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EWI Working Paper, No 02/24

May 2024

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ISSN: 1862-3808

Europe, the Green Island? Developing an integrated energy system model to assess an energy-independent, CO_2-neutral Europe

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Abstract

The paper at hand offers a quantitative assessment of the transformation of the European energy system in achieving the goal of the European Commission of carbon neutrality in Europe by 2050. In doing so, the investment and dispatch optimization model DIMENSION is extended to comprise a greater number of sectors and technologies as well as endogeneous links between energy supply and demand for 28 countries in Europe up to 2050. The model is applied to examine the cost-minimal decarbonization pathway for two scenarios with varying spatial boundaries of the optimization, namely the Green Island Europe and Green Importer Europe scenarios: Whereas the consumption of green hydrogen and/or synthetic fuels in the Green Island Europe scenario requires an investment in the necessary power-to-x production and electricity generating capacities within Europe, the Green Importer Europe scenario allows for such zero-carbon and carbon-neutral fuels to be available for purchase from outside of Europe. Results of the cost minimization in both scenarios show that the model chooses to most rapidly decarbonize the electricity sector, with capacities of wind and solar electricity generation in Europe tripling between 2019 and 2030. Simultaneously, a 500 TWh_{el} increase in electricity demand is observed as 77% of heat generation in Europe is supplied by electricity-consuming heating technologies in 2030. By 2050, flexibility options such as electricity storage, demand-side management and electric vehicles expand their market presence, while the more hard-to-abate sectors such as transport and industry experience a rapid shift from fossil fuels to biofuels as well as to green hydrogen. As a result, the cross-sectional European CO_2 shadow price rises to 225 €/tCO_2 in 2040 and to 559 €/tCO_2 in 2050. In the Green Island Europe scenario, carbon neutrality in an energy-independent Europe leads to an overall increase in electricity consumption in Europe of over 4000 TWh_{el} between 2019 and 2050. Yet the long-term results of the two scenarios diverge as the emergence of a demand for green hydrogen leads to a diversification of Europe's hydrogen supply, with approximately 300 TWh_{th} of green hydrogen (19% of total consumption) imported from outside of Europe in 2050. In turn, the 250 TWh_{th} decrease in domestic green hydrogen production leads to a ramping down of electrolysis systems in the Green Importer Europe scenario, creating an opportunity for other flexibility options. Finally, the difference in average consumer and producer surplus as well average total welfare between the scenarios is examined for players in the European electricity and green hydrogen markets.

Keywords: Energy system modeling, Flexibility options, Electricity sector, Power-to-x, Green hydrogen, Synthetic fuels, Green fuels, Sector coupling, Decarbonization, Carbon neutrality, Energy independence, Security of supply, Welfare analysis

JEL classification: C61, C68, D61, N70, Q41, Q42, Q48

⋆Funding by the center of excellence "Virtual Institute—Power to Gas and Heat" (EFRE-0400155) by the "Operational Program for the promotion of investments in growth and employment for North Rhine-Westphalia from the European fund for regional development" (OP EFRE NRW) through the Ministry of Economic Affairs, Innovation, Digitalization and Energy of the State of North Rhine-Westphalia is gratefully acknowledged. The author would like to thank Marc Oliver Bettzüge for his valuable input and constructive comments. Furthermore, this work benefited greatly from feedback from and discussions with former colleagues at the Institute of Energy Economics (EWI), especially Polina Emelianova, Eglantine Künle, Pranisaa Charnparttaravanit, Lukas Schmidt, David Schlund, Max Schönfisch and Simon Schulte. Moreover, parts of the methodology built upon previous research using the DIMENSION model from, for example, Stefan Lorenczik, Alexander Polisadov, Jakob Peter and Joachim Bertsch. The author is also grateful for the input received from the members of the "Virtual Institute - Power to Gas and Heat" project team as well as participants from the Joint EWI-FCN Seminar in April 2021.

