

Modelling a highly decarbonised North Sea energy system in 2050: A multinational approach

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ABSTRACT

The North Sea region, located in the Northwest of Europe, is expected to be a frontrunner in the European energy transition. This paper aims to analyse different optimal system configurations in order to meet net-zero emission targets in 2050. Overall, the paper presents two main contributions: first, we develop and introduce the IESA-NS model. The IESA-NS model is an optimization integrated energy system model written as a linear problem. The IESA-NS model optimizes the long-term investment planning and short-term operation of seven North Sea region countries (Belgium, Denmark, Germany, the Netherlands, Norway, Sweden and the United Kingdom). The model can optimize multiple years simultaneously, accounts for all the national GHG emissions and includes a thorough representation of all the sectors of the energy system. Second, we run several decarbonisation scenarios with net-zero emission targets in 2050. Relevant parameters varied to produce the scenarios include biomass availability, VRE potentials, low social acceptance of onshore VRE, ban of CCUS or mitigation targets in international transport and industry feedstock. Results show a large use of hydrogen when international transport emissions are considered in the targets (5.6 EJ to 7.3 EJ). Electrolysis is the preferred pathway for hydrogen production (up to 6.4 EJ), far ahead of natural gas reforming (up to 2.2 EJ). Allowing offshore interconnectors (e.g. meshed offshore grid between the Netherlands, Germany and the United Kingdom) permits to integrate larger amounts of offshore wind (122 GW to 191 GW of additional capacity compared to reference scenarios), while substantially increasing the cross-border interconnection capacities (up to 120 GW). All the biomass available is used in the scenarios across multiple end uses, including biofuel production (up to 3.5 EJ), high temperature heat (up to 2.5 EJ), feedstock for industry (up to 2 EJ), residential heat (up to 600 PJ) and power generation (up to 900 PJ). In general, most of the results justify the development of multinational energy system models, in which the spatial coverage lays between national and continental models.

1. Introduction and knowledge gaps

There is a global consensus about the need to drastically reduce greenhouse gas (GHG) emissions in the coming decades in order to reduce the risks and impacts of climate change. The Paris Agreement was signed by 195 countries in 2016, aiming to limit the increase in the global average temperature to at least 2 °C above pre-industrial levels [1]. The European Commission has also set different goals and milestones for the short, medium and long term. The 'European Green Deal', presented in 2020, the 'Clean energy for all Europeans' strategy, released in 2019, or the 'Fit for 55%' policy package, discussed in 2021, are ex-

amples of initiatives aiming to decarbonize the European energy system in the medium to long term [2,3,4].

The North Sea region (NSR)¹, located in the northwest of Europe, is expected to be a frontrunner in the continental energy transition. The NSR is an energy intensive region in Europe: it contains around 200 million inhabitants in a relatively small area, its countries add up around 60% of the GDP of the EU, it harbours multiple heavy industrial clusters, and it has been traditionally a key hub for the Oil and Gas (O&G) industry [5,6]. Moreover, the NSR presents ample potentials for different

¹ NSR countries include Belgium, Denmark, Germany, the Netherlands, Norway, Sweden and the United Kingdom

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Table 1
GHG emission targets and policies for the NSR countries.

Country	Policies for 2030	Policies for 2050	Ref
Netherlands	49% reduction of GHG emissions compared to 1990	95% reduction of GHG emissions compared to 1990	[12]
Germany	55% reduction of GHG emissions compared to 1990	Net-zero emissions by 2050	[13]
Denmark	70% reduction of GHG emissions compared to 1990	Net-zero emissions by 2050	[14]
Sweden	63% reduction of GHG emissions compared to 1990	Net-zero emissions by 2045	[15]
Norway	At least 50% and towards 55% reduction of GHG emission compared to 1990	90–95% reduction of GHG emissions compared to 1990	[16]
United Kingdom	68% reduction of GHG emissions compared to 1990	Net-zero emissions by 2050	[17]
Belgium	35% reduction of GHG emissions compared to 1990	At least 80% reduction of GHG emissions compared to 1990	[18]
Europe (Green Deal)	55% reduction of GHG emissions compared to 1990.	Net-zero emissions by 2050	[2]

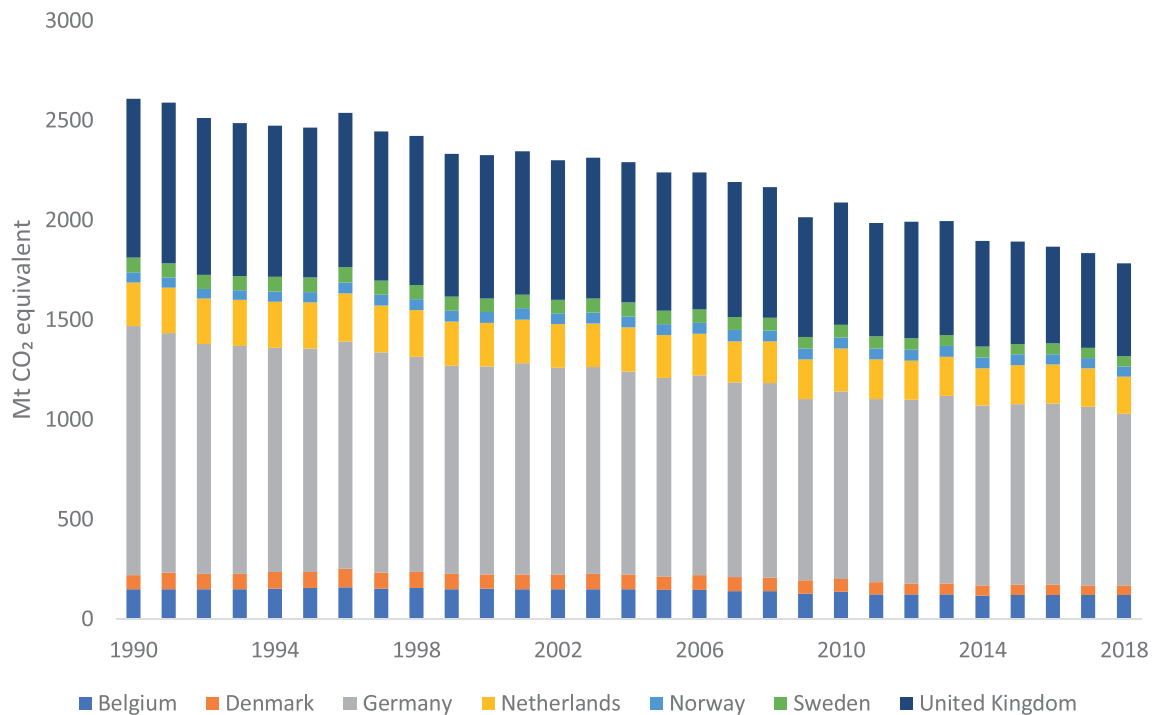


Fig. 1. Total GHG emissions in the NSR from 1990 to 2018, excluding LULUCF and international aviation [22].

variable renewable energy (VRE) sources. In particular, offshore wind deployments are expected to be relevant in order to decarbonise the region (together with other offshore technologies such as wave energy, tidal energy, ocean thermal energy conversion or micro-algae production) [7].

The NSR countries have set ambitious decarbonisation goals for the medium and long term, as shown in Table 1. Except Belgium, all countries propose higher targets from 2030 than the 40% emission reduction from 1990 levels suggested by the European Commission, ranging from the 49% target of the Netherlands to the 70% target of Denmark. By 2050, Germany, Denmark, Sweden and the United Kingdom aim to reach net-zero emissions, while the Netherlands, Norway and Belgium have set reduction targets of around 95% compared to 1990 levels.

In the last three decades, GHG emissions in the NSR have been reduced substantially, as seen in Fig. 1, moving from 2608 Mt of CO₂ equivalent in 1990 to 1784 Mt of CO₂ equivalent in 2018, which corresponds to approximately a 10% reduction per decade. In order to meet future mitigation targets this pace needs to be increased, and mitigation efforts need to be applied to both energy related and non-energy related sectors.

Many alternatives that can be combined in order to achieve the mitigation targets have been extensively analysed in the literature: large deployments of VRE; further electrification of multiple energy sectors, such as heat and transport; sustainable use of biomass as a fuel or as a

feedstock; improvement of energy efficiency of buildings and processes or carbon capture, utilization and storage (CCUS), among others [8]. From a system integration perspective, sector coupling and interconnection capacity expansion have been identified as key concepts in order to integrate VRES and decarbonize energy systems [9,10,11].

In order to understand how these alternatives can be economically integrated at the system level, energy system models (ESMs) are widely used. ESMs are useful tools used to understand how future energy systems might behave, to analyse cost-optimal system configurations and to define transition pathways towards decarbonised energy systems. As of today, there are hundreds of different energy models, with different methodologies (e.g., optimization or simulation), geographical coverage (local to international), sectoral coverage (e.g., power system models, gas models or integrated ESMs) and different mathematical approaches (e.g., Linear Programming (LP) or Mixed Integer Programming (MIP)). There is a large number of studies analysing in detail multiple energy models, pointing out their strengths and weaknesses and describing improvements needed to properly represent systems with high penetrations of VREs and high decarbonisation (see for example [19,20,21]).

ESMs have been extensively applied to analyse the energy system of individual NSR countries at the national level. For example, in [23], Maruf used the OSeM-DE model to analyse a 100% renewable based and sector coupled energy system in Germany, covering electricity and building heat. In [24], Sanchez et al. used the IESA-Opt modelling tool

to analyse a scenario with a 95% reduction of GHG in the Netherlands. In [25], Lund et al. used EnergyPLAN to analyse a system with 100% of renewable energy in 2050 in Denmark.

These national studies are useful to understand decarbonisation strategies in different countries, as they tend to zoom in with a high level of detail in multiple sectors of a national energy system. However, due to the national-scale focus, they tend to wrongly estimate or even completely ignore the interactions with surrounding countries, e.g., cross border electricity or gas trades, as these interactions are usually exogenous and not determined by the model, thus leading to misleading conclusions.

Other studies have analysed the NSR as a whole, especially paying attention to the role of international interconnectors in systems with high penetrations of offshore wind. In short, these studies can be divided into two categories:

- Studies analysing the ‘offshore grid’ concept in the NSR, i.e., how large deployments of offshore wind can be efficiently interconnected with different grid structures [26,27,28,29,30,31,32,33,34,35,36,37]. Most of these studies are exclusively focused on the power sector, with little or no interaction with other energy sectors.
- Studies analysing the role of offshore CCUS in the NSR, analysing the potential CO₂ storage capacity of different offshore sinks, and how they can be efficiently connected to onshore CO₂ sources [38,39].

Some studies cover the EU as a whole, and therefore include the NSR energy system. To name some, Zappa et al. [40] used PLEXOS to analyse whether a power system based on renewable sources is feasible by 2050 in the EU. Blanco et al. [41,42] used the JRC-EU TIMES model to analyse the role of hydrogen, power-to-gas and power-to-methane in highly decarbonised scenarios in 2050, covering all the energy sectors and GHG emissions of the whole EU. However, these EU-level analyses tend to include simplifications in order to reduce the computational effort (e.g., use of temporal time-slices or aggregation/simplification of energy sectors) [5]. Therefore, even though multinational regions are analysed in continental analyses (e.g., the NSR in EU analyses), the level of detail is in general low, and aspects such as offshore/onshore interactions, interconnectors, infrastructure, hourly system dynamics, spatial resolution and subnational implications (e.g., national grid congestion) are in general not considered in detail.

Finally, there is a considerable literature analysing system integration alternatives in the NSR, particularly paying attention to synergies between oil and gas activities and offshore wind deployment, by means of, for example, electrification of O&G activities or repurposing of offshore O&G assets (see e.g., [43,44,45,46]). However, these studies tend to include a high level of technical detail of individual offshore activities, and in general, do not capture the whole energy system.

The literature lacks energy system analyses and modelling tools covering the multinational (‘regional’) level in general and the NSR level in particular. National level analyses are abundant and tend to zoom in on particular aspects of national energy systems. Continental analyses are abundant as well and identify aggregated energy system trends for wider geographical areas, such as Europe or Africa. However, a knowledge gap, in general, is that a high level of detail is missing in energy system analyses at the intermediate scale (i.e., at the multi-country or multinational level), in which the energy systems of multiple countries within a certain region are included (e.g., the NSR).

The need for this type of multinational analyses is best exemplified with the NSR case study. NSR countries are highly interconnected (e.g., electricity and gas networks), and therefore the behaviour of each of them can highly affect the region as a whole. The North Sea harbours multiple energy related activities (from oil and gas to offshore wind) and non-energy related activities (e.g., sand extraction, fisheries or military use), which are highly interconnected, affecting the energy system development of all of them. These aspects cannot be captured in detail,

or not at all, if only one country is analysed, and might be extremely diluted if the geographical coverage is the whole EU. The same logic can be applied to similar multinational regions either in the EU or in the rest of the world.

As a consequence of this trend in the literature, the first knowledge gap that this paper aims to cover is identified:

- The NSR has been extensively analysed from a national perspective (i.e. complete analysis of single countries). From a multinational perspective, some analyses have been carried out focusing on a single sector or technology (mainly the power sector and CCUS). Continental (EU level) analyses are abundant but do not dig into particular aspects of the NSR with a high level of detail. Therefore, **a multinational analysis of the NSR in which all the sectors of the energy system and all the GHG emissions are included is missing in the literature.**
- One of the key factors in order to explore this knowledge gap is to use an ESM that can cover the whole energy system of the NSR. Selecting the proper ESM is not a straightforward step, as there are usually multiple trade-offs that should be considered. For example, sector-specific ESMs (e.g. power system models or gas system models) tend to describe a specific sector in a very detailed way, while using accurate spatiotemporal resolutions and eventually including non-linear (e.g., binary) decision variables. On the other hand, integrated ESMs tend to cover multiple sectors of the energy system, but in order to maintain a reasonable computational performance, they tend to sacrifice the temporal resolution (e.g., using timeslicing methods) and use oversimplified formulations.

This trade-off has been investigated in the literature at national scale. Fattahi et al. [19], analysed a selection of national integrated ESMs, finding out that none of them included simultaneously: hourly temporal resolution, multi-year investment optimization, endogenous inclusion of all national GHG emissions, a detailed technological representation of all the sectors of the energy system, endogenous cost-optimization of the infrastructure needs, and interconnection to neighbouring countries’ power dispatch.

A model covering all the aforementioned capabilities at national scale was proposed in [24], where Sanchez et al. presented IESA-Opt (Integrated Energy Systems Analysis – Optimization), an LP optimization model for the Netherlands. However, as of today, there is no ESM that includes these capabilities at multinational scale (i.e., the level of geographical coverage required to analyse multinational regions such as the NSR). In other words, there is a gap between detailed ESMs at a national scale, and continental models with simplifications in temporal, spatial and technological resolution.

Therefore, the second knowledge gap is identified:

- **Lack of an ESM covering the NSR that includes: hourly temporal resolution, multi-year investment optimization, endogenous inclusion of all the national GHG emissions, a detailed technological representation of all the sectors of the energy system, endogenous cost-optimization of the infrastructure needs, and interconnection to neighbouring countries’ power dispatch.**

In order to fill the two aforementioned knowledge gaps, this paper presents the IESA-NS model, Integrated Energy Systems Analysis – optimization of the North Sea region, a multinational extension of the IESA-Opt model [24,47]. In short, the IESA-NS model 1) optimizes both long-term investment decisions and short term operation, 2) is able to run with hourly resolution over a multi-year time span, and 3) permits to increase the spatial resolution of the offshore areas of the North Sea as much as desired. The model includes a European representation of power and gas network (i.e., hourly dispatch of European power and daily dispatch of European natural gas), and a complete representation of the energy system of the NSR countries (i.e., Belgium, Denmark, Germany, the Netherlands, Norway, Sweden and the United Kingdom).

This paper then provides the following two main contributions:

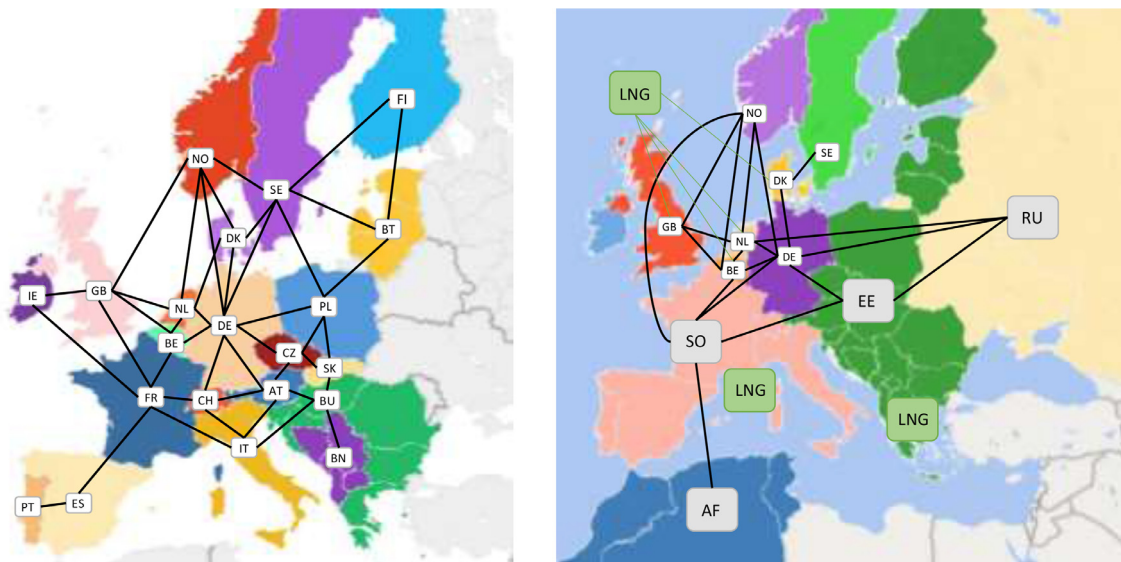


Fig. 2. European nodes and international interconnectors considered for the European power dispatch in IESA-NS (left) and European natural gas and LNG network considered in IESA-NS (right).

- We present the IESA-NS model, an integrated ESM covering the whole energy system of the NSR. The IESA-NS model, code, database and user interface are open source and can be freely downloaded in [48].
- We use the IESA-NS model to analyse a large variety of scenarios with different decarbonisation targets; various biomass, CO₂ storage and CCUS potentials; exogenous bans of certain technologies and imports; including some sensitivity analyses for some relevant parameters.

The rest of the paper is structured as follows: Section 2 provides a brief description of the IESA-NS model. Section 3 outlines the main scenarios that have been analysed for this paper. Section 4 presents and discusses the major results of the scenario model runs. Section 5 shows some sensitivity analyses for some relevant parameters and discusses the major outcomes of these analyses. Section 6 presents an analysis of the system costs. Finally, Section 7 provides a brief summary and discussion of the major findings, conclusions and limitations of this study.

2. Modelling approach: the IESA-NS model

In this paper, we developed the IESA-NS model based on the IESA-Opt model [24]. The IESA-Opt model was initially developed to cover the energy system of the Netherlands in detail, filling multiple knowledge gaps that most integrated ESMs have [19]. In this paper, we enhance the IESA-Opt model in order to cover the whole NSR with a high level of detail, including a detailed representation of the energy system of the Netherlands, Germany, Denmark, Sweden, Norway, the United Kingdom and Belgium.

The IESA-NS model is a cost-optimization model, formulated as an LP, that optimizes the long term investment planning and short term operation of the NSR energy system. The model can optimize multiple years simultaneously, accounts for all the national GHG emissions and includes a thorough representation of all the sectors of the energy system.

Appendix A presents a detailed explanation of the energy system representation in IESA-NS, the technologies included, the spatial, temporal and technological resolution, and many other assumptions and relevant information. Appendix B shows the mathematical formulation used in the IESA-NS model.

Even though the IESA-NS model is focused on the NSR, it also permits to analyse the interactions with the European power and gas grids. In order to do so, the IESA-NS model optimizes also the European power dispatch, and therefore electricity imports and exports between the NSR and the surrounding countries are completely endogenous. As shown in Fig. 2 left, the European power dispatch includes 14 additional nodes to represent the other EU countries. The European capacities and transmission interconnectors outside of the NSR are fixed according to the Ten Year Network Development Plan of ENTSOE [49], hence the model does not invest in capacity expansion outside of the NSR.² Regarding the gas network, there are two main external sources of natural gas: Russia (RU) and northern Africa (AF). These natural gas hubs are connected to Europe and to the NSR via the clustered regions of eastern Europe (EE) and southern Europe (SO). Additionally, LNG can be imported in countries that have an LNG terminal and a decompression station. Naturally, NSR countries with natural gas fields under their domain (like Norway) have access to a national natural gas source, which can also be traded across Europe to minimize the total system costs.

Another key aspect of the IESA-NS model is its modularity to represent the offshore part of the region with as many different offshore nodes as required by the user. The importance of properly representing the spatial components of the NSR in energy modelling approaches has already been evaluated in the literature [5,7]. Fig. 3 shows the design used in this paper with offshore nodes tailor-made for the Netherlands, the United Kingdom, Norway, Denmark and Germany,³ each of them with one interconnector to shore. This modularity allows that the offshore design can be adapted to any case study: analyses of particular regions of the NSR can be evaluated adding new nodes with different wind profiles; offshore grid case studies with different hub locations and meshed interconnectors can also be implemented; interactions between wind and hydrogen in certain areas; and, in general, any analysis that requires a high level of spatial resolution.

² Interconnector capacity between NSR countries is optimised, interconnector capacity between countries outside of the NSR is fixed according to the TYNDP

³ The North Sea area of Belgium is relatively small compared to the rest of NSR countries, and therefore for this publication, we do not enhance its spatial resolution including an additional node. Sweden does not have direct access to the NSR, and therefore no offshore node can be included.

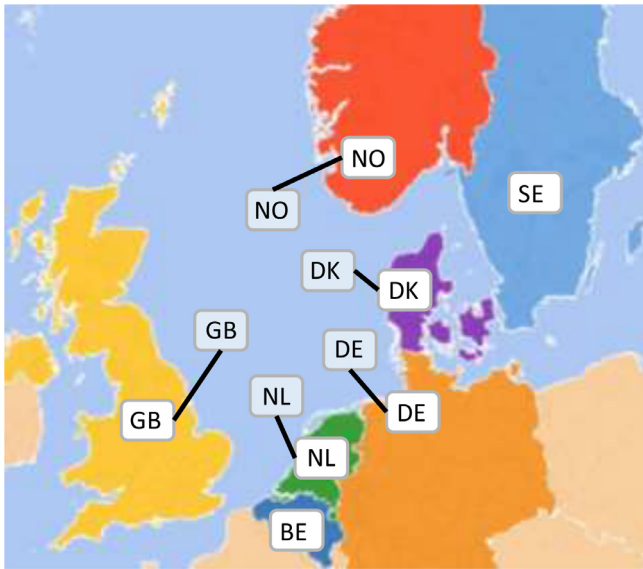


Fig. 3. Offshore design of the IESA-NS model for this paper. The offshore design in IESA-NS is modular and can be customized.

3. Scenario definition

Scenarios in IESA-NS are defined mainly by the six data inputs represented in Fig. 4: the projected demand of energy drivers (e.g., electricity demand of the residential sector or megatons produced of paper related products); the cost of input resources (e.g., cost of imported coal or cost of national biomass); the potentials for decarbonisation technologies (e.g., potentials for offshore wind or solar PV); the different policy regulations assumed for the transition in each country (e.g., GHG mitigation targets or political bans to certain technologies); the projected cost and operational parameters of the technologies (e.g., techno-economic data of a heat pump for residential heat); and the assumed installed capacities for European nodes.⁴

In order to analyse different decarbonisation alternatives, we present a set of scenarios, which are summarized in Table 2. With the proposed multiple scenarios in this study, we aim 1) to show that there are multiple feasible alternatives to meet the GHG emission mitigation targets,

⁴ Note that the IESA-NS model dispatches electricity for the whole EU, but does not optimize the capacity expansion of countries outside the NSR. Therefore, for the remaining European nodes, future capacity investments and developments are exogenous, based on the Ten Year Network Development Plan of ENTSOE [49]

which would entail different system costs and configurations; and 2) to show the effects of specific policy decisions, technology bans or cost developments in the whole energy system.

A complete description of all the scenarios (i.e., assumptions, drivers, data inputs and rationale) can be found in Appendix C. All the scenarios use as a starting point the Reference Scenario (REF). In all of them, most of the data for the energy drivers and some cost assumptions are derived from the JRC POTEnCIA Central scenario for all the NSR countries [50]. The POTEnCIA Central scenario assumes a business as usual economic development, with the European GDP growing accordingly to the '2018 Ageing report' (i.e., around 1.38% growth per year until 2050) [51], a growth of population and households based on EUROSTAT data, and projections of industry based on the sectoral Gross Value Added (GVA) values (see [50]). All the input data used for the reference scenario (i.e., energy drivers, techno-economic parameters and commodity costs disaggregated per country) can be consulted online in [48] together with the whole database of the model.

There are three key input parameters that have been modified to derive the scenarios shown in Table 2: the VRE and biomass availability, certain technology bans, and the mitigation ambition of the NSR countries. The VRE (i.e. solar PV, offshore and onshore wind) and biomass availability have been divided in three levels according to the ENSPRESO [52] scenarios: a reference value, a high (optimistic) value, and a low (pessimistic) value. More details about the input data and sources can be found in Appendix C. Regarding technology bans, Carbon Capture and Storage has been disallowed in one of the scenarios (NOCCS). Regarding the mitigation ambition, two different levels have been defined: high and low. In the low ambition mitigation scenarios, the mitigation targets of each one of the NSR countries are not increased. In the high ambition mitigation scenarios, all the NSR countries set a net-zero mitigation target for 2050, they include the emissions of international transport within the national targets, and the use of oil as feedstock for the chemical industry is banned.⁵ The reason to include these two 'mitigation ambition' levels is to show the impact on the optimal system configuration of broadening the emissions included in the national emission targets.

Regarding commodities, in all the scenarios all NSR countries can import natural gas, a certain amount of biomass and biofuels (variable per scenario), coal and crude oil. In the seven scenarios of Table 2 the

⁵ Current mitigation targets (see Table 1) do not include most of the emissions related to international aviation and navigation. Therefore, NSR countries might reach net-zero targets while emitting considerable amounts of CO₂ in the international space. Regarding the use of oil as feedstock in the chemical industry, due to the fact that the oil is embedded in the final product, no direct emissions are accounted in the process. These two areas are not covered in current mitigation targets, and therefore the 'High ambition' scenarios aim to include them.

