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(article starts on next page)

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Electrification of the energy-intensive basic materials industry – Implications for the European electricity system

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ABSTRACT

A techno-economic optimization model is developed to evaluate the impacts that the electrification of industry will have on investments in and operation of the European electricity system as well as the impact that the availability of low-cost electricity will have on the spatial distribution of future industrial plants and their production. The modeling includes trading of different types of commodities, including hot-briquetted iron, methanol and hydrogen.

The results show that the modeled geographic location of the industry when the export of commodities is allowed coincides with its present-day location, although the commodity production capacity increases for industries sited in regions with access to low-cost electricity. If present-day production levels are maintained in each region a hydrogen pipeline network provides a way to connect regions with access to low-cost electricity to industry-intense regions and can reduce hydrogen production costs by up to 3% as compared with a situation in which all of the hydrogen demand has to be provided on-site.

1. Introduction

In Europe, the industry sector is responsible for over 24% of the total carbon dioxide (CO_2) emissions, including both fossil fuel- and process-related emissions [1]. There are significant differences between the different types of industries in terms of the levels of energy consumption and CO_2 emissions. The steel, cement, chemical, and petrochemical industries, typically referred to as 'energy-intensive industries' (EIIs), are responsible for 70% of industrial CO_2 emissions (in Year 2020) [2]. These industries are embedded in many strategic value chains and account for more than half of the energy consumption of EU industry [3]. In Year 2021, the European Commission presented the 'Fit for 55' package [4]. The purpose of this package is the implementation of the European Union (EU) Green Deal [5], which aspires to attain a 55% reduction in greenhouse gases (GHGs) by Year 2030 (compared with Year 1990) and to reach net-zero GHG emissions by Year 2050. In 2023, the European Commission released the Net-Zero Industry Act (NZIA), aimed at scaling up the production of key technologies for achieving climate neutrality, such as solar panels, batteries, and electrolyzers [6]. To achieve such emissions reductions, decarbonization of EIIs is critical. However, as these industries have long-lived capital stocks, high-temperature heat requirements, process emissions, and are involved in the global trade of commodities, it is challenging to mitigate the emissions from EIIs [7,8]. In Europe, industrial facilities such as coke ovens, blast furnaces and steam crackers will need to be replaced or receive substantial re-investments over the next 15 years [9]. Thus, when formulating low-carbon options for EIIs, it is of the utmost importance to avoid a development that entails further lock-in to emissions-intensive infrastructures [10].

In the EU, the share of renewables in the final energy consumption had increased to 22% in Year 2020, as compared with 9.6% in Year 2004 [11]. This increase was mainly due to the fact that the carbon intensity of electricity generation declined from 399 gCO_2/kWh in Year 2004 to 215 gCO_2/kWh in Year 2020 [12]. The renewable energy technologies, which are mainly solar photovoltaics (PV) and wind turbines, have achieved rapid progress over the last decade, resulting in a substantial decrease in cost and improved cost-competitiveness relative to both fossil fuel and nuclear power technologies [13]. This makes the replacement of fossil fuels with electricity from renewable sources, together with flexibility measures, a core climate change mitigation strategy in the short and medium terms [14]. In the longer term, other options such as new nuclear power may contribute, although similar cost reductions are typically not envisioned for these options [15].

Despite the decarbonization potential of electrification, the extent to

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which electrification will be deployed in industry remains uncertain. Using a bottom-up approach, Neuwirth et al. [16] have modeled the amounts of electricity needed to apply hydrogen as a feedstock in the hydrogen-direct reduction (H2-DR) process and as a fuel for high-temperature process heat in many industries (e.g., in the production of iron and steel, non-metallic minerals, basic chemicals, non-ferrous metals, paper and printing) of North-Western Europe. Neuwirth et al. [16] have estimated an annual hydrogen demand of about 260 TWh for these purposes. Lechtenböhmer et al. [17] have estimated the annual industrial electricity demand of the energy-intensive, basic materials industries (for the production of steel, cement, glass, lime, petrochemicals, chlorine and ammonia) within the EU. Under the assumption that the demand for basic materials is maintained at current levels, they have concluded that the resulting electricity demand will be 1500 TWh. Madeddu et al. [18] have used bottom-up modeling to investigate the technical potential of electrification for 11 industry sectors (covering 88% of the final energy consumption level of Europe's industry). Their results show that 78% of the energy demand can be electrified through applying technologies that are already commercially available, while 99% of the electrification can be achieved if technologies that are currently under development are also included. New electricity demand will heavily influence the investments made in electricity generation capacity. Industrial demand-side flexibility, i.e., measures that allow shifting the demand over time, including the location of new demands [19], will also influence the operation of the dispatchable part of the electricity generation system. Applying a techno-economic optimization model of the European electricity system, Öberg et al. [20] have shown that the temporal flexibility of electrified industries can reduce the cost of hydrogen supply by up to 35%, as compared to a constant hydrogen demand.

With the shift of basic materials production towards electrification, the regional availability and competitiveness of renewable energy could become significant factors for decision of future location of electricity intensive industries. Samadi et al. [21] introduced and investigated the concept of the "renewables pull" effect, which refers to the economic attractiveness of renewable-rich regions leading to the relocation of industrial production as a result of regional differences in the marginal cost of renewable energy sources. Samadi and co-workers analyzed the electrified production of direct reduced iron (DRI) and ammonia (based on hydrogen produced via electrolysis) in Germany and Morocco in Year 2035. They found that DRI production is 26% cheaper and ammonia production is 62% cheaper in Morocco than in Germany, in spite of the higher weighted average cost of capital (WACC) in Morocco compared to Germany. The reason being the favorable conditions for low-cost solar power in Marocco. Verpoort et al. [22] have developed a generic framework to quantify relocating three energy-intensive industrial commodities: steel, urea and ethylene to further investigate the renewable pull effects. They found that a complete relocation of low-carbon production steel, urea and ethylene away from renewable-scarce and towards renewable-rich regions (assuming an electricity-price difference of €40 MW/h between these regions as well as transport and financing penalties) would result in energy-cost savings of 18%, 32% and 38%, respectively. Previous studies have focused on estimates of aggregated electricity demand and flexible hydrogen demand from industry but have not investigated the impacts of industrial electrification on process design (investments in overcapacity and available storage options) and on the localization of future industrial plants (including commodities trade). In addition to the renewable pull impact, the relocation of the energy-intensive basic materials industry is in this work governed by the existing infrastructure, raw material intensity, operational flexibility, and transportation costs. Moreover, this work illustrates the impact of industrial electrification on the electricity system and how industrial flexibility options impact the electricity system composition and the electricity price. To fill this gap in the knowledge, we apply a linear cost-optimization model of a future European electricity system with zero-CO_2 emissions, including electrified, energy-intensive industries to investigate the spatial distribution (across 22 regions) of future industrial plants, their production levels, and the corresponding electricity supply. We address the following research questions.

- How do the potential future electricity and hydrogen demands from the industry, with different types of flexibility, influence the source and composition of the electricity generation?
- Which parameters drive a cost-optimized spatial distribution of new locations for electrified industrial plants?

To answer these research questions will allow both policymakers and sector leaders to gain insight into possible ways of governing a long-term transition for the decarbonization of industry via electrification in the EU.

1.1. *Energy-intensive industries – general description of electrification options*

Table 1 presents the key assumptions for the electrified production options investigated in this study, listing the technological options, the energy intensity and the data sources. Direct electrification refers to the direct use of electricity as an input (e.g., for a plasma rotary kiln, electric arc furnace or electrified heat of a steam cracker). Indirect electrification is the production of hydrogen and hydrogen-rich fuels and feedstocks through electrolysis. Figures A1-4 in Appendix A show the schematic representation of the electrified production processes investigated in this study.

Steel industry. The EU steel industry aims to reduce carbon emissions by 55% by 2030, compared to 1990 levels. Of the 60 low-CO_2 emissions steel projects planned or underway across the EU, 70% are based on the direct and indirect electrification of steel production [31]. In the present study, the H2-DR process is used as the electrification option for the steel industry. This process comprises a hydrogen production step, and two major steps for steel production from the iron ore: ironmaking and steelmaking. The iron ore pellets are reduced to direct reduced iron (DRI) by adding hydrogen as the reducing agent in a shaft furnace during the ironmaking step. DRI production requires high-quality iron ore (DR-grade) with an average iron content of 67% or more [32]. Direct reduction (DR-grade) iron ore pellets containing at least 67% iron (Fe) are assumed for use in the investigated H2-DR process. The deposits of DR-grade iron ore are scarce. In the EU, Sweden can supply 11% of the DR-grade iron ore pellets needed for primary steel production via the H2-DR process [33]. One of the options to address the DRI iron ore supply issues is to improve the quality of hematite iron ores, which have

Table 1
Specifications of assumed electrified options for the energy-intensive industries.

Industry	Process/ Technology	Direct electricity demand, MWh/ t of commodity	(Indirect) Electricity demand for H_2, MWh_{el}/t of commodity	Reference
Steel	Hydrogen-direct reduction	1	2.2	[23–26]
Cement	Plasma	1.2–1.3	–	[27]
Ammonia	Power-to-ammonia	1	8.6	[28,29]
Plastics	Gasification via electrified steam cracker	7.5	0–6.7[a]	[30]

[a] Depends on CO_2 utilization, i.e., the CO_2 emissions that arise from the process can be captured and converted to olefins through a synthesis process. Alternatively, the CO_2 can be captured and stored. The total electricity consumption of the plastics production process is in the range of 7.5–14.2 MWh per tonne of plastics, assuming that the CO_2 emissions that arise from the process can be captured and converted to olefins through a synthesis process.

an average Fe content of 57.4%, through the beneficiation process. This process involves grinding, separation and dewatering. These additional steps require extra costs [32] The availability of DR-grade iron ore is a potential challenge to the global expansion of the H2-DR process. To store and transport the reduced iron ore, i.e., DRI, it is compacted into hot-briquetted iron (HBI). HBI is charged together with steel scrap in varying amounts to an electric arc furnace (EAF) to produce molten steel at 1600 °C. Increasing the scrap charge will reduce slag demand, lime demand, and EAF electricity consumption. The quality requirements for the steel product set boundaries for the flexible use of scrap [24,34,35]. The steel production process without scrap charging is assumed in this study. The electricity consumption of the direct reduction shaft furnace and electric arc furnace is 322 kWh and 494 kWh per tonne of steel, respectively [36]. To convert 1500 kg of iron ore to 1000 kg of HBI, 51 kg of hydrogen is needed [24], which entails an electricity demand of 2.15 MWh, assuming an electrolyzer efficiency of 79% [37]. Further details of the electrified steel production process assumed in this work can be found in studies from Refs. [23,24,38,39]. The electrification of the steel production via a hydrogen-based direct reduction process removes almost all of the carbon compared to what is used in a blast furnace. Yet, a certain amount of carbon is required to produce the C–Fe alloy necessary in the EAF. The carbon content in steel ranges from <0.3 to 1.5% depending on the steel quality. In commercial direct reduction, carbon is added through the natural gas stream. For hydrogen-based direct reduction steel, the carbon required can be from injection of pulverised coal, bio-methane, biochar or other sources of carbon. Thus, there will still be some process emissions of around 3% of the conventional steel production via blast furnace; 17 kg CO_2/t steel from carbon injection into the EAF, 28 kg CO_2/t steel from lime and 6 kg CO_2/t steel from the consumption of the graphite electrodes [40].