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1. Introduction

1.1. Background and research objective

The goal of the European Commission to achieve net-zero greenhouse gas emissions by the year 2050 will require a significant change in the European energy system. Faced with a politically-binding target, energy transformation and end-use sectors must consider the adoption of zero-carbon and carbon-neutral fuels and technologies, which often come at higher costs than the more mature fossil options. In this case, the discussion tends to focus on two main pathways: (i) the electrification of the end-use sectors to increase the direct consumption of renewable electricity (e.g., via electric vehicles and heat pumps) or (ii) the replacement of fossil fuels with zero-carbon or carbon-neutral alternatives, often separated into those produced via the indirect use of renewable electricity (i.e., via power-to-x) or those made from bio-products (e.g., biofuels, biogas). Although the political dialogue tends to fixate on finding the single solution (e.g., hydrogen), the ideal case from an economic standpoint would be to create a level playing field for all decarbonization options to compete and, in doing so, reach the goals of net-zero emissions at the lowest system costs. Yet in practice, such a market situation would only be possible with transparent economic signals, e.g., a clear cross-sectional carbon price, which would in turn create a merit order of decarbonization options according to, e.g., the marginal abatement costs of the technologies in the energy transformation and end-use sectors.

At the same time, however, the transformation to carbon neutrality could have significant side effects for the electricity market. More specifically, decarbonizing the energy system with electricity, regardless if used directly or indirectly, will require a rapid increase in the share of intermittent renewable electricity generation. In turn, the uncertainty in short-term forecasting may lead to a more frequent occurrence of low or even negative electricity prices on spot and intraday markets as sudden, unforeseen changes in supply create moments of surplus electricity. This market situation facilitates an opportunity for flexible electricity consumers that are able to quickly react to such price signals, bringing stability to both the market and grid while benefiting financially via arbitrage. In this case, assuming transparent and real-time price signals, a market would emerge in which flexibility options including heat pumps and other power-to-heat technologies as well as electric vehicles, battery storage, demand-side management (DSM) and electrolysis (i.e., power-to-x) systems all compete for the electricity during times of surges in intermittent renewable generation. Moreover, a handful of these technologies may also provide positive flexibility in times of, e.g., high demand and low renewable availability to increase profitability. In other words, a merit order would emerge based on the marginal value of a technology's flexibility at a given point in time.

As such, the simultaneous need for decarbonization and flexibility creates a complex economic environment that may lead to various combinations of winners and losers in the future energy market. In other words, the merit order of decarbonization options becomes dependent on the value and potential of a technology's flexibility, and the merit order of flexibility options must account for the carbon abatement potential of the technology. Furthermore, just as decarbonization is critical to reach carbon neutrality, flexibility may become increasingly important to ensure security of supply as the energy system becomes more and more disrupted. To better understand how a flexible, carbon-neutral, reliable energy system could look like in the future, the paper at hand seeks to answer the following research questions: (i) What is the least-cost pathway for the European energy system to reach carbon neutrality, and what role will electricity and electricity-based fuels (i.e., green hydrogen and synthetic fuels) play in reducing emissions? (ii) Which technologies will emerge to offer flexibility in the short-/long-term, and how will these compete to balance supply and demand fluctuations at least cost? and (iii) how would the results be affected by changes in the market boundaries and, thus, the level of competition within and across decarbonization and flexibility options, and what could this mean for the welfare of players in the electricity and green hydrogen markets?

To address the research questions, the investment and dispatch optimization model DIMENSION developed in Helgeson and Peter (2020) is extended to comprise the complete European energy system, which is done by increasing the number of sectors and technologies as well as further developing the endogenous links between energy supply and demand. More specifically, the electricity market, power-to-x (ptx) and road transport modules are complemented by a heat module, which includes forty different heating technologies for district heat, individual heating, cooling and cooking. Certain heating technologies are endogenously linked to the electricity market module as electricity suppliers (e.g., combined heat and power (CHP) plants) or electricity consumers (e.g., heat pumps), whereas others may implicitly demand zero-carbon and carbon-neutral fuels from the ptx module. Furthermore, the three modules from Helgeson and Peter (2020) are improved to account for more decarbonization and flexibility options. For example, four industrial processes and six household types are added to electricity market module in order to offer DSM as a flexibility option, and bidirectional, endogenous charging of electric vehicles is included in the road transport module to take into account both the negative and positive flexibility potential of electric vehicles. Furthermore, to expand the model's reach beyond the modules, fuel consumption pathways are defined for the industry and agriculture sectors as well as for the transport sector excluding road transport. The energy provision for the end-use sectors is fed endogenously into the modules and, in turn, affect their investment and dispatch decisions. All in all, the extensions allow the model to be equipped to evaluate a wider range of flexibility and decarbonization options while also considering a larger share of the costs and CO_2 emissions associated with both the supply and consumption of energy in Europe up to 2050.