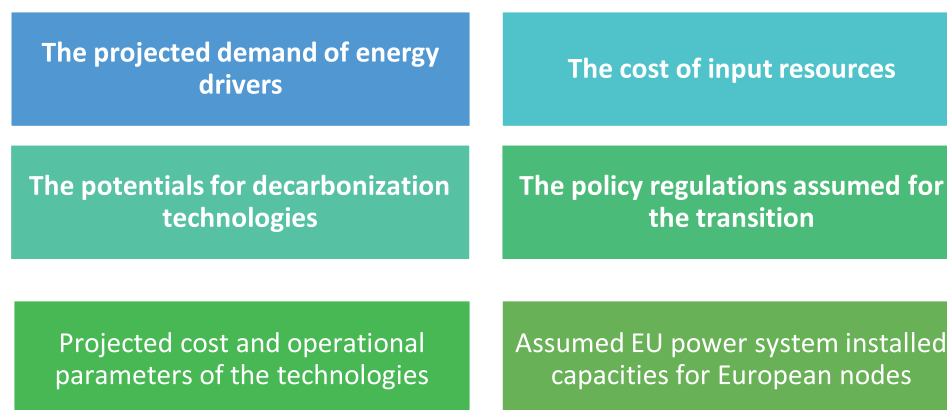


Fig. 4. Inputs required for scenario definition in IESA-NS.

Table 2
Decarbonisation scenarios used in this paper.

Parameter	Explanation	Rationale	Key values	Code	Mitigation ambition
Reference scenario	All the NSR countries follow the defined 'High ambition' targets. There are no major technology bans or incentives.	The reference scenario aims to be a benchmark to compare it with more constrained scenarios.	n/a	REF	High
Biomass availability	In this scenario the biomass potentials of the NSR countries (national and imported) are modified, assuming an optimistic scenario with higher availability, and a pessimistic scenario with lower availability.	Biomass plays a crucial role in highly decarbonised energy systems, due to its versatility (i.e. it can be used in multiple sectors of the energy system for a variety of purposes). This scenario explores system implications of different levels of biomass availability.	• High biomass potential, derived from the high biomass ENSPRESO scenario	HBIO	High
			• Low biomass potential, derived from the low biomass ENSPRESO scenario	LBIO	Low
Wind and solar PV potentials	In this scenario, the potentials of wind and solar PV are modified, assuming an optimistic scenario with high wind and solar availability and a pessimistic scenario with more constrained values.	The potentials of renewable energies such as wind and solar are not only determined by the meteorological profiles, but also by policies and regulations. If the use of space for wind and solar is prioritised, setback distances are reduced, and synergies between different activities are enhanced the availability of wind and solar can be boosted. On the other hand, policies can also limit potential deployments.	• Wind and solar PV potentials increased in line with the ENSPRESO high VRES scenario	HVRES	High
			• Wind and solar PV potentials decreased in line with the ENSPRESO low VRES scenario	LVRES	Low
Onshore wind and solar PV potentials	In this scenario, the potentials of onshore wind and solar PV in the NSR are reduced. Costs of offshore wind are reduced assuming a faster learning rate. To compensate, the availability of offshore wind is increased in line with the HVRES scenario	Onshore deployments of solar PV and wind might face social acceptance problems, especially in areas with high population density. This scenario explores implications in the NSR if onshore potential are reduced, and therefore the system needs to rely more on offshore technologies.	• Onshore and solar PV availability reduced in line with the ENSPRESO low VRES scenarios. Offshore wind potential aligned with the ENSPRESO high VRE scenario	LONSH	High
CCS and CO ₂ storage	In this scenario CO ₂ storage is not allowed in any of the NSR countries. Therefore, CO ₂ can only be captured if it is used in other processes of the energy system. In order to alleviate the system, the VRE availability is increased to the values of the HVRES scenario, and the biomass availability is increased to the values of the HBIO scenario.	The availability of CO ₂ storage as an option is heavily affected by policy regulations and social acceptance. This scenario explores system implications of a CO ₂ storage ban in the NSR.	• No CO ₂ storage • Wind and solar PV potentials increased in line with the ENSPRESO high VRES scenario • Biomass potentials increased in line with the ENSPRESO high biomass scenario	NOCCS	High

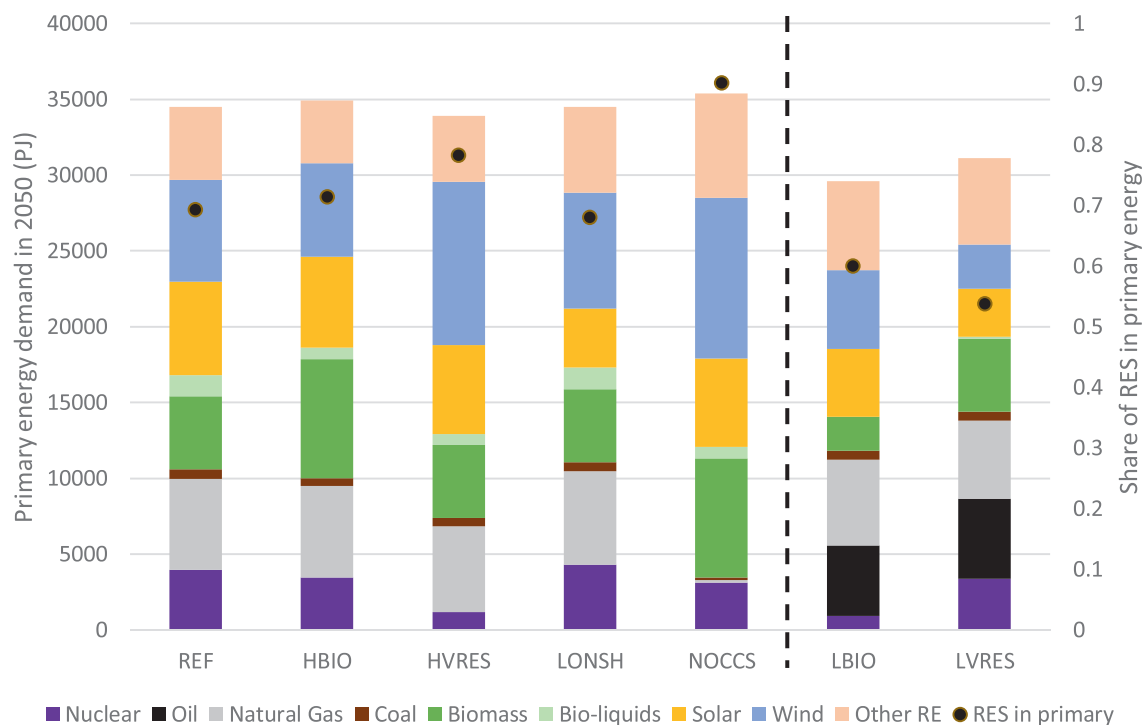


Fig. 5. Primary energy mix in the NSR for selected scenarios in 2050.

hydrogen used in all the countries is produced internally, and therefore no trade and imports/exports of hydrogen with other countries or regions are allowed. Due to the fact that imports of low-cost green hydrogen from external countries can have a large impact on the system costs, system configuration and VRE needs, a set of dedicated 'hydrogen trade' scenarios will be evaluated separately in a sensitivity analysis in Section 5.

4. Scenario results

The results for this paper have been obtained by running the scenarios outlined above by means of the IESA-NS model in a laptop with 32 GB of RAM and an Intel i8750-H processor, using the Gurobi 9.01 solver via the barrier method. The IESA-NS model is implemented in AIMMS. The computational time required to run the scenarios ranges from 2 h (single year, optimization of the energy system in 2050) to 30 h (3 years, simultaneous optimization of 2030, 2040 and 2050). Since the objective of this paper is to analyse decarbonisation scenarios in 2050, and not the pathway towards these scenarios (e.g., intermediate targets), and to reduce the computational load, only the year 2050 is optimized. In any case, the IESA-NS model has the option to optimize multiple years simultaneously and analyse transition pathways. The scenario runs of this paper were implemented without any type of timeslicing strategy, and therefore the temporal resolutions employed are the default ones, explained in Section 2: hourly for the power sector, and daily for the gas sector.

This section will provide a selection of results from the scenarios analysed for the NSR. The full set of all model results (disaggregated by country) and the databases used are openly accessible through the online user interface of the model in [48].

4.1. Primary energy mix

Fig. 5 shows the primary energy mix of the NSR in different scenarios. Results evidence a clear difference between the low and high mitigation ambition scenarios. In the low mitigation ambition scenarios, **LBIO** and **LVRES**, the primary energy demand ranges from 29.5 EJ to

31 EJ, with a considerable contribution of oil, natural gas and coal (37% in **LBIO** and 35% in **LVRES**), being the share of RES 60% for **LBIO** and 54% for **LVRES**. In the high mitigation ambition scenarios, the primary energy demand ranges between 34 EJ and 35 EJ, with no presence of oil. In the scenarios with CCS (**REF**, **HBIO**, **HVRES** and **LONSH**) there is around 20% of fossil fuels in the primary mix, mainly natural gas, while in the **NOCCS** scenario the contribution of fossil fuels (i.e., natural gas and coal) is negligible (around 0.9%).

These results exemplify the huge difference in the energy system configuration of the NSR under different mitigation ambitions. If the emissions for international transport are not accounted in the national budgets, and if oil can be freely used as a feedstock in the chemical industry, the NSR can reach net-zero emissions while having around a 35% of fossil fuel contribution, including around 5 EJ of crude oil in its energy mix. Under higher mitigation ambitions, the share of oil is displaced mainly by power-to-liquid (PtL) processes, which are less efficient than oil refining and therefore require a higher total primary energy use.

Within the high mitigation ambition scenarios, there is also a notable change in the energy mix when CCS is not allowed (**NOCCS** scenario). In the rest of the scenarios, the net-zero target can be met while using around 6 EJ of natural gas, mainly due to the large scale use of bioenergy combined by CCS, and the deployment of power-to-chemicals (PtC), which provide a large budget of negative emissions. When CCS is not allowed, the budget of negative emissions is substantially reduced, and therefore the system cannot offset large amounts of natural gas related emissions.

Biomass is a key carrier in all primary mixes, and most of the biomass available is used in all scenarios. The reason is that biomass provides a huge versatility to the system, as its price is relatively low, and it can be used to produce low carbon electricity, heat (in both industry, residential, services and agriculture sectors), biofuels or biogas, among others. Aside from biomass, the other renewable energy sources (RES) available in IESA-NS (i.e., solar, wind, hydro and ambient energy) are predominant in all scenarios, especially in the ones with high mitigation ambition (e.g., the share of RES in **NOCCS** reaches 90%).

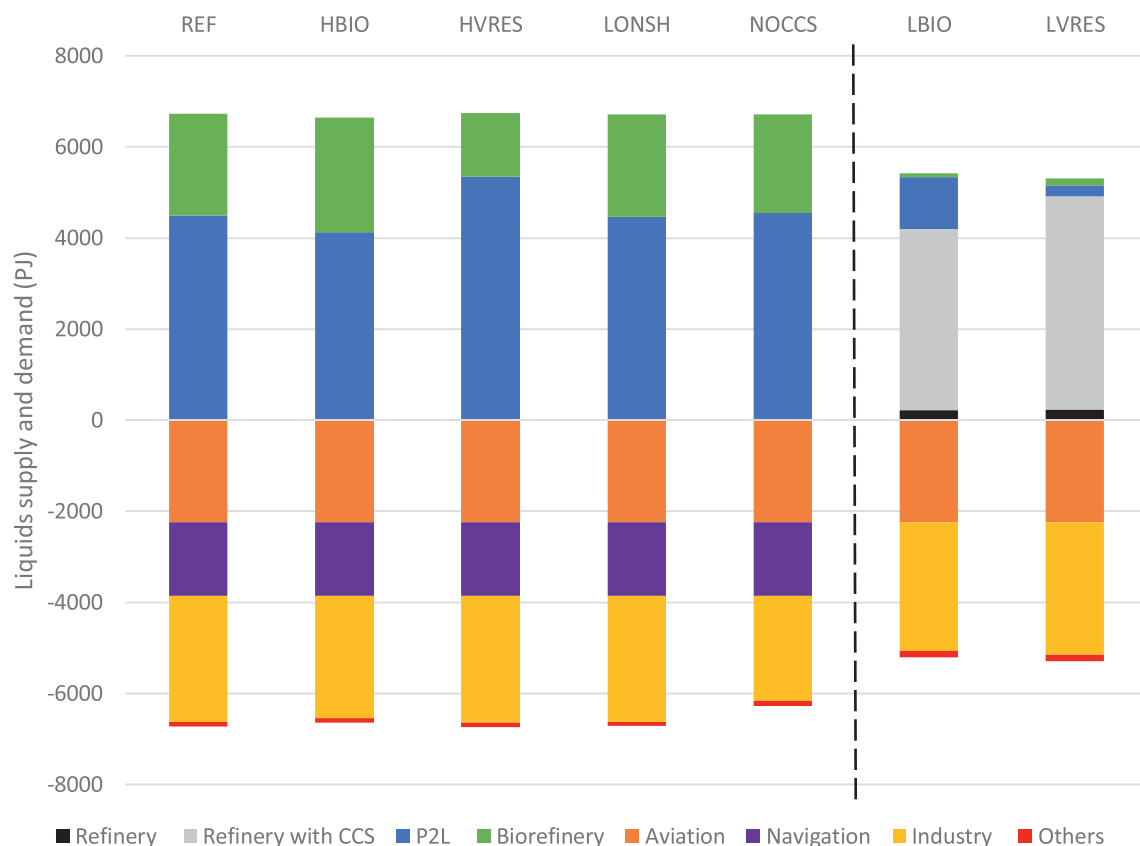


Fig. 6. Supply and demand of liquids in the NSR for selected scenarios in 2050.

4.2. Supply and demand of liquids, natural gas and biomass

As already mentioned, even with stringent mitigation targets and with most NSR countries reaching net-zero emissions in 2050, oil and natural gas can still be relevant in the energy system. Fig. 6 shows the supply and demand of liquids across all the scenarios analysed. There is, again, a big difference between the low and high mitigation ambition scenarios. In the low ambition scenarios, **LBIO** and **LVRES**, most of the liquids are produced via crude oil refining (4 EJ and 4.9 EJ respectively), whereas the contribution of PtL (1.1 EJ and 228 PJ) and bio-liquids (71 PJ and 166 PJ) is marginal. From the demand side, in the low ambition scenarios, there are two main end-uses. First, the industry sector, especially the chemical industry, where most of the liquids are used as feedstock. Second, the aviation sector, where liquids (mainly kerosene) are used as fuel. Liquids used in these sectors have little influence on the mitigation targets. Regarding the ones used as feedstock in industry, most of them remain embedded in the final product, and therefore no direct emissions are released to the air related to them. Regarding the ones used for international aviation, current mitigation targets do not account for emissions related to international aviation. Therefore, under current regulations (i.e., the 'low mitigation ambition scenarios'), the presence of refineries with CCS is fully compatible with net-zero mitigation strategies.

In the case of the high mitigation ambition scenarios, due to the inclusion of international emissions and industry feedstock targets, all the supply of liquids is provided via PtL and bio-refineries. The supply of PtL in these scenarios ranges from 4.1 EJ to 5.3 EJ, while the supply of bio-liquids ranges from 1.4 EJ to 2.5 EJ. It is interesting to notice that the **HVRES** scenario presents the highest production of liquids vis PtL, mainly due to the larger VRE potentials compared to other scenarios. From the demand side, compared to the low mitigation ambition scenarios, there is an additional demand of around 1.6 EJ for the navi-

gation sector in all scenarios, because with the inclusion of international emissions in the mitigation targets, the navigation sector is decarbonised using synthetic fuels and biofuels. In the case of the low mitigation ambition scenarios this is not necessary, due to the fact that most of the emissions of the navigation sector are international, and therefore cheaper alternatives such as compressed natural gas boats (CNG) are perfectly compatible with net-zero national targets.

Natural gas is also used in all scenarios. Fig. 7 shows its supply and demand across all the scenarios analysed in this chapter. The scenarios that rely heavily on CCUS use between 5.5 EJ and 6 EJ of natural gas, which is supplied mostly by national extraction of countries in the NSR, and imports mainly from Russia. The scenario without CCUS (**NOCCS**) reduces the gas use to around 350 PJ.

It is relevant to notice that the supply of natural gas is very similar in the low mitigation ambition scenarios and the high mitigation ambition scenarios, with a combination of North Sea extraction and imports, and a marginal contribution of LNG. In contrast, from the demand side perspective, there are relevant differences. In the low ambition scenarios, **LBIO** and **LVRES**, there are three main end uses: power sector, heat for residential and services, and navigation, with a use of around 1.5 EJ in each of them. In the high ambition mitigation scenarios with CCS there is no natural gas use in the navigation sector, the use in the power sector is negligible, and the main end uses are heat for residential and services (ranging from 2.5 EJ to 4 EJ) and hydrogen production via natural gas reforming (1 EJ to 3 EJ). The gas reforming process is especially relevant in the **LONSH** scenario: the low availability of renewables limits the hydrogen that can be produced via electrolysis, and therefore natural gas reforming emerges as the only remaining alternative. In the case of the **NOCCS** scenario, the use of gas is negligible, being the largest part of the supply (700 PJ) biogas produced from biomass.

The industry use of natural gas remains also stable across all the scenarios. The reason is that most of it is used as feedstock, mainly for

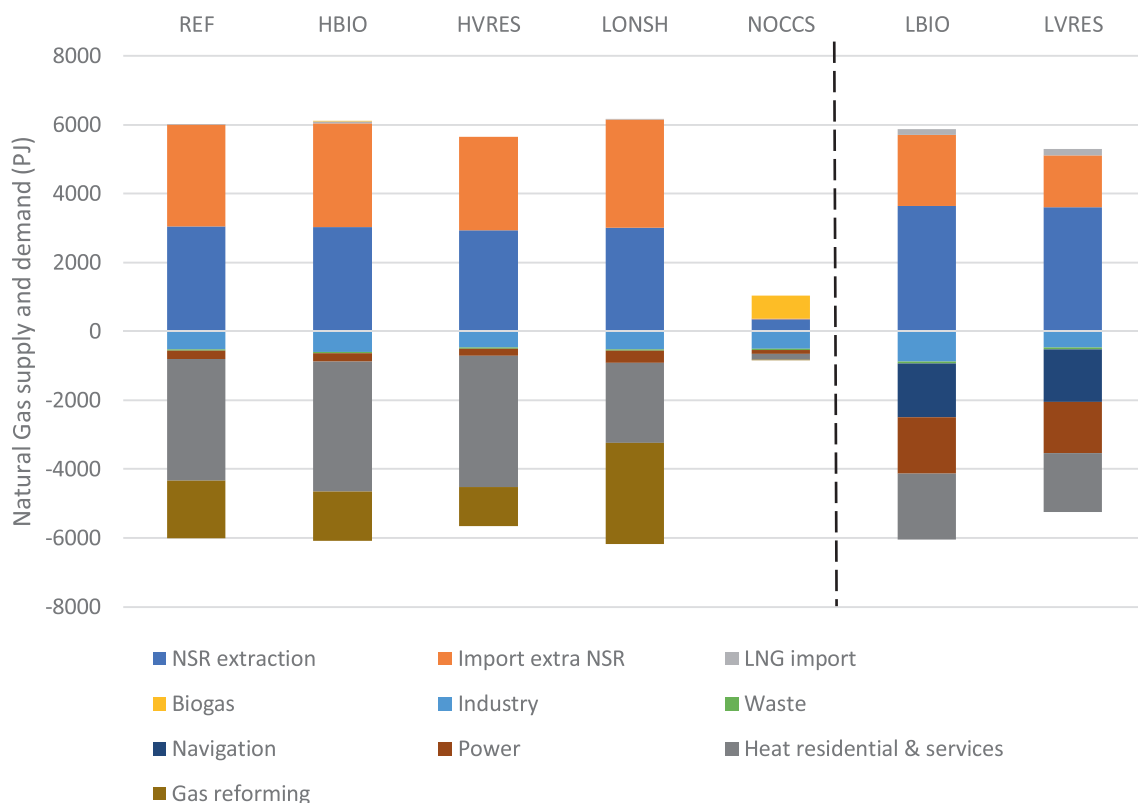


Fig. 7. Supply and demand of natural gas and biogas in the NSR for selected scenarios in 2050.

ammonia and basic chemicals production, and the technological configuration used in these sectors is similar in all scenarios. Note that in **LBIO** the industry demand is slightly higher. The reason is that in scenarios with higher availabilities of biomass, a part of the total available biomass is used to supply high temperature heat in industrial processes. Due to the fact that in **LBIO** the availability of biomass is lower, natural gas needs to supply a portion of this high temperature heat.

Natural gas is also intensively used to provide heat to the residential and heat services. There are mainly two technologies involved in this demand: natural gas boilers and hybrid heat pumps. These two technologies are very cost effective according to the cost projections assumed in the scenarios, and therefore, the system finds efficient to keep them and assume the related emissions, and puts effort to compensate these emissions in other sectors.

Regarding biomass, as mentioned previously, its availability is relevant for the energy system. All the scenarios analysed in this chapter used almost the maximum potential of biomass available. Fig. 8 shows the sources and uses of biomass across all the scenarios. Note that there are three levels of biomass availability: high, around 6 EJ of national biomass (used in **NOCCS** and **HBIO**), reference, around 3.6 EJ of national biomass (used in **REF**, **HVRES**, **LVRES**, **LONSH**), and low, around 2.2 EJ of national biomass (used in **LBIO**). To meet the ambitious net-zero mitigation targets of the NSR negative emissions are needed, in order to compensate GHG emissions that cannot be removed otherwise. Therefore, bioenergy with CCS or the use of biomass as chemical feedstock are very attractive alternatives to the system in order to achieve negative emissions in a cost-effective way. That is the reason why biomass is a heavily demanded resource in all scenarios, and the biomass potential is fully used.

Biomass is used across all scenarios to provide heat to industrial processes. There are multiple reasons to justify this trend. First, the use of biomass boilers with CCS (which is the most used technology for industrial heating in the scenarios) permits to reach negative emission

and alleviate the system mitigation needs. Additionally, competing technologies are either not cost competitive (e.g. hydrogen boilers), pollutant (e.g., natural gas boilers) or their potential is limited because they cannot reach the high temperatures required for specific processes (e.g. industrial heat pumps or industrial electric heaters).

The use of biomass to produce biofuels in biorefineries is relevant in scenarios with high mitigation ambition, ranging from 1.5 EJ to 3.5 EJ. In low mitigation ambition scenarios, as explained in Fig. 6, the use of biofuels is marginal, due to the extensive use of (cheap) refined crude oil. Biomass is also slightly used in the power sector in all scenarios (to provide extra peak capacity), to provide heat to the residential and services sector, to produce liquids in bio-refineries and, in some cases, to produce biogas.

4.3. Power sector

Most IEMs use time-slices to simplify the temporal resolution, and as a consequence, the variability of renewables cannot be correctly captured [5]. To overcome this drawback, the IESA-NS model optimizes the investment and operation of the NSR power sector using hourly resolution, thus correctly capturing the variability of renewables and their actual flexibility needs, which are then supplied optimally as a solution of the model through the interactions of the power sector with other sectors of the energy system. These cross-sectoral interactions are crucial, as the model can find the optimal way to, for example, increase the electricity generation to electrify the road transport fleet, increase the PtL supply via electrolysis, or electrify heat generation for the residential sector. Since the model optimizes all the energy sectors simultaneously, these dynamics are fully endogenous and therefore affect the optimal system configuration.

All things considered, Fig. 9 shows the total installed generation capacities aggregated for the whole NSR for the different scenarios, while Fig. 10 shows the total electricity generation. It is interesting to notice

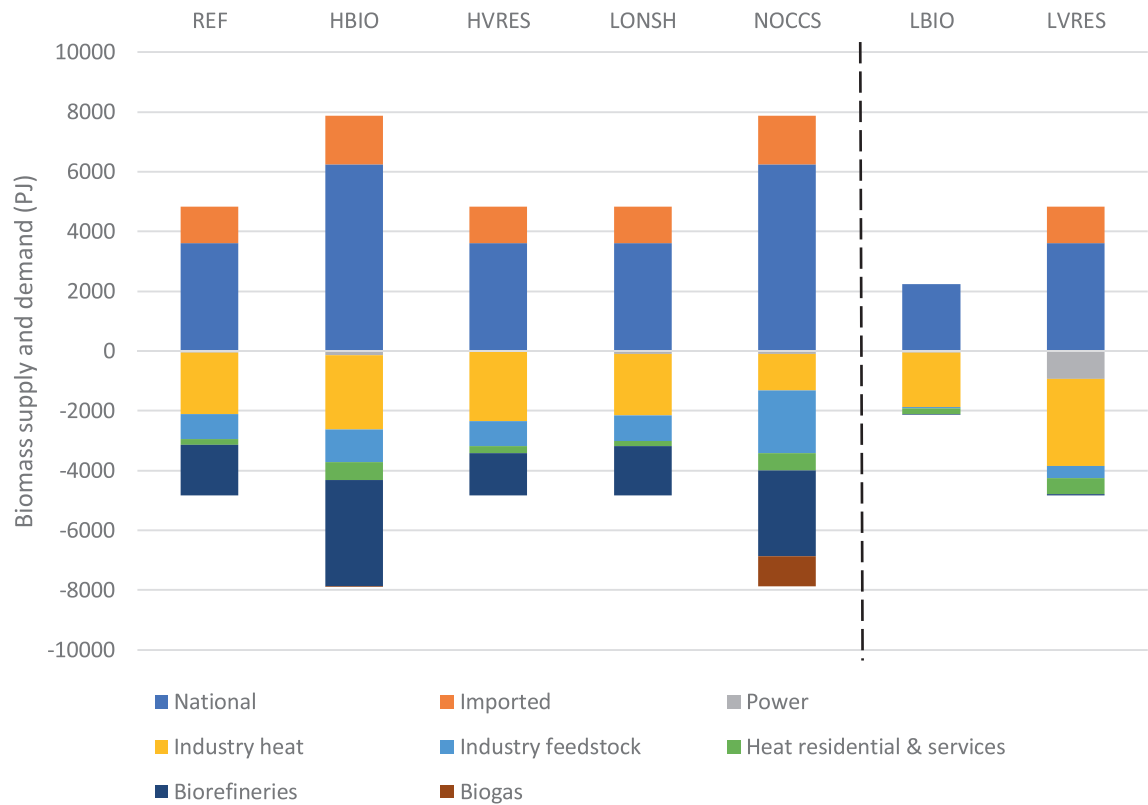


Fig. 8. Supply and demand of biomass in the NSR for selected scenarios in 2050.

