e.g., a larger production of electrofuels and considerably more excess heat and geothermal heating for district heating (DH). These are only a few of the differences between the scenarios, while a full comparison of the different scenarios is presented in Sorknæs et al. [23].

Fig. 1 illustrates a comparison of the primary energy supply of the three analysed scenarios, providing an overview of the entire fuel consumption across all energy sectors. The higher total consumption in the IDA2050 scenario is mainly the result of a higher electrofuel production that supports all internal demands, without fuel imports. Fig. 2 provides more insights into the production and consumption of electricity across the scenarios.

The ST2050 and GCA2050 scenarios import more electricity compared to the IDA2050 scenario, thereby reducing the production from thermal plants and Combined Heat and Power (CHP) plants. The variable RES production is highest in the IDA2050 scenario, followed by the GCA2050 and then the ST2050 scenario. The electricity demand from electric vehicles (EVs) is comparable in the ST2050 and GCA2050 scenarios, but higher than the level assumed

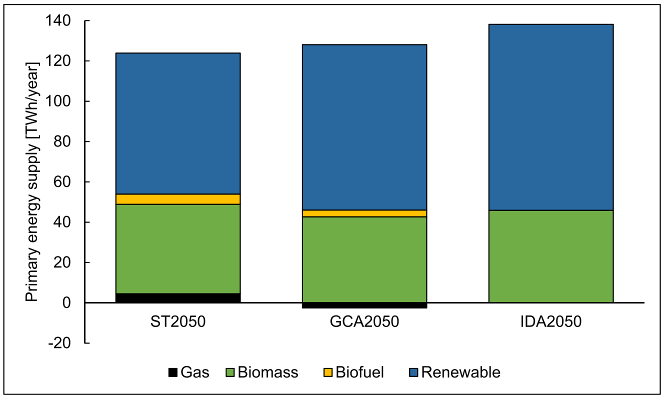

Fig. 1. Primary energy supply in analysed scenarios.

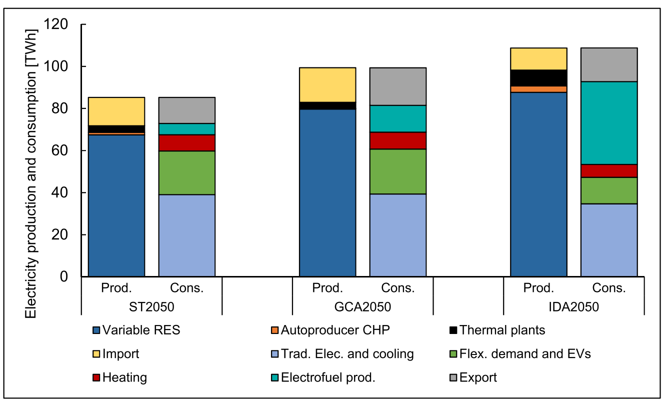

Fig. 2. Electricity production and consumption in analysed scenarios.

in the IDA2050 scenario.

Both the Energinet and IDA scenarios are based on data from the Danish Energy Agency's energy balance model, although from different years. As different versions of the model were used, differences occur in the projection of future demands towards 2035 and 2050, with regard to the industry sector boundary definition. Furthermore, there are some differences in the modelling of process heat. In Energinet's scenarios, process heat is separated into more sub-categories based on the temperature level, unlike the IDA scenario, which does not make this differentiation. Thus, the energy consumption of the industry sector cannot be directly compared between the Energinet scenarios and the IDA scenario. Fig. 3 presents the energy demand for process heating in the different scenarios, but as mentioned before, the boundary definitions are not entirely consistent across the Energinet and IDA scenarios.

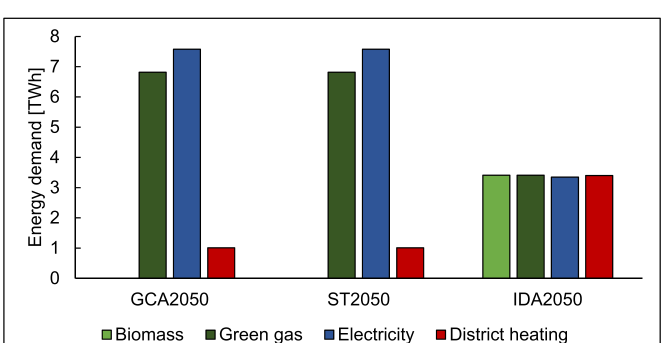

Fig. 3. Energy demands for process heating in analysed scenarios.