Cement industry. An innovative near-zero emissions production route for cement uses electricity as the primary source of thermal energy, i.e., creating heat via plasma generators. Within the CemZero project (a partnership between Vattenfall and the Swedish cement manufacturer Cementa), cement clinker has been produced using the electric plasma kiln technology [27]. The significant advantage of the electrification process lies in the pure CO_2 stream that emerges from the production process, which means that there is no need for CO_2 separation from the flue gas. This reduces significantly the investment cost for CCS, as well as the operational and maintenance costs. Electrified cement production that uses plasma heating requires 1.2–1.3 MWh of electricity per tonne of clinker [27]. A global construction materials company, CEMEX, and a Finnish-Dutch technology and engineering company, Coolbrook Ltd., are jointly evaluating electrification of the cement kiln heating process. These companies expect that the electrification of the heating and calcination processes of cement production will be ready for commercial use at the industrial scale in Year 2024 [41]. However, electrifying the kiln is not a near-term solution because the electrification process needs to be developed, scaled up and optimized [42]. Nevertheless, we include the electrified cement production process in the present study, as it represents a process with different characteristics than the other industries investigated, i.e., it is a process with high electricity intensity and medium operational flexibility (which is the ability of the electrified cement kiln to vary the output within the operational range down to 50% of full capacity) [27].

Ammonia industry. The most utilized ammonia production method is the Haber-Bosch (HB) process, with an average CO_2 emission footprint of 2.4 tonnes per 1 tonne of ammonia. The HB process combines elemental hydrogen and nitrogen under high pressure and temperature. An air separation unit (ASU) uses a cryogenic distillation process to separate ambient air into nitrogen, oxygen, and argon. The difference between the present-day ammonia production process and the electrified ammonia production process arises from the hydrogen production process. Currently, hydrogen required to produce ammonia is derived from fossil fuels and produced via the steam methane reforming (SMR) process. The SMR process produces approximately 9–10 tonnes of CO_2 emissions for each tonne of hydrogen produced [43]. The electrified ammonia production process incorporates electrolysis for H_2 production. The total electricity consumption of the ammonia production process, including electricity for hydrogen production, is 9.6 MWh per tonne of NH3.

The HB process is normally optimized for continuous mass production, although reconfiguration for dynamic production is possible [28]. The minimum load can be 20% [44] or 30% of the total installed capacity [37]. Ammonia is both transportable and storable [45]. All the products can be stored in storage tanks [46].

Plastics industry. The transition towards a circular economy requires a plastics production process that can handle any type of plastic waste (sorted or mixed) and that produces plastics of the same quality as the original. Thermochemical recycling is an alternative to conventional methods for plastic waste treatment (i.e., mechanical recycling and incineration). Thermochemical recycling allows theoretically unlimited recycling of any plastic material (sorted or mixed) [30,47]. The process uses plastic waste to produce a raw syngas, which is further reformed into pure CO and H_2. The reformed syngas is used for methanol synthesis. The produced raw methanol is converted to olefins via the methanol-to-olefins process. Olefins are the building blocks for the production of plastics. For thermochemical recycling of plastics, two forms of electrification are used in this study: direct use of electricity to provide heating; and indirect use of electricity to synthesize an alternative feedstock. The heat for the cracker is provided by electric heating, which is delivered through electrical coils installed in the bed material loop located before the combustor (Pissot et al., 2020). The total electricity consumption of the plastics production process is in the range of 7.5–14.2 MWh per tonne of plastics, depending on CO_2 utilization, i.e., the CO_2 emissions that arise from the process can be captured and converted to olefins through a synthesis process or the CO_2 can be captured and stored.

H_2 production. Overall, 96% of this hydrogen production is from natural gas, resulting in significant levels of CO_2 emissions (production via steam methane reforming generates 9–10 tonnes of CO_2 per tonne of hydrogen) [48]. In this study, hydrogen is assumed to be produced through electrolysis. Thus, renewable hydrogen can be obtained via electrolysis using renewable electricity to split water into hydrogen and oxygen. By Year 2050, the Hydrogen Roadmap Europe report projects that renewable hydrogen will provide up to 24% of the total energy demand, corresponding to around 2251 TWh of the energy in the EU [49]. Of the different electrolysis technologies, alkaline electrolysis is included in this study. Alkaline electrolysis is a mature and commercially available technology which is has operating temperatures between 70 and 140 °C and pressures up to 30 bar [50]. The electrolyzer has a high level of operational flexibility, i.e., this unit can be stopped and started relatively rapidly and at a low cost. The electrolyzer has a low minimum load, short start-up time, and high ramp rate.

2. Methods

To investigate the impact of the electrification of industry in Europe, we deploy the cost-minimizing electricity system investment model eNODE. In this work, we develop and implement a modeling module that describes the electrification of energy-intensive industries for the eNODE model. The impacts of the electrification of industry on investments in and operation of the electricity system are considered in a context in which the transportation and heating sectors also use electrification as a strategy to avoid CO_2 emissions. The geographic scope corresponds to the area of the EU (excluding Cyprus and Malta), the UK, Norway and Switzerland, subdivided into 22 regions corresponding to the major bottlenecks in the transmission grid (see Figure C1, Appendix C). The investigated regions are designated as follows: Northern Sweden (SE_N), Southern Sweden (SE_S), Northern Germany (DE_N), Southern Germany (DE_S), Estonia, Latvia and Lithuania (BAL), Northern Poland (PO_N), Southern Poland (PO_S), Ireland (IE_T), Norway (NO_T), Portugal and Western Spain (IB_W), Eastern Spain (IB_E), Northern France (FR_N), Southern France (FR_S), Switzerland and Northern Italy (ALP_W), Southern Italy (IT_S), Austria, Czech Republic and Slovakia (ATCZSK), Croatia, Slovakia (Slovak Republic) and Hungary (CRSIHU), Romania, Bulgaria and Greece (ROBGGR), Belgium, Netherlands and Luxembourg (BENELUX), Finland (FI_T), Scotland (UK_N), and Southern UK (UK_S). The geographic scope of this work enables the representation of renewable potentials and the topology of the transmission grid between the investigated regions. This is crucial for addressing research questions related to renewable potentials and the optimal siting of energy infrastructure, including electricity generation technologies, transmission lines, and energy storage systems [51].

Within the investigated regions, it is assumed that electricity can be transmitted without internal congestion. Trade between regions is limited by the transmission capacity with the existing grid capacity as a starting point, as well as the possibility to invest in additional capacity. In the current model, investments in additional grid capacity are constrained by the projected capacity increases for Year 2040 provided by ENTSO-E [52]. The electricity generation technologies considered in the model, including batteries and transmission technologies, and their main properties are listed in Appendix B, Table B1.Existing hydropower is included in the model and no new hydropower investments are allowed. The Olkiluoto nuclear power plant with capacity of 1.6 GW in Finland is included in the model. For other types of electricity generation and storage, the model is formulated as a greenfield optimization problem (i.e., capacity is only available if new investments are made) and is used to determine the optimal electricity system configurations under a zero-CO_2 emissions constraint. As for industry, the modeling takes into account the locations and capacities of current industrial production sites. The main properties of the units producing commodities considered in the model, including the storage of commodities and hydrogen and hydrogen pipelines, are listed in Appendix B, Table B1. The main characteristics of the eNODE model are shown in Table 2. A full mathematical description of the original eNODE model is given in a recent publication [53]. Details of the objective function of the model and the electrified industry sectors module are provided in Appendix D. The included module for the electrification of energy-intensive industries provides descriptions of: (i) the decisions made regarding investments in industrial production capacities and storage of commodities (see Fig. 2); (ii) the cost of commodities produced by the electrified EIIs; and (iii) the commodity trade flows between the regions investigated. The time resolution is developed by implementing the chronological time period clustering algorithm (CTPC) [54]. Based on load, wind, and solar power profiles the CTPC algorithm recursively finds the consecutive time steps with the smallest difference and merges them, increasing the weight of the merged time step accordingly. The CTPC algorithm averages periods of low variability. The model applies 730 consecutive time-steps, which vary in length from 5 to 19 h and represent a single future year. The main advantage of CTPC is that the operation of both short-term and long-term storage units can be investigated since the chronology is preserved. The detailed supply curves and hourly capacity factors for solar power, onshore and offshore wind power used in this work are based on ERA5 global re-analysis data [55], and generated using publicly available Julia scripts [56] developed for a study by Mattsson et al. [57].

Table 2
Overview of the eNODE model applied to study electrification of the industry sector.

	Characteristics	Description
Model type	Linear programming optimization model	Minimizes the investments and running costs of the electricity system, while meeting the demands for electricity (see Section 2.1).
Geographic scope	The EU (excluding Cyprus and Malta), the UK, Norway and Switzerland	Investigated area is subdivided into 22 regions (see Appendix C) to represent the main transmission grid bottlenecks.
Time resolution	730 consecutive time-steps of one year[a]	The length of the time-steps varies from 5 to 19 h [54]
Sectors included	Industry (steel, cement, ammonia, plastics)	In addition, electrification of the passenger car fleet, partial electrification (60%) of the heavy-duty vehicle fleet, and the electricity demand from replacing natural gas-based heating with decentralized heat pumps are all included in the model.
CO_2 emissions constraint	Zero emissions	The zero-CO_2 emissions constraint means that no emissions are allowed in the modeled system, which is in line with the ambitions of the European Commission [58].

[a] Around Year 2050 if complying with the Paris Agreement.

2.1. Electricity demands

The electricity demands applied in the eNODE model for the investigated regions are divided into four categories: the present demand, which is used as the baseline level for the hourly demand profile, and the new electricity demands from the transport, heat and industry sectors, respectively. The present electricity demand is based on the annual electricity consumption levels in European countries, obtained from Eurostat [59], and is subject to an hourly demand profile obtained from ENTSO-E [60]. It is assumed that the present electricity demand will retain the current consumption profile in the future zero-emissions system. In reality, any eventual activation of demand response within current demands will change the consumption profile, but this is not investigated in the present study. The electricity demands from the transport and heat sectors are exogenously added to the present electricity demand. The electricity demand from the heat sector is the electricity required to replace individual natural gas-based heating with decentralized heat pumps, which is investigated only in Germany and the UK [61]. The electricity demand from the transport sector is modeled based on a previous publication [62]. Full electrification of the passenger car fleet and partial (60%) electrification of the heavy-duty vehicle fleet are both considered in this model. Assumptions regarding annual driving demands, hourly driving patterns, and electricity consumption per kilometer are all presented in a previously published paper [62]. The annual demand for commodities production is given exogenously, while the hourly electricity demand from EIIs is endogenous, such that investments in units producing commodities, as well as the dispatch of these units are results of the optimization. The details of each type of EIIs are given in Table B1, Appendix B. Only part of the heat, industry, and transportation sectors are represented in this work. Refineries and biorefineries can decarbonize production via electrification. Hydrogen, hydrogen-based fuels (such as ammonia) and hydrogen technologies offer the potential for emissions reduction in the maritime sector. Such development could further increase future electricity demand.

2.2. Modeling the electrified EIIs

In this section, we describe the key characteristics of the electricity consumption patterns of the EIIs, as well as the parameters used to represent these in the model.