The model is then applied to examine the developments in the European energy system in achieving carbon neutrality by 2050 in two scenarios that vary in the spatial boundaries of the optimization: The first, a so-called "Green Island Europe" scenario assumes a world in which Europe must reach carbon neutrality on its own. In other words, any zero-carbon or carbon-neutral fuels that are to be consumed in Europe must be produced within Europe. The Green Island Europe scenario should mimic a political and regulatory environment where Europe emerges early on as a pioneer in global decarbonization and considers long-term energy independence to be necessary to reach its targets. The second, a so-called "Green Importer Europe" scenario, relaxes this assumption to allow for European energy transformation and end-use sectors to purchase green hydrogen and synthetic fuels imported from outside of Europe. In this reality, countries worldwide seek to reduce carbon emissions, driving a global market for zero-carbon and carbon-neutral fuels.

The two scenarios are designed to create two different market environments with varying levels of cross-sectoral competition in the investment in decarbonization and flexibility options: Due to the design of model, the consumption of green hydrogen and/or synthetic fuels in the Green Island Europe scenario requires an investment in the necessary ptx and electricity generating capacities, whereas the Green Importer Europe scenario allows for such zero-carbon and carbon-neutral fuels to be available for purchase at an exogeneously-defined price without any additional investments in the European energy transformation sector. As such, the Green Island Europe scenario can be interpreted as a hypothetical 'extreme' case in which the model's solution space is restricted such that the pressure to decarbonize and ensure flexibility is at its highest. Therefore, depending on the least-cost pathway chosen by the model in the Green Island Europe scenario, the ability to outsource the production of zero-carbon and carbon-neutral fuels could have significant consequences for the need for flexibility in the electricity market as well as the choice of decarbonization technologies in the end-use sectors. Furthermore, the restriction of the supply of zero-carbon and carbon-neutral fuels to within European borders in the Green Island Europe scenario allows the model to be simplified in such a way that key economic challenges such as, e.g., investments in international transport infrastructure can be disregarded. In reality, such aspects may play a decisive role in the economic feasibility of different import options; yet the Green Island Europe scenarios offers a robust starting point to understand an autarkic solution for Europe.

The results of the cost minimization in the Green Island Europe scenario show that the model chooses to most rapidly decarbonize the electricity sector: In fact, between 2019 and 2030, capacities of wind and solar electricity generation in Europe are tripled. Simultaneously, a surge in system flexibility allows for the dispatchable fossil electric capacity to be reduced by nearly 50% despite a 500 TWh_{el} increase in electricity demand. Heat pumps and electric vehicles are found to be the largest consumers of this intermittent renewable generation to reduce carbon emissions and offer system flexibility in the short to medium term. In fact, the heat module developed in this study finds 77% of heat generation in Europe is supplied by electricity-consuming heating technologies in 2030 compared to 19% in 2019. The 41% decrease in total emissions between 2019 and 2030 results in a relatively modest change in the cross-sectional European CO_2 shadow price from 22 €/tCO_2 in 2019 to 36 €/tCO_2 in 2030. Between 2030 and 2050, electricity consumption doubles in order to reach carbon neutrality by 2050, at which point the share of intermittent renewable electricity generation reaches 70% alongside generation from hydro plants, nuclear, geothermal and hydrogen power plants. Flexibility options such as electricity storage, DSM and electric vehicles expand their market presence, while the more hard-to-abate sectors such as transport and industry experience a rapid shift from fossil fuels to biofuels as well as to green hydrogen. As such, over 500 GW_{el} of electrolyzer capacity is installed between 2030 and 2050, consuming 2167 TWh_{el} of electricity to produce 1528 TWh_{th} of green hydrogen in 2050. As a result, the cross-sectional European CO_2 shadow price rises to 225 €/tCO_2 in 2040 and to 559 €/tCO_2 in 2050. All in all, carbon neutrality in an energy-independent Europe leads to an overall increase in electricity consumption in Europe of over 4000 TWh_{el} between 2019 and 2050.