In Fig. 3, it is observed that the GCA and ST are similar in terms of energy demands for the industry sector. Demands are mainly supplied by electricity and green gas, with a small amount of heat supplied by DH. Both the GCA and ST scenarios are, however, included in this paper due to the differences in their respective energy systems, outside the industrial sector. In the IDA scenarios, the origin source of heating is evenly distributed between biomass, green gas, electricity and DH. As stated, these scenarios are tested with various levels of industry electrification.

2.1. Analysis testbed

Different energy system simulation tools have been applied to the development of the different scenarios. The ST and GCA scenarios were developed in Energinet's internally developed tool Sifre-Adapt [20], and the IDA scenario was developed in the free-to-use tool EnergyPLAN [24]. Both energy system analysis tools simulate hourly energy balances, although their simulation approach and technology details vary. For a quantifiable cross-scenario comparison, the three scenarios are all modelled in EnergyPLAN v15.1. The details on the remodelling of the ST and GCA in EnergyPLAN can be found in Sorknæs et al. [23].

EnergyPLAN is developed and maintained by the Sustainable Energy Planning research group at Aalborg University and already in 2015, it was applied in 95 different analyses for research papers and PhD theses [25]. EnergyPLAN has, e.g., been used in the context of analysing electrification, both concerning country-wide RE systems [26–30] and sectorial renewable transition studies [31–33].

EnergyPLAN can assist in the design of energy systems and energy strategies by using different operation strategies to determine the yearly output of an energy system, to a given input. Chronologically, it determines the hourly energy balances for the heating, cooling, electricity and gas demand and summarises the yearly results in terms of annual conversion of energy, import and export of electricity from other countries or regions, total annual costs, fuel consumption, and yearly CO_2 both emitted directly from the energy system, but also as a consequence of importing electricity from other countries or regions.

An overview of the flow of energy in the various sectors is shown in Fig. 4.

As seen in Fig. 4, the different energy sectors are interconnected in the simulation; i.e., the industry sector is both a producer of process heat for internal purposes, but can also deliver excess heat to households and electricity to the electricity system if CHP units are used for the production of process heat. EnergyPLAN thereby enables the use of potential synergies between different energy sectors, as it is built around the concept of Smart Energy Systems.

EnergyPLAN allows for two different overall simulation strategies depending on the goal of the simulation: a Technical Simulation where EnergyPLAN aims at operating the energy system in a fuel-efficient manner, and a Market Economic Simulation where EnergyPLAN operates the energy system based on the current European day-ahead electricity market model aiming at minimising the short-term marginal costs of the energy system. Unless otherwise stated, the scenarios are modelled in a Market Economic Simulation strategy, as it allows for a better understanding of how different energy systems import and export electricity.

The three energy system scenarios are tested in different variations to see their responses to different levels of industrial electrification. This ultimately results in different levels of electricity demands, superseding the electricity demand of the original scenarios. To keep the emission neutrality of the different scenarios, the installed offshore WT capacity in the scenarios is adjusted