2.2.1. Flexibility options

Flexibility in time. Daryanian et al. [63] have described three categories of industry responses to variations in the electricity price (i.e., flexible-in-time electricity consumption): curtailment, substitution, and storage. Curtailment is the on-off operation of industries that depends on electricity price variations. Substitution is the on-off operation of electricity-consuming units in industries, whereby the production is continued by other means. Storage is the rescheduling of electricity usage to periods with lower costs, without any curtailment of production. In this paper, the storage of intermediate products, such as hydrogen, HBI, nitrogen, and methanol (Table 3), allows for the temporal distribution of the electricity consumption of the industries producing the commodities included in this work. The storage of clinker is not considered in this study, and all the steps of cement production are assumed to be continuous, with the output varying within the operational range down to 50% of full capacity [64]. The olefins that are stream-produced from cracking plastic waste are costly to store and transport, so they are assumed to be supplied directly to the chemical plant to produce plastics [65]. The time distribution of the raw material/feedstock supply depends on the operational flexibility of the production units that use these products, and it is assumed that the raw material/feedstock is always available at the production site when needed. The temporal distribution of the final product depends on the operational flexibility of the plant producing the final product. It is assumed that the annual production levels of the final products remain constant. In the model, the parameter of "operational flexibility" is used to represent the flexibility-in-time of the industrial electricity-consuming processes. The parameter represents the ability of these processes to vary the output within specific load ranges (see Table B1 in Appendix B). In this study, it is assumed that commodities production units have medium operational flexibility when their outputs can vary down to 50% of full capacity (e.g., an electrified cement kiln). When the operational range can vary below 50% of full capacity the unit is considered as to have high operational flexibility (e.g., an electrolyzer).

Flexibility in location of new industrial facilities. New production methods can fundamentally change the cost structures for industrial production and, thereby, geographic locations for new sites. With the objective of zero-emissions production, the optimal location for production may shift from being close to the demand and/or raw material supply centers to places where zero-emissions electricity is readily available at low cost, or where there are favorable conditions for CCS [66]. To represent flexibility in relation to location in the model, i.e., the ability and willingness to shift the locations of various business entities [67], an export-of-commodities parameter is used. The exportation of raw materials and feedstock (iron ore, plastic waste and waste), intermediate products (hydrogen, HBI and methanol) and final products (ammonia, cement and steel) is allowed in the model (see Table 3). The locations and capacities of the existing chemical factories are used in the model (Appendix B, Table B3), and the export of plastics is neglected, so as to make use of the logistics and infrastructure of the existing chemical factories. The trading of lime products is not considered as the wide geographic availability of raw materials (i.e., limestone) and the low value-to-weight ratio mean that lime is typically produced close to its markets and is not transported over long distances. This applies to both trade within the EU (intra-EU trade) and exports out of the EU (extra-EU exports).

As for hydrogen, a commodity that is part of most of the production chains of the electrified EIIs, the possible future topology of the hydrogen infrastructure (i.e., pipeline types, lengths, locations and costs) is taken from Ref. [68]. Since Europe has a sizeable existing natural gas transmission network that is set to become increasingly redundant as the system transitions towards climate neutrality, the option to repurpose the natural gas network to transport hydrogen is considered in the model. Thus, the eNODE model includes options to invest in developing a new network of hydrogen pipelines, as well as retrofitting the existing natural gas pipelines, i.e., investments in new, offshore and retrofitted pipelines are possible (see Appendix B, Table B1). The cost of transporting commodities is assumed to depend on the distance and the commodity and is taken from Ref. [69].

Flexibility in CO_2 utilization. The production of plastics is associated with CO_2 emissions despite electrification of the process. In this study, it is assumed that for plastics production, the CO_2 emissions that arise from the process can be captured and converted to olefins through a synthesis process. Alternatively, the CO_2 can be captured and stored. Utilization of the CO_2 stream for olefin synthesis requires balancing of the hydrogen content of the syngas. Further details of the assumptions regarding thermochemical recycling of plastics waste can be found elsewhere [30,65]. The term 'flexibility in CO_2 utilization' is used to describe the abilities of production units to vary their CO_2 utilization modes, i.e., CO_2 usage for plastics production and CCS. The CO_2 emissions from electrified cement production are assumed to be captured and stored.

2.2.2. Costs of electricity and hydrogen

The costs of electricity and hydrogen for the industries (ammonia, cement, steel and plastics) are calculated according to Eq. (1), where the marginal cost $\left(C_{t,i}^{maginal}\right)$ of electricity or hydrogen (i) per time-step (t) is weighted according to the amount of electricity or hydrogen demanded by the commodities production units (g_t) in each time-step.

$$C_i = \frac{\sum_t C_{t,i}^{maginal} g_t}{\sum_t g_t}$$

2.3. Scenarios

Table 4 gives an overview of the different scenarios applied in the eNODE model analysis. The investigated scenarios are defined by the extent to which commodities can be traded.

The *Present-day_location* scenario describes the case in which all parts

Table 4
Schematic overview of the investigated scenarios, which are defined by the extent to which it is possible to trade commodities.

Scenario name	Trade of commodities	Main characteristics
Present-day_location	Iron ore[a], plastic waste[a]	All parts of the production chain of the electrified EIIs are located in the same regions as today
Present-day_location_H$_2$_export	Iron ore[a], plastic waste[a], H_2	Cost-optimized geographic localization of the hydrogen production step, i.e., hydrogen trade via pipelines
Optimized_location	Iron ore[a], HBI, steel; plastic waste[a], waste, methanol; cement; ammonia.	Cost-optimized geographic localization of the parts of the supply chains of the electrified EIIs without hydrogen export
Optimized_location_H$_2$_export	Iron ore[a], HBI, steel; plastic waste[a], waste, methanol; cement; ammonia; H_2	Export of all commodities is allowed

[a] Exports of iron ore and plastic waste are allowed in all the investigated scenarios. Otherwise, the commodities demands (i.e., steel and plastics) cannot be satisfied at the present-day locations.

Table 3
Overview of the products included into the supply chains of the EIIs.

Industry	Raw material/ Feedstock	Intermediate products	Final commodities
Steel	Iron ore	H_2, HBI	Steel
Cement	Limestone	Clinker	Cement
Ammonia	Water, air	H_2, N_2	Ammonia
Plastics	Plastic waste, waste	H_2, methanol, olefins	Plastics

of the production chain of the electrified EIIs are located in the same regions as today, i.e., limited export of commodities (exports of iron ore and plastic waste are allowed). The *Present-day_location_H₂_export* scenario allows for the cost-optimal geographic localization of the hydrogen production step, i.e., hydrogen trade via pipelines. Developing a new network of hydrogen pipelines and retrofitting of the existing natural gas pipelines are considered in the model. The *Optimized_location* scenario presents the cost-optimized geographic localization of the parts of the supply chains of the electrified EIIs without hydrogen export. Hydrogen is in this scenario required to be produced in the same location as the hydrogen-consuming units. The export of all the commodities is allowed in the *Optimized_location_H₂_export* scenario. To represent some of the material and immaterial values at the current industrial sites, i.e., regions with existing EIIs, we introduce a penalty for investments in new production sites for regions without existing EIIs. A 50% increase in investment cost is assumed for units that are producing commodities in regions without existing ammonia, cement, steel and plastics production units. In addition, the current production level of commodities in the investigated regions are used as the regional demand for commodities in all the scenarios, so as to reflect the connection between the basic materials industry and the locations of other industries.

2.4. Sensitivity analysis

100% carbon capture and utilization (CCU) for plastics production. In the model, the utilization of the CO_2 stream is part of the optimization, i.e., flexible operation ranging between CO_2 usage for plastics production and CCS is assumed in the model. A sensitivity analysis was conducted to investigate the impact of plastic production processes in which all of the carbon in the plastic waste and waste is utilized. Four scenarios with 100% carbon capture and utilization for plastic production, termed *Present-day_location_CCU, Present-day_location_H₂_export_CCU, Optimized_location_CCU* and *Optimized_location_H₂_export_*CCU, were investigated.

Inflexible operation of industries. The impact of the operational flexibility of the units that produce commodities while consuming electricity was tested by adding scenarios that lacked flexibility in time, i.e., the capacity utilization rate was 100% and there were no investments in overcapacity or storage. Four "*inflex*" scenarios, designated as *Present-day_location_inflex_ind, Present-day_location_H₂_export_inflex_ind, Optimized_location_inflex_ind* and *Optimized_location_H₂_export_inflex_ind*, were investigated. The details of scenarios are described in Section 2.3.

Inflexible operation of the electrolyzer. To investigate the impact of the electricity price on the hydrogen production cost, a sensitivity analysis was conducted that involved scenarios that lacked flexibility in time for both the units that produce the commodities and the electrolyzer. The scenarios termed *Present-day_location_inflex*, *Present-day_location_H₂_export_inflex*, *Optimized_location_inflex* and *Optimized_location_H₂_export_inflex* were investigated.

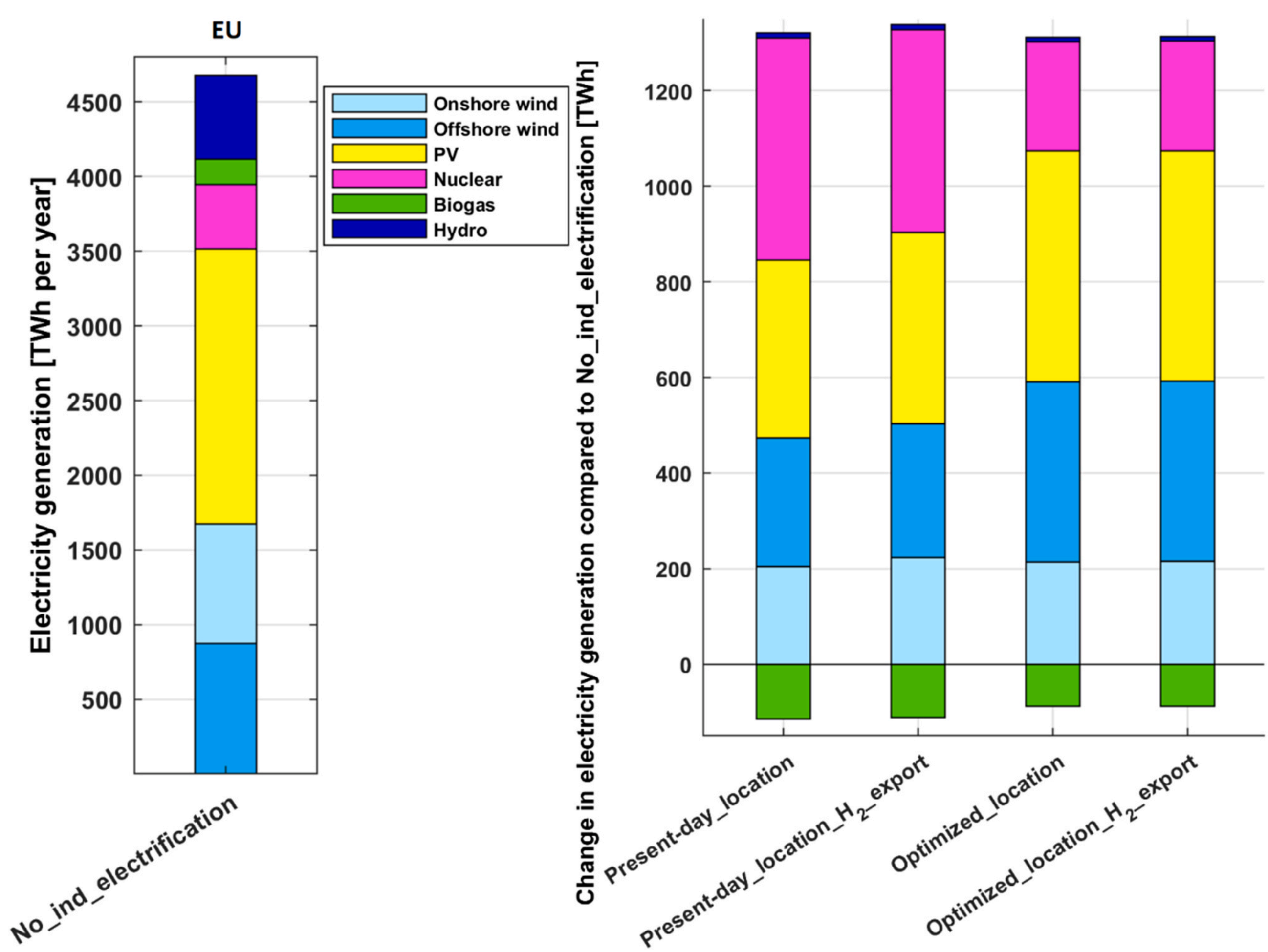

Fig. 1. Total annual electricity generation (in TWh) that can meet the present electricity demand and an assumed future electricity demand from the transport and heat sectors (left-hand panel), and the changes in electricity generation (in TWh) when including electrification of the industries (i.e., ammonia, cement, steel and plastics) (right-hand panel).