A comparison of the results of the Green Island Europe scenario to the second scenario, the Green Importer Europe scenario, reveals a consistent decarbonization strategy in the short to medium term. In other words, between 2019 and 2030, the rapid increase in intermittent renewable electricity generation complemented by the electrification of heat generation and road transport is the cost-minimizing solution in both scenarios. Even between 2030 and 2040, the availability of zero-carbon and carbon-neutral fuels from outside of Europe does not lead to a significant shift in the investment decisions compared to the Green Island Europe scenario. By 2050, however, the emergence of a demand for green hydrogen creates an opportunity for competition between European and non-European green hydrogen supply; yet the green import possibilities from outside of Europe are not attractive enough to drive a change in the investment decisions in the end-use sectors seen in the Green Island Europe scenario. Put differently, the model chooses to only diversify the source of the green hydrogen supply rather than altering the technology of the final consumer (i.e., a static rather than dynamic result). In doing so, approximately 300 TWh_{th} of green hydrogen (i.e., 19% of total consumption) is imported from outside of Europe in 2050, which in turn results in 16% decrease in domestic production and a 28% reduction in export volumes between European countries.

The ramping down of stand-alone electrolysis systems in the Green Importer Europe scenario creates an opportunity for other flexibility options to benefit from lower electricity prices, namely high-temperature electrolysis integrated with a Fischer-Tropsch system as well as battery storage and electric heat generators. As a result, the electricity consumption is found to be only 154 TWh_{el} and the installed electric capacity 26 GW_{el} less in the Green Importer Europe scenario than in the Green Island Europe scenario in 2050. In particular, the reduced need for electricity input for electrolysis systems allows the model to avoid investing in intermittent renewable electricity generation technologies in sub-par locations. Nevertheless, the cross-sectional European CO_2 shadow prices in all years remain more or less unchanged across scenarios, with the long-term, price-setting marginal abatement in both scenarios occurring via the consumption of biofuels.

Finally, in a detailed analysis analogous to Schlund and Schönfisch (2021), the difference in average consumer and producer surplus as well average total welfare between the scenarios is examined for the European electricity and green hydrogen markets. In doing so, the economic consequences of long-term energy independence are quantified for selected players across Europe for 2050. The results show that the introduction of the economic pressure to produce green hydrogen in Europe at an endogenous price below the exogenous price of importing green hydrogen from outside of Europe has positive effects for consumers: Averaged across all time slices and all countries in 2050, the endogenous price for green hydrogen decreases from 86.8 €/MWh_{th} to 77.3 €/MWh_{th}, and the endogenous electricity price from 52.3 €/MWh_{el} to 47.9€/MWh_{el}, in the Green Island Europe and Green Importer Europe scenarios, respectively.

Yet the welfare analysis highlights that an increase in average total welfare is only possible as long as producers/generators are able to reduce their average variable costs beyond the point of simply covering their average revenue losses from the price decrease. In the case of green hydrogen, the results indicate that this is best achieved by reducing the full-load hours of the electrolysis system in order to operate more flexibly and take greater advantage of fluctuations in the electricity price. In doing so, average total welfare for the green hydrogen market is increased by 8.3 €/MWh_{th} in the Green Importer Europe scenario compared to the Green Island Europe scenario. For electricity generators, however, the change in the load profile of green hydrogen producers means that electricity demand in certain hours is lower compared to the Green Island Europe scenario. As a result, the model chooses to reduce supply by decreasing the installed capacity of intermittent electricity generation in sub-par locations. In turn, however, this makes it difficult for electricity generators to reduce their average variable costs as less low-/zero-cost electricity is consumed. Nevertheless, electricity generators are able to take advantage of the reduction in electricity demand as well as increase in hydrogen turbine (CCGT) capacities by decreasing the supply from the most expensive zero carbon/carbon-neutral dispatchable technology, often turbines running on biofuels. These two counteracting effects lead to a moderate increase in average total welfare for the electricity market equal to 0.9 €/MWh_{el}.