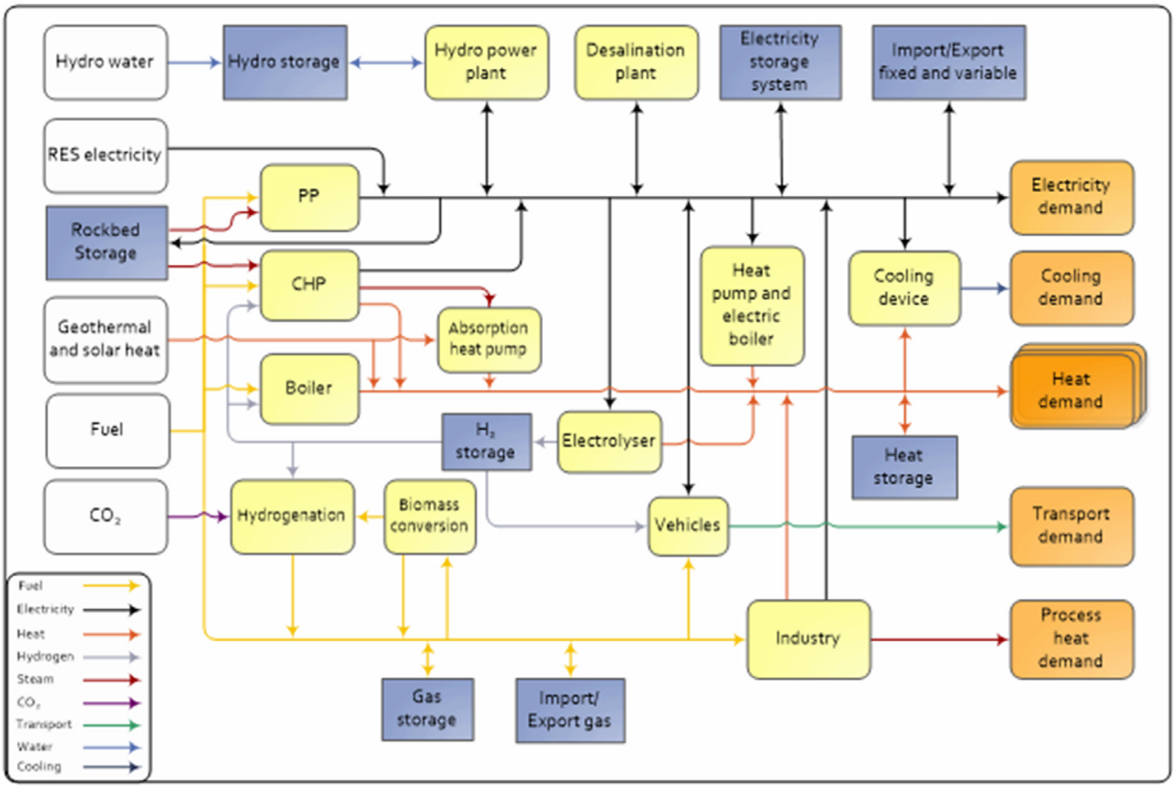

Fig. 4. The energy flow in EnergyPLAN. Here the various colours of the boxes symbolise different elements in the energy system: White represents the primary energy sources, yellow the energy conversion units, blue the energy storage, and orange the energy demands.

accordingly to make up for this demand. Offshore WT is used for adjustments, rather than other types of non-fuel use RES since all scenarios are below the theorised capacity of 40 TWh/year of offshore WT within the Danish waters [34]. The IDA scenario for 2050 comes closest with 14 TWh/year. The capacity adjustment for offshore WT is based on the apparent change in critical excess electricity production (CEEP) that would occur within the system if no export of electricity was possible and the transmission line capacity was zero. CEEP is the electricity produced that cannot be utilised, stored or transmitted to other areas at the time of use. The method is used first to identify the CEEP in the original scenario without a transmission capacity. Then, the new parameters for the scenario are implemented, and lastly, the offshore WT capacity is increased or decreased until the same level of CEEP is obtained, again without any transmission line capacity. After this, the original transmission line capacity is again included in the scenario. By using this method throughout all analyses, the electricity production can be increased without superseding the theorised transmission capacity within the system, thereby avoiding grid instabilities. The added offshore WT capacity is also considered when comparing the total system costs of the different scenarios, which indicate the economic feasibility of the various adjustments to the scenarios. In this process, it is also ensured that any scenario principles used in the development of the original scenarios are maintained. This relates mainly to the IDA2050 scenario, which has been developed based on a principle that all gaseous and liquid fuels must be produced within the Danish energy system, which is ensured by adjusting the yearly fuel input and capacity of the biomass gasification to reach a yearly net exchange of gas of zero.

2.2. Industry electrification

Industry electrification can be achieved by two methods: direct electrification and indirect electrification. Direct electrification occurs by producing heat using electric boilers and HPs. Indirect electrification requires the production of electricity-based fuels, which then can be burned in boilers or similar. The simplest fuel to produce with the highest energy efficiency is hydrogen from electrolysis. Both electrification methods are tested in each scenario to see their effects under different energy system conditions. However, since the operation strategies differ across scenarios, the analysis uses different methods for testing electrification.