3. Results

This section is divided into the following four parts: the ways in which the electrified EIIs influence investments in electricity generation capacities (Section 3.1); the production costs of commodities for the investigated scenarios (Section 3.2); the locations and production levels of the electrified industrial plants for the investigated scenarios (Section 3.3); and the results of the sensitivity analysis (Section 3.4).

3.1. Changes in electricity generation linked to the electrification of industry

Fig. 1 shows the electricity generation mixes of the investigated regions without electrified industry (left-hand panels), i.e., the generation mix that can meet the present electricity demand (i.e., the present hourly demand profiles obtained from ENTSO-E; see Section 2.1), as well as the assumed electricity demands from the transport and heat sectors, together with the changes in electricity generation for the different scenarios (see Table 4) with electrified industry (right-hand panels) for the zero-emissions system.

The cost-optimal electricity mix when not including electrification of industry is dominated by electricity generation from PV and wind power, with these technologies supplying 39% and 36% of the electricity demand, respectively. In the scenarios that include electrified industry, hydrogen consumption and electricity demand from the production units offer demand that is flexible in time. Owing to this demand-side flexibility, the need for biogas peak- and mid-merit-generation is reduced compared to the case without industry electrification (negative green bars in Fig. 1, right-hand panel). The share of the increase in electricity generation from PV is in the range of 28%–37% in all the scenarios. In the *Present-day_location* scenario, in which industrial plants are located as they are today, solar power (26%), wind power (35%), and nuclear power (39%) cover the additional electricity demand from industry. The export of hydrogen via pipelines, as applied in the *Present-day_location_H$_2$_export* scenario, decreases the level of generation from nuclear power and increases the level of electricity production from solar power (i.e., nuclear power and solar power cover 37% and 27% of the total electricity generation increase, respectively). The hydrogen is exported from the regions with the highest numbers of low-electricity-price events [Eastern Spain (IB_E), Northern France (FR_N), and Southern France (FR_S)] to the industry-intense regions [Southern Germany (DE_S) and Belgium, The Netherlands and Luxembourg (BENELUX)]. The hydrogen is exported from the regions with the highest numbers of low-electricity-price events (*Optimized_location* and *Optimized_location_H$_2$_export* scenarios) when investments in industrial sites at locations that differ from the current ones are allowed; the flexibility in terms of the location of the industrial sites results in a 15% decrease in electricity generation from nuclear power and 10% and 5% increases in electricity generation from wind and solar power, respectively, as compared to scenarios with the current locations of the

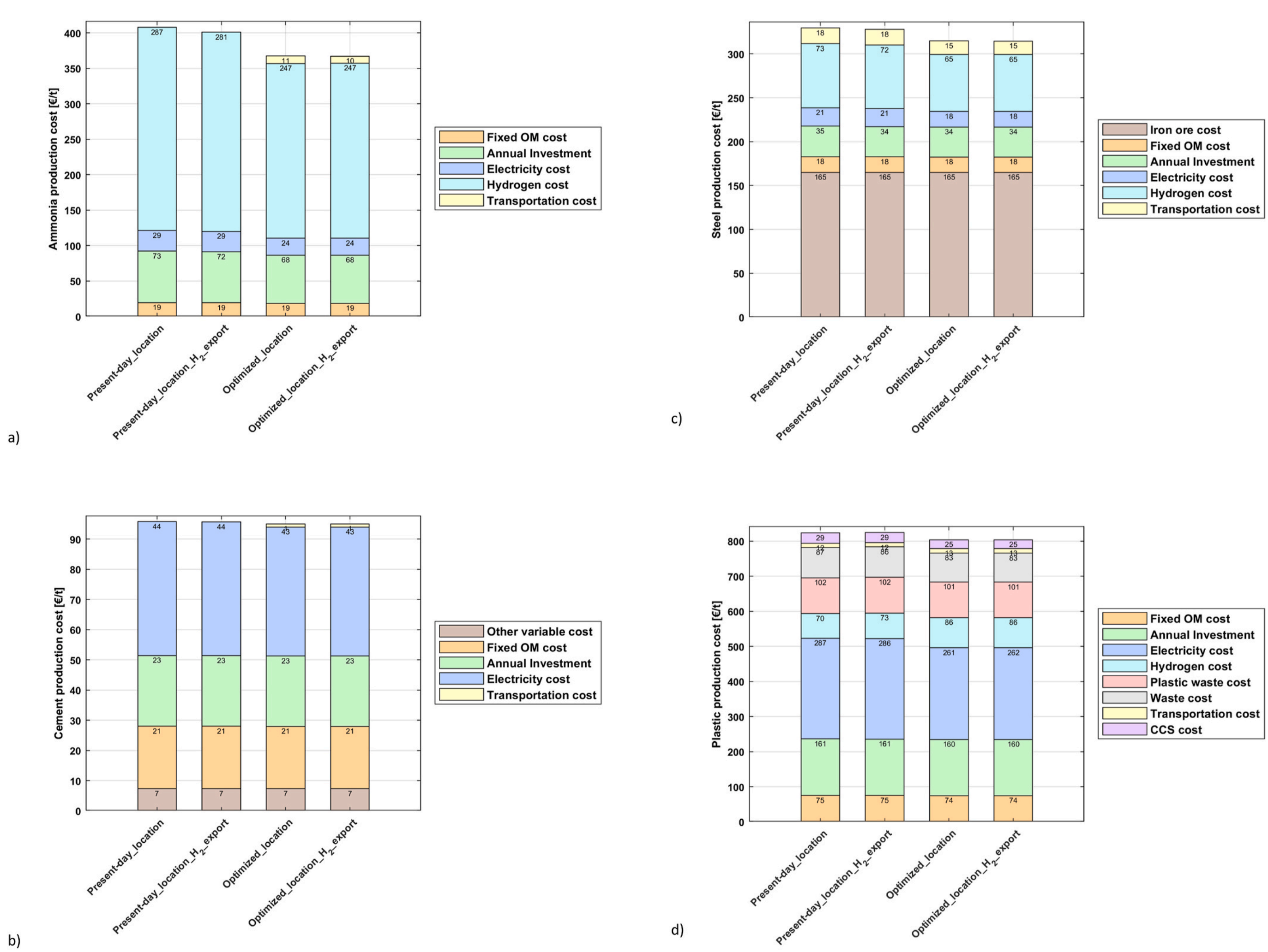

Fig. 2. Breakdown of the modeled production cost per tonne of commodity for ammonia (a), cement (b), steel (c), and plastics (d) in the investigated scenarios. The costs are divided into feedstock costs, cost of capture and storage of CO_2, annualized investment cost, fixed O&M costs, electricity cost, transportation costs and hydrogen costs.

industries.

The current production level of commodities in the investigated regions is used as the regional demand for commodities. The electrification of industry, including the ammonia, cement, steel and plastics industries, in the EU will increase the electricity demand by 43%–44% (i.e., by 1205–1227 TWh). The differences in the electricity demand as obtained from the modeling are attributed to the operations within the plastics production industry. In plastics production, CO_2 emissions can either be captured and converted to olefins through a synthesis process or captured and stored. The synthesis process for converting CO_2 to olefins requires a balance in the hydrogen content of the syngas, which leads to a higher electricity demand compared to the carbon capture and storage (CCS) scenario. The electricity generation mixes of the investigated regions depend on the level of flexibility in locating the industries, which is determined by the extent to which it is possible to trade commodities.

3.2. Cost of commodities production

Fig. 2 shows the breakdown of the production cost per tonne of commodity for ammonia (a), cement (b), steel (c), and plastics (d) for the investigated scenarios. The cost is divided into feedstock costs, cost to capture and store CO_2, annualized investment cost, fixed operational and maintenance costs (O&M) costs, cost of electricity, transportation costs, and hydrogen cost. The cost of electricity as experienced by the industry is taken as the demand-weighted electricity price, where the marginal cost of electricity is taken as a proxy for the electricity price and is a result of the modeling, i.e., the marginal value from Eq. (C2). The resulting marginal electricity cost curves are included in the supplementary material. The marginal value reflects the cost to supply one additional unit of electricity to the energy system. In analogy, the cost of hydrogen is taken as the demand-weighted hydrogen price, for which the marginal cost of hydrogen from the modeling is used as a proxy [i.e., the marginal value from Eq. (C3)]. All costs (investment, operational and maintenance, transportation/transmission costs) related to electricity or hydrogen production are embedded in the marginal value.

3.2.1. Ammonia production cost

The hydrogen cost (see Section 3.3.2) represents the largest share (70%) of the cost for ammonia production in all of the investigated scenarios (Fig. 2a). The electricity cost share is 7% of the total ammonia production, which corresponds to the direct electricity demand from the ammonia production units (HB process plant and air separation unit, see Appendix B, Table B1). Trade in hydrogen, as applied in the *Present-day_location_H_2_export* scenario, leads to a 2% reduction of the hydrogen cost for ammonia producers, as compared with the *Present-day_location* scenario. This is because hydrogen production moves to regions with: existing ammonia production plants (i.e., existing hydrogen demand); more-favorable conditions for low-cost electricity; and proximity to regions with an existing hydrogen demand (to drive down the cost of hydrogen transportation). For the *Present-day_location_H_2_export* scenario, the costs of investments in ammonia production units (HB process plant, air separation unit, nitrogen storage; see Appendix B, Table B1) are also reduced. The relocation of hydrogen production to new locations increases access to low-cost electricity for ammonia production units at the present-day locations, which leads to a decrease in the demand for overcapacity at these units (i.e., a higher utilization ratio). The optimized location of ammonia production (*Optimized_location* and *Optimized_location_H_2_export* scenarios) increases ammonia production in the regions that have existing ammonia production plants and which also have access to low-cost electricity, resulting in electricity and hydrogen cost reductions of 18% and 14%, respectively, as compared to the *Present-day_location* scenario. In the *Optimized_location* and *Optimized_location_H_2_export* scenarios, the optimized location of ammonia production decreases the total ammonia production cost by 10% in comparison with the *Present-day_location* scenario.

3.2.2. Cement production cost

Fig. 2b shows that the investment costs (including the fixed O&M costs) and electricity costs account for the largest share (90%) of the cement production cost. In the *Present-day_location_H_2_export* scenario, hydrogen export drives down the cement production costs, even though hydrogen is not used in the cement production process. In this scenario, hydrogen production moves to regions that have access to low-cost electricity, which results in a decrease in the cost of electricity for cement production in the existing locations, as compared with the *Present-day_location* scenario. In the *Optimized_location* and *Optimized_location_H_2_export* scenarios, cement production is localized to regions that have access to low-cost electricity and that are geographically close to the regions with a high demand for cement. This localization results in a 4% decrease in the cost of electricity for cement production, together with an increase in the cost for transporting cement, as compared with the *Present-day_location* scenario.