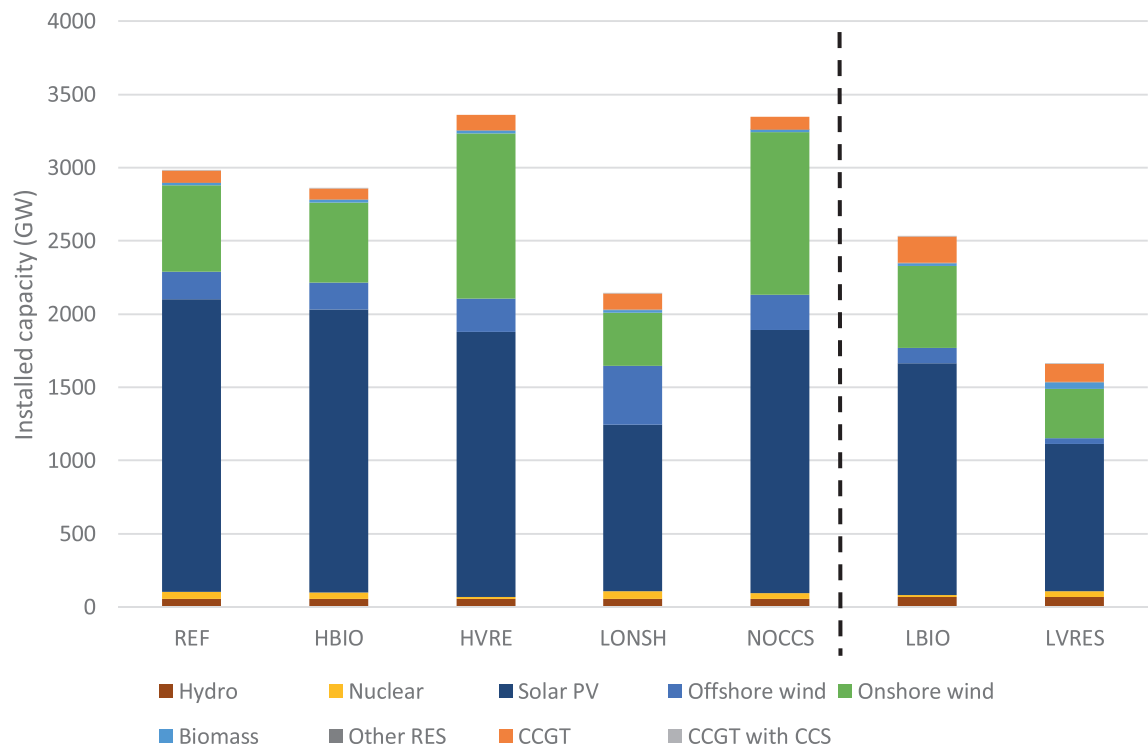


Fig. 9. Installed capacity in the NSR for selected scenarios in 2050.

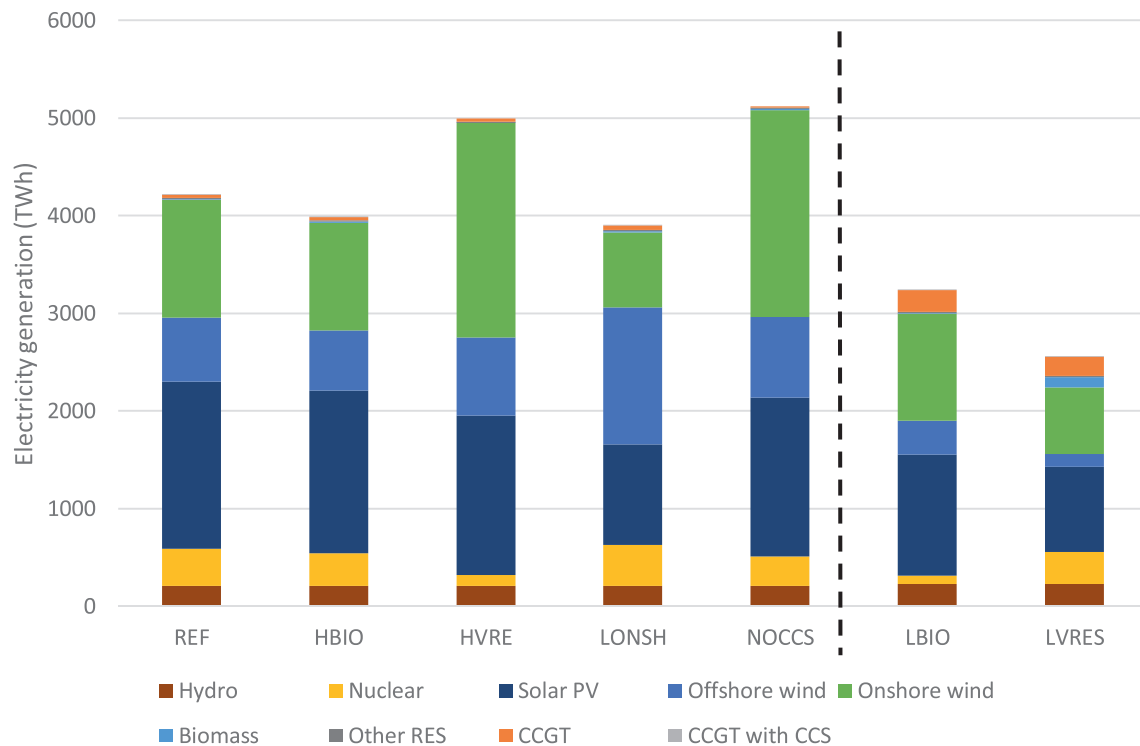


Fig. 10. Electricity generation in the NSR for selected scenarios in 2050.

that onshore wind and solar PV account for most of the installed capacity and power generation in all scenarios. The power generation from onshore wind ranges from 682 TWh, in **LVRES**, to 2200 TWh, in **HVRES**, with installed capacities of 337 GW and 1128 GW, respectively; while in the same scenarios, solar PV accounts for 878 TWh and 1632 TWh, and installed capacities of 1005 GW and 1807 GW. As a share of the total generation, this means that onshore wind and solar PV account for over 80% of the total capacity and over 60% of all the power generation in most of the scenarios (except in **LONSH**, where onshore wind is exogenously limited).

Offshore wind also plays a relevant role in the electricity mix, although its contribution is more variable across scenarios. The deployment is extensive in **LONSH**, with a total installed capacity of 405 GW. In **HVRE** and **NOCCS** the installed capacities are 230 GW and 237 GW, respectively. In contrast, in **LVRES**, less favourable for offshore wind investments, 37 GW of offshore wind are deployed. Its share in electricity generation compared to installed capacity is higher, as shown in Fig. 9, due to the high capacity factor that offshore wind has, especially when it is deployed far from shore. However, except **LONSH**, in all the scenarios the installed capacity is lower than the theoretical maximum potential, pointing out that different integration routes (e.g. design of an offshore grid or combination of offshore wind with in situ production of hydrogen) should be explored in order to find scenarios with higher deployments of offshore wind in all the countries across the NSR.

It is interesting to see that CCGTs, with and without CCS, are part of all the scenarios, in order to provide flexibility in certain hours. Their contribution to the electricity generation ranges from 16 TWh to 225 TWh. Even though this generation is not a large share of the total, the CCGT installed capacity is considerable, ranging from 86 GW to 180 GW. Even in the scenario with the lowest generation (**NOCCS**, 16 TWh), the installed capacity is high (86 GW, corresponding to a capacity factor of around 2%). The reason is that CCGTs provide multiple high peaks of energy to the system in limited periods during the year (i.e. when the RES availability is low due to low wind or radiation).

Looking at the aggregated numbers in all the scenarios, it is possible to find differences between the high and low mitigation ambition scenarios. In the high ambition ones, the electricity generation ranges from 3900 TWh to 5121 TWh, whereas in **LBIO** the total generation is 3240 TWh and in **LVRES** 2570 TWh. The reason is that the decarbonisation of international transport and industry feedstock increases the production of PtL, and therefore additional electricity is needed to produce hydrogen via electrolysis.

Curtailement is also present in the system, especially in those scenarios with large penetrations of VRE. Fig. 11 shows the curtailment volumes per scenario and per technology, and the share of curtailment in the total VRE generation. It can be seen that the curtailment relative to the total VRE generation ranges from 5% to 15%. Relative curtailment levels are slightly higher in low mitigation ambition scenarios, **LBIO** and **LVRES**. One of the reasons is that in these two scenarios the total installed electrolyser capacity is marginal, while in the other scenarios, due to the high use of PtL, there is a considerable electrolyser capacity. Electrolysers in IESA-NS can provide flexibility to the system via load shedding, and therefore can help to integrate variable renewable sources and reduce the curtailment levels. Otherwise, VREs provide flexibility themselves by being optimally dispatched (curtailed) [53].

One of the conclusions looking at the national level (the database and results are available in [48]) is that there is a major difference between the VRE curtailment in Scandinavian countries and the rest of the NSR. In Scandinavian countries the curtailment is relatively low, accounting in most scenarios for around 5% of the total curtailment of the NSR, while in Germany, the Netherlands, Belgium and the UK the curtailment share is much higher. The reason is that Scandinavian countries have, in general, lower energy demands compared to the size of their energy systems, better renewable resources (i.e., enough space for offshore/onshore wind, solar PV and large amounts of biomass) and large amounts of flexible sources (i.e., hydro storage in Sweden and Norway and a considerable amount of PtL in some scenarios). In contrast, the rest of the NSR has more energy intensive economies (in general more industrial clusters), less space availability due to a higher population density and less biomass resources in relative terms. Therefore,

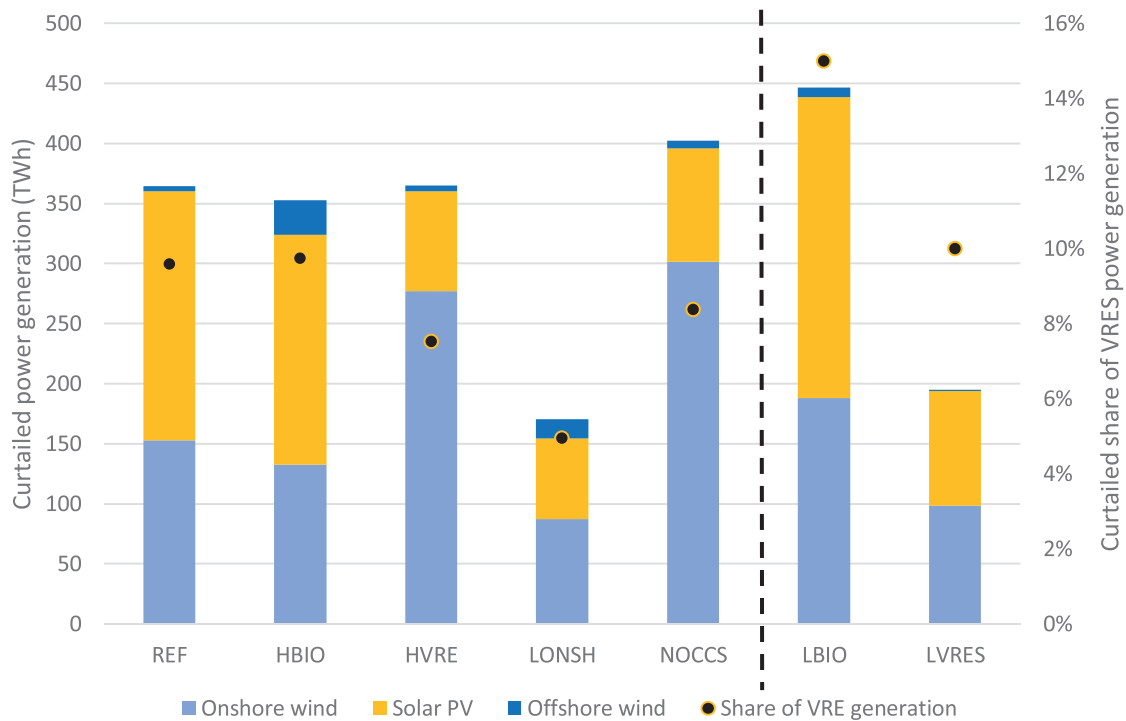


Fig. 11. Curtailment of VRES in the NSR for selected scenarios in 2050.

Table 3

Offshore wind installed per country and per scenario (the percentage in brackets shows the share of wind connected via HVDC, bold numbers show that the maximum investable capacity has been reached).

Offshore wind capacity (GW)	REF	HBIO	HVRES	LONSH	NOCCS	LBIO	LVRES
The Netherlands	47.7 (87%)	47.7 (87%)	86.8 (85%)	86.8 (85%)	86.8 (85%)	47.7 (87%)	6 (0%)
Germany	27.9 (63%)	27.9 (63%)	80.2 (66%)	80.2 (66%)	80.2 (66%)	27.9 (63%)	1.1 (0%)
United Kingdom	103.6 (55%)	102.1 (54%)	49.11 (5%)	190.8 (76%)	66.22 (29%)	19.01 (0%)	13.6 (0%)
Denmark	2.27 (0%)	2.27 (0%)	2.27 (0%)	28 (46%)	2.27 (0%)	2.27 (0%)	0 (0%)
Sweden	0.2 (0%)	0.2 (0%)	0.2 (0%)	0.2 (0%)	0.2 (0%)	0.2 (0%)	0.2 (0%)
Norway	9.3 (23%)	2.22 (50%)	9.3 (23%)	17 (59%)	0 (0%)	2.6 (0%)	0 (0%)
Belgium	1.78 (0%)	1.78 (0%)	1.78 (0%)	1.78 (0%)	1.78 (0%)	1.78 (0%)	0 (0%)

Scandinavian countries are more resilient to extreme scenarios (i.e., low availability of biomass or VRE space), while in these scenarios countries like Germany face a higher increase of system costs in order to meet the national targets.

As already mentioned in the Introduction, one of the benefits of the IESA-NS model is that it allows to analyse synergies and interactions between NSR countries using hourly resolution while including all the sectors of the energy system. Thanks to these features, power system dynamics such as interconnector capacity expansion,⁶ electricity imports/exports and offshore infrastructure can be identified.

In this regard, Table 3 shows the offshore wind installed per country and per scenario, and the share of total offshore wind capacity connected via HVDC. For the scenarios analysed, the offshore wind capacity located over 100 km from the shore is connected using HVDC, while distances under 100 km use HVAC.⁷ This type of disaggregated analyses permits

to understand which countries are not using their full offshore wind potential, which countries do not have the need to explore offshore areas far from shore, and as a consequence, which countries can be benefitted if a more interconnected offshore grid is deployed.

It is interesting to see that the Netherlands and Germany invest in all their offshore wind potential in all scenarios, with a high share of HVDC interconnectors (up to 85% in NL and 66% in DE), pointing out that they use all the available space near shore (with cheaper costs, due to the use of HVAC and less km of interconnectors required) and they deploy large amounts of extra offshore wind in far HVDC areas. For the rest of NSR countries there is an opposite trend. The United Kingdom has high wind potential available near shore and only uses all the offshore potential when the availability of onshore energy is reduced (**LONSH**). Similarly, Denmark and Norway do not deploy large amounts of offshore wind except in **LONSH**, where they reach their maximum potentials.

It is also interesting to analyse the total electricity imports, exports and net balance per country, in order to see the dynamics in each of the countries across all scenarios. This information is shown in Table 4. The United Kingdom, Denmark, Sweden and Norway have a net exporting balance in all scenarios, due to their high VRE availability and relatively low electricity demand compared to the available space. Belgium, the Netherlands and especially Germany have a strong import profile. In

⁶ The IESA-NS model can invest in additional interconnector capacity only between the NSR countries, the interconnectors of the rest of the EU are limited by the TYNDP.

⁷ The use of 100 km as a tipping point is not arbitrary, multiple technical analyses have defined the range [90,110] km as the critical distance where HVDC is competitive compared to HVAC [91].

Table 4

Cross border flows (electricity imports and exports) per scenario and per country

Cross border flows (PJ)		REF	HBIO	HVRES	LONSH	NOCCS	LBIO	LVRES
NL	Import	405	421	588	330	534	152	98
	Export	86	66	3	113	30	268	363
	Net	319	355	585	217	504	-116	-265
DE	Import	1324	1274	780	1381	823	974	1379
	Export	181	213	458	175	468	218	124
	Net	1143	1061	322	1206	355	756	1255
GB	Import	220	250	158	226	217	118	64
	Export	221	214	266	260	230	294	390
	Net	-1	36	-108	-34	-13	-176	-326
DK	Import	141	125	99	152	131	132	222
	Export	293	301	219	279	222	260	255
	Net	-152	-176	-120	-127	-91	-128	-33
SE	Import	24	41	24	22	29	15	15
	Export	418	315	217	424	233	344	439
	Net	-394	-274	-193	-402	-204	-329	-424
NO	Import	184	98	23	182	17	86	137
	Export	189	221	156	211	205	194	241
	Net	-5	-123	-133	-29	-188	-108	-104
BE	Import	382	378	461	467	480	209	281
	Export	202	214	193	121	180	121	90
	Net	180	164	268	346	300	88	191

Table 5

Hydrogen production pathways for all the scenarios for the whole NSR.

Hydrogen production (PJ)	REF	HBIO	HVRES	LONSH	NOCCS	LBIO	LVRES
Centralized electrolysis	4025	3786	5347	2859	4187	1407	595
Decentralized electrolysis	842	767	1094	1025	1982	0	0
Natural gas reforming	1238	1064	833	2184	21	0	0

the case of Germany this is especially extreme in the low VRE availability scenarios (**LVRES** and **LONSH**), where the imports are around 20% of the total national electricity demand. Again, these results show that Germany needs proper spatial planning and policies easing wind and solar deployment in order to meet their decarbonisation targets without depending heavily on surrounding countries.

Additional information of the power sector results, such as the installed capacity and generation per country, the hourly operation of all the generators and the hourly match of supply and demand, among others, can be found in the user interface of the model for further analysis [48].

4.4. Hydrogen use

Hydrogen is used in all scenarios, although its contribution is considerably higher in the scenarios with higher shares of PtL. Fig. 12 shows the total hydrogen use per scenario, disaggregated per country, and the relative share of hydrogen with respect to the primary energy demand.

There is a considerable difference between the low and high ambition scenarios. In the low mitigation ambition scenarios, **LBIO** and **LVRES**, the use of hydrogen is low, being 1153 PJ and 687 PJ respectively. In the high mitigation ambition scenarios the use of hydrogen is multiplied, ranging from 5617 PJ to 7274 PJ. This difference is justified with the targets of international transport and industry feedstock. As already explained with the supply and demand of liquids in Fig. 6, in the high mitigation ambition scenarios most of the liquids are supplied via PtL processes where hydrogen is extensively used.

It is also interesting to evaluate how the hydrogen used across the scenarios is produced. IESA-NS includes three different alternatives: 1) via centralized electrolyzers, in which the hydrogen is produced and sent to a national hydrogen network, which can be expanded in order to provide hydrogen to any end user; 2) via decentralized electrolyzers, in which the hydrogen is produced in situ to serve a certain process; and 3) via natural gas reforming, with or without CCS. Table 5 shows the production pathways used across all the scenarios. Centralized electrolysis

seems the preferred option from a system perspective, probably in order to invest in oversized electrolyzers that can provide precious flexibility to the system, and help to integrate large amounts of intermittent generators. Decentralized electrolysis is also present in the high ambition scenarios, although it is considerably less used than centralized electrolysis. Hydrogen production via natural gas reforming is also used in the high ambition scenarios, except when CCS is not allowed (**NOCCS**).

The fact that the IESA-NS model includes detailed offshore nodes opens the door to additional analyses pointing out possible synergies that might be interesting to explore, for example potential interactions between offshore wind and hydrogen production. For the two scenarios with higher hydrogen use, **HVRES** and **NOCCS**, Fig. 13 shows the generation of offshore wind, the HVDC interconnectors deployed, and the onshore green hydrogen production.

There are two strong conclusions that can be derived from Fig. 13. First, the Netherlands and Germany are the countries that present larger investments in offshore wind and HVDC infrastructure (in both scenarios they reach their technical potential limits, see Table 3). Second, the rest of the countries, especially the United Kingdom, do not reach their technical limit in these scenarios (i.e. if needed they could deploy extra wind capacity, mainly in HVDC-connected areas, see Table 3).

Different alternatives might be interesting to facilitate this integration between offshore wind and hydrogen. First, as mentioned above, Germany and the Netherlands invest heavily in HVDC interconnectors and produce large amounts of green hydrogen via electrolysis onshore. Therefore, it might be relevant to analyse whether it is more cost-efficient to place electrolyzers offshore (e.g. on oil and gas platforms), use offshore power on-site, transport hydrogen to shore via existing natural gas pipelines or new infrastructure, and reduce drastically the investment in expensive HVDC interconnectors.

Another interesting question that arises from the insights of Fig. 13 is the potential benefit of an interconnected offshore grid. As mentioned above, countries like Germany or the Netherlands reach their offshore wind limit, whereas other countries such as the United Kingdom have

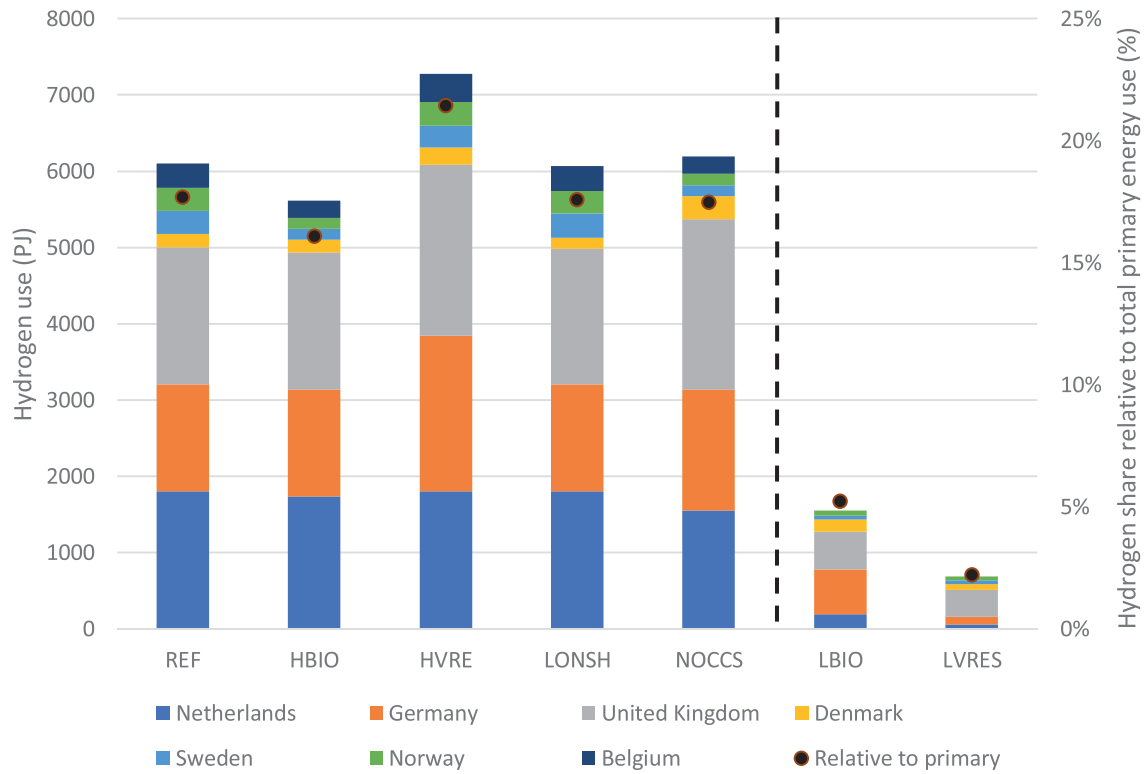


Fig. 12. Hydrogen use across all the scenarios for the whole NSR.

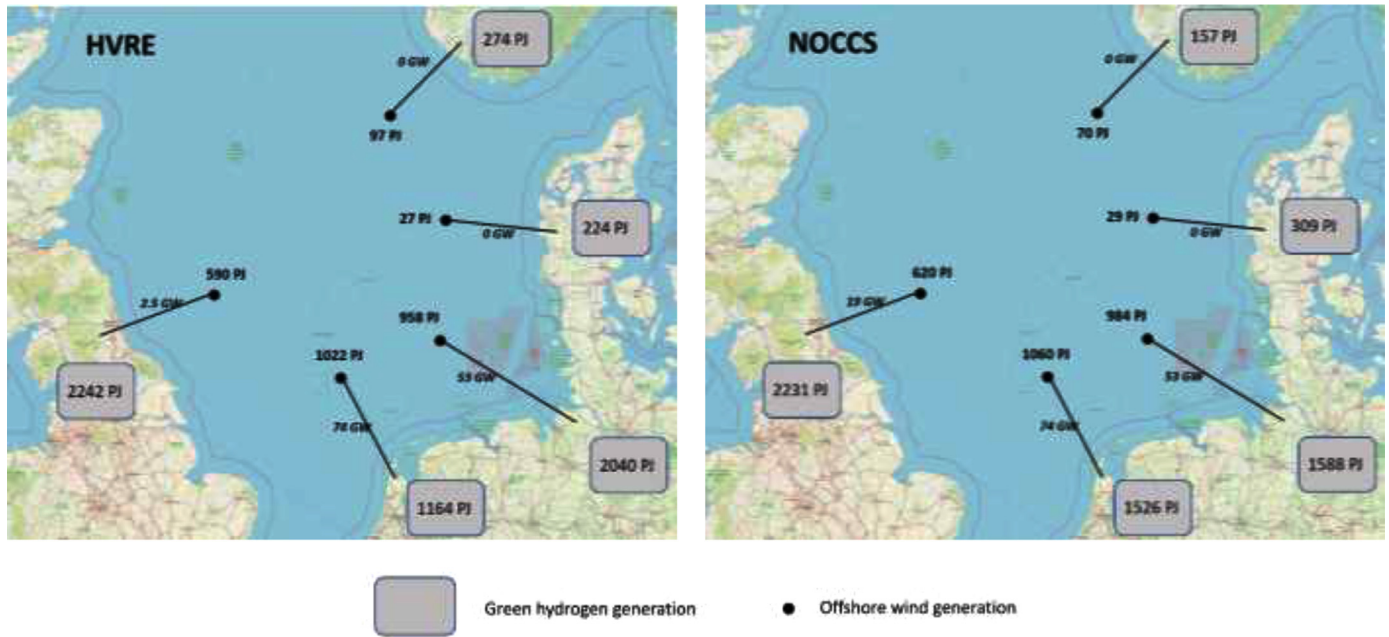


Fig. 13. Offshore wind generation, hydrogen use and HVDC interconnectors in the HVRE and NOCCS scenarios. HVAC capacity for offshore wind near shore is not plotted.

multiple non-invested areas (i.e. areas where additional offshore wind might be deployed). If offshore grid investments are available, it might be interesting from a system perspective to deploy more offshore wind that can be distributed to multiple countries of the NSR (and not to each country individually).

These type of research questions require a multinational modelling approach, with enough level of detail of the involved countries, a proper spatial representation of the offshore and onshore areas as well as a decent temporal resolution. Even though these scenarios are out of the

scope of this paper, they are useful to understand the need for modelling tools such as the IESA-NS, covering this 'multinational' landscape between national and continental analyses.

4.5. CO₂ storage, CO₂ emissions and other results

The IESA-NS permits to analyse a plethora of results, from the hourly operation of each power generation technology in each NSR country to the full system configuration in the NSR as a whole. All the results of

Table 6
Sensitivity analyses included evaluated.