2.2.1. Direct electrification

For the scenarios made by Energinet, i.e., the ST and the GCA scenarios, two different methods are used for testing the effects of shifting the demands from gas towards electrification. The first method is to replace the use of biogas in boilers, with an efficiency of 80%, with electric-driven compression HPs with a relatively low coefficient of performance (COP) of 1. The relatively low COP of the HPs is due to the fact that they supply heat to parts of the industry operating at temperatures above 150 °C, which currently are not reachable with commercially available HPs [35]. The maximum potential available for shifting from electricity to gas-based processes is equal to the energy demand currently supplied by the electric HPs with a COP of 1, as these low-efficiency high-temperature processes have the highest potential efficiency gain when shifted to a gas supply. This simple approach does not consider boundaries for the available biomass potential that can be used for biogas production, nor does it consider changes in investment costs related to the technical installations at the industries. The second method includes the available biomass potential in Denmark. This is achieved by utilising a more complex method, assuming that the biogas and synthetic gas production already used in the scenarios are at their maximum sustainable utilisation. Therefore, increased gas consumption will result in equivalently higher gas production at biomass gasification plants. With a lower biomass consumption due to electrification, the biomass consumption in the gasification plant will decrease. This will be referred to as “gas adjustment”.

For the IDA scenario, the industrial biomass demand is shifted to an electricity-based demand assuming an efficiency gain of 20%, similar to the first method used for the ST and GCA scenarios by Energinet.

2.2.2. Indirect electrification

The ST and GCA scenarios are tested in two ways, a simple and a complex method. The simple method again does not consider the gas supply side, but shifts existing biogas demand to a hydrogen demand, only considering a boiler efficiency of 80% and an electrolyser efficiency of 74%. The complex method, using gas adjustment, reduces the production at the biogas and biogas hydrogenation plants, with the fuel shift towards hydrogen produced through electrolysis at the industrial site.

The IDA scenario is again slightly different in the sense that the biogas production is balanced by default to a yearly net-zero import; thus, reductions in the biomass demand will also be reflected in the supply side, like in the principle described for the complex method.

3. Results

The following analyses investigate the challenges of industry electrification, outlining the effects of both an increased and decreased electrification rate, considering process heat demand temperature levels and the utilisation of HPs in the baseline scenarios.

3.1. Direct electrification

Fig. 5 shows that for all scenarios, an increased level of electrification (fuel input decreasing towards zero) allows for a larger offshore WT capacity without causing additional CEEP. This indicates that continued electrification can contribute to increased VRE integration. For the IDA scenario, it can be observed that the maximum fuel input is significantly lower than for the Energinet scenarios. This is due to a complete shift of the biomass demand to electricity occurring earlier in the IDA scenario, as the industrial energy demand is also supplied by DH and renewable gas, which remains unchanged for this analysis. The starting point for fuel inputs differs for the scenarios as they have different total fuel inputs.

Another observation from Fig. 5 is the differences in the increase of offshore WT capacity at the total electrification of industry (zero fuel input). There are several reasons for this difference in maximum offshore WT capacity, with the most influential factor being the already existing installed capacity in the different scenarios. Fig. 5 shows that the highest potential capacity can be installed in the ST2050 scenario, which also has the smallest offshore WT capacity. The GCA2050 and IDA2050 scenarios have approximately 4 GW and 6 GW more offshore WT capacity, respectively, which to some extent limits further expansion from an energy system perspective.

Finally, a significant difference can be observed when comparing the GCA2050 (gas adjustment) to the GCA2050 without gas adjustment – a difference that does not occur for the ST2050 scenarios. This is due to the differences between electrofuel production in the GCA2050 and ST2050 scenarios, and the previously described methodological approach to this analysis. The GCA2050 scenario has an electrofuel production from electrolysers and biogas hydrogenation that is significantly larger than in the ST2050. As the industrial renewable gas demand is shifted to electricity, biogas production decreases (together with the production of electrofuels from biogas hydrogenation). Thus, the increased electricity demand from industry is partly offset by a reduced electricity consumption during electrofuel production, resulting in a lower maximum offshore WT potential at complete electrification for the GCA2050 (gas adjustment) scenario.

Fig. 6 shows how the biomass consumption of the entire energy system is impacted by the changes to the industry electrification rate. Biomass consumption includes both the biomass directly consumed in the industry sector and the biomass consumed in other parts of the energy system.