3.2.3. Steel production cost

The cost of feedstock, i.e., iron ore, represents the largest fraction (50%) of the steel production cost, followed by the cost of hydrogen (20%) (Fig. 2c). The introduction of hydrogen trading, as applied in the *Present-day_location_H_2_export* scenario, decreases the costs of hydrogen by 1%, electricity by 0.6%, and investments by 1.2%, as compared with the *Present-day_location* scenario (Fig. 2a). The optimized location of steel production, as applied in the *Optimized_location* and *Optimized_location_H_2_export* scenarios, reduces the total steel production cost by 5% in comparison with the *Present-day_location* scenario. The corresponding decreases in electricity and transportation costs are 15% for both of these scenarios. This is due to the fact that the steel production chains are clustered to regions that have low-cost access to iron ore and electricity. The decreased transportation cost in the *Optimized_location* and *Optimized_location_H_2_export* scenarios is attributable to the shorter distances for iron ore transportation and the lower weight of the material transported (steel instead of iron ore), as compared with the *Present-day_location* scenario (in which only iron ore export is allowed).

3.2.4. Plastics production cost

For the plastics production costs, the dominant shares are electricity costs (35%) and investment costs (20%), as can be seen in Fig. 2d. Hydrogen trade increases the utilization of the carbon emissions to produce plastics, as seen from the decrease in the CCS cost, as well as the increase in the cost of waste in the *Present-day_location_H_2_export* scenario, as compared with the *Present-day_location* scenario. However, while hydrogen export reduces the total costs of ammonia, cement, and steel production in the *Present-day_location_H_2_export* scenario as compared with the *Present-day_location* scenario, the cost of plastics production increases due to the increased usage of hydrogen. In the *Optimized_location* and *Optimized_location_H_2_export* scenarios, the utilization of carbon emissions to produce plastics increases further in comparison to the *Present-day_location_H_2_export* scenario, and this results in increased hydrogen usage, with an increased cost of hydrogen as a consequence. Yet, the relocation of the plastics production units (i.e., the stream cracker with plastic waste as feedstock, stream cracker with waste as feedstock, synthesis plant, and methanol-to-olefins plant) to regions with low-cost electricity gives access to electricity at a lower cost compared to the *Present-day_location* scenario. For the *Optimized_location* and *Optimized_location_H_2_export* scenarios, the reduction in the cost of electricity is greater than the increase in hydrogen cost, and this drives down the total cost for plastics production.

The modeling shows that allowing for hydrogen trade when the location of the production of commodities is optimized, i.e., allowing for new locations of industrial sites as well as increased production at the existing locations (*Optimized_location_H_2_export* scenario), has no significant impact on the production cost of commodities, i.e., the production costs of the commodities decreases in the range of 0.01%–0.04%, as compared with the *Optimized_location* scenario.

This paper provides insights into the production cost characteristics when electrifying key energy intensive industries, in terms of the distribution across annualized investment costs, fixed O&M costs, electricity costs and transportation costs. In reality, the production cost and market price of the commodities are interconnected. Their market prices reflect the outcomes of complex interactions between supply and demand factors (such as capital intensity, industry concentration, production facilities, labor costs, and technological advancements), and distinctive factors such as product characteristics (quality, storability or substitutability), as well as the ways in which the international markets and the global climate policy will develop.

3.3. Production levels and locations of industrial plants

3.3.1. Electrolyzer sizes and locations

Fig. 3 presents the modeled regional locations of the electrolyzers, together with their capacities (in GW) for the investigated scenarios.

In the *Present-day_location* scenario, the location of the electrolyzer capacity is determined exogenously to the regions with ammonia, steel, and plastics production (i.e., at the sites of the industries that required hydrogen in their production process). The average capacity utilization ratio of the electrolyzer in the *Present-day_location* scenario is 60%, which means that it is cost-optimal to invest in the overcapacity of the electrolyzer, so as to follow the electricity price variations. In the *Present-day_location_H$_2$_export* scenario, the capacity of the electrolyzer in regions with high demand for hydrogen (BENELUX, DE_S, PO_S, FR_N, ALP-W, ATCZSK and UK_S) decreases when the electrolyzers are moved to regions with access to low-cost electricity and proximity to hydrogen demand (low transportation cost) (FR_S, UK_N, IB_E).

In the scenarios with optimized localization of the industrial clusters (*Optimized_location* and *Optimized_location_H$_2$_export* scenarios), the production of hydrogen increases in the regions that have access to low-cost electricity and that lie in proximity to regions with high demands for commodities (SE_N, IB_W, IB_E and UK_N), as compared with the *Present-day_location* scenario. The total increase in hydrogen production is 3.5% and the increase in electrolyzer capacity is 2% in all the regions investigated for the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios, as compared with the *Present-day_location* scenario. The reason for the increases in hydrogen production for the scenarios with optimized locations (*Optimized_location* and *Optimized_location_H$_2$_export* scenarios), as compared with the *Present-day_location* scenario, is that the plastics industry has the ability to allow the plastics production units to vary their CO_2 utilization modes, i.e., CO_2 released from the process can be either used for plastics production or stored (CCS). Hydrogen export, as applied in the *Optimized_location_H$_2$_export* scenario, has no impact on the geographic location of the electrolyzer capacity, as compared with the *Optimized_location* scenario. If the relocation of industrial clusters is allowed, the electrolyzer follows the location of the production unit that has a hydrogen demand.

Fig. 4 presents the net electricity (a) and hydrogen (b) exports, i.e., the difference between the export and import levels for Northern Sweden (SE_N), Southern Germany (DE_S), Eastern Spain (IB_E), and Austria, Czech Republic and Slovakia (ATCZSK) in the investigated scenarios.

In the case of large-scale electrification of the industries, the industry-intense regions such as DE_S and ATCZSK become regions that have high demands for electricity and hydrogen. In these regions in the *Present-day_location_H$_2$_export* scenario, the electricity import level (Fig. 4a) decreases, and the hydrogen import level (Fig. 4b) increases, as compared with the *Present-day_location* scenario, since hydrogen production moves to those regions that have access to low-cost electricity (Fig. 2). With the optimized location of the industrial clusters, as applied in the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios, the

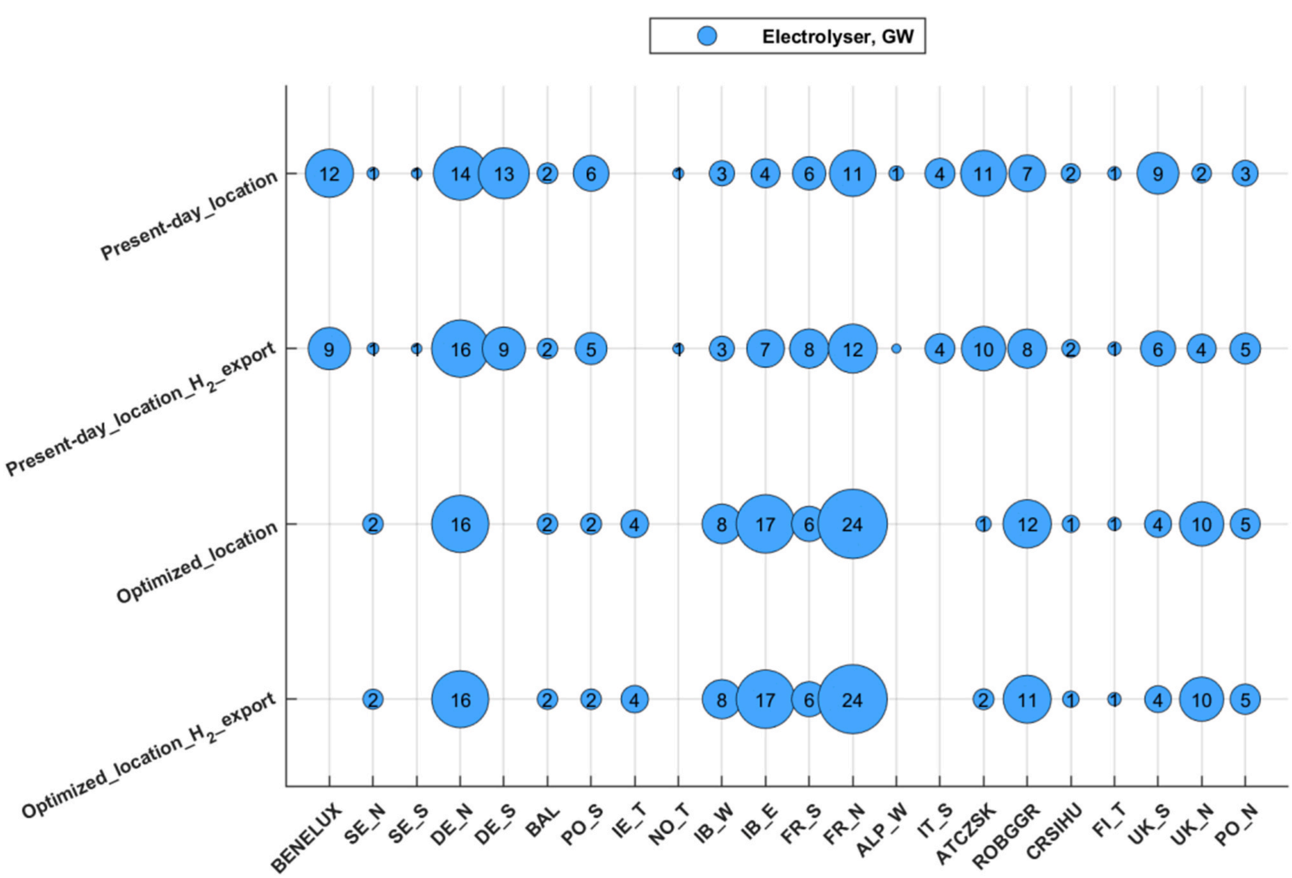

Fig. 3. The modeling results for the regional locations (*x*-axis) and capacities (in GW) of the electrolyzers for the investigated scenarios (*y*-axis).