1.2. Literature review and contribution

A handful of models exist that use linear-programming methods to optimize the investment and dispatch decisions in a flexible, decarbonized European energy system, similar to DIMENSION. As explained in Helgeson and Peter (2020), the TIMES and TIAM models have emerged as the favorite successors to the MARKAL model to assess the long-term, least-cost energy provision for many different regions as well as globally.[1] More specificially, MARKAL models and its decedents are partial equilibrium, bottom-up dynamic optimization models that can determine how the energy system may cover energy demands when minimizing the discounted capital, operating and resource costs. Rodrigues et al. (2022), for example, apply the European TIMES Model at UCL (ETM-UCL) to explore stakeholder-designed narratives of the future energy system development under deep decarbonization. Other non-MARKAL models include ELTRAMOD and ENERTILE, for example, which are bottom-up European electricity market models capable of examining a wide range of flexibility and decarbonization options and their interdependence within the power sector as well as with other energy transformation and end-use sectors.[2] Final energy consumption within the end-use sectors, however, is defined exogenously by coupling ELTRAMOD or ENERTILE with other models. Another electricity market model is dynELMOD, as described in Gerbaulet and Lorenz (2017). A dynamic partial equilibrium model of the European electricity sector, this model minimizes costs while determining the long-term invest and dispatch strategies for electricity transmission and generation as well as flexibility options such as storage and demand-side management measures. Finally, the sector-coupled energy model of Europe PyPSA-Eur-Sec-30 developed by Brown et al. (2018) considers both cross-sector and cross-border integration of the European energy system, incorporating electricity, transport and heat demand. A unique aspect of this model is the focus on flexibility options, including electric vehicles, power-to-gas units and long-term thermal energy storage. As such, the authors investigate the cost-optimal system under a 95% reduction in CO_2 emissions, developing scenarios that successively increase the amount of demand and flexibility from the transport and heating sectors.

Yet many of the existing linear models either account for the complete energy system with limited detail or focus intensively on one specific market, sector or energy carrier (e.g., electricity). In other words, a

[1] See, e.g., `https://iea-etsap.org/index.php/etsap-tools/model-generators/times` and `https://iea-etsap.org/index.php/applications/global`.

[2] See, e.g., Möst et al. (2021), Dresden (2021) and Zöphel et al. (2019) for more information on ELTRAMOD and Sensfuß et al. (2019) and Crespo Del Granado et al. (2020) for more information on ENERTILE.

trade off often exists between complexity and computational tractability, which may inhibit the technical and economic scope. As such, the model developed within this paper is novel in its ability to both account for the complete European energy system and achieve a high degree of endogeneity in the investment and dispatch decisions within and across multiple sectors over future time horizons. Although several of the aforementioned models may consider similar types of technologies or energy demands, the majority rely on exogenous assumptions on, e.g., investment pathways in the energy transformation and/or end-use sectors. Such models often fall under the category of simulation models, e.g., the METIS model series of the European Commission[3], which focus on the dispatch results in one single model year and do not consider investment decisions. Furthermore, the high level of endogeneity in the modeling of the supply and demand of energy carriers such as, e.g., electricity, heat, biofuels as well as other carbon-neutral and zero-carbon fuels for a wide-range of applications is a key contribution of this research. By interlinking multiple equilibrium conditions, endogenous prices for a wide range of energy carriers can be investigated. Moreover, the attention to detail regarding the modeling of flexibility options is particularly noteworthy, especially the introduction of endogenous, bidirectional charging of electric vehicles as well as industry and household DSM processes. Lastly, to the best of the author's knowledge, a scenario analysis examining the pathway to an energy-independent, carbon-neutral Europe under open competition across sectors, countries and technologies has yet to be performed.[4] In particular, the in-depth investigation of the consequences of energy-independence on the consumer and producer surplus of European electricity and green hydrogen producers offers novel insights on the economic effects associated with restricting long-term non-European imports of zero-carbon and carbon-neutral fuels.

The remainder of the paper is structured as follows: Section 2 provides a detailed overview of the model and the key methodological extensions realized within this work. The following section, Section 3, then presents the definitions of the Green Island Europe and Green Importer Europe scenarios along with the central data and assumptions before discussing and comparing the results. An extensive welfare analysis based on the scenario results can be found in Section 4. Section 5 concludes.