One of the most significant differences across the scenarios is the low impact on biomass consumption for the GCA2050 and ST2050 scenarios. This is because of the methodological approach applied, specifically the biogas production adjustment relative to industry renewable gas consumption. In the GCA2050 and ST2050 scenarios without gas adjustment, the supply side is not changed. Therefore, the total biomass consumption of the system is not impacted by shifting fuels in the industry sector, as the same amount of biogas is produced within the system. However, the

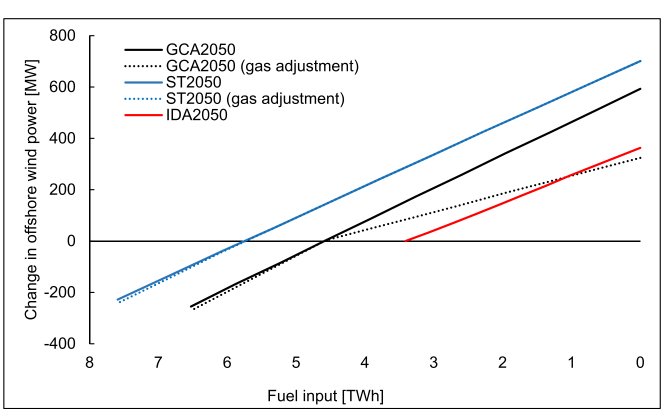

Fig. 5. The change in offshore WT capacity in each scenario at different biomass/biogas fuel input levels for high-temperature processes in the industry.

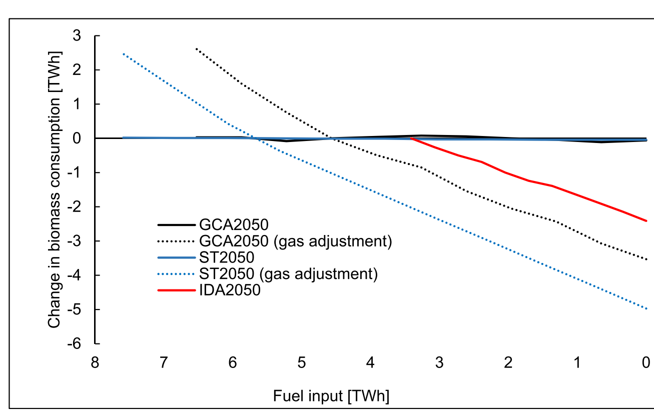

Fig. 6. The change in biomass consumption for each scenario at different levels of biomass/biogas fuel input.

export of biogas increases as the electrification rate increases, as illustrated in Fig. 7, except for the IDA2050 scenario, where the net gas import remains at zero.

Fig. 8 shows the energy system cost variation for the different scenarios, where the electrification of the industry is heavily dependent on the analysed scenario.

For all scenarios, the change in offshore WT capacity is a deciding factor in energy system costs; a large increase in offshore WT capacity needs to be accompanied by correspondingly large savings elsewhere in the system. Thus, the results on installed offshore WT capacity from Fig. 5 have an important influence on the energy system cost results in Fig. 8.

Common to all the Energinet scenarios is that the installed capacity for both large power plants and small CHP plants is smaller than in the IDA scenario, making international electricity exchange more prevalent. This causes the ST and GCA scenarios to increase the electricity import as the industry electrification rate increases. Further differences can be found in the gas sector, where the yearly import and export of gas are balanced for the IDA scenario, while these are not balanced for the Energinet scenarios. Hence, in the Energinet scenarios, the Danish system can fluctuate from operating as a net importer to a net exporter of gas (Fig. 7), where the industry electrification rate can influence this balance.

The GCA2050 scenario shows an increase in energy system cost, but mainly due to the large increase in WT capacity; whereas if this investment is excluded, the increased electrification rate results in a lower total cost for the system. Because of the simple methodology applied in the GCA2050 scenario, gas production is not changed as the industry is electrified. Due to this reduced renewable gas demand in the industry sector, the system can, to a large extent, export the produced gas, resulting in an income for the system. However, as the production volume is unchanged in the scenario, the production capacity is also unchanged, and the income from gas export cannot offset the increased costs of offshore WT and electricity import. On the contrary, the GCA2050 (gas adjustment) scenario allows for a reduced biogas production along with a reduced installed capacity for the biogas and biomass gasification plants. This results in lower energy system costs as the electrification rate increases. Therefore, the results for the GCA2050 and GCA2050 (gas adjustment) scenarios trend in opposite directions, as illustrated in Fig. 8.