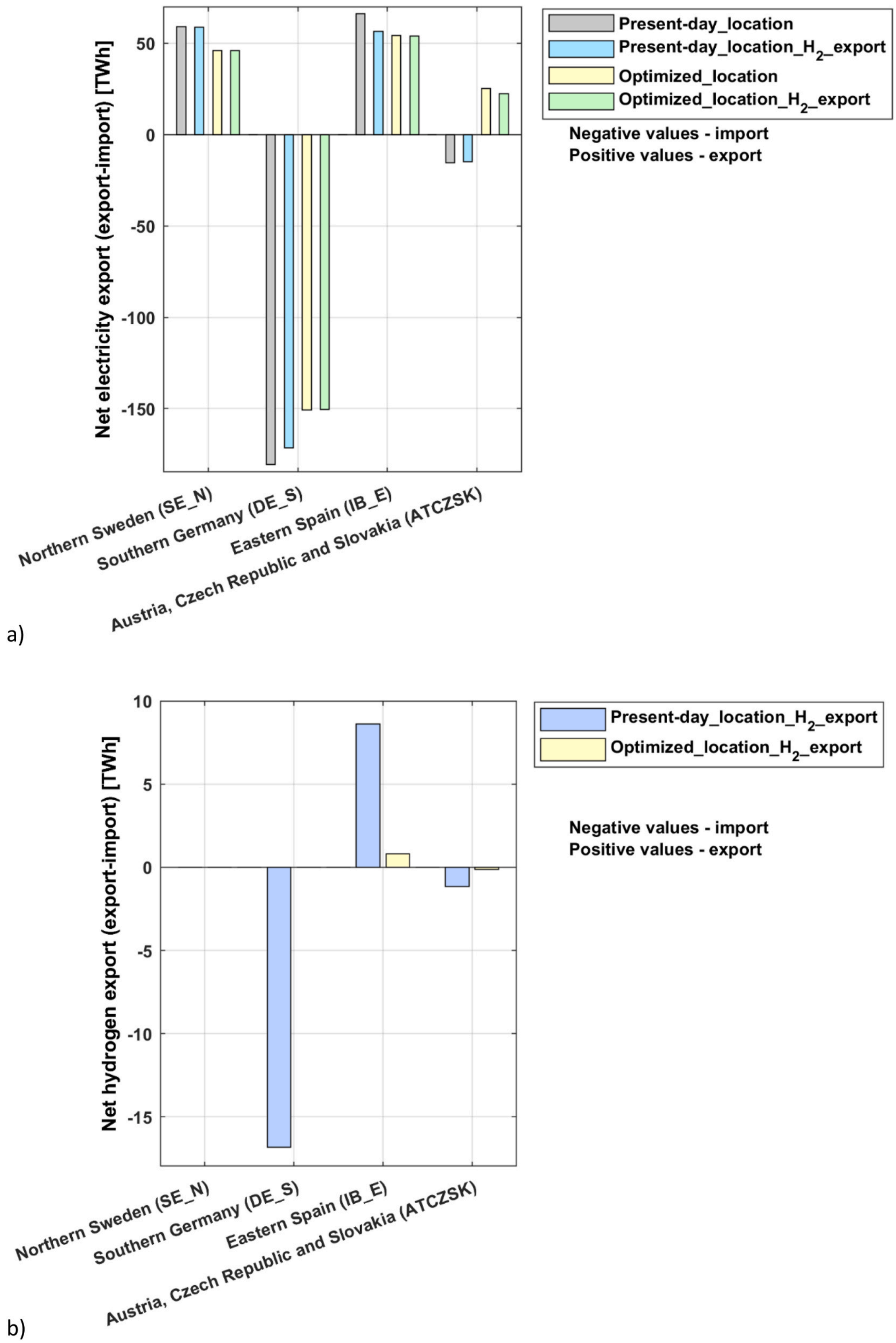

Fig. 4. The net export of electricity (a) and the net export of hydrogen (b) in Northern Sweden (SE_N), Southern Germany (DE_S), Eastern Spain (IB_E), and Austria, Czech Republic and Slovakia (ATCZSK) for the investigated scenarios. Note the different scale of the *y*-axis in Fig. 4b.

level of electricity import decreases further in the industry-intense regions, such as Southern Germany (DE_S). Industry-intensive regions, such as Austria, Czech Republic and Slovakia (ATCZSK), start to export electricity with the optimized location of industries. This happens because the electrolyzer capacity, as well as the commodity production units with high electricity demand move to the regions with low-cost electricity (Fig. 2). As for the regions with access to low-cost electricity, the level of electricity export decreases as in Northern Sweden

(SE_N) and Eastern Spain (IB_E), while the level of commodities export increases.

3.3.2. Hydrogen

Fig. 5 shows the breakdown of the hydrogen production cost per MWh for the investigated scenarios. The cost is divided into the annualized investment cost, the fixed O&M costs, the cost of electricity, and the transportation costs.

The modeled costs given in Fig. 5 yield a hydrogen production cost in the range of 25–28 €/MWh$_{h2}$ (corresponding to 0.8–0.9 €/kg of hydrogen) for the investigated scenarios. The modeled cost of hydrogen derived from this study is 30% lower than the lowest range of hydrogen costs projected by IEA, i.e., 1.1–4.0 €/kg of hydrogen [70]. An average capacity utilization ratio of around 60% (in all scenarios investigated), which means the electrolyzer operates approximately 5300 h per year, enables the electrolyzer to respond to electricity price fluctuations and avoid high-cost electricity price periods. This is the reason for the low hydrogen cost, since the cost of electricity constitutes the major share of the hydrogen cost. The results of the sensitivity analysis for the scenarios without investments in overcapacity of the industry that includes the electrolyzer and has no storage (e.g., hydrogen, HBI, methanol etc.) reveal that the hydrogen production cost increases by 44%–46% (1.5–1.7 €/kg) compared with the *Present-day_location*, *Present-day_location_H$_2$_export*, *Optimized_location* and *Optimized_location_H$_2$_export* scenarios (Appendix E, Figure E1). In addition, the electricity cost share of the hydrogen production cost increases from 61% to 64% (*Present-day_location*, *Present-day_location_H$_2$_export*, *Optimized_location* and *Optimized_location_H$_2$_export* scenarios) to 87%–89% (*Present-day_location_inflex*, *Present-day_location_H$_2$_export_inflex*, *Optimized_location_inflex* and *Optimized_location_H$_2$_export_inflex* scenarios). The electrolyzer costs are based on an estimation made for alkaline electrolysis and are 350 €/kW$_{el}$ with an efficiency of 79%. These data, as well as the data on hydrogen storage, were acquired from the Danish Energy Agency, *Energistyrelsen* [37].

As indicated in Fig. 5, the electricity cost has the greatest impact on the cost of hydrogen and constitutes 60% of the total hydrogen production cost for all the scenarios. The export of hydrogen (*Present-day_location_H$_2$_export* scenario), i.e., relocation of the electrolyzer capacity to regions with access to low-cost electricity, results in a reduction in the cost of electricity and an emerging transportation cost, as compared with the *Present-day_location* scenario. For the *Present-day_location_H$_2$_export* scenario, hydrogen export has a weak impact (an increase of 0.02% as compared to the *Present-day_location* scenario) on the investments in hydrogen production units (electrolyzer capacity and hydrogen storage). With hydrogen export, the electrolyzer investment costs grow due to the increased capacity of the electrolyzer to absorb more low-electricity-price events and to satisfy a higher CO_2 utilization rate for the production of plastics.

Optimal localization of the industry (*Optimized_location* and *Optimized_location_H$_2$_export* scenarios) results in the hydrogen production costs falling by 9%, as compared with the present-day location of industry (scenario *Present-day_location*). In the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios, most of the decrease in hydrogen cost (13%) comes from the electricity cost, followed by a 3.5% reduction in investment costs. Even though in these scenarios, the full-load hours, capacity and generation of the electrolyzer increase due to an emerging additional demand for hydrogen to utilize CO_2 emissions to produce methanol instead of capturing and storing them due to available low-cost electricity prices, the production-weighted investments are lower

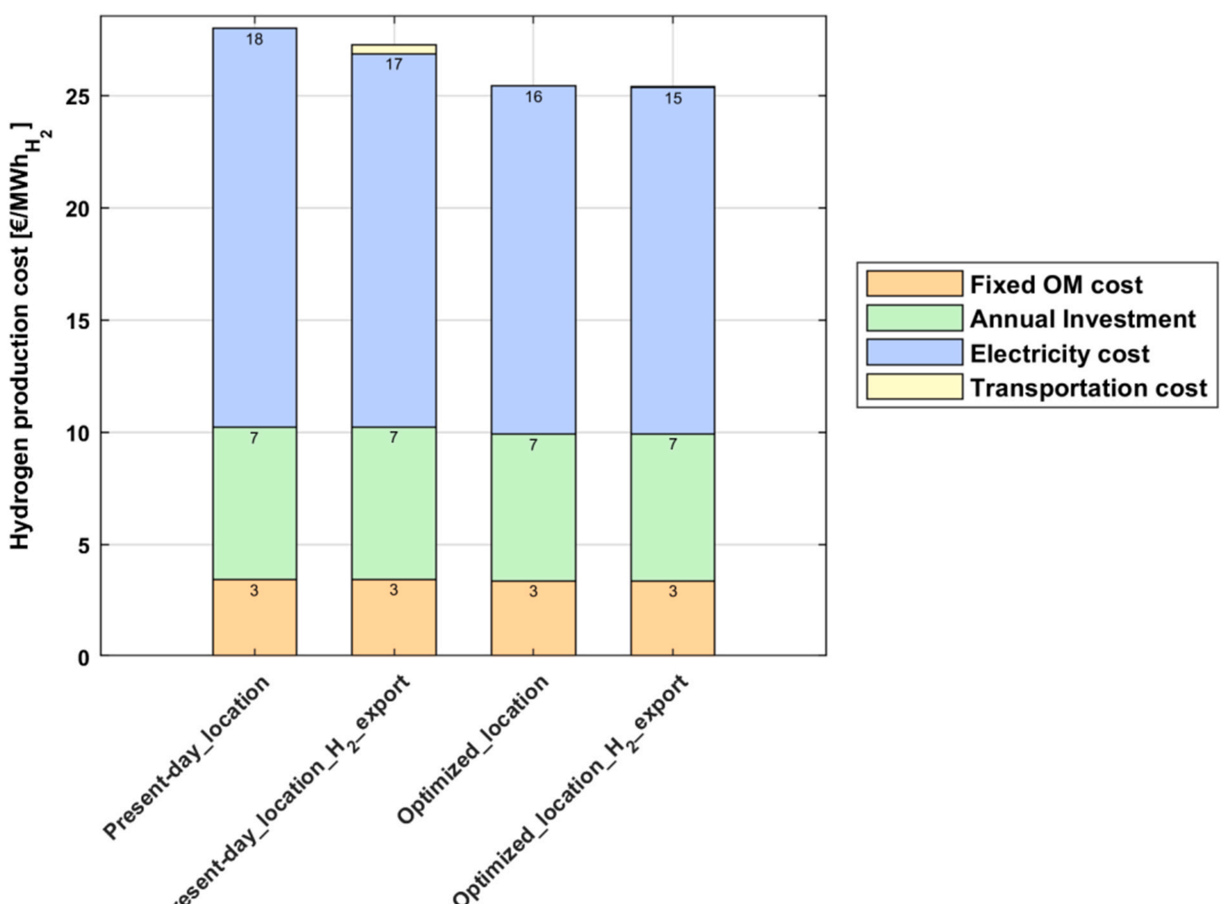

Fig. 5. Breakdown of the modeled cost of hydrogen production into the annualized investment cost, fixed O&M costs, electricity cost, and hydrogen transportation costs for the investigated scenarios.

compared to the *Present-day_location* scenario. If the plastics production process assumed in the present study would have no flexibility in relation to CO_2 utilization and all the emissions needed to be utilized to produce plastics, the capacity of the electrolyzer would decrease while the number of full-load hours would increase in the *Optimized_location* and *Optimized_location_H₂_export* scenarios, as compared with the *Present-day_location* scenario.

For the scenarios with the present-day locations of industry and hydrogen trade possibility, the hydrogen pipeline network provides a way to connect regions that have access to low-cost electricity with industry-intensive regions, yielding a 3% reduction in hydrogen production compared to the scenarios with the present-day locations of industry and without possibility to trade hydrogen. With optimal geographic location of the industries, hydrogen production is sited within the same region as the hydrogen-consuming units. Thus, the hydrogen pipeline has no significant impact on the hydrogen production cost.

Neumann et al. [71] employed a capacity expansion model of the European energy system to assess the impacts of the hydrogen network when there are limitations on the temporal distribution of electricity consumption for the electrified industries (i.e., investments in overcapacity and commodities storage are not allowed). Their findings show that a hydrogen network gives the reduction in total system costs, amounting to 3.4%, in the scenario where power grid expansion is limited, compared to scenarios without a hydrogen network. In net-zero emission scenarios, regions with low average electricity prices would supply hydrogen to industry-intensive regions.