Sensitivity analysis	Explanation	Rationale	Scenario modified
Offshore grid interconnectors	Offshore grid interconnectors between Germany, the Netherlands and the United Kingdom are allowed in this sensitivity.	The optimal outcome of all the scenarios analysed in Section 4 includes considerable amounts of offshore wind. In these scenarios offshore wind can only be connected radially to one single country. If investments in a 'meshed offshore grid' are allowed (i.e. offshore wind deployments can be connected to multiple countries via offshore interconnectors), the cost optimal solution might include them.	LONSH, HVRE
Extra NSR imports of hydrogen	Hydrogen can be imported from external countries at different costs.	In the scenarios evaluated, large amounts of hydrogen are used in the optimal system configuration. As mentioned in the scenario description, all the hydrogen use in any country has to be produced nationally, i.e. no imports of hydrogen are allowed. This sensitivity allows imports of hydrogen from outside the NSR at different costs.	REF
No mitigation in international transport and feedstock	The scenarios of Section 4 are run with 'low mitigation ambition'.	In the 'high mitigation ambition' scenarios evaluated in Section 4 it is assumed that the future political landscape will include international transport and industry feedstock as part of the mitigation targets. In this sensitivity all the scenarios are run under the 'low mitigation ambition', to evaluate the differences in the optimal system configuration.	REF, HBIO, HVRE, LONSH, NOCCS
Variations in projected demands in 2050	We evaluate the impact on the objective function of different deviations of the projected demands in 2050 in the residential, services, agriculture, industry and transport sectors.	All the scenarios evaluated in this paper use the REF scenario as starting point. Thus, all scenarios consider similar macroeconomic trends, similar energy demands and similar economic growth in 2050. In this sensitivity we run the reference scenario with different variations in projected future energy demands.	REF
Cost and efficiency assumptions of hydrogen production pathways	We evaluate the system impact of different electrolyser costs and natural gas reforming costs.	As seen in the 'high mitigation ambition' scenarios, hydrogen is a key component of the 2050 energy system configuration. In this scenario, we evaluate how robust is the penetration of hydrogen in the energy system under different techno-economic conditions.	REF

the scenarios considered in this paper can be explored by means of the open online user interface of the model [48]. Additionally, the results related to CO₂ storage use and CO₂ emissions (both ETS and non-ETS), marginal electricity prices, imports and exports can be found with detailed explanations in Appendix D.

5. Sensitivity analysis

This section evaluates different sensitivity analyses around a selection of key parameters in order to complement the findings of the scenario analysis, and because multiple parameters can affect the total system costs and the optimal configuration of the system. The explanation, rationale and details about the sensitivities are shown in Table 6.

5.1. Offshore grid interconnectors

In the scenarios of Section 4, the offshore wind capacity deployed by each country is connected radially to shore, as depicted in Fig. 3. Therefore, scenarios of Section 4 do not allow that offshore wind deployments are connected simultaneously to multiple countries. Moreover, one of the insights of the results of Section 4 is that, in all scenarios, the Netherlands and Germany invest in all their available offshore wind capacity, while other countries, such as the United Kingdom, do not reach that technical limit (see Table 3).

These two conclusions open the door to additional analyses where the offshore deployments of the Netherlands, Germany and the United

Kingdom can be interconnected. The hypothesis is that, if these offshore interconnectors are allowed, the cost-optimal solution might include additional offshore wind investments in the United Kingdom area, together with considerable offshore interconnection with the Netherlands and Germany (and, therefore, large amounts of exports of energy via 'offshore grid' interconnectors).

In order to evaluate this hypothesis, the offshore setup of the IESA-NS model is modified according to Fig. 14, allowing investments in interconnectors between the 'GB', 'DE' and 'NL' nodes. The scenarios chosen to evaluate this sensitivity are **HVRE** and **LONSH**, due to the fact that these are the scenarios with higher investments in offshore wind capacity in Section 4 (See Table 3). These 'offshore interconnectors' are assumed to be HVDC due to the long distances covered, and their cost assumptions are the same used for the HVDC interconnectors of the reference scenario (see Appendix C). Note that the offshore wind capacities shown in Fig. 15 and Fig. 16 are those connected via HVDC (i.e. further than 100 km from shore), as HVAC connected offshore wind (i.e. near shore wind) is not assumed to be hub-connected.

The results of the two scenarios are shown in Fig. 15 (**HVRE** scenario) and Fig. 16 (**LONSH** scenario). In both cases the hypothesis formulated is confirmed, as there are considerable additional offshore wind investments in the United Kingdom, together with a large deployment of offshore interconnectors with Germany and the Netherlands.

In the base scenario **HVRE** the wind installed capacity of the United Kingdom is 49 GW, which is mostly connected to shore via HVAC interconnectors (see Table 3), with only 2.5 GW of HVDC interconnectors.

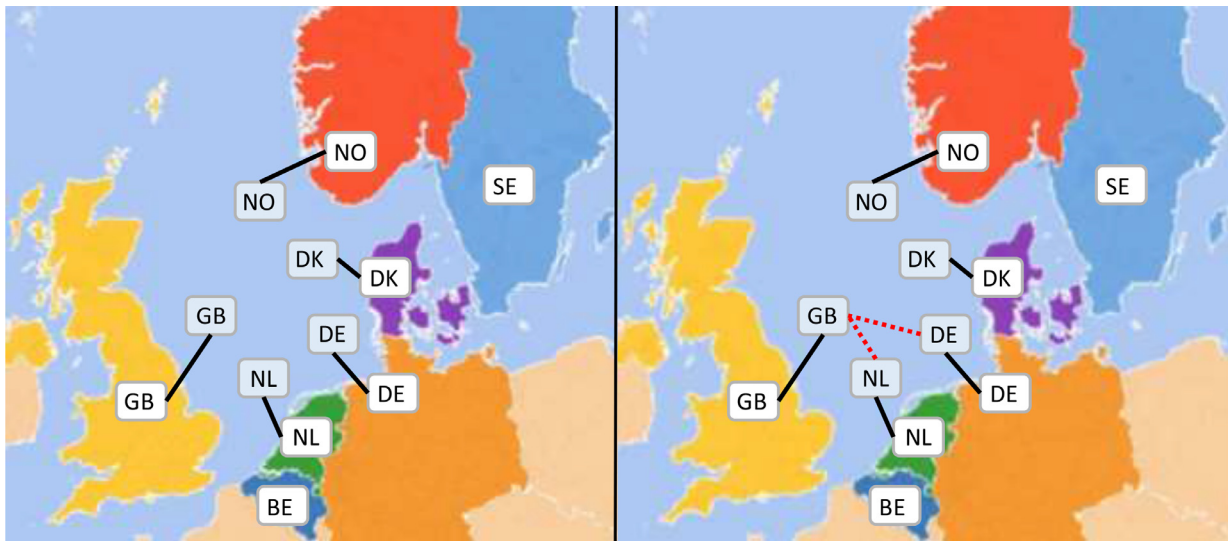


Fig. 14. new offshore interconnectors added in the sensitivity (right) compared to the base scenarios (left).

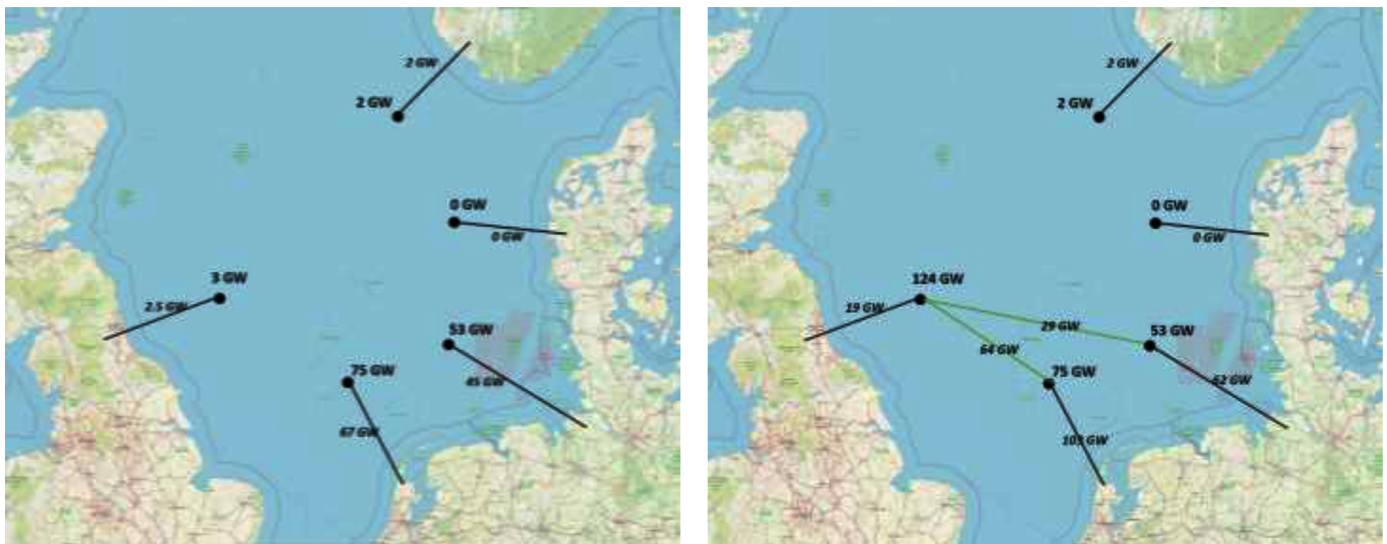


Fig. 15. Installed capacities and HVDC interconnectors deployed in the scenario HVRE.

Germany and the Netherlands invest all their technical wind potential (53 GW and 75 GW of HVDC connected offshore wind) and deploy considerable HVDC interconnection (45 GW and 67 GW). When the ‘off-shore grid’ interconnectors are allowed (Fig. 15 right), the investments in offshore wind in the United Kingdom are increased to 124 GW of HVDC connected offshore wind (+122 GW compared to the base case). There is a large investment in the new offshore interconnectors, being the UK-NL HVDC link of 64 GW, and the UK-DE HVDC link of 29 GW.

The impact of these additional interconnectors is even larger in the case of the LONSH scenario. The total deployment of HVDC connected offshore wind in the United Kingdom is increased from 145 GW (Fig. 16 left) to 340 GW (Fig. 16 right), with a considerable contribution of floating wind (see Table 7). There are also considerable investments in the new UK-NL HVDC link (76 GW) and the UK-DE HVDC link (120 GW).

These two scenario sensitivities exemplify the benefits of a more interconnected offshore grid and show how these additional interconnectors might drive additional investments in offshore wind. In ‘non interconnected’ offshore scenarios, the United Kingdom does not reach its technical maximum offshore wind limit, while the Netherlands and

Germany do reach it. Allowing these HVDC offshore interconnectors alleviates the system, and provides a new lower cost-optimal solution, in which there is an additional investment of offshore wind in the United Kingdom and considerable imports to the Netherlands and Germany.

5.2. Extra NSR imports of hydrogen

One of the key assumptions of the scenarios described in Section 3 is that the hydrogen used in all the countries is produced internally, and therefore no trade and imports/exports of hydrogen with other countries or regions are allowed. The cost-optimal solution provided by the ‘high mitigation ambition’ scenarios provides considerable amounts of hydrogen use in 2050 (i.e. from 5.6 EJ to 7.3 EJ), and therefore it is interesting to evaluate at what cost imported hydrogen is competitive and displaces the domestic production.

There is considerable literature evaluating the levelised cost of imported hydrogen in the European context, evaluating production areas with considerable VRE resources (i.e., high solar radiation and/or wind potential) and enough space availability. Some potential target areas are North Africa, Middle Eastern countries or South America (e.g., see

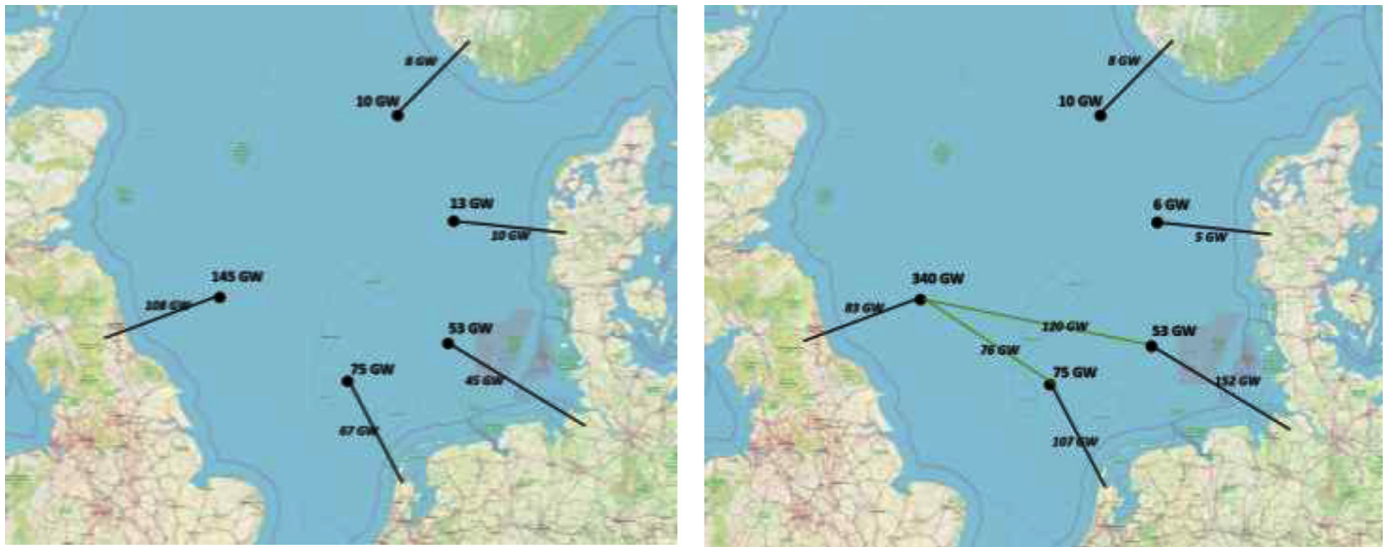


Fig. 16. Installed capacities and HVDC interconnectors deployed in the scenario LONSH.

Table 7

Breakdown of offshore wind and interconnector capacities in the sensitivity scenarios.

	HVRE	HVRE + GRID	LONSH	LONSH + GRID
Fixed-bottom (HVAC + HVDC)(GW)	227	349	403	402
Floating (GW)	0	0	0	198
Link UK-DE (GW)	–	29	–	120
Link UK-NL (GW)	–	64	–	76

Table 8

Hydrogen cost assumptions used in the sensitivity analysis.

	REF	REF10	REF20	REF30	REF40	REF50	REF60
Imported hydrogen cost (€/GJ)	–	10	20	30	40	50	60
Imported hydrogen cost (€/kg)	–	1.2	2.4	3.6	4.8	6	7.2

[54,55,56]). However, there is still high uncertainty on the imported hydrogen cost in 2050 (e.g., in [56] the estimated cost of imported hydrogen in 2050 ranges from 23.6€/MWh to 105.3€/MWh depending on the production site, distance and transport method).

Due to this import cost uncertainty, this sensitivity will allow imports of hydrogen to the REF scenario at different costs, to evaluate the impact of these imports in the total hydrogen use and in the cost-optimal system configuration. The cost assumptions used in the different sensitivity analyses are written in Table 8. It is important to remark that the costs shown in Table 8 represent the total cost of the imported hydrogen, including its production abroad, and its transport and delivery to the NSR. These total costs are highly uncertain, and that is the main reason to choose a broad range of costs (from 10 €/GJ to 60 €/GJ).

The total hydrogen use and production pathways across the sensitivity scenarios are plotted in Fig. 17. The first interesting finding is that, when hydrogen imports are inexpensive, the use of hydrogen in the system is multiplied, and the domestic production is almost negligible, being the system fully dependent on external countries. For example, in REF10 imports account for 10.8 EJ (98% of the total hydrogen use) and the use of hydrogen in PtL processes is increased considerably (9.3 EJ compared to 6.1 EJ of REF). At this cost, hydrogen is also used to provide high temperature heat in industry (roughly 700 PJ) and in fuel cell vehicles (750 PJ). In REF20 hydrogen imports are still dominant (86%), and the total use of hydrogen is also increased (9.2 EJ). However, at this cost, hydrogen is not competitive to provide high temperature heat or

in fuel cell vehicles, and therefore PtL pathways remain the only cost-effective use. In REF30 imports account for 60% of the total hydrogen use (7 EJ). From 40 €/GJ (REF40) imports of hydrogen are not dominant anymore (17% of the total use), and the hydrogen use remains stable around the 6.1 EJ of the reference scenario.

Another interesting analysis is to evaluate the effect of these hydrogen imports on the electricity generation mix of the NSR. As discussed in Section 4, most of the hydrogen production is derived from renewable energy sources via electrolysis, and therefore the increase of imports (which are carbon free from the system perspective) alleviates the need for green electricity generation. In this regard, Fig. 18 shows the VRE installed capacities in each of the scenarios, while Table 9 shows the installed capacity of offshore wind per country in each of the scenarios analysed.

It can be seen that in scenarios with high shares of hydrogen imports, REF10 and REF20, the VRE installed capacity is drastically reduced compared to the REF scenario (627 GW and 844 GW versus 1015 GW). Proportionally, offshore wind is the source with more variation across the scenarios, due to the fact that the CAPEX of offshore wind is considerably higher than the one of onshore wind or solar PV. In the scenarios with a higher cost of imported hydrogen (REF40, REF50 and REF60) the total installed capacity remains stable at around 1000 GW, since that large amounts of hydrogen need to be supplied via electrolysis, increasing the demand for green electricity.

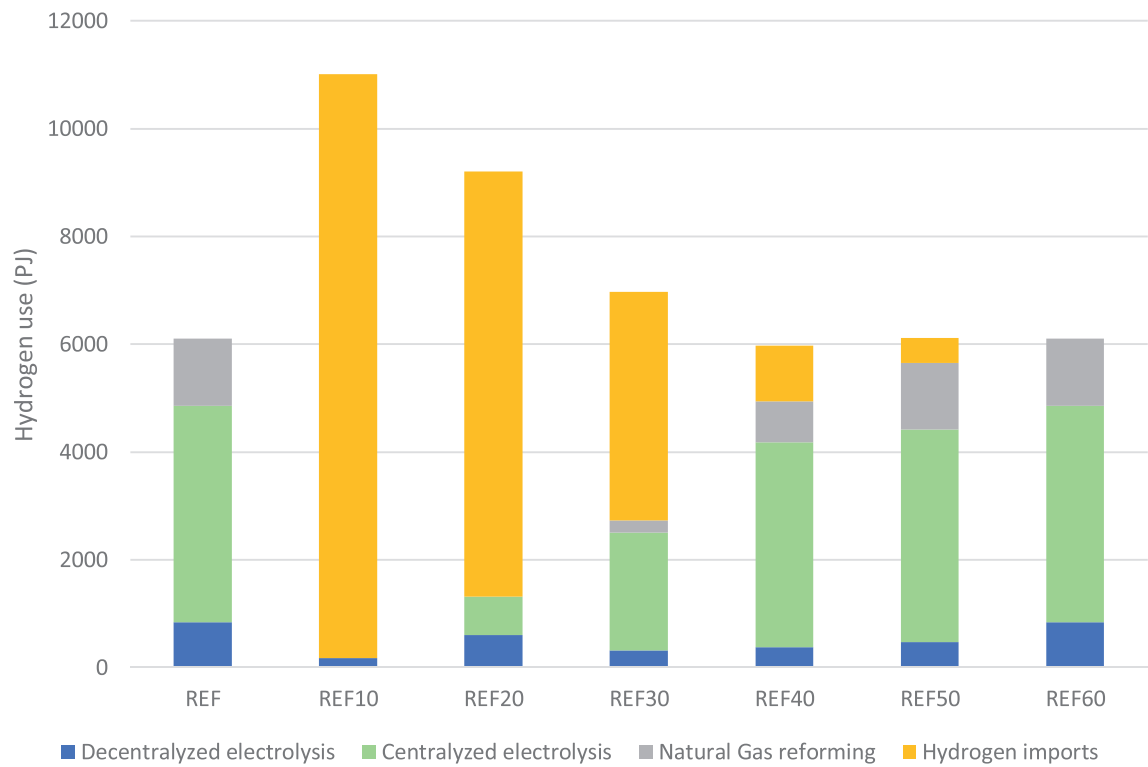


Fig. 17. Hydrogen production pathways across the sensitivity analyses scenarios.

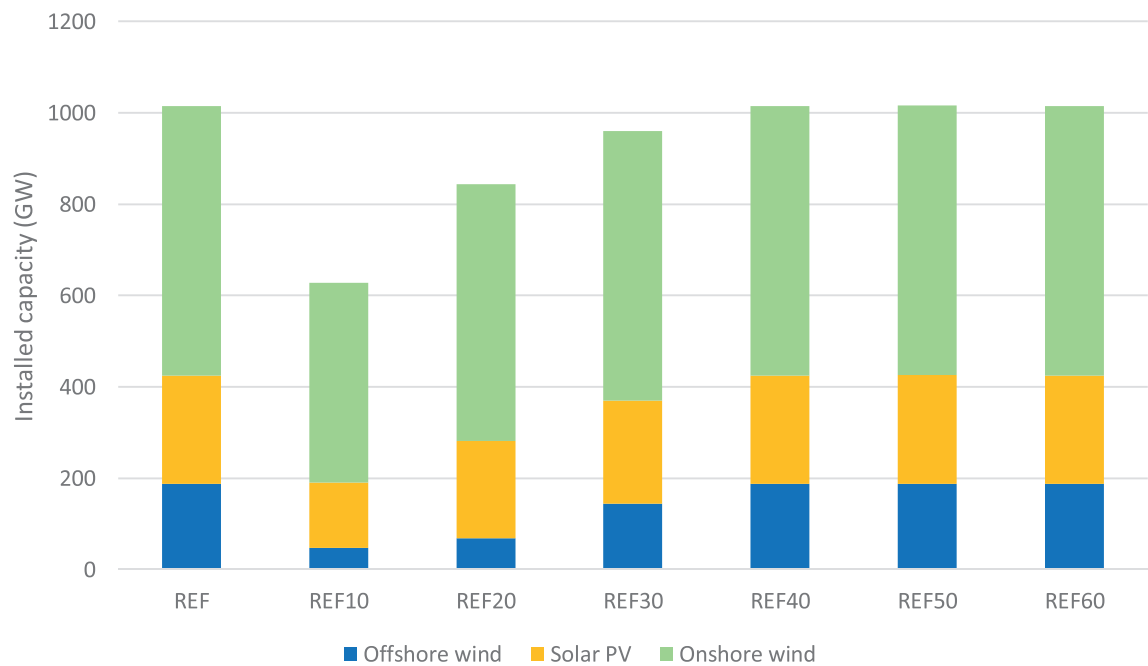


Fig. 18. VRE installed capacities across the sensitivity analyses scenarios.

Table 9
Offshore wind generation capacity across the sensitivity analyses scenarios.

Offshore wind capacity	REF	REF10	REF20	REF30	REF40	REF50	REF60
The Netherlands	47.4	7.5	20.5	36	47.7	47.7	47.4
Germany	27.9	27.9	27.52	27.9	27.9	27.9	27.9
United Kingdom	103.6	8.23	10.77	71.29	103.6	103.6	103.6
Denmark	2.3	2.3	4	2.3	2.3	2.3	2.3
Sweden	0	0	1.4	0	0	0	0
Norway	4.7	0	2.8	4.6	4.7	4.7	4.7
Belgium	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Total	188	47.8	68.7	144	188	188	188

As mentioned before, the offshore wind capacity presents huge variations across the scenarios. The breakdown per country can be consulted in Table 9. The total capacity varies from 47.8 GW (REF10) to 188 GW (REF60). This change is mainly driven by the Netherlands and the United Kingdom. These two countries are the higher importers of hydrogen of the NSR, and therefore, under cheap hydrogen costs (REF10) they can drastically reduce their investments in offshore wind (7.5 GW and 8.23 GW respectively). However, under more stringent import costs (REF60) these numbers increase to 47.4 GW and 103.6 GW.

5.3. No mitigation in international transport and industry feedstock

As explained in Section 3, scenarios have been divided in 'high mitigation ambition' and 'low mitigation ambition'. The results showed that 'low mitigation ambition' scenarios meet the target with a larger use of fossil fuels, because using oil based products in aviation, navigation and industrial feedstock is weakly penalised in the national emissions accountancy.

In this sensitivity, all the 'high mitigation ambition scenarios' (REF, HBIO, HVRE, LONSH and NOCCS) are run under the 'low mitigation ambition' policies (i.e. international emissions and industrial feedstock are not part of the national targets). The results of this comparison are shown in Fig. 19. The top part of Fig. 19 shows the scenarios run under the 'low mitigation ambition' parameters, while the bottom part of Fig. 19 shows the scenarios under the 'high mitigation ambition' hypothesis, as discussed in Section 4.

The first clear difference is that, under the 'low mitigation ambition' policy framework, the targets can be met using considerable amounts of oil. Except in NOCCS*, where the use of oil is negligible, the rest of scenarios use between 4.1 EJ (HVRES*) and 5 EJ (LONSH*) of oil. Interestingly, with 'high mitigation ambition' policies, the use of natural gas is, in general, slightly higher than under 'low mitigation ambition' policies. Overall, and as expected, 'low mitigation ambition scenarios' have a considerably higher contribution of fossil fuels in their energy mixes (36% vs 26% in REF, 34% vs 25% in HBIO, 33% vs 24% in HVRES, 35% vs 28% in LONSH, 10% vs 9% in NOCCS).

It is also noticeable that the total primary energy demand is around 5 EJ higher under 'high mitigation ambition' scenarios. The main reason is the massive adoption of e-fuels to (partially) substitute oil based products. Under the 'low mitigation ambition' parameters, oil is directly used in refineries to produce oil based products, with relatively low energy losses. In the case of e-fuels, the whole PtL process entails considerable energy losses.

The nuclear contribution is relatively low under both mitigation strategies, but it is relevant to remark that the figures are higher in the 'high mitigation ambition' scenarios. The reason is, again, that the massive adoption of e-fuels and PtL pathways increases the system need for electricity, and in most scenarios the contribution of VRE alone is not enough. That is the reason why, in HVRE/HVRE*, with optimistic VRE projections, the use of nuclear energy is negligible. However, in the 'high mitigation ambition' scenarios without optimistic VRE projection,

the contribution of nuclear is slightly higher, in order to provide low carbon electricity to produce the aforementioned e-fuels.

5.4. Sensitivity analysis of projected demands in 2050

One of the shortcomings of the scenarios evaluated throughout this paper is that, from a macroeconomic point of view, all of them are based on the REF scenario and rely, mostly, on the POTEnCIA projections of future economic growth, energy demand, industry production volumes and transport use. The goal of this sensitivity is to explore how variations of these projected demands in 2050 affect the objective function value, in order to understand 1) which sector/s have the larger effect on the total system cost and 2) how robust is the NSR system to changes in the input data.

In this sensitivity, the demand volumes of four energy sectors have been modified in the REF scenario. These sectors are the industrial sector (formed by iron and steel, non-ferrous metals, basic chemicals, ammonia, non-metallic minerals, paper related, machinery and other industrial activities); the transport sector (motorcycles, passenger cars, light and heavy duty vehicles, buses, rail, and domestic, intra EU and extra EU aviation and navigation); the built environment sector (electricity and heat demand in residential and services sectors) and the agriculture sector (electricity, heat and machinery demands). Table 10 shows the volumes of the mentioned subsectors in the reference scenario. The sensitivity explores the effect in the objective function of variations of these parameters within the range [−20% +20%].