The energy system cost for the ST2050 scenario seen in Fig. 8 does not change drastically, since the scenario relies heavily on the import of gas, which can be reduced with increased electrification. However, this increases the investment in offshore WT and increases the import of electricity, thus effectively offsetting each other. The results for ST2050 and ST2050 (gas adjustment) do not differ much, unlike the results for the GCA2050 scenario, since the production of renewable gas from biomass hydrogenation is reduced, and the difference in methodology for gas adjustment does not influence the result as much. A change in the trend occurs for the ST2050 (gas adjustment) scenario in Fig. 8 after a fuel input of approximately 6 TWh, because at this point, the maximum capacity for the biogas plant is reached, and further increases in biogas consumption will need to be supplied by an increase in biomass gasification output.

For the IDA2050 scenario, a trend of increasing system cost with increasing electrification rate can be observed in Fig. 8. This is because fuel savings for biomass cannot be offset by the increased investment in WT and the small increase in electricity imports, resulting in high costs with high electrification rates. The direct use of biomass in the IDA reference scenario is also a cheaper option than the renewable gas used in the Energinet scenarios, which is part of the reason why there is little to no economic incentive for shifting to electricity in the IDA scenario. If the investment cost, which correlates to the increased WT capacity, is not included in the system cost, there is no real difference in the energy system cost.

3.2. Indirect electrification

For this part of the analysis, the results are shown for indirect electrification with H_2 produced via electrolysers, which allows for increased flexibility but at lower energy efficiency. In Fig. 9, the

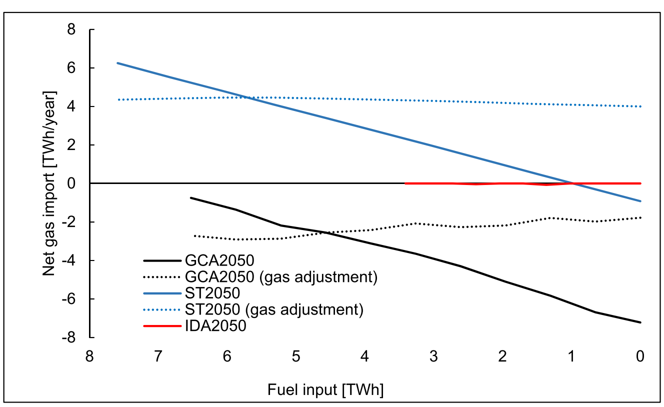

Fig. 7. Net gas exchange for each scenario at different levels of biomass/biogas fuel input. Negative values mean that a net gas export occurs in the scenario.

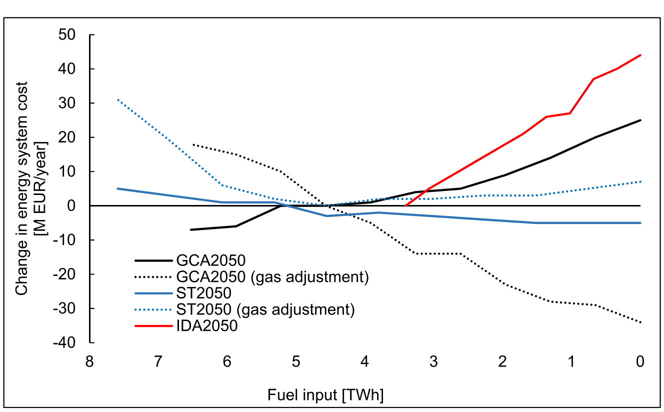

Fig. 8. The change in energy system costs for each scenario at different levels of biomass/biogas fuel input.

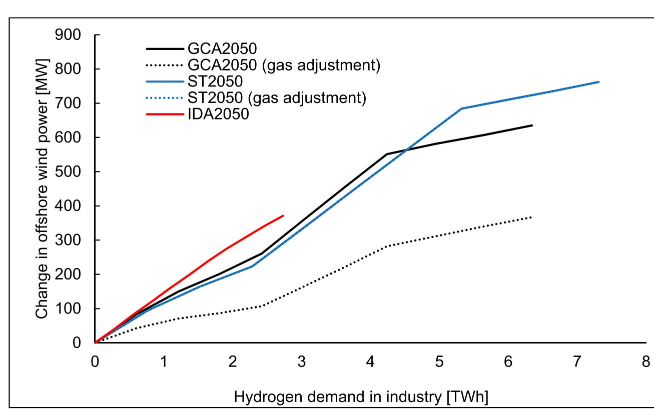

Fig. 9. The change in offshore WT capacity made in each scenario at different levels of hydrogen fuel input for high-temperature processes in the industry.

resulting change in offshore WT capacity with an increasing shift to hydrogen can be seen for all analysed scenarios.