[3]See `https://energy.ec.europa.eu/data-and-analysis/energy-modelling/metis_en`.

[4]Nuñez-Jimenez and De Blasio (2022) do consider 'Hydrogen Independence' in 2050 as one of three strategic scenarios for the European Union; however, the optimization is based solely on each country's production cost curves for hydrogen rather than on the total costs of the complete energy system.

2. Methodology

Within this section, the methodology behind the energy system model is presented in detail.[5] As explained in Section 1.2, one key contribution of this work is the high level of endogeneity as well as techno-economic detail in the optimization of the energy transformation and end-use sectors. To achieve this objective, the model developed in Helgeson and Peter (2020) is extended to account for the greater energy system and to include a larger selection of flexibility and decarbonization options. The goal of the optimization is to minimize the accumulated discounted total system costs subject to regulatory conditions such as carbon emission reduction targets[6] as well as technical constraints including energy balance restrictions. As such, the model is able to determine the cost-minimal, welfare-optimal[7] pathway to achieving long-term decarbonization of the future European energy system. The spatial scope of the model covers 28 countries, including 25 countries of the European Union as well as Norway, Great Britain and Switzerland.[8] The analyzed time period begins in 2019 and then spans from 2025 to 2050 in 5-year steps. For computational tractability, the model applies a reduced temporal resolution based on 16 typical days.[9] The typical days are selected according to a clustering algorithm, described in detail in Appendix B.

2.1. Understanding the model structure

The model developed can be understood as a combination of interlinked modules, each of which responsible for making endogenous investments in technologies to supply a certain type of generation to cover a corresponding demand. Within this analysis, four modules are considered: the electricity market module, the power-to-x (ptx) module[10], the road transport module and the heat module, depicted in Figure 1 by the yellow, blue, red and purple boxes, respectively. The basis of the first three modules were developed by Helgeson and Peter (2020); therefore, the reader is referred to the original work for a thorough description. The heat module, however, is a key extension of the model designed in the research at hand and is presented

[5]See Appendix A for a complete overview of the nomenclature used in the equations presented in this section.

[6]In its current form, the model only considers CO_2 emissions and does not account for other externalities such as air pollution and resulting health damage.

[7]The cost-minimization problem corresponds to a welfare-maximization approach under the assumption of price-inelastic energy demand (see Jägemann et al. (2013)).

[8]See Table A.3 in Appendix A for a complete list of countries considered in this analysis.

[9]In order to represent a full year, the typical days are scaled up by multiplying each typical day with its frequency of occurrence. The typical days vary according to wind speed, solar irradiance, winter or summer as well as week or weekend day. The optimization presented in Section 3 assumes that each typical day consists of four time slices representing six consecutive hours. This temporal resolution is chosen due to restrictions in computational power given the complexity of the multi-sectoral modeling framework. As shown in Nahmmacher et al. (2016), a temporal resolution exceeding 48 time slices is assumed to be sufficient to ensure reliable results when using investment models for electricity markets.

[10]The "power-to-x module" referred to in the paper at hand is equivalent to the "energy transformation module" presented in Helgeson and Peter (2020). The name was changed to avoid confusion with the other modules, which also include technologies that transform energy from one type to another.

in detail in Section 2.4. The black and grey area on the right-hand side of Figure 1 describes the four end-use sectors that are accounted for in the extended model: residential and commercial, industry, transport and agriculture. The conversion of energy that takes place within the electricity market, ptx and heat modules falls under a fifth sector, a so-called 'energy transformation sector'.