Fig. 20 shows the results of the sensitivity analysis. The largest impact in the objective function is observed when the transport sector demand is modified. Variations of 20% of the transport demand volumes entail variations of around 10% of the objective function value. These results, in line with the findings of the scenario analyses of section 4, point out the relevance of international transport (i.e. international aviation and navigation) in the future energy system configuration. Industry and built environment sectors also show a moderate impact in the objective function, with an impact of around 4% in the objective function for variations of 20% in the demand volumes. The impact of the agriculture sector demand variation is negligible, with impacts of less than 1% in the objective function in all cases.

5.5. Sensitivity analysis of hydrogen production pathways

One of the key findings of the scenario analysis of Section 4 is the large use of hydrogen in the 'high mitigation ambition' scenarios. Under the assumptions of the aforementioned scenarios, and as shown in Section 4.4, the preferred hydrogen production pathway was in all cases centralized electrolysis. However, there are multiple techno-economic uncertainties that can affect the optimal system configuration in 2050.

In this sensitivity analysis we explore the effect of different electrolyser and natural gas reforming costs in 2050. We use the REF scenario as the starting point and define three levels of costs for all hydrogen production pathways: reference, high and low. The values of these three

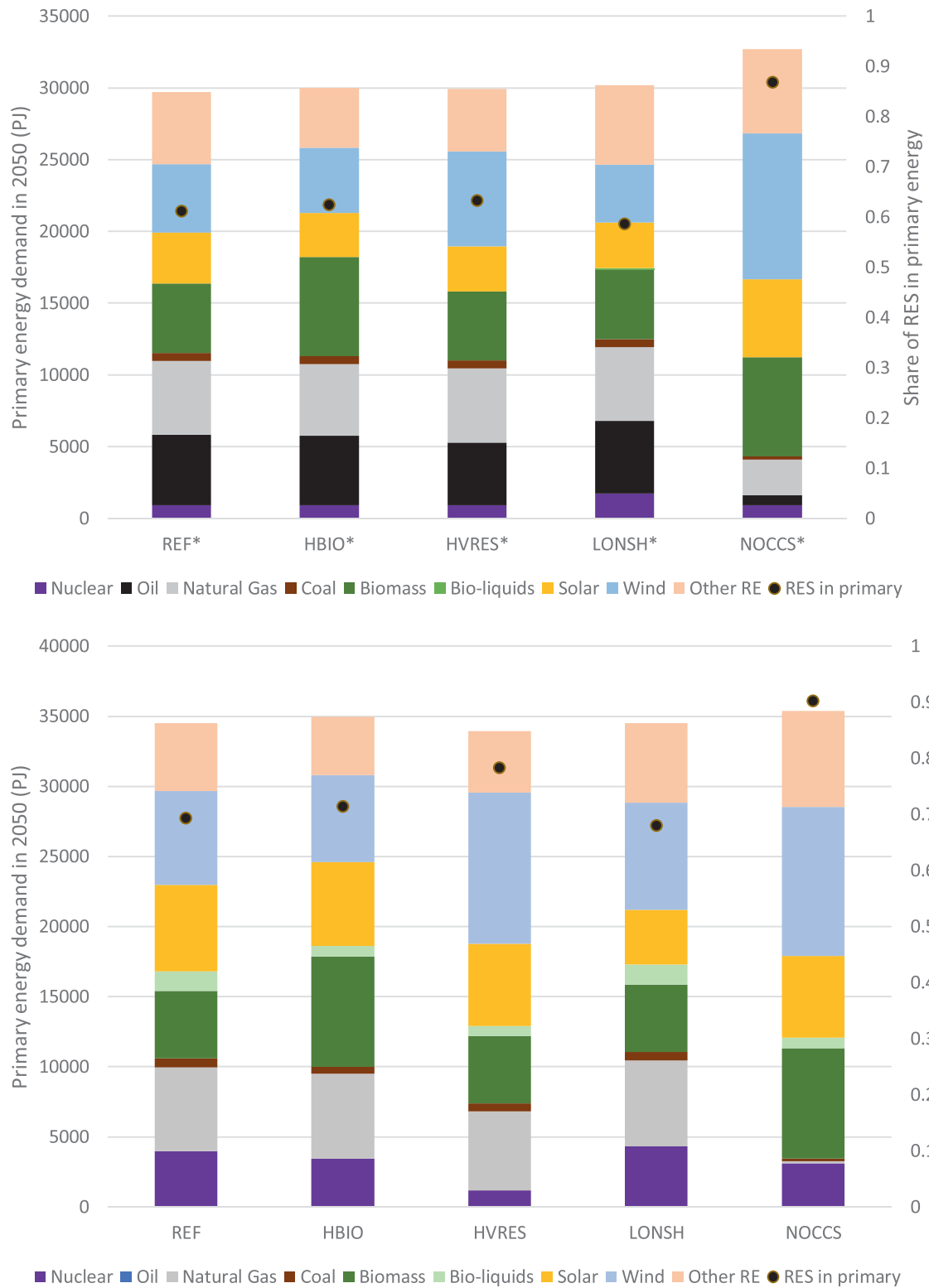


Fig. 19. Primary energy mix in the NSR for selected scenarios in 2050 under 'low mitigation ambition' (top) and 'high mitigation ambition' (bottom).

Table 10

Demand volumes used in the reference scenario.

Sector	Activity	Units	The Netherlands	Germany	The United Kingdom	Denmark	Sweden	Norway	Belgium
Industry	Iron and steel	Mton	6.55	31.00	9.38	0.68	3.38	0.56	6.41
Industry	Non-ferrous metals	Mton	0.96	6.59	1.39	0.00	0.83	1.10	2.91
Industry	Basic chemicals	Mton	17.02	31.28	8.79	0.00	2.58	3.24	6.63
Industry	Ammonia	Mton	2.72	3.44	1.00	0.00	0.00	0.30	1.02
Industry	Non-metallic minerals	Mton	8.69	86.80	99.84	1.53	7.04	5.40	24.96
Industry	Paper related	Mton	4.18	32.51	7.22	18.59	30.44	1.10	5.52
Industry	Machinery	PJ	35.78	365.47	184.26	0.79	31.25	8.90	22.52
Industry	Other non-ETS	Indexed	1.22	1.18	1.53	11.54	1.29	1.47	1.44
Transport	Motorcycles	Gvkm	7.20	19.47	13.76	1.59	1.97	1.59	3.19
Transport	Passenger cars	Gvkm	117.35	632.33	489.37	62.15	104.99	48.00	90.96
Transport	Light-duty vehicles	Gvkm	32.31	61.65	128.93	9.26	15.57	13.50	17.24
Transport	Heavy-duty vehicles	Gvkm	8.77	58.00	28.43	3.53	8.31	3.50	5.15
Transport	Buses	Mvkm	650.56	3884.22	2235.67	697.82	1044.23	400.00	869.95
Transport	Rail	Mvkm	248.51	1634.59	1037.78	125.16	286.98	85.07	164.81
Transport	Domestic aviation	Mvkm	0.00	219.77	165.90	5.46	91.51	98.63	0.00
Transport	Intra-EU aviation	Mvkm	432.23	1245.59	1189.11	140.03	285.30	81.85	254.11
Transport	Extra-EU aviation	Mvkm	848.15	2736.47	2835.56	161.78	268.60	74.06	327.47
Transport	Domestic navigation	Mvkm	92.89	102.29	49.72	3.78	2.67	1.86	25.83
Transport	Intra EU navigation	Mvkm	17.63	10.06	10.83	3.45	7.69	5.36	4.93
Transport	Extra-EU navigation	Mvkm	128.65	18.81	19.95	6.85	18.11	12.62	57.22
Residential	Electricity (appliances)	PJ	83.43	346.71	263.63	41.37	73.29	50.00	53.39
Residential	Heat	PJ	279.88	1740.91	1409.87	152.17	264.11	127.30	273.05
Services	Electricity (appliances)	PJ	126.00	393.56	306.26	38.81	76.62	57.60	46.95
Services	Heat	PJ	134.08	736.27	454.95	40.23	105.13	60.43	135.33
Agriculture	Electricity	PJ	37.65	35.85	18.43	10.31	7.02	10.71	6.57
Agriculture	Heat	PJ	107.46	14.87	22.71	24.72	12.11	21.42	22.37
Agriculture	Machinery	PJ	29.82	5.17	12.46	16.07	4.84	11.19	6.36

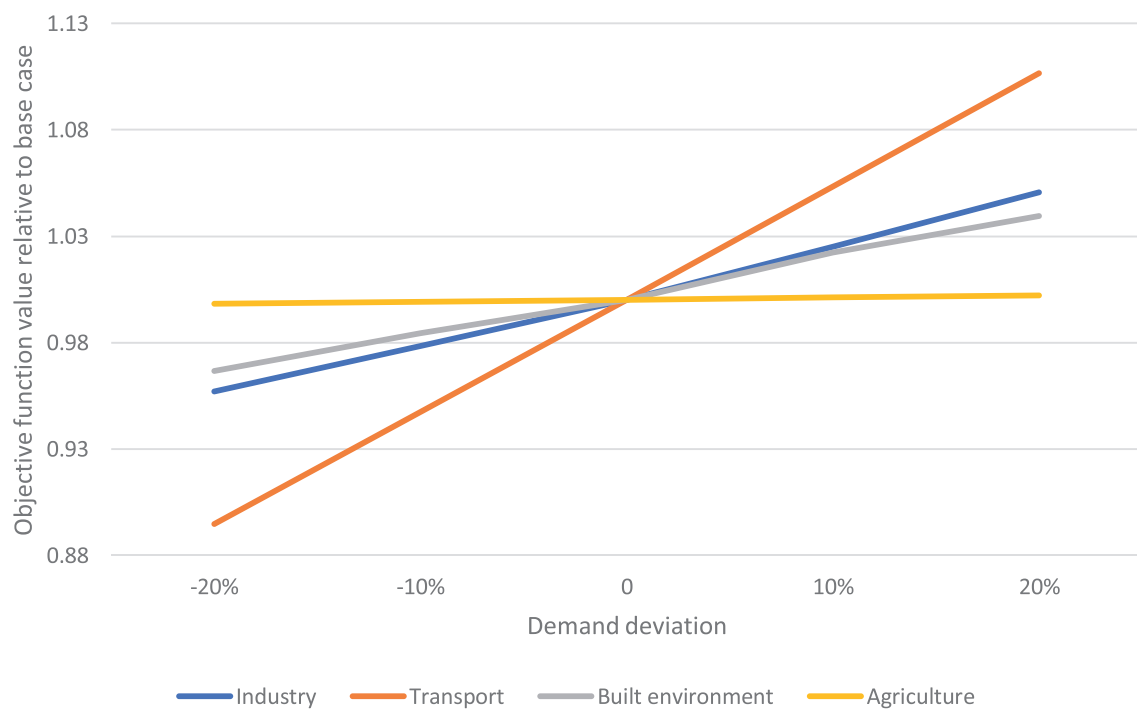
**Fig. 20.** Relative variation of the objective function value versus changes in projected demand.

Table 11
CAPEX used in the different scenarios of the sensitivity analysis.

	Units	CAPEX		
		Reference scenario	Low cost	High cost
Alkaline electrolyser	M€/PJ/y	10	7	13
Natural gas reforming	M€/PJ/y	14.91	10	20
Natural gas reforming with CCS	M€/PJ/y	15.99	11	21

Table 12
Share of hydrogen produced via electrolysis in the different sensitivity scenarios.

Electrolyser-based generation (%)	Low electrolyser	Reference electrolyser	High electrolyser
Low NG reforming	81%	78%	76%
Reference NG reforming	81%	79%	76%
High NG reforming	83%	80%	77%

levels for the three technologies included in this sensitivity are shown in Table 11.

With these three price levels, we generate nine scenarios, in which we evaluate all possible combinations of electrolyser cost development versus natural gas reforming (with and without CCS) price development.

Table 12 shows the share of hydrogen generation via electrolysis (centralized and decentralized) in all the scenarios evaluated. It is highly interesting to notice that even in an unfavourable scenario for green hydrogen production (i.e. high electrolyser cost projection versus low natural gas reforming cost projection) the overall hydrogen supply is still dominated by electrolysis processes (76%). The difference between the most extreme cases (high electrolyser-low NG / low electrolyser-high NG) is only 7%. The main reasons to justify this prevalence of electrolysis versus natural gas reforming are the stringent mitigation policies in the REF scenario in 2050, the large deployment of cheap VRE generation (which reduces the hydrogen production cost via electrolysis), the massive need for flexibility from the system perspective (which makes the electrolyser deployment attractive even at higher costs, due to its ability to provide load shedding), the high estimated costs of natural gas in 2050, and the limited availability of CO₂ storage, which is mainly used to provide negative emissions via bioenergy with CCS. In any case, additional sensitivities should be carried on to evaluate the role of natural gas reforming in intermediate steps towards the 2050 targets.

6. System cost analysis

In this section, we compare the system costs between the analysed scenarios to evaluate not only the technological aspects of the energy system but also the cost impacts of these scenarios. Fig. 21 shows the total system costs across all the scenarios (both the Section 2 scenarios and the sensitivity analyses), disaggregated in capital costs, fixed operational costs, variable operational costs, and trading costs (i.e., the net balance of imports and exports of commodities, such as electricity, oil or natural gas), while Table 13 shows the definitions of the different cost perspectives included in the IESA-NS model.

Regarding the scenarios of Section 4, higher availability of renewables and/or biomass entails a reduction of the system costs, as expected. Compared to REF, the HBIO system cost reduction of 2% (27 bn€) while the reduction in HVRE is of 4% (46 bn€). The scenario LONSH presents approximately the same system costs as the REF scenario, while the NOCCS one is around 1% more costly (10 bn€). However, it is important to remark that NOCCS includes a high potential of biomass and VRE (combination of values of HBIO and HVRE), and therefore the benchmark to compare the total system cost should be a scenario combining HBIO and HVRE and allowing CCS.

It is also interesting to analyse the cost difference between the ‘high mitigation ambition’ scenarios (REF, HBIO, HVRE, LONSH and NOCCS) and ‘low mitigation ambition’ scenarios (REF*, HBIO*,

HVRE*, LONSH*, NOCCS*, LBIO, LVRE). ‘Low mitigation ambition scenarios’ are between 7% and 10% more expensive in terms of system cost than their analogous ‘high mitigation ambition’ ones. This difference highlights the huge efforts required from a system perspective to effectively decarbonise the international transport and industry feedstock.

There is also an interesting hint in the hydrogen cost sensitivity analyses. Under very cheap import assumptions (i.e., REF10) the system costs are reduced dramatically (14%, 184 bn€), due to the massive adoption of imported hydrogen (1.2 €/kg) in multiple sectors. At more conservative import costs the cost reductions are reduced, but still considerable (REF20 4%, REF30 2%). At higher costs, the effect in the system costs compared to REF is negligible, due to the low share of imported hydrogen in the total use (see Fig. 17).

It is important to remark that, since all the scenarios are run only for the year 2050, the system costs plotted and analysed do not consider the transition pathways towards the final system configuration. This is relevant because certain scenarios might entail competitive system costs caused by the optimistic cost projections of certain technologies. In order to gain additional insights on the total system costs plotted in this section, future research should also include intermediate time steps (i.e., 2030, 2040) in order to understand the effect of intermediate emission targets and the learning process of novel technologies.

7. Discussion and conclusions

This paper synthesized the main results and findings of the different scenarios for the North Sea region as a whole, without intensively digging into national and subnational implications. The high number of scenarios analysed provides a plethora of results for each country, including a detailed breakout of all the energy sectors and national scale, and the hourly operational details of hundreds of technologies and networks. All the results derived from the scenario runs can be freely consulted in the interactive IESA-NS model interface [48].

In general, most of the results shown across the paper justify the development of multinational integrated ESMs, in which the spatial coverage is wider than national models, but more focused on a specific region than continental (or even global) models. For example, analysis of offshore and onshore infrastructure or imports/export dynamics are very difficult to study in detail in continental models. In contrast, these features can be widely analysed in national energy models, but at the cost of underestimating the interactions with surrounding countries. In the NSR these interactions are crucial, because NSR countries are highly interconnected and share large amounts of offshore space. Therefore, the use and development of models such as the IESA-NS adds value to the modelling landscape.

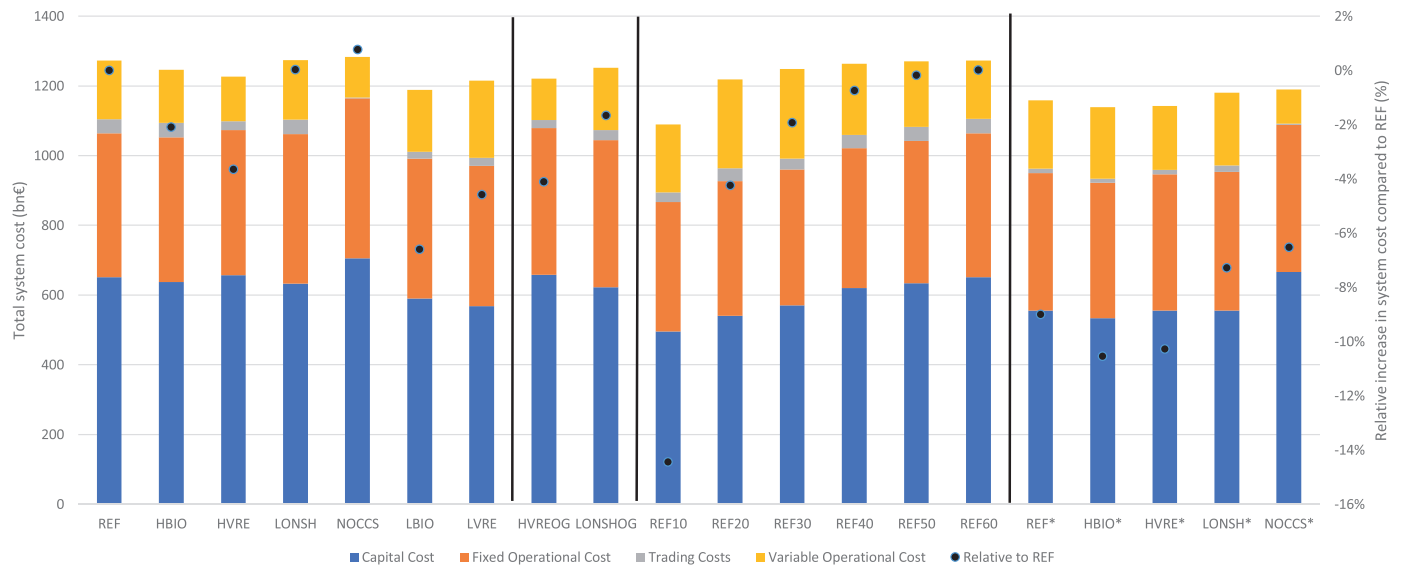


Fig. 21. Total system cost across the scenarios and sensitivities for the whole NSR.

Table 13

Definitions of the different cost perspectives included in the IESA-NS model.

Cost perspective	Definition
Objective function (Problem perspective)	This cost perspective directly reflects the planning and operational decisions in the mathematical problem. Hence, it reflects annualised (and discounted) investments for new and retrofitted technologies, fixed costs of having a technology in the system, capital recovery (if any) of premature decommissioning, and variable operational costs (fuel consumption and other variable costs).
Energy prices (Market perspective)	The energy prices are reflected by the dual variables of the energy balance constraints. Therefore, they reflect the market value of a commodity in the model and are used to account for the energy costs of imports and exports as well as for sectoral costs analyses.
System costs (National perspective)	System costs are obtained after post-processing planning and operational decisions as considered in the objective function. Here, the distinction between the national system and “problem appendices” is made explicit (EU power system, refineries exports, and gas exports). The post-processing accounts for the cross-border trading component of electricity, gas, and OBPs. It should be noted that this form of reporting keeps track of the capital cost component of the planning decisions based on the costs of the decision period and the economic lifetime of the decision.
Sectoral costs (Users’ perspective)	Sectoral costs explicitly account for the fuel prices paid by each sector based on the market perspective of the energy costs. This means that the total sum of costs in all sectors will be higher than the system costs, as this definition accounts for the hidden added value of the energy prices. Furthermore, the trading component mentioned for the national system costs is allocated to each specific sector under this definition. Finally, the sectoral cost provides a further disaggregation, as the infrastructure costs are explicitly reported here (while they are regarded as capital and fixed operational costs from the national perspective), which is also the case for the ETS emission costs (which are regarded as variable costs in the system costs definition).

Out of the analysis of the results provided in this paper, some general insights can be drawn.

- Most of the base scenarios hinted that a more interconnected offshore infrastructure (e.g. power, hydrogen and CCS offshore grids) can be beneficial for the system. In constrained scenarios, the Netherlands and Germany invest heavily in far from shore offshore wind, deploy large amounts of HVDC infrastructure and reach their technical potential limits, whereas the rest of the countries never reach their limits. A sensitivity analyses was carried out allowing HVDC offshore interconnectors between the United Kingdom, the Netherlands and Germany. In scenarios with high offshore potential (HVRE and LONSH), investments in considerable offshore HDVC interconnector capacity are cost-optimal (up to 76 GW in the link NL-UK and 120 GW in the link DE-UK) and allow for extra investments of offshore wind (122 GW and 191 GW of additional offshore wind capacity in the analysed scenarios).
- The role of biomass is crucial in order to meet the mitigation targets. Most of the countries use all their available biomass resource in all scenarios. The share of biomass in the primary energy reaches 20% in the scenarios with high availability of biomass, 15% in scenarios with a reference value, and 8% when biomass is constrained to a pessimistic availability. Biomass is a very versatile resource and it is used across multiple sectors: biofuel production for aviation and navigation is relevant when targets on international transport are imposed (in the ‘high mitigation ambition scenarios’ this use is between 1.4 EJ and 3.5 EJ). Biomass is also used to provide high temperature heat in industry when natural gas is displaced (up to 2.5 EJ of biomass used in constrained scenarios). Most of the time the heat production is complemented with CCS in order to reach negative emissions. Biomass is also widely used as feedstock in the chemical industry, permitting the system to reach, again, negative emissions (up to 2 EJ used as feedstock). Biomass is also used in CHPs and boilers for residential and services heat, especially in Scandinavian

- countries (up to 600 PJ). Biomass is also used in the power sector as a peak generator (up to 900 PJ of biomass used, mainly in Germany).
- There is a large use of hydrogen in the scenarios with 'high mitigation ambition', ranging from 5.6 EJ to 7.3 EJ. This hydrogen is crucial in order to decarbonise the international aviation and navigation, via the production of synthetic fuels, and the industry feedstock. In these scenarios, electrolysis is the preferred hydrogen production route (4.5 EJ to 6.4 EJ), while natural gas reforming is only an attractive option when VRE potentials are low (2.2 EJ in **LONSH**). In the scenarios with 'low mitigation ambition' the use of hydrogen is considerably lower (1.6 EJ in **LBIO** and 690 PJ in **LVRES**). As shown in the dedicated sensitivity analyses, the availability of imported hydrogen can heavily affect the optimal system configuration. If hydrogen can be imported at costs below 3.6 €/kg, the imported hydrogen is dominant compared to national production, and the total hydrogen use is considerably increased compared to the base scenarios (9.2 EJ in **REF20** and 11 EJ in **REF10**)
 - Power to liquids is a key technology in order to reduce the dependency on crude oil. Additionally, the PtL pathway with green hydrogen allows to integrate large amounts of VRES in a cost-effective manner, while providing the system with considerable flexibility. In the 'high mitigation ambition' scenarios 4.1 EJ to 5.3 EJ of liquids were produced via PtL pathways.
 - One of the relevant conclusions of the analysis of national results (which is not fully covered in this section, but can be consulted in [48]) is the contrast between the Scandinavian countries (Denmark, Sweden and Norway) and the rest of the NSR (i.e. Germany, the Netherlands, Belgium and the UK). In general, across all the scenarios, Scandinavian countries can meet their targets without a high increase of system costs, with relatively low CO₂ shadow prices and low energy costs. In contrast, the rest of the NSR, notably Germany, pays a higher price, especially in constrained scenarios. The main reason is that Scandinavian countries have to satisfy a lower energy demand, while they have high VRE potentials (due to the low density of population the space availability is relatively high), high biomass resources and enough hydro capacity is used as a valuable flexibility source. In contrast, the rest of the NSR presents very high energy demands, large energy intensive industrial clusters, less space available for VRE deployment and a lower biomass availability compared to the size of the energy system.
 - Another relevant benefit of the IESA-NS model that can be deduced from the results is the importance of combining hourly resolution with a decent representation of all the sectors of the energy system. Since the IESA-NS is an integrated energy model, different resources can compete across many different sectors to provide the cheapest configuration. The use of biomass exemplifies this competition: if we evaluate the NSR using a model with only power coverage the biomass availability should be defined exogenously, and the model might determine that using biomass turbines as a peak generator is optimal. In contrast, if all the sectors of the energy system are modelled, biomass might be better used in alternative sectors with fewer decarbonisation options.

The IESA-NS model also includes some limitations. First, it is very demanding from the computational side, requiring long computing times (2 to 3 h for one year time span, 6 to 8 h for 2 years, and over 30 h for three years). Further work is required in order to lighten it without losing accuracy. As a consequence of these computational limitations, some sectors and streams are simplified: biomass resources are aggregated, and therefore the model cannot differentiate between different biomass sources, such as manure or wood. When large availability of biomass is considered this is not a big issue, but in scenarios with low availability this assumption can overestimate the use of biomass in certain sectors (e.g., biomass might be fully allocated as feedstock for industry while

in reality some biomass streams cannot be used for that purpose). Another simplification is that the IESA-NS model only includes one voltage level per country, and therefore conversion losses and use of different transmission grids are not included in the analysis. So far, the IESA-NS model has not been used to optimize scenarios under uncertainty. Incorporating uncertainty in optimization (e.g. by means of stochastic optimization) has been proved in the literature as a relevant methodology, especially in energy systems with a large amount of VRES, or in scenarios with a long time span, where for example cost development of certain technologies are highly uncertain [57,58,59,60]. These features can be modelled in the IESA-NS framework and might be a relevant future research pathway. Finally, even though all industrial processes are described with multiple alternatives and decarbonisation options, some promising processes are not fully integrated. Future research work should improve these limitations providing a better representation of the energy system while improving the computational requirements to run the IESA-NS model.

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APPENDIX A. IESA-NS model description and calibration

The IESA-NS model has been developed based on the IESA-Opt framework, which was thoroughly described in [24]. The IESA-Opt model was initially developed to cover in detail the energy system of the Netherlands, filling multiple knowledge gaps that most integrated energy system models in the literature present [19]. For the purpose of this paper, the IESA-Opt model is enhanced, in order to cover the whole NSR with a high level of detail, including a detailed representation of the energy system of the Netherlands, Germany, Denmark, Sweden, Norway, the United Kingdom and Belgium.