A consistent trend can be observed for all scenarios; as the share of hydrogen increases, an increased offshore WT capacity can be installed without increasing the CEEP of the system. The results for the GCA2050 and GCA2050 (gas adjustment) scenarios are different due to the difference in methodology, where the GCA2050 (gas adjustment) has a reduced biogas hydrogenation production and thus reduced electrofuel demand, offsetting some of the increased electricity demand. That is not the case for the ST2050 scenario, as the biogas hydrogenation production is so low that it is not considered for this analysis, leading to the result shown with no difference between the two methodologies. A distinct flattening of the curve appears eventually for all Energinet scenarios, but not for the IDA scenario. This curve flattening happens once the entire original renewable gas demand has been converted to hydrogen demand, and any further expansion of hydrogen is subtracted from the industrial electricity demand. This is not the case for the IDA scenario, because of the principle of balancing gas exchange to a yearly net-zero.

Fig. 10 shows the resulting change in biomass consumption with the increase of hydrogen use in the industry sector for all analysed scenarios.

The change in biomass seen in Fig. 10 shows a trend similar to what was observed for direct electrification; an increasing electrification rate, or in this case, indirect electrification through hydrogen processes, can reduce the biomass consumption of the energy system. However, this requires a concurrent adjustment of the gas supply side, as can be seen from the results for the GCA2050 and ST2050 scenarios. If the gas production remains unchanged, the system will simply export any excess production, thus effectively negating any potential savings obtained from the fuel shift in the industry sector.

Looking at the change in energy system costs in Fig. 11 and Fig. 12, it can be seen that the differences in system design for the scenarios by Energinet and IDA, respectively, result in very different results.

The results for the IDA scenario in Fig. 11 show a relatively straightforward trend of increasing energy system cost as the demand for hydrogen in industry increases. The Energinet scenarios are also trending upwards, but generally, show more significant fluctuations and variations. First of all, the general explanation for the increasing system cost across all scenarios shown in Fig. 11 is

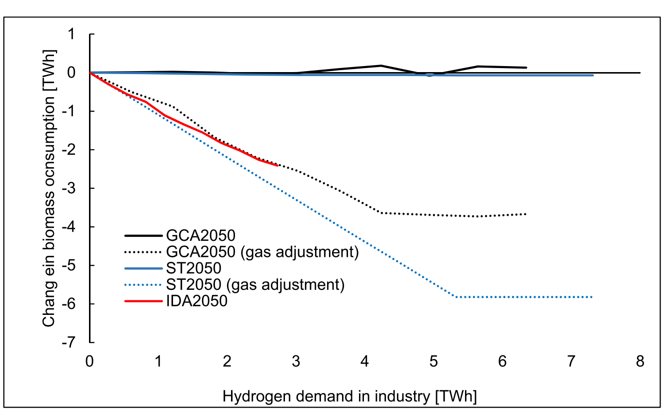

Fig. 10. The change in biomass consumption at different levels of hydrogen fuel input.

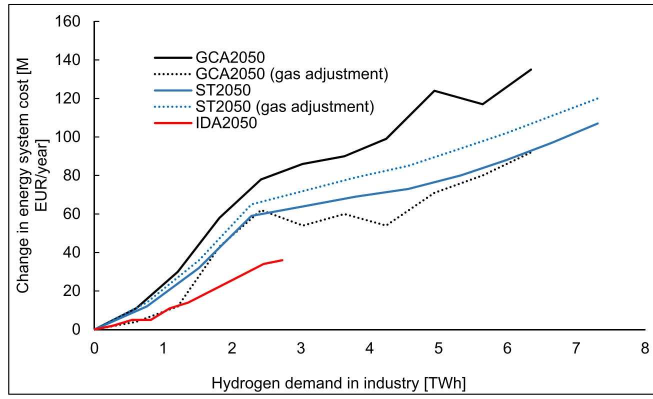

Fig. 11. The change in energy system costs at different levels of hydrogen fuel input.