As described in Section 3.2, hydrogen constitutes a large proportion of the ammonia and steel production costs. For ammonia production, the marginal cost of hydrogen is driven by the high hydrogen intensity of the process (see Table 1; the hydrogen demand is 3.8-times higher to produce 1 tonne of ammonia that it is to produce 1 tonne of steel). As for the marginal cost of hydrogen for steel producers, it is driven in the model by the high demand for steel. The total consumption of hydrogen for steel production is 1.4-times higher than it is for ammonia production, with the assumed annual demands for ammonia and steel.

The low marginal cost of hydrogen for plastics producers, as compared with that for the ammonia and steel producers, in all the investigated scenarios (Fig. 6) is a consequence of the flexibility in relation to CO_2 utilization offered by the plastics production process. Fig. 6 also shows that flexibility in relation to CO_2 utilization yields a similar marginal cost of hydrogen for the plastics producer for all the scenarios investigated (i.e., 30 €/MWh in the *Present-day_location* scenario, and 31 €/MWh in the *Present-day_location_H₂_export*, *Optimized_location* and *Optimized_location_H₂_export* scenarios). The ability of plastics production units to vary the CO_2 utilization modes, i.e., CO_2 usage for plastics production and CCS, allows these units to absorb low-cost-electricity hours for hydrogen production.

The optimized location of the electrolyzer and industries (*Optimized_location* and *Optimized_location_H₂_export* scenarios) leads to a smoothing out of the electricity costs between the investigated regions, as compared with the *Present-day_location* scenario, and this is reflected in the marginal costs of hydrogen for ammonia and steel production shown in Fig. 6.

3.3.3. Ammonia, cement, steel and plastics

Fig. 7 shows the modeled regional locations for the production of commodities (ammonia, cement, steel and plastics) in terms of the required electricity demands (in TWh) for the investigated scenarios in Austria, Czech Republic and Slovakia (ATCZSK), Southern Italy (IT_S), Southern Poland (PO_S), Eastern Spain (IB_E), Scotland (UK_N), and Northern Sweden (SE_N).

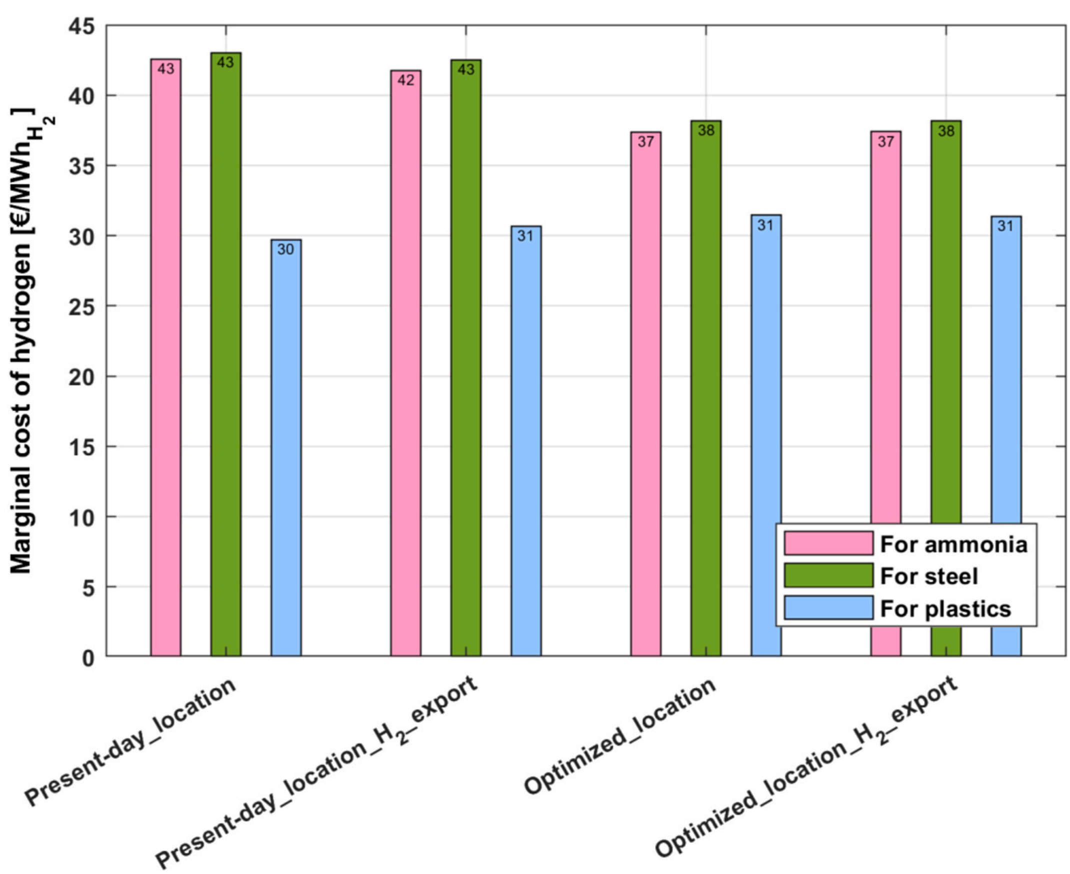

Fig. 6. Modeling results for the marginal cost of hydrogen for industries (ammonia, steel and plastics) that use hydrogen in the commodities production process, for the investigated scenarios.

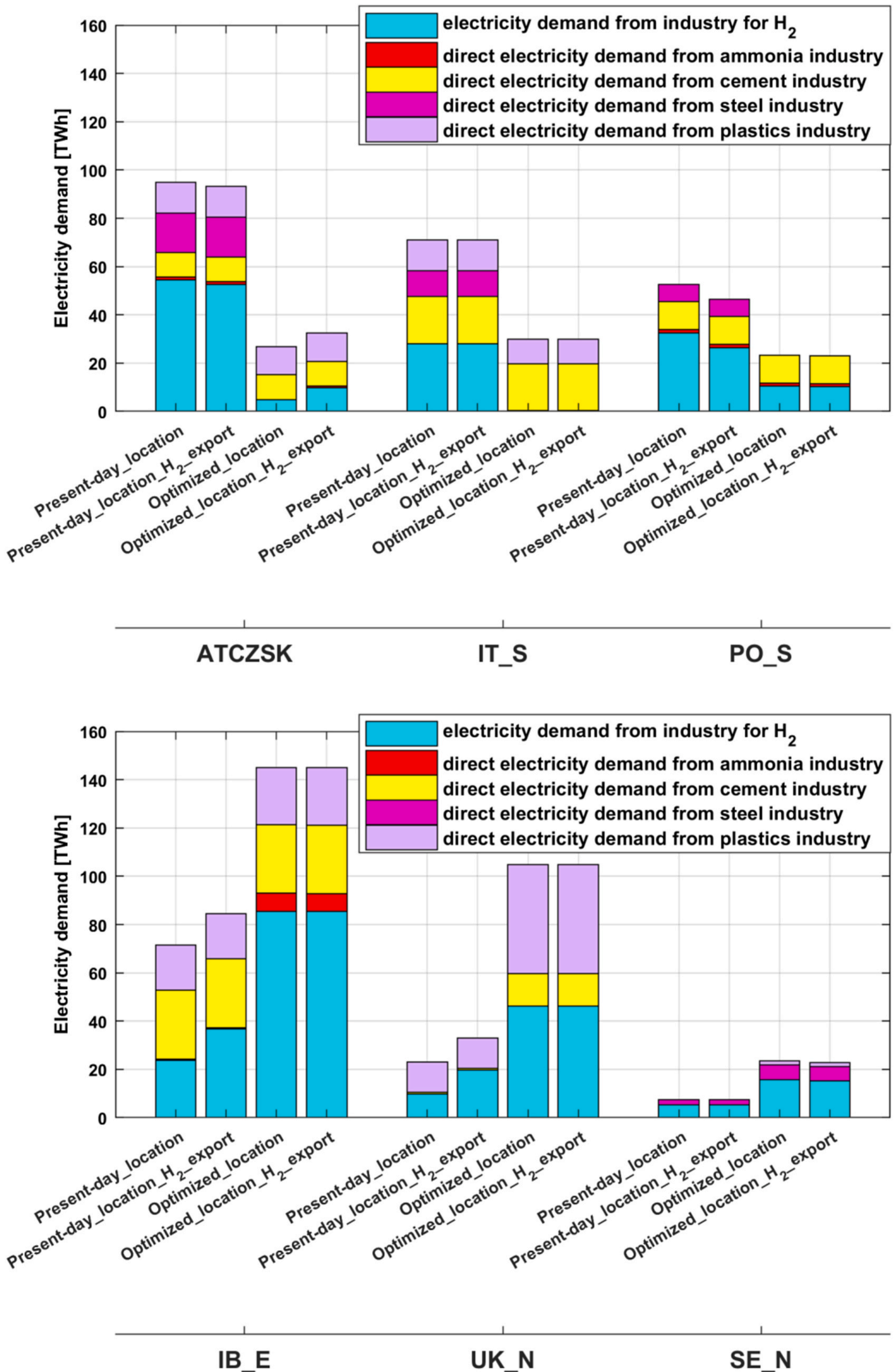

Fig. 7. Electricity demand distributions for the electrified industries (ammonia, cement, steel and plastics), including the electricity demands for hydrogen production in Austria, Czech Republic and Slovakia (ATCZSK), Southern Italy (IT_S), Southern Poland (PO_S), Eastern Spain (IB_E), Scotland (UK_N) and Northern Sweden (SE_N), for the investigated scenarios.

The outcomes presented in Fig. 7 for the scenario with the present-day location of industries and hydrogen trade (*Present-day_location_H$_2$_export* scenario) confirm the results described in Section 3.3.1, showing that hydrogen production (indicated by the blue color) moves from the industry-dominated regions, such as Austria, Czech Republic and Slovakia (ATCZSK), Southern Italy (IT_S), Southern Poland (PO_S) to the regions with access to low-cost electricity and low hydrogen transportation costs, such as Eastern Spain (IB_E) and Scotland (UK_N), as compared with the *Present-day_location* scenario.

Flexibility in terms of location for the cement industry is represented by the export of cement. Thus, the spatial distribution of cement production is limited by the transportation costs for cement in the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios. Cement production moves from the present-day locations (the *Present-day_location* and *Present-day_location_H$_2$_export* scenarios) to new locations only in cases that have low transportation costs for cement and low electricity costs, e.g., Scotland (UK_N) in the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios.

The optimized location, as applied in *Optimized_location* and *Optimized_location_H$_2$_export* scenarios, leads to clustering of the ammonia production plants in regions with low-cost electricity and in regions that already have existing ammonia production units, such as Eastern Spain (IB_E). The clustered ammonia production results in decreased electricity and investment costs and increased ammonia transportation costs (*cf*. Fig. 2a).

The optimized location (*Optimized_location* and *Optimized_location_H$_2$_export* scenarios) of the steel production plants is driven by proximity to iron ore, which results in a reduction in the transportation cost compared to the *Present-day_location* scenario (*cf*. Fig. 2c) and low-cost electricity (SE_N). There is no investment in steel production in locations that lack any existing steel production plants. Instead, steel generation increases in the present-day locations that also have access to the raw material and to low-cost electricity.

As indicated previously, the locations and capacities of the existing chemical factories are used in the eNODE model (Appendix B, Table B3), while the capacities and locations of other parts of the plastics recycling process are decision variables in the model. Thus, 40% of the direct electricity demand associated with plastics production remains at the same location for all the investigated scenarios. For the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios, exports of waste and methanol allow shifting of part of the plastics production (i.e., the steam cracker capacity with waste and the synthesis plant, which requires hydrogen to convert CO_2 to methanol) to regions with high availability of low-cost electricity, such as Ireland (IE_T) and Scotland (UK_N).