Additional information and more details about assumptions, background and relevant sources can be found in the IESA-Opt methodological publication [47,24]. The goal of this section is to summarize the main capabilities of the new-built IESA-NS and to briefly describe its data inputs and outputs.

The IESA-NS model is a cost-optimization model, formulated as a linear problem (LP), that, in short, optimizes the long term investment planning and short term operation of the NSR energy system. The model can optimize multiple periods simultaneously (and therefore can be used to analyse single year optimization scenarios or transition pathways towards 2050), accounts for all the national GHG emissions and includes a thorough representation of all the sectors of the energy system.

Fig. 22 shows a brief flowchart summarizing the methodological elements and steps followed by the IESA-NS model. As seen, there are mainly 6 different required inputs: activity demands, driven by macroeconomic data; technology data in order to create the technology portfolio; available potentials of multiple resources and technologies; primary energy prices; national mitigation targets and specific technology bans; and finally data for the European power system, which is also endogenously represented in the system.

As mentioned, the IESA-NS model is formulated as an LP, whose objective function comprises the minimization of investments, retrofitting

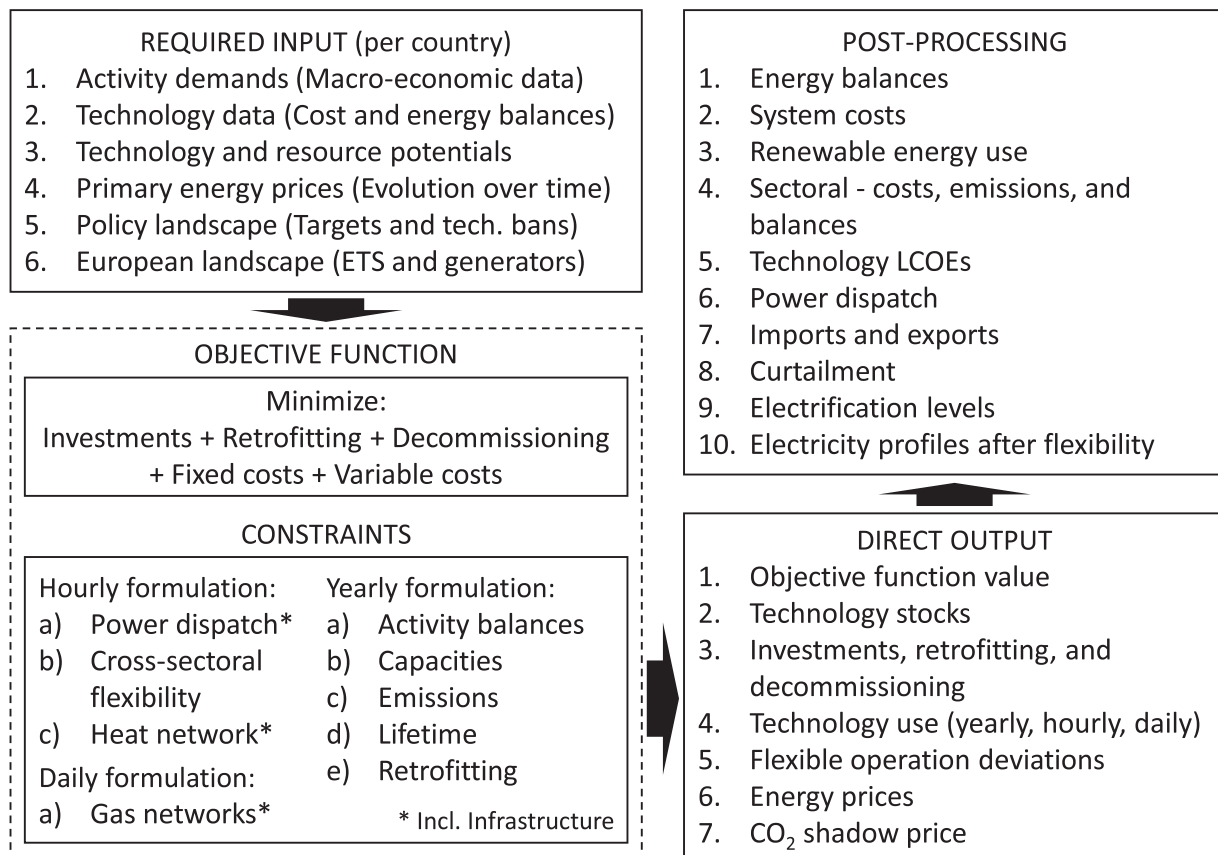


Fig. 22. Methodological elements in the IESA-NS framework.

costs, decommissioning costs and both fixed and variable operation costs. The formulation presents a wide range of constraints to ensure that the optimal system configuration is feasible and respects different physical and theoretical boundaries.

One of the interesting features of the IESA-NS model is that its formulation includes different temporal resolutions. The power sector and the heat networks are optimized with hourly resolution, allowing to properly capture the intermittency of variable renewable sources, and the dynamics of short and long term energy storage, among others. The multiple cross-sectoral flexibility options that the model includes (e.g. demand shedding, load shifting, flexible CHPs) are also formulated with hourly resolution. The gas and hydrogen network are modelled using daily resolution. Finally, some other constraints are formulated with yearly resolution, like the activity balance (i.e. the system should satisfy all the exogenous demands driven by macro-economic trends), certain system capacities, retrofitting decisions or the technology lifetimes.

The optimization process provides a plethora of direct results, like the optimal objective function value, all the technology stocks and their operation levels, the investment, retrofitting and decommissioning decisions, the operation of the flexible technologies, including their deviation from their reference profiles, the different energy prices, and all the CO₂ shadow prices. Moreover, the IESA-NS model includes a thorough post processing that permits to analyse, among others, the energy balances, system costs, use of renewables, emissions, levelized costs of electricity (LCOE), hourly power dispatch in every node of the system, imports and exports dynamics, curtailment and electrification levels, and many more. All the data can be visualized in the tailor-made online user interface of the model [48].

As mentioned, the IESA-NS model is defined by activities and technologies. The activities are exogenous parameters, linked to macro-

economic data and estimations, while the technologies are the tools that the model has to satisfy these activities. The whole list of activities and technologies can be found in the different databases attached as supplementary material or in [48].

Fig. 23 describes the list of activities that is part of each country of the NSR in the IESA-NS model. The driver activities are the exogenous demand volumes corresponding to the residential, services, agriculture, industry and transport sector, together with aggregated emissions not fully contained in the energy system (and modelled with MACC curves). The model, with these demand volumes, decides which of the available technologies should be used to satisfy these demands. The use of technologies entails (sometimes) direct CO₂ emissions, and certain energy requirements (either primary energy or processed energy). This processed energy has to be provided by endogenous energy activities, and the model has also to select which process is optimal to do so. For example: if there is an exogenous transport demand, and the model decides to satisfy it with an electric car, there will be an endogenous demand for electricity to power this car. Therefore, the model has to decide which process is optimal in order to supply this electricity.

The IESA-NS model has been calibrated following multiple different reliable sources, in order to align the outcomes of the base year (2020) with real data. Data sources used for calibration included the IEA and the Eurostat energy balance sheets. The latest calibration of the IESA-NS model took place in spring 2021, with real data from 2019. Fig. 24 shows the comparison between the IESA-NS power generation outcomes in the base year compared to the real values provided by the IEA. Fig. 25 shows the same comparison with the electricity demand of different end sectors. Additional calibration results can be consulted in [48].

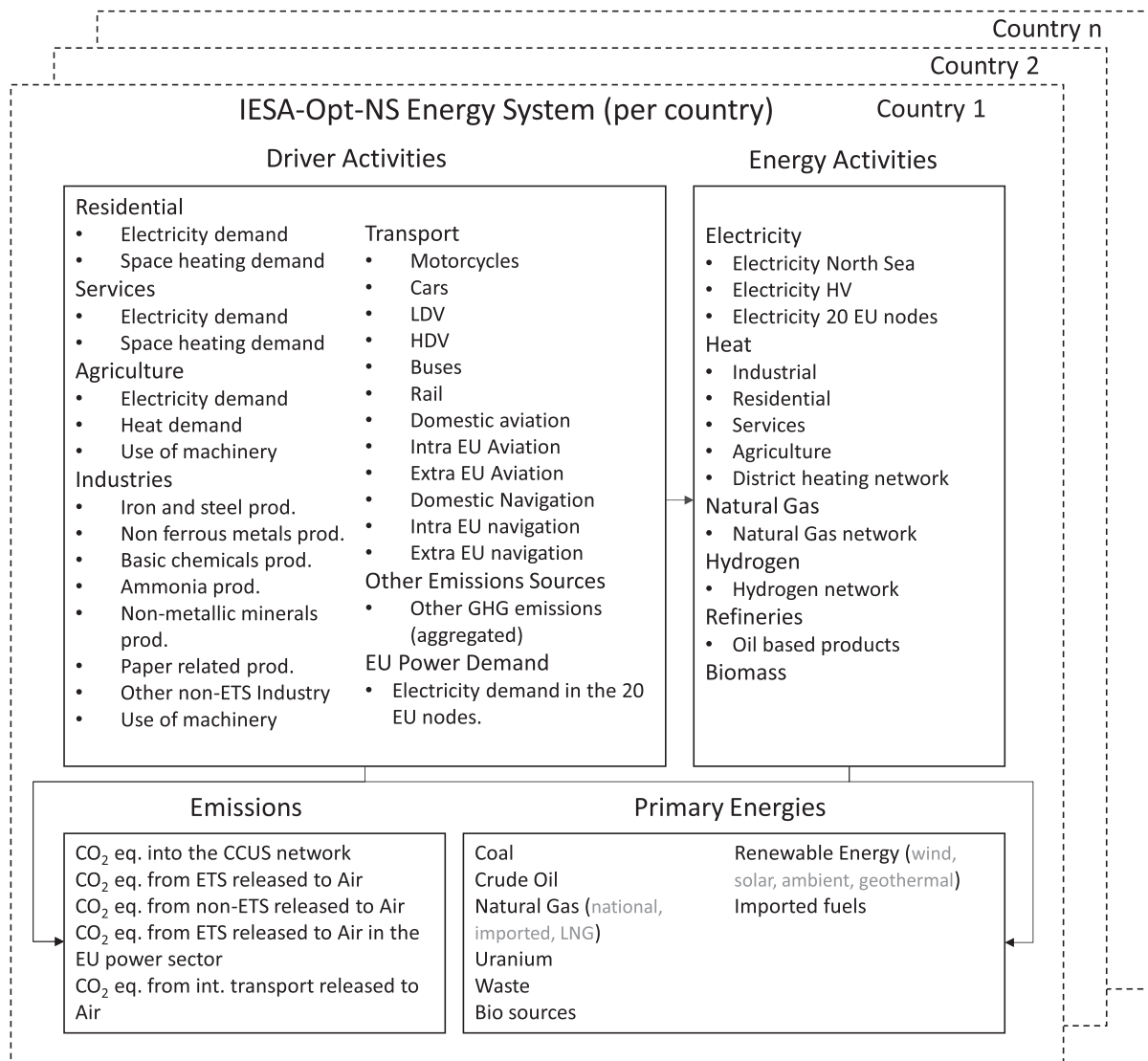


Fig. 23. Energy system representation of activities considered within the IESA-NS framework.

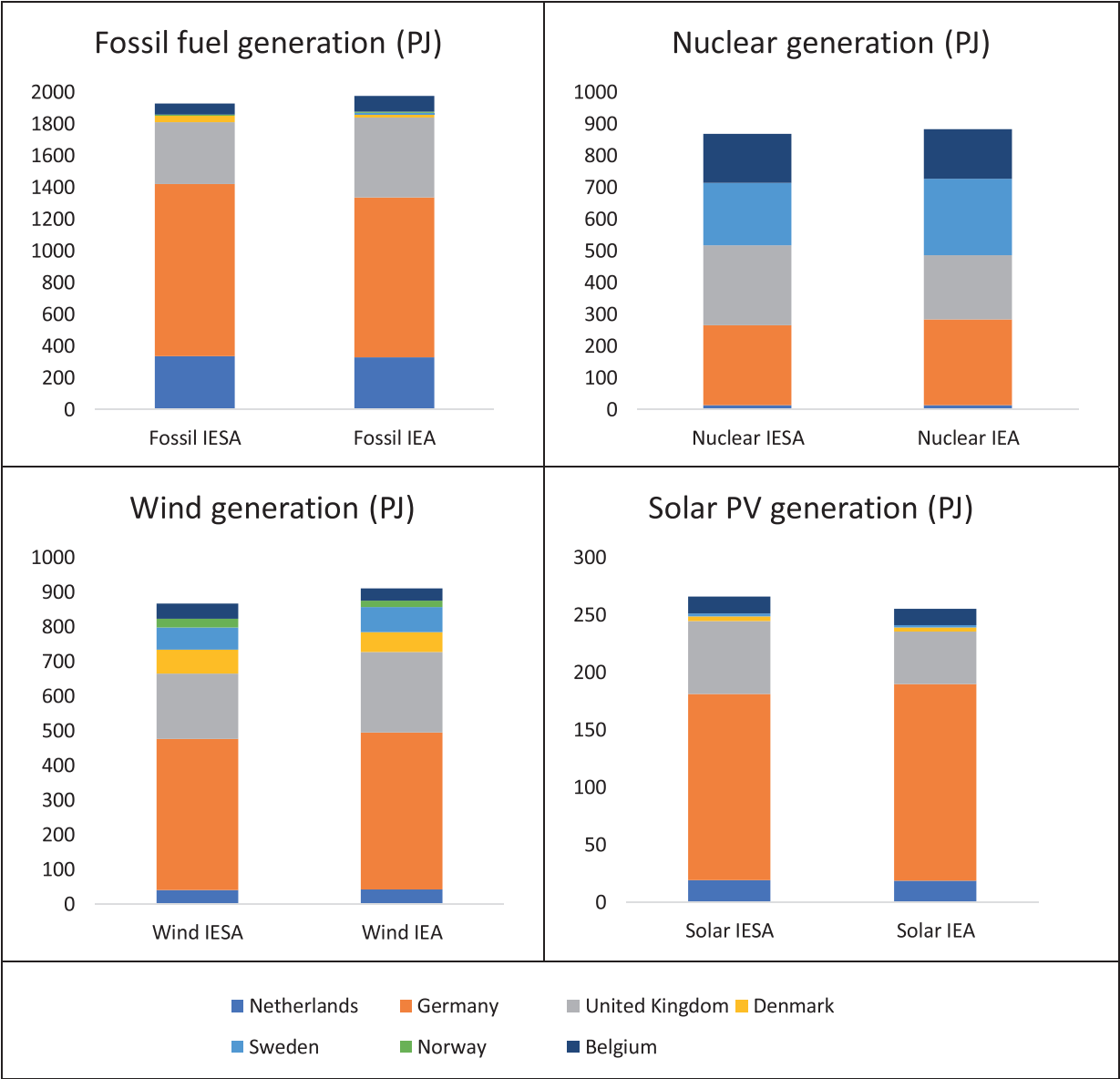


Fig. 24. Observed power generation values in the reference year (2020) of the IESA-NS model versus realized values (2019) from the IEA.

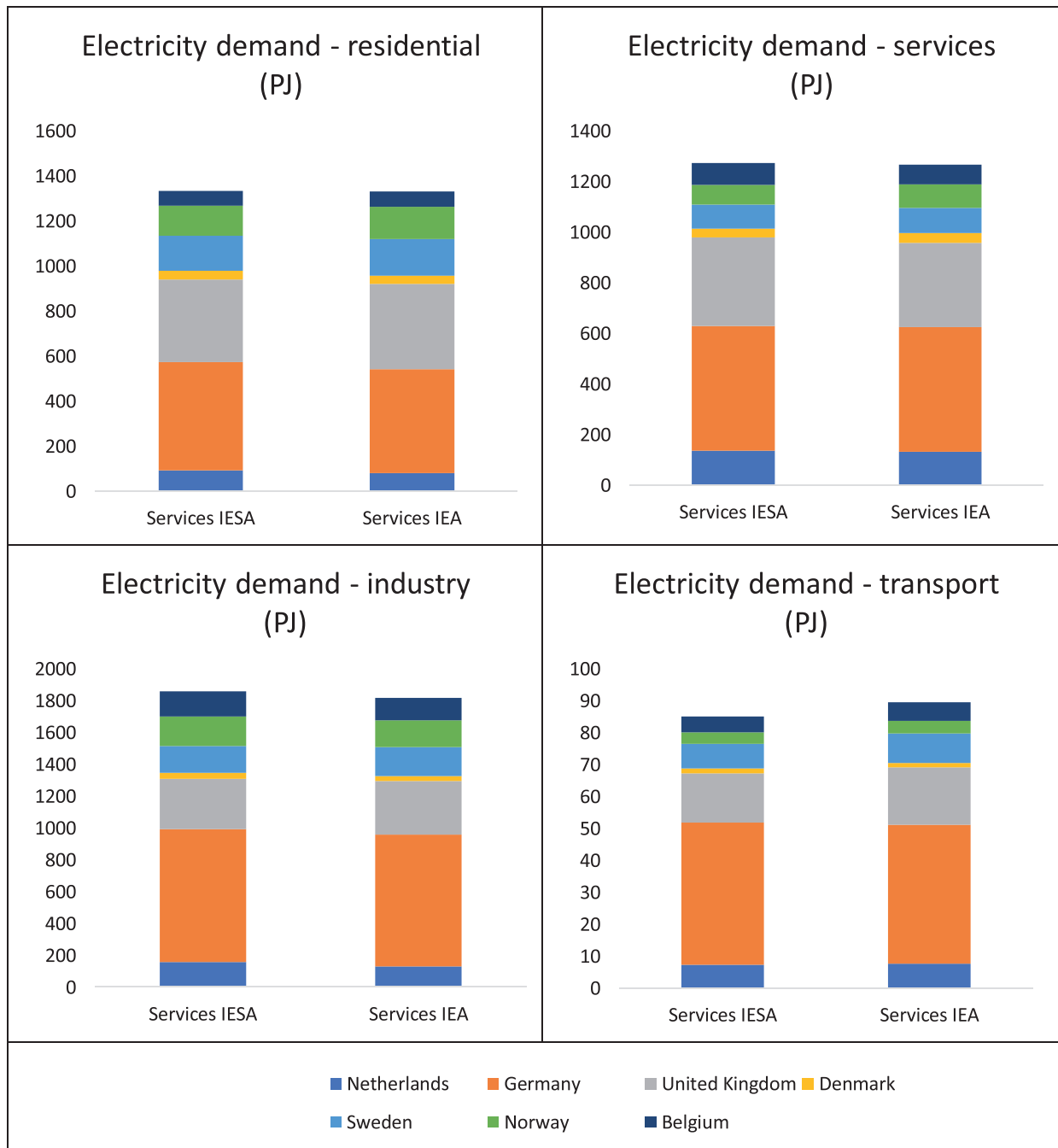


Fig. 25. Observed electricity demand values in the reference year (2020) of the IESA-NS model versus realized values (2019) from the IEA.

APPENDIX B: Model formulation

Nomenclature of the model

Indexes

Symbol	Description
p	Index of the set conformed by all the modelled periods
h	Index of the set conformed by all the hours in a year
d	Index of the set conformed by all the days in a year
n	Index of the set conformed by all the nodes representing integrated energy systems
a	Index of the activities set
ae	Index electricity related activities subset, A^e
ah	Index of the national heat related activities subset, A^h
ag	Index of the gas related activities subset, A^g
t, t_i, t_j	Indexes of the technologies set
te	Index of the technologies representing air released emissions in the considered target scope.
td	Index of the dispatchable technologies subset
tp	Index of the operation technologies subset
tf	Index of the flexible technologies subset
tf_b	Index of the flexible technologies of the battery type subset
tc	Index of the flexible CHP technologies subset
ts	Index of the shedding technologies subset
ti	Index of the infrastructure technologies subset

Parameters

Symbol	Description
$VC_{i,p}$	The variable cost of a technology in a period
α_i	Annuity factor of a technology (or in this case the inverse)
$IC_{i,p}$	Investment cost of a technology in a period
DF_i	Fraction of the capital cost of a technology that remains after premature decom
$RC_{i,j,p}$	Retrofitting cost from one technology to another
$FC_{i,p}$	Fixed operational cost of a technology in a period
$AP_{i,a,p}$	Activities inputs and outputs profile of a technology
$V_{a,p}$	Exogenous required activity volumes in a period
Γ_i	Available use of a technology per unit of capacity
E_p	Absolute CO ₂ emission target in a certain period.
RM_{i,t_j}	Binary matrix specifying which technologies can be retrofitted into others
$S_{i,p}^{min}, S_{i,p}^{max}$	Minimum and maximum allowed installed capacities of a technology in a year
$P_{h,p}$	Hourly availability or reference operational profile of a technology
$AE_{i,a}$	Binary parameter indicating the hourly electricity activities of a technology
$R_{id,p}^{dw}, R_{id,p}^{up}$	Ramping up and down limits of hourly dispatchable technologies
η_{tc}	Only-heat reference efficiency of a flexible CHP
ε_{tc}	Only-power reference efficiency of a flexible CHP
SC_{ts}	Power shedding of a technology per unit of capacity
$U_{t,ts,p}$	Use-to-power ratio of a shedding technology in a period
SF_{ts}	Maximum allowed shedding fraction of a shedding technology
$AG_{t,f,a}$	Binary parameter indicating the gas activities of a technology
$FC_{t,f}$	Flexibility capacity in terms of the impact on the corresponding network of a technology.
NN_{tf}	Non-negotiable load of flexible technologies.
$CC_{t,f}$	Charging (or discharging) capacity of a storage technology.
$CT_{t,f}$	Charging time of a storage technology.
$VU_{t,f}$	Hourly profile of the usage of a flexible vehicle (not connected to the grid).
$AS_{t,f}$	Average speed of a flexible vehicle.

Variables

Symbol	Description
$u_{i,p}$	Use of a technology in a period
$i_{i,p}$	Investments in a technology in a period
$d_{i,p}^{pre}$	Premature decommissioning of a technology in a period
$r_{t_i,t_j,p}$	Retrofitting from one technology to another in a period
$s_{i,p}$	Stock (installed capacity) of a technology in a period
$d_{i,p}^{cum}$	Cumulative decommissioning of a technology in a period
$d_{i,p}^{lt}$	Decommissioning of a technology in a period due to lifetime expiry
$u_{h,td,p}$	Hourly use of a dispatchable technology in a period
$\Delta q_{h,tf,p}^{up}$	Increase in electricity demand from a flexible technology in an hour in a period
$\Delta q_{h,tf,p}^{dw}$	Decrease in electricity demand from a flexible technology in an hour in a period
$\Delta u_{h,tc,p}$	Deviation in use of a flexible CHP technology in an hour in a period
$\Delta p_{h,tc,p}$	Deviation in power output of a CHP technology in an hour in a period
$\Delta u_{h,ts,p}$	Decrease in use of a shedding technology in an hour in a period
$l_{h,tf,p}$	Losses from deviations in use of flexible technologies in an hour in a period
$\Delta q_{h,tf,p}^{max}$	Maximum increase limit of power demand of a flexible technology in an hour
$\Delta q_{h,tf,p}^{min}$	Maximum decrease limit of power demand of a flexible technology in an hour
$u_{h,tf,p}^{max}$	Upper saturation limit from shifted volume in an hour in a period
$u_{h,tf,p}^{min}$	Lower saturation limit from shifted volume in an hour in a period
$u_{d,td,p}$	Daily use of a dispatchable technology in a period
$\Delta q_{d,sg,p}^{up}$	Upwards deviation in use of a daily storage technology in a period
$\Delta q_{d,sg,p}^{dw}$	Downwards deviation in use of a daily storage technology in a period

Sectoral integrated cost-optimized energy system towards decarbonisation targets

As described in the IESA-NS conceptual framework, sectoral integration in IESA-NS turns around two main axes, activities and technologies (analogously to the commodities and processes nomenclature in TIMES). Thus, under a richly described technological landscape, there are many technology use combinations able to satisfy a desired volume of activities. From such a broad domain, the model simultaneously determines the optimal configuration and use of technologies to satisfy the required activities' volumes. It does so by minimizing system costs resulting from the set of decision variables confirmed by use, investments, decommissioning, and retrofitting of technologies accordingly with the following expression.

$$\min \left[\sum_{i,p} u_{i,p} VC_{i,p} + i_{i,p} \alpha_i IC_{i,p} + d_{i,p}^{pre} DF_i \alpha_i IC_{i,p} + r_{t_i,t_j,p} \alpha_{t_j} RC_{t_i,t_j,p} + s_{i,p} FC_{i,p} \right] \quad (1)$$

Subject to ensure that the use of technologies meets at least the required exogenous activities drivers, as described by

$$\sum_t u_{t,p} AP_{t,a,p} \geq V_{a,p} \quad (2)$$

Also subject, as shown in (3), to the available installed capacities of the technologies and the particular activity-to-capacity ratio for each technology, Γ_i .

$$u_{i,p} \leq s_{i,p} \Gamma_i \quad (3)$$

Every single technology can affect one of the five accounts of emissions considered as activities: CCUS network, national ETS, national non-ETS, external ETS, and international transport emissions. Most technologies increase the net volume of the emitting activity and some technologies decrease it (such as carbon capture and direct air capture). To keep the emission activities balanced there are four 'technologies' who match their net account, which are named: CO₂ released to air in the national ETS, national non-ETS, external ETS and international transport accounts. The emission constraint is therefore enforced by ensuring that

the CO₂ released to air in the national ETS and non-ETS accounts does not exceed the national targets of each node defined for the different periods as described by the following constraint:

$$\sum_{te} u_{te,p,n} \leq E_{p,n} \quad (4)$$

Nevertheless, it is important to mention that not all the sources of emissions considered within the scope of the targets are included within the activities that are covered by IESA-NS. To be precise roughly 85% of the emissions considered within the national inventories of NSR countries are covered by the activities included in the energy system framework, then for the remaining 15% (mostly agricultural activities), a less detailed approach is used. Here, the emissions resulting from activities such as enteric fermentation, manure management, use of fertilizers and use of refrigeration fluids are input to the model as driving activities, and their potential reductions and costs are addressed with MACC curves (extracted from the IMAGE model database).

Next to the previous formulation, other aspects must be included to better represent the feasible operation of the energy system. These aspects are an adequate multi-year transitional path representation, the hourly representation of the European power system dispatch, including the flexibility representation and technical limits in the operation of flexible demand and generation technologies, the consideration of gaseous networks operation and the impact of available infrastructure in the intra-year operation of technologies.