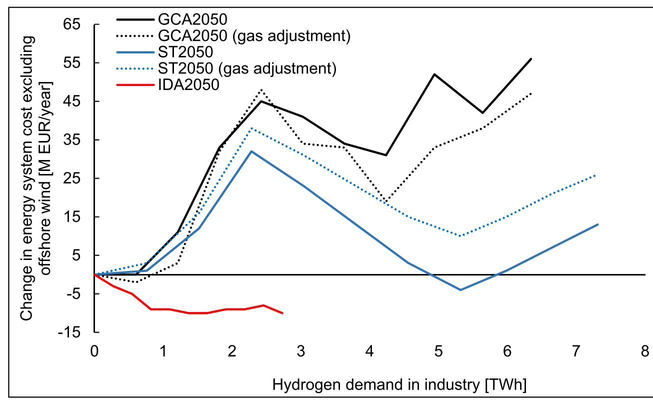

Fig. 12. The change in energy system cost, excluding the investment cost for WT at different levels of hydrogen fuel input.

the increase of the installed offshore WT capacity and thereby also the associated investment costs. This is the primary reason for the change in system cost for the IDA scenario, as it is illustrated in Fig. 12, where the WT investment is excluded and energy system cost reductions can be attained.

In Fig. 12, the ST2050 and GCA2050 scenarios by Energinet show large variations in cost. The cost level depends on the amount of industrial energy demand shifted to hydrogen, as a biogas demand is being shifted indirectly to an electricity demand based on electrolyser efficiency. Therefore, an increase in electricity demand occurs, and because of the applied market economic simulation strategy and the principle of chronological simulation in EnergyPLAN, changes to the electricity demand can result in large variations in electricity production, consumption, and import/export. In this case, the cost of electricity import increases significantly in the beginning, due to import during high price periods. However, after reaching a hydrogen demand of 2.28 TWh, the trend changes as the incremental increase in electricity import is profound, and savings elsewhere in the system (e.g. reduced biomass fuel consumption) can negate the increase in electricity import. This issue is exacerbated in the ST2050 and GCA2050 scenarios, because of the low internal dispatchable production capacity, making the system susceptible to external market prices. Eventually, the trend changes again after 4 TWh to 5 TWh, when a complete shift from biogas to hydrogen has occurred. At this point, the shift occurs from electricity to hydrogen, which results in a net increase in electricity demand due to electrolyser efficiency losses. These losses cannot be recovered through the increase in flexibility obtained from the 1-day hydrogen storage available at the industrial sites.

4. Conclusion

In this paper, three RE system scenarios for 2050 from different Danish actors are analysed to compare how industry electrification affects different system configurations.

It is found that systems with a low internal dispatchable power production capacity are more sensitive to external markets and external electricity prices. This is important as the future electrification of the energy system is inherently connected to both internal electricity production capacity and transmission capacity. If the Danish energy system has a low internal dispatchable power production, then it must also be expected that the costs of the energy system will vary to a greater extent from year to year, depending on the seasonal and yearly fluctuations of market prices. Similarly, the advantages of electrification and its optimal level are also more uncertain in such an energy system.

It is found that the direct electrification of industrial process heat demands should be favoured over a fuel shift to hydrogen-based processes, due to the lower costs of the energy system and a higher energy system efficiency with direct electrification. From an energy system perspective, the direct use of hydrogen for industrial processes should only be applied where no alternative solution exists or if the alternative is unsustainable amounts of biomass. Finally, this analysis did not include all potential gains from by-products of the electrolyses, such as O_2, which may influence the results.

Author statement

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Nomenclature

CEEP	Critical excess electricity power
CHP	Combined heat and power
COP	Coefficient of performance
DH	District heating
EU	European Union
EV	Electric vehicle
GCA	Global Climate Action scenario
HP	Heat pump
IDA	IDA's Energy Vision 2050 scenario
PV	Photovoltaic panels
RE	Renewable energy
RES	Renewable energy sources
ST	Sustainable transition scenario
TYNDP2018	Ten Year Network Development Plan 2018
VRE	Variable renewable energy sources
WT	Wind turbines

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