3.4. Sensitivity analysis

3.4.1. 100% CCU for plastics production

The limitation of flexibility in relation to CO_2 utilization (when all the CO_2 emissions need to be utilized to produce plastics), as applied in *Present-day_location_CCU, Present-day_location_H$_2$_export_CCU, Optimized_location_CCU* and *Optimized_location_H$_2$_export_CCU* scenarios, results in an increase in the marginal cost of hydrogen, as compared to the scenarios with flexible CO_2 utilization (Fig. 6).

Without flexibility relation to CO_2 utilization (i.e., CO_2 usage exclusively for plastics production), the marginal cost of hydrogen for plastics producers is in the same range (39–45 €/MWh) as the marginal cost of hydrogen for ammonia and steel producers and is driven by the high hydrogen intensity of the synthesis process, which is the part of the plastics production process (see Appendix F).

For the scenarios without flexibility in relation to CO_2 utilization, the annual level of hydrogen generation is the same in all the scenarios, unlike in the scenarios with flexibility in relation to CO_2 utilization. The total electrolyzer capacity decreases (the number of full-load hours of production by the electrolyzer increases) for the scenarios with optimized location (*Optimized_location_CCU* and *Optimized_location_H$_2$_export_CCU*), as compared with the present-day location scenarios (*Present-day_location_CCU* and *Present-day_location_H$_2$_export_CCU*). This is because the electrolyzer capacities move to the regions that have higher numbers of hours with low-cost electricity, i.e., the utilization ratio of the electrolyzer capacity increases.

3.4.2. Inflexible operation of the industries

If investments in overcapacity and storage are not allowed, as is the case in the four *inflex* scenarios (defined in Section 2.4), the sizes of the production units are the smallest possible (and the utilization rate is the highest possible) to meet the annual demand for commodities (Appendix G, Figure G1). Yet, this does not necessarily result in the lowest production cost. Despite the investment cost reductions for all the scenarios with limited operational flexibility, the total production cost of the investigated commodities increases in the *inflex* scenarios.

For scenarios with the present-day locations of the plants and limited operational flexibility, with and without hydrogen export (*Present-day_location_inflex_ind* and *Present-day_location_H$_2$_export_inflex_ind*), the total production costs for ammonia, cement, steel, and plastics increase by 26%, 7%, 10% and 5%, respectively, as compared to the scenarios with the present-day locations of the plants and operational flexibility (*Present-day_location* and *Present-day_location_H$_2$_export*). The ammonia, cement, steel and plastics production costs grow by 23%, 8%, 9% and 3%, respectively, for the scenarios with limited operational flexibility and optimized plant location (Appendix G, Figure G1), as compared with the *Optimized_location_H$_2$_export* scenario in Fig. 2.

The limited operational flexibility for the industries with high operational flexibility, such as the steel and ammonia industry, for the present-day location, leads to reductions in investment costs of up to 36% and 37%, respectively (Appendix G, Figure G1, a and c), as compared with the *Present-day_locatio*n scenario. For the optimized location and limited operational flexibility scenarios (Appendix G, Figure G1a), the decline in investments in ammonia production units is only 8% larger than in the *Optimized_location* and *Optimized_location_H$_2$_export* scenarios. This is due to the localization of the ammonia production capacity to the region without an existing ammonia industry and the availability of low-cost electricity, which increases investment costs due to the penalty imposed on investments in new production sites. For plastics production, flexibility in relation to CO_2 utilization compensates for the limited flexibility in time for scenarios with limited operational flexibility, i.e., the ability to switch between CO_2 utilization modes (CCU or CCS) allows one to avoid the consumption of electricity during high-cost events, which also implies increased costs for feedstock and CCS (Appendix G, Figure G1d).

4. Discussion

The applied model reveals that the future electricity demand of the EU, including the present electricity demand and the new electricity demands from the transport, heat and industry sectors, is around 5900 TWh for all the scenarios investigated. The net-zero scenario from the European Commission estimates a future electricity demand that is 6800 TWh, which is 13% higher than the estimate made in this study (5900 TWh) [72]. The discrepancy is likely to be because not all applications for electrification are included in the modeling of the present work, such as synthetic fuels for aviation and maritime transport, and the non-ferrous metals industry. Thus, future demands for electricity and hydrogen may be higher than what is assumed in this work, and the results should not be interpreted as a forecast but rather as an illustration of the characteristics and new flexibility that will emerge from the electrification of industry. The present electricity demand (56% of the total modeled future demand) is assumed to remain at the current level for the zero-emissions year (2050), although this may of course also change in the future – either decreasing due to efficiency measures or increasing due to additional energy services in buildings and in transport [73]. In addition, future load variations may change due to demand-side management strategies.

The modeling shows that the additional electricity demand is met primarily by wind and solar power within the EU, i.e., all the modeled scenarios require substantial and rapid increases in renewable electricity capacity. For example, in Germany (DE_N and DE_S regions), the average expansion rate of PV for the period of2020–2050 should be 3 GW per year in all the investigated scenarios, to attain a capacity of 153 GW in Year 2050. This increase capacity is only somewhat higher than that achieved in recent years, when the average expansion rate of PV was 2.5 GW per year (between 2005 and 2020). The expansion rate of offshore wind in the EU (current capacity of 22 GW) will need to be 8 GW annually to reach the modeled result of 300 GW in Year 2050 [74]. Thus, there is a clear need to accelerate the deployment of renewable electricity if one is to meet the EU targets for climate neutrality by Year 2050.

There is an obvious need for scaling-up of the electrolyzer capacity. Starting from 135 MW electrolyzer capacity in the EU in Year 2021 [75], the electrolyzer capacity deployment rate needs to be 4 GW per year to meet the hydrogen demands of the electrified basic material industries obtained in this work (i.e., 114 GW in Year 2050). Electrolyzer producers in the EU have signed a declaration of commitment to have installed an electrolyzer capacity of 17.5 GW_{h2} in the EU by 2025, which is in line with what is required to realise the outcomes obtained in this work [76]. Germany's national hydrogen strategy [77], target 10 GW of electrolyzer capacity to be installed by Year 2030. Based on the results of this study, an electrolyzer capacity deployment rate of 0.9 GW per year from 2030 to 2050 is necessary to achieve the self-sufficient electrification of industry within Germany's zero-emission electricity system, reaching 27 GW of electrolyzer capacity in 2050 for the present-day location scenario.

Complete self-sufficiency for the electricity and hydrogen supply of the EU is investigated in this study. It should be noted that importing electricity, hydrogen, or hydrogen derivatives such as ammonia or steel produced using renewable energy technologies can alleviate the pressure on the domestic deployment of renewable infrastructure and reduce land use pressure in the EU. By partnering with regions that have low-cost renewable energy supply potentials, Europe could advance towards its carbon neutrality goals while fostering economic development in the exporting countries. However, a strong reliance on imports is not desirable because of energy security concerns. Neumann et al. [78] applied a global energy supply chain model with the sector-coupled energy system model for Europe to investigate scenarios with varying imports for electricity, hydrogen and hydrogen derivatives volumes, costs, and vectors. They found that imports of electricity and materials produced using renewable energy technologies (wind and solar) reduce the costs of a carbon-neutral European energy system by 5% in comparison to a fully self-sufficient European energy supply scenario.

Although electrification of industry is a key measure for decarbonization, decarbonization of industry requires the implementation of several emissions mitigation options, which are outside the scope of this work. These include efficiency measures and investments in best-available process technologies, including the use of more circular systems, in addition to other societal measures such as the promotion of reduced consumption. In addition, current industries are heterogeneous throughout Europe with respect to CO_2 intensity and age, and as a consequence are most likely to experience increased costs linked to carbon pricing (e.g., from the EU ETS system) [79]. In contrast, the modeling of this work assumes that each industry is the same throughout Europe. Therefore, the timing and cost of the mitigation strategies for a certain type of industry may be country-specific [80].

Historically, access to the market, labor, transportation, and raw materials have all contributed to dictating the siting of industries. The electrification of industrial processes can lead to significant changes with respect to the jobs and skills required by the industry. Thus, the workforce would need to be retrained or require new education, which could create new employment opportunities but might also cause disruption to current employment patterns. While these traditional factors most likely will continue to be important, so will new factors related to the business climate, education, taxes and policies. The electrification of industries relies on social acceptance of the technology and the transition process. To obtain a transition which is perceived to be just, it should be important to engage with stakeholders, i.e., community members, workers, and industry representatives, to ensure that their concerns and perspectives are considered. New production methods, such as those linked to the electrification investigated in this work, will expand the list of relevant factors influencing the localization of industries. Most notably, access to low-cost electricity is a crucial factor, as shown in this work. The model used in this work indicates that with respect to the present-day locations of industries, it is beneficial to export hydrogen from the regions with access to low-cost electricity, while the locations of new industries are mainly governed by access to low-cost electricity and they instead produce the required hydrogen on-site.

Future work could include further development of the model, refining the description of the product demand side, such as differentiating between the quality levels of commodities and products [81].

5. Conclusions

An electricity systems model is applied to evaluate the impacts of electrification of energy-intensive industries on investments in and operation of the European electricity system, as well as on the spatial distribution of future industrial plants and their production levels. The context of this work is a zero-carbon emissions energy system, including future electricity demands from the transport, heat and industry sectors. In the context of the research questions posed in the Introduction section, the findings and conclusions from this work can be summarized as follows.

- *How do the potential future electricity and hydrogen demands from the industry, with different types of flexibility, influence the source and composition of the electricity generation?*

The modeling shows that the electrification of industry, including the ammonia, cement, steel and plastics industries, in the EU will increase the electricity demand by around 44% (i.e., by 1200 TWh). The electricity generation mix depends on the level of flexibility in locating the industries, which will be determined by the extent to which it is possible to trade commodities.

With the present-day locations of the industries, their electricity demands are primarily met by nuclear, solar and wind power generation. If changes to the annual production volumes and relocation of industry are allowed, more commodities will be produced in regions that have both existing industries and access to low-cost electricity. Thus, an optimized geographic localization of industry increases the electricity generation from wind and solar power.

- *Which parameters drive a cost-optimized spatial distribution of new locations for electrified industrial plants?*

The modeling results show that for the ammonia industry, which is an industry with high operational flexibility, i.e., the ability of the industry to vary the output within a broad range of loads and with dependency on hydrogen, the main parameter that affects its geographic location is the availability of low-cost electricity generation. The spatial distribution of the electrified plastics and steel industries, for which feedstock and electricity costs constitute the largest shares of the production cost, is affected by the low-cost access to feedstock (e.g., regions that produce or distribute feedstock or have low costs for feedstock transportation) and the availability of low-cost electricity generation.

For the steel industry, locating the production plant so as to access low-cost electricity is particularly favorable if the feedstock (iron ore) can be transported to the region using low-cost electricity and at a low cost. For the plastics industry, locating production to regions with low-cost electricity results in an increase in hydrogen utilization to produce plastics, i.e., a high rate of carbon recovery, and decreased costs for CCS. The modelling results of this work indicate that an industry with low operational flexibility (cement industry) is limited in terms of its ability to take advantage of low-cost electricity from wind and solar power and, thus, investments in new infrastructure are made in existing sites. For the electrified industries for which existing industrial units can be used in the new electrified process and with high hydrogen intensity, the hydrogen production step moves to a new location with availability of low-cost electricity generation, rather than being located at the same site as the existing industrial units.

CRediT authorship contribution statement

Alla Toktarova: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Lisa Göransson:** Writing – review & editing, Validation, Supervision, Methodology, Conceptualization. **Filip Johnsson:** Writing – review & editing, Validation, Supervision, Project administration, Funding acquisition.

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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Appendix A. Supplementary data

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