Transition path

The transitional capability of the model derives from the fact that it can plan for the optimal system configuration for the different periods covered in the transition, at the same time that it determines the optimal intra-year operation of the stocks. The transitional elements are described by the investment, premature decommissioning, and retrofitting decisions that give shape to the technological stock accordingly with the following formulation:

$$s_{t,p} = s_{t,p-1} + i_{t,p} + r_{t,i,t,p} - r_{t,i,t,p} - (d_{t,p}^{cum} - d_{t,p-1}^{cum}) \quad (5)$$

being:

$$d_{t,p}^{cum} = d_{t,p-1}^{cum} + d_{t,p}^{pre} + d_{t,p}^{lt} \quad (6)$$

It is important to ensure that premature decommissioning can freely happen at any period if convenient, but to avoid that decommissioned technologies cannot be decommissioned in a year and recommissioned back in a subsequent period. Simultaneously, the model must be able to address the costs of premature decommissioning. For this purpose, the following constraint together with (5) and (6) ensure both requirements to be satisfied:

$$d_{t,p}^{cum} \geq d_{t,p-1}^{cum} \quad (7)$$

Also, as part of the scenario descriptions, some technologies are defined within a certain bandwidth of deployment. This same constraint, depicted in (8), is used to set the adoption potentials for technologies and to cap system emissions.

$$S_{t,p}^{min} \leq s_{t,p} \leq S_{t,p}^{max} \quad (8)$$

Lastly, the retrofitting of technologies is constrained by the available stocks of the original technology, and by an input binary parameter which determines which are the possible retrofitting relations. This results in the following formulation:

$$r_{t,i,t_j,p} \leq s_{t,p-1} RM_{i,t_j} \quad (9)$$

European hourly power sector dispatch

Modelling power dispatch within ESMs asks for choices to be made to avoid enormous computational requirements. To start with, the study [61] concluded that considering poor temporal resolutions negatively affects outcomes reliability for scenarios with moderate and high presence of VRES, and greatly recommend to prioritize using at least hourly resolution. Also, adopting a sequential description of the power dispatch enables to retain the chronological order in the variability of the events,

which is key for short and long term storage technologies. Thus, IESA-NS adopted an hourly resolution of the complete year operation (8760 sequential points per year).

Furthermore, the same study [61] also mentions that operational detailing, namely unit commitment, increases reliability as the presence of VRES start to increase. However, it also states that adopting unit commitment loses relevance after a certain level of VRES penetration, as fewer thermal units affect the system dynamics. This observation is further reinforced by another study which states that MIP unit commitment performs better in scenarios with low presence of VRES, but for scenarios with high levels of VRES an LP approach suffices to provide reliable results [62]. Also, there is plenty of evidence that increasing the geographical scope of the model to consider European cross-border interactions has a significant impact on the outcome reliability of the models [63]. Therefore, in this model we exclude the unit commitment formulation (MIP) and rather include the whole European power system represented in 20 nodes. This penalizes the ability of the model to reliably analyse low VRES scenarios with a high presence of thermal generators (as unit commitment is excluded), but keeping the convenient LP formulation enables IESA-NS to simultaneously solve the EU power dispatch and the integrated national energy system within the same formulation while considering a high temporal resolution and a moderate and high presence of VRES. Thanks to such modelling choice it is possible to analyse the interaction of storage, flexible demand technologies, VRES, and cross-border interconnection within the sector-coupled energy system of the Netherlands.

The following linear formulation is used to include the previously described concepts within the IESA-Opt framework. First, the fundamental constraint that supply and demand of electricity must remain balanced at every hour is included. For this purpose, we divide technologies into five main groups: dispatching technologies, t_d , technologies with flexible, t_{pf} , and non-flexible operation, t_{pn} , flexible CHPs, t_c , and shedders, t_s . For each of the 24 different electricity networks considered in the model, conforming the set A^e , the hourly balance is represented with the following constraint:

$$\begin{aligned} u_{h,t,d,p} AP_{t,d,a,p} = & \\ u_{t,p,p} P_{h,t,p} AP_{t,p,a,p} + (\Delta q_{h,t,f,p}^{up} + \Delta q_{h,t,f,p}^{dw}) AE_{t,f,a} & \\ + (u_{t,c,p} P_{h,t,c} + \Delta u_{h,t,c,p}) AP_{t,c,a,p} + \Delta p_{h,t,c,p} AE_{t,c,a} & \\ + (u_{t,s,p} P_{h,t,s} + \Delta u_{h,t,s,p}) AP_{t,s,a,p} \quad \forall a \mid a \in A^e & \end{aligned} \quad (10)$$

This equation can be read as supply is equal to reference hourly demand, plus flexible demand variations ($\Delta q_{h,t,f,p}^{up}$ and $\Delta q_{h,t,f,p}^{dw}$), plus the bi-dimensional CHP flexibility variations ($\Delta u_{h,t,c,p}$ and $\Delta p_{h,t,c,p}$), and plus the shedding demand variations ($\Delta u_{h,t,s,p}$), for each interconnected node.

Another major determinant for the dispatch of electricity is resource availability, and this turns relevant for two reasons: the installed capacities of generation technologies and the intermittency of renewable energy sources. Every single technology in the model is described with an hourly operation $P_{h,t}$. For the dispatching technologies, this profile represents the hourly availability of the resource, and for the other technologies, it represents the hourly reference operation.⁸ The following

⁸ The profiles are normalized and extracted from historical datasets such as the wind and solar availability in the NSR countries and the other 20 considered EU regions; the load profile of the NSR and EU regions; reference EV charging and connection profiles; temperature profiles; and a flat profile. Due to availability of data, so far only 84 hourly profiles have been included, but every technology is assigned to one of them, which means that many technologies share profiles. However, if more data becomes available the model is already enhanced to easily include it into the database, and would not result in increased computational times.

constraint ensures that supply occurs accordingly with the existent installed capacity and to the extent at which the hourly resource availability allows it:

$$u_{h,t,d,p} \leq s_{t,d,p} \Gamma_{td} P_{h,t,d} \quad (11)$$

Also, ramping constraints are considered for dispatchable generation accordingly with the following constraint:

$$-R_{t,d,p}^{dw} \leq (u_{h,t,d,p} - u_{h-1,t,d,p}) \leq R_{t,d,p}^{up} \quad (12)$$

Lastly, the European representation, the dispatch architecture, the data on profiles and operational parameters are strongly based on the same modelling structure used as input by COMPETES model [64].

Hourly flexible operation in coupled sectors

Next to the power dispatch description, the representation of possible deviations from reference hourly operation profiles are paramount for the dispatch and to adequately represent sector coupling. With this aim, IESA-NS considers three different types of intra-year operational decisions: flexible CHPs, shedding technologies, and demand technologies with flexible operation.

Flexible CHPs

CHPs are modelled as operation technologies, which means that their hourly operation profile is fixed, and the changes in their use affect such profiles proportionally. However, some CHPs, known as extraction-condensing steam turbines, can extract a fraction of the condensed steam before (or during) the expansion phase (the power turbine) to be used to provide heat [65]. Such enhancement allows these turbines to adjust their power-to-heat ratio, which in combination with the amount of steam generated before the expansion, gives the technology a huge potential to modify its power and heat outputs and fuel inputs to adapt to electricity price events (among other externalities [66]). The resulting bi-dimensional flexibility (the fuel inputted into the boiler, and the extraction flow of the condensed steam) is considered by IESA-NS using a convenient LP simplification (resembling other ESMs [9]).

In a linear representation of a flexible CHP, the fuel requirement, F , is assumed to be determined by the heat and power outputs, H and P , accordingly with $F = H/\eta + P/\epsilon$. Where η and ϵ represent the CHPs' efficiencies when producing only heat and power respectively. For this, IESA-NS considers two dimensions in which flexibility takes place: the hourly deviations in the fuel input representing the deviations in use, $\Delta u_{h,t,c,p}$; and the hourly deviations in the power output, $\Delta p_{h,t,c,p}$. This leads to the following constraint to ensure satisfying heat the heat demand provided by the CHP, in a specific time window:

$$\begin{aligned} & \sum_{h \in TW_{tc}} \left[(u_{t,c,p} P_{h,t,c} + \Delta u_{h,t,c,p}) A P_{t,c,a,p} - \eta_{tc}/\epsilon_{tc} \Delta p_{h,t,c,p} \right] \\ & = \sum_{h \in TW_{tc}} u_{t,c,p} P_{h,t,c} A P_{t,c,a,p} \end{aligned} \quad (13)$$

As the model distinguish from different temperature levels and different sectors, A^h represents the set of activities corresponding to the different heat forms that can be produced by the different CHPs in the model.

Shedding technologies

The upcoming energy transition will deliver a set of technologies that could provide sector coupling via the conversion of electricity into other energy forms (such as heat [67], hydrogen [68], methanol [69], methane [41], hydrocarbons [42], chlorine [70], ammonia [71], and other chemicals [72]) via the means of technologies such as heat pumps or electrolyzers. We use the word shedding to refer to the action taken by abovementioned technologies of cutting down operations in a critical hour to decrease electricity consumption and help to alleviate the system. This opens the door to foreseeable scenarios where these type of technologies could be interruptedly operated to avoid high electricity price events and decrease their operational costs [72]. However, extra capacity must be installed to be able to satisfy demand while sacrificing operational times [73]. Summarizing, shedding technologies in IESA-

NS can selectively operate in specific hours in exchange for overinvestments.

The representation of these technologies in the model assumes they can shed their hourly activities by the means of an hourly decision variable which represents the decrease in use for each hour. This variable is capped by the installed capacity of the technology, as shown below:

$$\Delta u_{h,t,s,p} \leq s_{t,s,p} SC_{ts} U_t P_{t,s,p} \quad (14)$$

Because, as stated in (2), the model must ensure sufficiency in the activities balances, it will determine the required technological stock, determining in this way the necessary excess capacity to cope with such shedding.

Furthermore, technologies might not have a flat operational profile and might be subject to specific sectoral dynamics, or perhaps a certain technology may require a minimum level of operation. For these cases the following constraint is imposed:

$$\Delta u_{h,t,s,p} \leq u_{t,s,p} P_{h,t,s} S F_{ts} \quad (15)$$

where $S F_{ts}$ represents the assumed potential shedding fraction of each shedding technology. And the profile is flat for technologies without specific sectoral dynamics.

Conservative flexibility

The last element presented here consists of the formulation used for technologies that allow for deviations in the reference profile without compromising the technology output and with or without paying an efficiency penalty. We call these options here as conservative flexibility, as all the up or down flexibility must be eventually recovered with an action in the opposite direction. Some examples of these technologies are some residential and services appliances such as dishwashers, washing machines, fridges or freezers [74,75]; electric heating appliances with active or passive storage [76,77,78]; electric vehicles with smart charging or vehicle-to-grid enhancements [79]; industrial processes with opportunities for flexible programming of their operations [74,80,81,82]; and all sort of different kind of batteries and storage technologies [83,84,85].

To be able to model such a vast group of technologies, they were grouped into 4 different archetypes⁹: load shifting for typical demand response and active thermal storage; smart charging of electric vehicles; vehicle-to-grid; and storage technologies. Each of these groups is represented under a specific formulation in the model and can be applied to all of the technologies considered under each category. However, all of the formulations share three elements in common: a balance constraint, a capacity constraint, and a saturation constraint, and each of the elements is interpreted differently for each archetype.

The energy balance states that the net energy demand should remain constant for the considered time window, and the use of time windows is adopted to maintain a linear formulation of the balance. This implies that the net balance of the upwards and downwards gross shifted load within the time window should be equal to the corresponding losses if any, as follows:

$$\sum_{h \in TW_{tf}} \Delta q_{h,t,f,p}^{up} + \sum_{h \in TW_{tf}} \Delta q_{h,t,f,p}^{dw} = \sum_{h \in TW_{tf}} l_{h,t,f,p} \quad (16)$$

Both upward and downward shifts are subject to a physical capacity constraint determining the minimum and maximum boundaries of the feasible rescheduling capacity. For instance, this constraint in flexible heat-pumps sets the maximum available upward shift equal to the difference between reference profile and heat-pump's maximum capacity. These limits can be asymmetrical to each other and can be hourly variables. This second element is illustrated in the two following equations:

$$\Delta q_{h,t,f,p}^{up} \leq \Delta q_{h,t,f,p}^{max} \quad (17)$$

⁹ There is a fifth archetype considered by the model: load recovery for passive or latent thermal storage [79,94]. However, as it plays no role in the results obtained in this scenario, it was excluded from this description.

$$\Delta q_{h,t,f,p}^{dw} \geq \Delta q_{h,t,f,p}^{min} \quad (18)$$

Finally, a saturation constraint ensures that the shifted volume does not violate a feasible operational limit, such as the storage capacity of an active storage unit or a latent heat requirement of a built environment system. These saturation limits can be either fix or represented by a combination of parameters and variables depending on the archetype involved, therefore the third type of constraints follow the below structure:

$$v_{h,t,f,p}^{min} \leq \sum_{h \in TW_{tf}} [B^{up} \Delta q_{h,t,f,p}^{up} + B^{dw} \Delta q_{h,t,f,p}^{dw}] \leq v_{h,t,f,p}^{max} \quad (19)$$

B^{up} and B^{dw} are two conceptual binary parameters used to illustrate that the saturation constraint can be imposed independently on both shift directions.

The interpretation of these three forms of constraints is presented below for all the 4 presented archetypes.

Demand Response

This form of flexibility assumes that the application of flexibility is capped by the installed capacity of the technology. This directly affects the capacity constraint interpretation stating that the maximum upward deviation available is given by the difference between the installed capacity and the use of the technology determined by the hourly profile in the following way:

$$\Delta q_{h,t,f,p}^{up} \leq (s_{t,f,p} F C_{tf} - u_{t,f,p} P_{h,t,f}) A E_{t,f,a} \quad (20)$$

and the maximum upward deviation is given by the ability of the technology to decrease its reference hourly consumption given by

$$\Delta q_{h,t,f,p}^{dw} \leq (1 - N N_{tf}) u_{t,f,p} P_{h,t,f} A E_{t,f,a} \quad (21)$$

The volume constraint ensures that the reallocated energy consumption within a time window does not exceed the original total consumption of the time window, nor upwards nor downwards as shown below.

$$\sum_{h \in TW_{tf}} \Delta q_{h,t,f,p} \leq \sum_{h \in TW_{tf}} u_{t,f,p} P_{h,t,f} A E_{t,f,a} \quad (22)$$

Storage

The interpretation of the capacity constraint for storage is given by the (dis)charging capacity. The maximum amount of flexibility that any storage technology can provide is determined by the following constraint:

$$\Delta q_{h,t,f,p} \leq s_{t,f,p} C C_{tf} \quad (23)$$

The interpretation of the volume constraint for storage is marked by the storage capacity as described by the theoretical charging time of a battery accordingly with the following constraint.

$$\sum_{i \leq h} \Delta q_{i,t,f,p} \leq s_{t,f,p} C C_{tf} C T_{tf} \quad (24)$$

Smart Charging and Vehicle-to-Grid

The main characteristic of these forms of flexibility is that they are dependent on the number of vehicles connected to the grid in a given moment. Thus, the upward capacity is capped by the difference between the charging capacity of connected EV's and the reference charging profile as given by:

$$\Delta q_{h,t,f,p}^{up} \leq C C_{tf} \left(s_{t,f,p} - \frac{u_{t,f,p} V U_{h,t,f}}{A S_{tf}} \right) - u_{t,f,p} P_{h,t,f} A E_{t,f,a} \quad (25)$$

While the downwards flexibility is constrained by the reference consumption and the non-negotiable load for smart charging:

$$\Delta q_{h,t,f,p}^{dw} \leq (1 - N N_{tf}) u_{t,f,p} P_{h,t,f} A E_{t,f,a} \quad (26)$$

And by the discharging capacity of connected vehicles for vehicle-to-grid flexibility:

$$\Delta q_{h,t,f,p}^{dw} \leq D C_{tf} \left(s_{t,f,p} - \frac{u_{t,f,p} V U_{h,t,f}}{A S_{tf}} \right) \quad (27)$$

The volume constraint for both Smart Charging and V-to-G is given similar to the storage, where the cumulative application of flexibility cannot exceed the difference between the available storage capacity of connected vehicles and the minimum required stored energy for the journeys of the vehicles departing in that hour given by:

$$\sum_{i \leq h} \Delta q_{i,t,f,p} \leq C C_{tf} C T_{tf} \left(s_{t,f,p} - \frac{u_{t,f,p} V U_{h,t,f}}{A S_{tf}} \right) - \sum_{h \leq t \leq h+A J} u_{t,f,p} P_{i,t,f} A E_{t,f,a} \quad (28)$$

Operation of gaseous networks

Integrated electricity and gas models usually focus on designing a proper nodal representation of the network based on pressure tolerances and Bernoulli equations, intending to provide detailed planning and operation optimization [86]. Because of the large scope of the problem and specific goals of the methodology, IEM often ignores any type of detailed description of the gas system. However, because we aim to address seasonality, buffer opportunities, and infrastructure costs, IESA-NS includes a simplified representation of gaseous networks operation based on a daily balance dispatch approach. This representation is presented below.

Gas networks, as transporters of a compressible fluid, are inherently provided with a buffer which allows for damping (i.e. the temporal discoordination between the input and output flows to the gas network) [87]. However, operation of the network must occur within safety pressure boundaries, meaning that the size of the buffer has limits (and regions), thus requiring intra-day balancing actions to keep networks functional.¹⁰ There is no specific balancing period in this scheme. The imbalances are corrected when the magnitude of the imbalance reaches a certain predefined level [88].

A daily balancing approach was selected for activities distributed by the network of gaseous pipelines. This approach was selected first due to the previously described damping characteristic, and second, due to a typical daily flat price profile resulting from models with the hourly balancing of gas dispatch [89]. Such modelling choice allows for dispatching national wells and imports, considering the daily operation of the buffers (e.g., gas storage chambers), and describing other generation processes with particular sectoral dynamics such as fermentation, (bio)gasification, and methanation.¹¹ However, this representation cannot provide network planning or operation of circulating compressors. Finally, the same approach is used for all the gases transported in pipelines, namely, natural gas, hydrogen, and sequestered carbon dioxide for CCUS.

Similar to the electric balancing description, the gas dispatch is described for each day accordingly with:

$$u_{d,t,d,p} A P_{t,d,a,p} = u_{t,p} P_{d,t,p} A P_{t,p,a,p} + (\Delta q_{d,t,g,p}^{up} + \Delta q_{d,t,g,p}^{dw}) A G_{t,g,a} \quad (29)$$

Also, the daily dispatch technologies, analogously to the power dispatch, are bounded by their daily availability profiles and installed capacities accordingly with:

$$u_{d,t,d,p} \leq s_{t,d,p} \Gamma_{td} P_{d,t,d} \quad (30)$$

Infrastructure description

The infrastructure imposes a limitation to the system in terms of the extent an activity can be carried out within a certain time-frame and

¹⁰ There are different types of balancing actions designed accordingly with the size of the imbalance. As reference of the magnitude, no balancing action is required for hourly imbalances of ~2% of the daily market volume. In average, 3 balancing actions per day were required between November 5th 2019 and December 4th 2019 (high demand season) [87].

¹¹ Methanation, as an electricity consumer, is already subject to hourly shedding constraints. Thus, the daily gas dispatch formulation further restricts its operation.

geographical area. This restriction provides an extra incentive for flexibility as it can avoid network reinforcement costs [86]. Furthermore, infrastructure descriptions help to provide a better representation of the expected transitional costs, as the energy system must adapt to enable the deployment of infrastructure intensive technologies, such as CCUS, hydrogen, and district heating.

The activities constrained by available infrastructure are described with daily and hourly timeframes. For the hourly ones, infrastructure limits the volumes of the activity in a time frame accordingly with:

$$(u_{t,p}P_{h,t} + \Delta u_{h,t,p})AP_{t,a,p} + (\Delta q_{h,t,f,p}^{up} + \Delta q_{h,t,f,p}^{dw} | t_f \neq t_{f,b,p})AE_{t,f,a} \leq s_{ti_h,p}\Gamma_{ti_h} \\ \forall a | a \in A^e \ \& \ \forall t | AP_{t,a,p} > 0 \quad (31)$$

Very similarly, the model considers the following constraint for the daily described infrastructure technologies, $t_{i,d}$:

$$(u_{tp,p}P_{d,tp} + \Delta u_{h,t,c,p} + \Delta u_{h,t,s,p})AP_{tp,a,p} + (\Delta q_{d,t,f,p}^{up})AG_{t,f,a} \leq s_{ti_d,p}\Gamma_{ti_d} \\ \forall a | a \in A^g \ \& \ \forall t | AP_{t,a,p} > 0 \quad (32)$$

Other elements of the energy infrastructure, such as transformers and buffers, are considered as operational technologies. Thus, both their investment and operational costs are determined as for any other operational technology within the model. Therefore, the formulation presented in this section only refers to infrastructure which exerts no action other than enabling the flow of an activity to a certain volume.

APPENDIX C: Scenario definition

Reference scenario

In the reference scenario all the NSR countries must meet their GHG emission targets (i.e. targets summarized in Table 1). Most of the data for the energy drivers and some cost assumptions are derived from the JRC POTEnCIA Central scenario for all the NSR countries. The POTEnCIA Central scenario assumes a business as usual economic development, with the European GDP growing accordingly to the '2018 Ageing report' (i.e. around 1.38% growth per year until 2050), a growth of population and households based on EUROSTAT data, and projections of industry based on the sectoral Gross Value Added (GVA) values. Therefore, the impact of different demographic projections in the future energy demand is not considered in the set of scenarios of this paper, as it does not fall within the scope of the paper. Future research should address this topic, as the impact in the modelling outcomes can be relevant. All the input data used for the reference scenario (i.e. drivers for energy demand, techno-economic parameters and commodity costs disaggregated per country) can be consulted in [48] together with the whole database of the model.

Fig. 26 shows some relevant input data of the reference scenario aggregated for the whole NSR. All the industry production volumes (Fig. 26 top left) are increased during the period 2020–2050, except the ammonia production, which is assumed to remain constant. The production of non-metallic minerals increases by around 40%, the production of iron and steel increases by 10%, while the production of basic chemicals, paper related industry, non-ferrous metals and other industrial products is increased around 25%. Regarding electricity demand¹² (Fig. 26 top right) there is a steady growth in the residential and services sector (around 6% growth) and in the agriculture sector (roughly 21%). Regarding heat demand (Fig. 26 bottom left), the POTEnCIA central scenario assumes a 25% increase of the demand in the agriculture sector. In order to estimate the space heating demands for residential and services sector, a methodology is developed. The scenario assumes a steady growth of housing stock in the NSR, and a high increase of efficiency and better insulations from 2030, resulting in a slow increase of

the heating demand from 2020 to 2035, and a decline from 2035 until 2050, where both heat demands are reduced around 3% compared to 2020 levels. The transport sector also increases its volume (Fig. 26 bottom right), with motorcycles and light-duty vehicles increasing around 70% their kilometres served, while trains, buses heavy-duty vehicles and passenger cars increase their volume between 10 and 30% in 2050.

The input data related to fuel and commodity costs are based on multiple sources, mainly the POTEnCIA central scenario, the ENSPRESO database and different TNO factsheets. Table 14 shows values of a selection of key parameters and their evolution during the transition 2020–2050. Note that some of the values are common to the whole NSR (e.g. coal or crude oil), while others are country dependent (e.g. biomass, in which each country has different biomass sources and therefore different costs). Additionally, extra costs of import/export of fuels are not considered in these figures (e.g. tariffs or infrastructure costs when importing natural gas from abroad).

The IESA-NS includes around 250 technologies per country, in order to provide multiple alternatives to supply the activity demands per sector. Each technology requires, among others, techno economic data (i.e. CAPEXfixed and variable O&M costs and lifetimes), operation and flexibility profiles, and energy balances (i.e. energy inputs and outputs of each technology).

Regarding wind and solar PV energy, all the relevant technological data is extracted from the JRC technical report 'Cost development of low carbon energy technologies'. The scenario used is the 'ProRES', in which the world moves towards decarbonisation reducing fossil fuel use, renewables account for 93% of electricity demand, and as a consequence the learning process in renewable technologies is moderate. Regarding offshore interconnectors, it is assumed that HVDC becomes competitive beyond 100 km from shore, which is in line with most studies in the literature [90]. Therefore, offshore wind potential in areas beyond 100 km is allocated to the offshore nodes of the system (i.e. Fig. 3), which are connected to shore via HVDC. The cost for the HVDC lines is calculated following the methodology of [91]. Offshore wind potential in areas up to 100 km are directly connected to shore via cheaper HVAC interconnectors.

Most of the remaining data is compiled from the ENSYSI model, and certain specific technologies are based on data from POTEnCIA, JRC and TNO factsheets. The input data of all the technologies included in the reference scenario can be consulted in [48].

The wind, solar and biomass potentials of the reference scenario are taken from the ENSPRESO reference scenario. Regarding onshore wind, the ENSPRESO scenario assumes that current legal requirements for exclusion zones and setback distances are respected. This results in a potential of 4710 GW from the EU, and 634 GW for the NSR, excluding Norway.¹³ Regarding offshore wind, ENSPRESO assumes that current legal requirements for exclusion zones are maintained, offshore can only be installed in zones with a depth of 50 m or lower, and the shipping density is assumed to be lower than 1000 ships per year. This results in 324.2 GW for the whole EU, and 239.4 GW for the NSR, excluding Norway. For solar PV, the ENSPRESO scenario selected assumes a density of 170 MW/km², with a 3% of the non-artificial areas available for PV deployment. This results in a potential of 10,127 GWe for the whole EU, and of 2213 GWe for the NSR, excluding Norway. Biomass potentials are also derived from the ENSPRESO medium scenario, which includes more than 30 different types of biomass feedstocks.

Regarding CO₂ storage, in the NSR there are multiple studies at national and multinational level assessing the total storage potential. For this reference scenario, we use the numbers from the EU GeoCapacity project, in which 66 GtCO₂ storage availability are estimated using deep saline aquifers, hydrocarbon fields and coal fields in the NSR [92]. Other

¹² Note that here electricity demand includes only appliances and electric devices of the residential, services and agriculture sector, i.e. end-uses that can only be satisfied by electricity. Electricity used for other end uses, e.g. space heating or industrial processes is not quantified here.

¹³ The JRC POTEnCIA database excludes Norway. Therefore, in all the cases where NORWAY data is not available, we use the data from the well-known TIMES-NORWAY model [95].

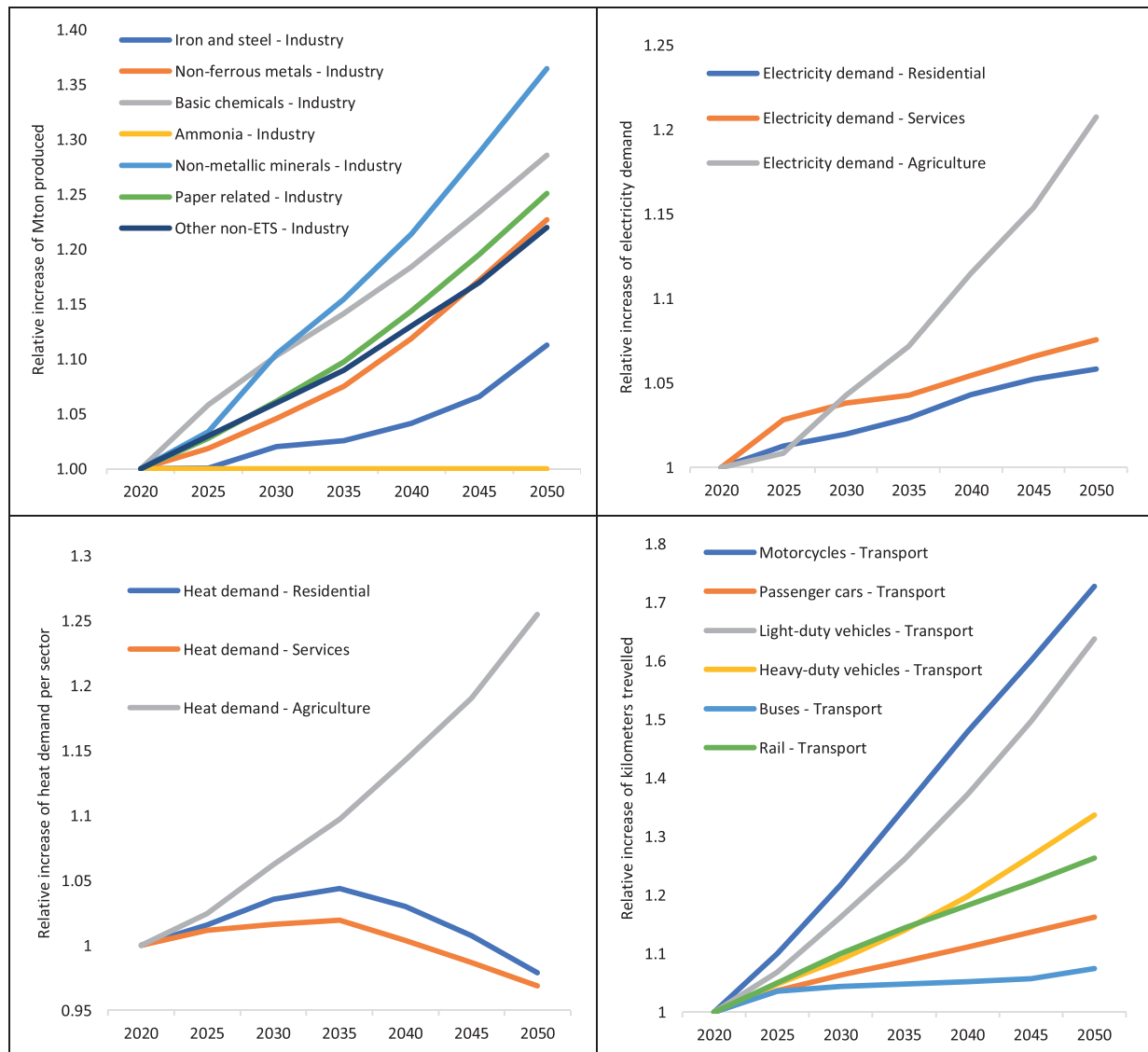


Fig. 26. evolution of different input data compared to 2020 levels: industry production volumes (top left), electricity demand per sector (top right), heat demand per sector (bottom left), kilometres per type of transport (bottom right).

Table 14

Price projections of different commodities considered in IESA-NS.

Commodity	Units	Values				Source
		2020	2030	2040	2050	
Coal	[€/2019/GJ]	3.0	3.7	4.1	4.4	[47][24]
Crude oil	[€/2019/GJ]	11.6	17.0	18.8	19.6	[47][24]
Natural gas	[€/2019/GJ]	6	8.74	9.64	10	[47][24]
Liquefied natural gas (LNG)	[€/2019/GJ]	7	8	8.5	9	[47][24]
Uranium	[€/2019/GJ]	0.8	0.8	0.8	0.8	[47][24]
Waste	[€/2019/GJ]	6.9	7.0	7.0	7.0	[47][24]
National biomass	[€/2019/GJ]	6.9	6.6	6.2	5.7	[52]

Average value of all the NSR countries. The disaggregated values per country can be found in the model database [48].

studies in the literature present more ambitious and optimistic potentials (e.g. [93] where 264 GtCO₂ are estimated for the NSR). However, the conservative value is included in the reference scenario because: 1) there is not a clear common roadmap around CCUS in the NSR. 2) there are different political attitudes in the NSR countries (e.g. Sweden, Norway, UK and Netherlands have a negative view around onshore storage [93]). The yearly availability of CO₂ storage is assumed to be 1% (i.e.

100 years of availability at maximum yearly injection rate) of the total storage capacity, in order to prevent that in 2050 the systems are heavily dependent on CCUS and the storage availability is scarce.

Although the idea of the reference scenario is remain as unconstrained as possible, there are two exogenous constraints related that are imposed to the power generation sector. First, coal power generation is banned in all the NSR countries from 2030. Most NSR countries

have policies and regulations in order to phase out coal generators from 2025 to 2030, and seems likely that these efforts will continue in the near future. Regarding nuclear generation, Germany and Belgium are not allowed to invest in additional capacity or to extend the lifetime of their operating plants, due to the fact that both countries have a clear political agenda in order to phase out nuclear power generators during the 2020 decade.

As mentioned in the methodological section, the IESA-NS model dispatches the power sector of the whole Europe with a hourly resolution, but the model does not optimize the capacity expansion or the capacity mix. For this scenario, the EU projections of European capacities from 2020 to 2050 are derived from the Ten Year Network Development Plan (TYNDP) from ENTSOE.

Biomass availability scenarios

The biomass potential for the NSR is modified in two scenarios:

- Ø In **HBIO** the total biomass potential is derived from the 'ENSPRESO high scenario for biomass'. This scenario assumes around 22.6 EJ of biomass potential for Europe in 2050 (compared to 13 EJ in the reference scenario), and a potential of 6.25 EJ in the NSR (3.6 EJ in the reference scenario). Biomass imports are limited to a 33% of the total national biomass production of each country, therefore limiting dependence on external sources.
- Ø In **LBIO** the total biomass potential is derived from the 'ENSPRESO low scenario for biomass'. This scenario assumes around 8.67 EJ of biomass potential for Europe in 2050 (compared to 13 EJ in the reference scenario), and a potential of 2.25 EJ in the NSR (3.6 EJ in the reference scenario). Imports of biomass are not allowed in this scenario.

High solar and wind availability scenario

Two scenarios are drawn with different potential ranges for wind and solar PV:

- Ø In **HVRES**, the most optimistic ENSPRESO scenarios for solar PV and wind are considered. Regarding onshore wind, the 'ENSPRESO wide low restrictions' is used, in which the exclusion of surfaces for wind converges in all countries to a low level, and the setback distance is set to 400 m. This results in a potential of 1253 GW for the NSR, compared to the 634 GW of the reference scenario (both numbers excluding Norway). Regarding offshore wind, the same 'wide low restriction scenario' is used, in which floating wind is allowed, low buffer zones are assumed and there is a shipping density of less than 5000 ships per year. In this case, the potential for fixed bottom offshore wind is 556 GW, compared to the 239 GW of the reference scenario, while there is a floating wind potential of 1707 GW, mainly in deep waters of United Kingdom and, again, potentials of Norway are not included. Regarding solar PV, a density of 300 MW/km² is assumed, together with a 3% of available non artificial areas. This results in a potential of 3905 GW, compared to the 2213 of the reference scenario, again without considering Norway.
- Ø In **LVRES**, the most pessimistic ENSPRESO scenarios for solar PV and wind are considered. For onshore wind and solar PV the same assumptions than in the **LONSH** scenario are considered (i.e. 394 GW for onshore wind and 1106 GWe for solar PV). Regarding offshore wind, the 'ENSPRESO EU-Wide high restrictions' is adopted, in which exclusion of surfaces for offshore wind converges in all countries to a high level, offshore wind can only be installed in areas with a depth lower than 50 m, and the shipping density is assumed to be lower than 500 ships per year. Therefore, the offshore wind potential is assumed to be 55.9 GW, compared to the 239 GW of the reference scenario.

Low onshore solar and solar availability scenario

The **LONSH** limits the availability of onshore wind and solar power:

- Ø Onshore wind is constrained by using the 'ENSPRESO EU-Wide high restrictions', in which the exclusion of surfaces for wind converges

in all countries to a high level, and the setback distance is set to 1200 m. In this scenario, the potential of onshore wind in the NSR is 394 GW, compared to the 634 GW of the reference scenario, with Norway excluded.

- Ø Solar PV potential is constrained by using the 'ENSPRESO solar PV' scenario and assuming a density of 85 MW/km² and an availability of 3% of the available non-artificial areas. In this scenario, the solar PV potential of the NSR is 1106 GWe, compared to the 2213 GWe of the reference scenario, with Norway excluded.
- Ø Due to the reduction of offshore deployments, we assume higher investments in offshore wind, and therefore a faster learning rate and cost reduction. Therefore, the cost estimate for offshore wind in 2050 is assumed to be around 20% cheaper than the reference scenario.

Low CCUS and no CO₂ storage scenario

The **NOCCS** scenario adds two extra constraints to the reference scenario:

- Ø CO₂ storage is not allowed in any of the NSR countries.
- Ø CO₂ can be captured only if it is used in another activity of the energy system. Therefore, the CCUS network can operate, and the network buffers permit a certain flexibility (i.e. CO₂ does not need to be captured and used instantaneously), always respecting that the net balance of CO₂ captured and used is zero.
- Ø In order to alleviate the system, the VRE availability is increased to the values of the **HVRES** scenario, and the biomass availability is increased to the values of the **HBIO** scenario.

APPENDIX D: Additional scenario results

CO₂ storage

As seen in previous figures, the availability of CCUS highly affects how is the optimal configuration of the system. The question that arises is which processes are using the available CO₂ storage, and how different is the CO₂ storage use across different scenarios.

Fig. 27 shows the available CO₂ storage in each scenario, and which are the processes that are using this CCS capacity. It looks clear that, across all scenarios using CCS, the industry sector is the highest contributor to the CCUS network. There are two main reasons to explain this trend: first, as mentioned in the previous section, biomass is heavily used in the industry sector to provide heat. Therefore, if the system wants to reach to negative emissions, it needs to add CCS to the biomass boilers and CHP plants used to provide heat to the industrial sector. Second, there are some industrial processes, like ammonia or steel production, that are very difficult to decarbonise. Therefore, a cheap solution from a system perspective is to maintain the existing technologies and include CCS in them.

One interesting conclusion of the scenarios (with the exception of **NOCCS**) is that CO₂ storage is, as biomass, a resource that the model uses at almost full capacity, especially in Germany, the Netherlands, Belgium and United Kingdom, where the total energy demand is relatively high and the space available is relatively low (and therefore the VRE potentials are limited). Therefore, exploring alternative scenarios with higher CO₂ storage might be relevant to analyse to what extent the system can be benefited if such storage is available.

Emissions

Due to the fact that the IESA-NS model includes a very detailed description of all the GHG emissions of the energy system (divided in ETS emissions and non-ETS emissions), different mitigation pathways towards the climate targets can be analysed for different scenarios. This is precisely what Fig. 28 shows: the CO₂ equivalent emissions of the ETS and non-ETS sectors, and the CO₂ shadow prices¹⁴ across all the scenarios of the section.

¹⁴ The CO₂ shadow price reported in Figure 28 corresponds to the arithmetic mean of the shadow prices of all the NSR countries in each scenario.

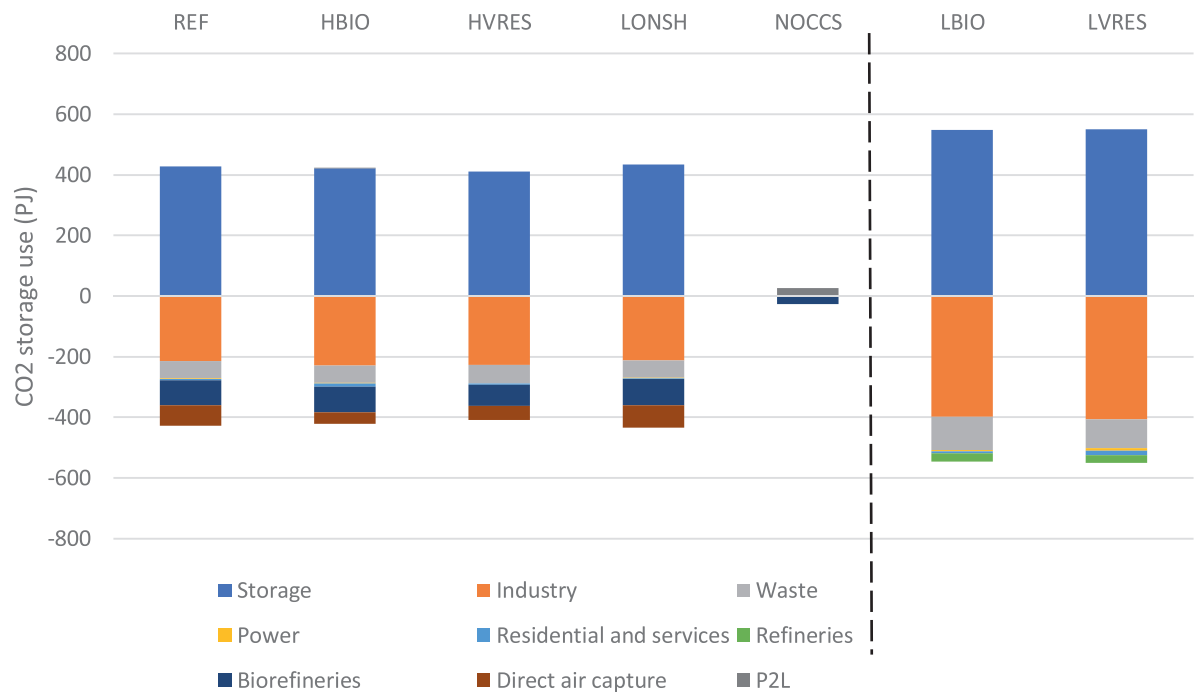


Fig. 27. use and availability of CO2 storage in all the scenarios for the whole NSR in 2050.

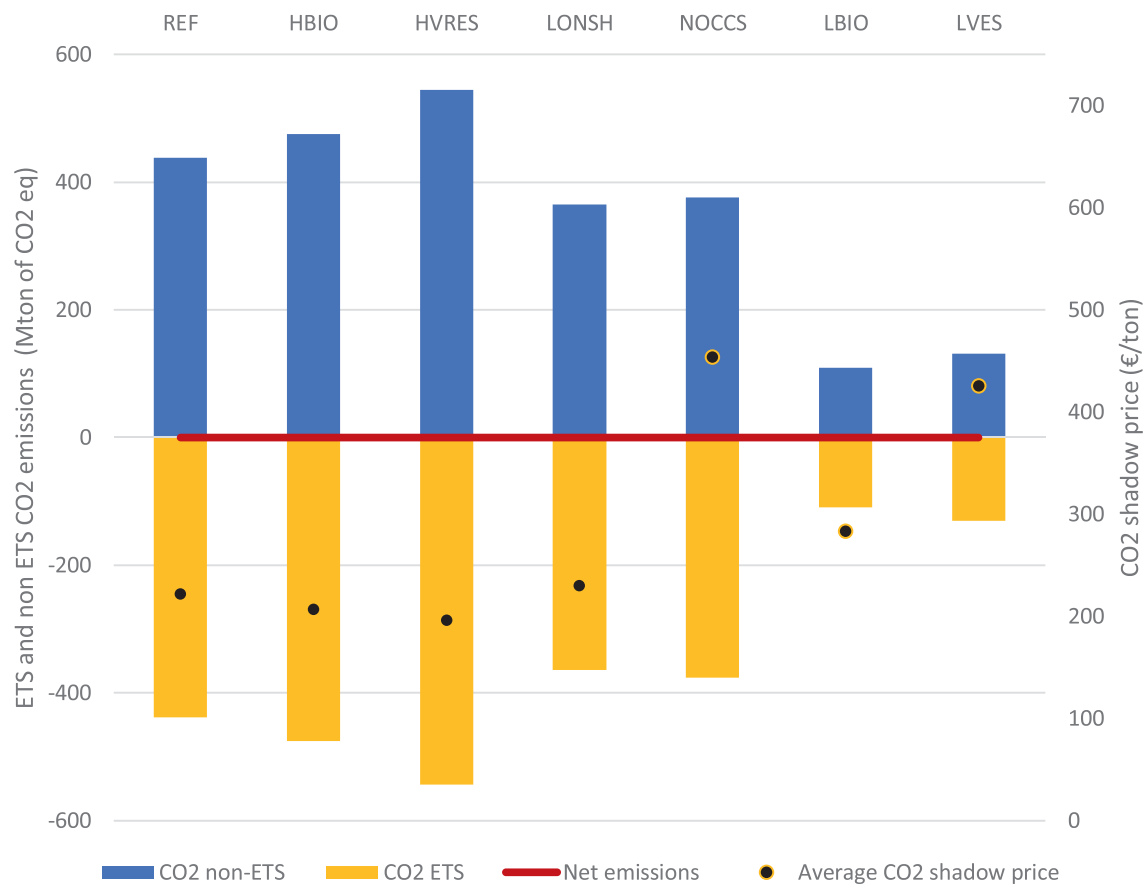


Fig. 28. ETS and non-ETS emissions across all the scenarios for the whole NSR.

Table 15
CO₂ shadow price per country in all the scenarios analysed.

CO ₂ shadow price (€/ton)	REF	HBIO	HVRES	LONSH	NOCCS	LBIO	LVRES
The Netherlands	469	467	423	471	463	441	414
Germany	303	293	224	319	635	512	1417
United Kingdom	194	194	178	194	593	200	197
Denmark	156	120	155	167	548	196	306
Sweden	90	81	89	90	368	103	100
Norway	144	97	114	144	289	194	153
Belgium	194	193	188	222	278	336	390

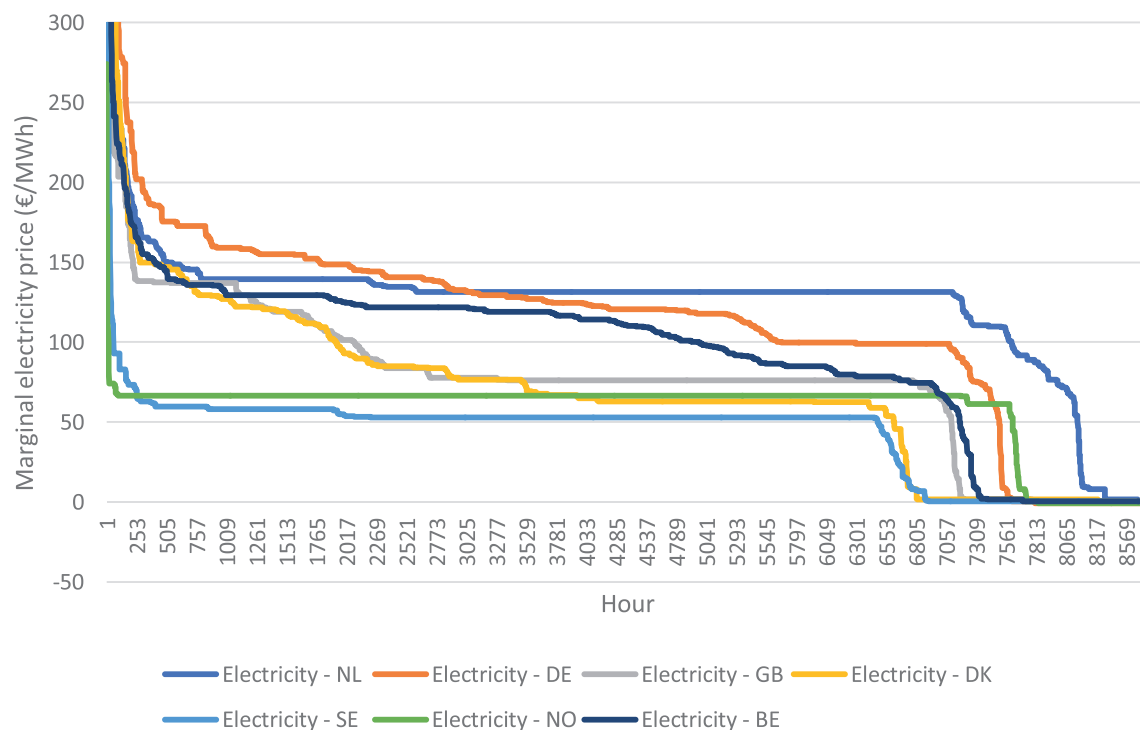


Fig. 29. Marginal electricity prices of the NSR countries in the REF scenario.

As it can be seen, for all scenarios the net emissions are net-zero, following the up to date European targets and policies as explained in the Introduction of this paper. In all scenarios the ETS sectors reach negative emissions in order to compensate the non-ETS emissions. This trend is motivated by the fact of CO₂ abatement in ETS sectors is usually cheaper, the ETS sector has more alternatives to reach to negative emissions via the use of biomass or PtL, and the non-ETS sector includes some activities that are very difficult or even impossible to mitigate (e.g. international aviation or some other non-energy related emissions such as CH₄ emissions from enteric fermentation).

It can be seen that biomass availability is a key enabler to reach to high negative emissions. The **HBIO** scenario reaches to over 450 Mton of negative emissions in the whole NSR, while the **LBIO** can only reach to around 100 Mton. Same trend can be observed with the availability of VRES, which opens the door to the use of PtL, and therefore gives room to negative emissions. That is why the ETS sectors of **HVRES** and **NOCCS** reach between -400 and -600 Mton of CO₂ equivalent, while the **LVRES** and **LONSH** remain between -170 Mton and -380 Mton.

The CO₂ shadow price is a very good indicator to compare how difficult (expensive) is to meet the climate targets in different scenarios. The ban of CO₂ storage, lower availabilities of biomass, and lower availabilities of wind and solar resources increase the abatement costs consid-

erably, being **LVRES** and **NOCCS** the extreme cases with an average shadow price of 450 €/ton of CO₂.

Another interesting analysis is to compare the CO₂ shadow prices of each country across all the scenarios, to understand in which countries the abatement is more challenging. This information is shown in Table 15. Similar to what happened in the previous section, there is a clear gap between Scandinavian countries and the rest, mainly Germany, the Netherlands and Belgium. While Scandinavian shadow prices are relatively low and stable across all scenarios, Germany faces large CO₂ shadow prices when the biomass potential is not high, when CCS is not allowed and when VRE availability is low. Similar trends, although less pronounced, can be seen in the Netherlands and Belgium. These numbers, together with the insights from the power sector, point out that Germany should carefully assess their national and imported biomass potentials, and work in policies to incentivise and promote the deployments of onshore and offshore VRES in order to achieve their targets in a more cost-effective way.

Marginal electricity prices

Analysing the marginal electricity prices is a good exercise to understand the system behaviour in 2050. Fig. 29 shows the marginal electricity prices of all NSR countries in the **REF** scenario. It is interesting to see that the Netherlands, Germany and Belgium have quite similar price

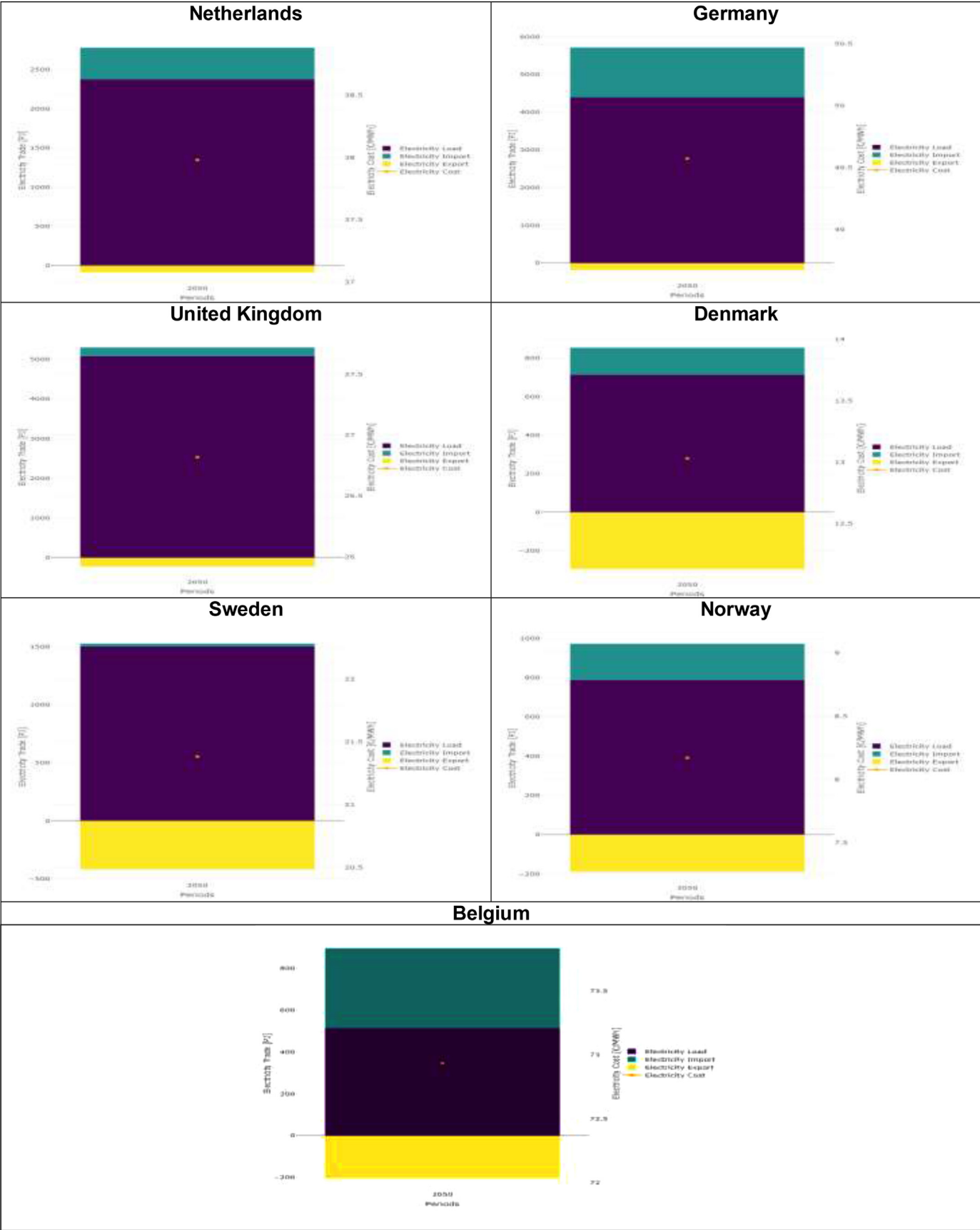


Fig. 30. Imports, exports, net load and average energy cost of the NSR countries in the REF scenario.

curves. The main reason of this similarity is that these three energy systems are heavily interconnected. The United Kingdom, Denmark, Norway and Sweden present, on average, lower marginal electricity prices, due to the larger penetration in their energy systems of low bidding power generators, such as onshore and offshore wind, solar PV or hydro.

Electricity load, imports and exports

Another interesting result that the IESA-NS model provides is the balance between power imports, exports and net load. These results are shown in Fig. 30 for the REF scenario. It is interesting to see that, in this scenario, the Netherlands, Germany and Belgium are net importers of electricity, Denmark and Sweden are net exporters, while the United Kingdom and Norway have similar imports and exports.

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