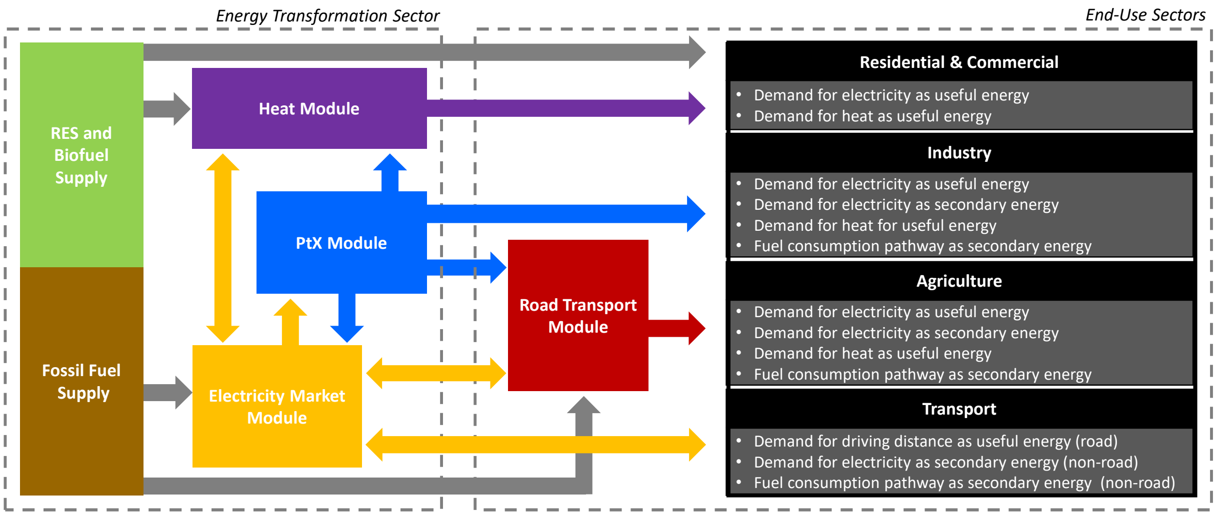

Figure 1: Endogenous energy flows between supply from the modules and demand from the end-use sectors, where the grey arrows depict the flow of renewable energy sources (RES), biofuels or fossil fuels, yellow the flow of electricity, purple the flow of heat, red the flow of road transport and blue the flow of energy carriers produced via ptx processes

The integrated energy system model simultaneously optimizes the ptx, heat, road transport and electricity market modules to determine the cost-efficient investment and dispatch decisions. In doing so, the modules may choose to invest in technologies from an extensive catalog as per the corresponding module name.[11] If installed, technologies within the modules may consume a range of fossil fuels, biofuels and renewable energy sources (RES) as well as energy carriers such as electricity and synthetic (i.e., ptx) fuels.

Whereas the modules correspond to the technical design and operation of the different parts of the energy system, the end-use sectors describe the types and levels of demand that need to be supplied by the energy system to satisfy end consumers energy needs in each country, time slice and year. As such, a single module may serve to cover the demands in multiple end-use sectors. More specifically, each end-use sector is characterized by an exogenously-given demand for useful energy (e.g., direct electricity consumption, heat use or driving distance) for each country and model year.[12] In the case of useful energy, the exogenously-

[11]In other words, the electricity market module includes electricity generation technologies, the power-to-x module includes power-to-x technologies, the road transport module includes vehicle technologies and the heat module includes heat generation technologies. More information on the technologies included in the modules are given in Sections 2.4, 2.5 and Appendix C.2.

[12]Within this work, the term 'useful energy' is meant to denote the final stage of energy use. In other words, any energy that is defined as useful may be used directly in its final form, i.e., without any further conversion to a different energy type (see `https://ourworldindata.org/energy-definitions`).

given demand in the end-use sectors feeds directly into the equilibrium condition of the corresponding module. For the road transport module, for example, useful energy for driving distance defined within the assumptions of the transport sector makes up the entirety of the module's demand. In other words, as indicated by the single red arrow in Figure 1, this module must invest in sufficient vehicle technologies to supply the transport sector with a certain amount of vehicle kilometers. The equilibrium condition can then be understood as,

$$\sum_{s} dr_{m,s,t,y}\bigg|_{s=trans} = \sum_{i} \mathbf{sr}_{i,m,t,y}\bigg|_{i\in\mathbf{I_{rt}}} \qquad \forall m,t,y \tag{1}$$

where $dr_{m,s,t,y}$ represents the exogenous demand for road transport in sector s equal to transport and $\mathbf{sr}_{i,m,t,y}$ the supply (in km) from vehicles technologies $i \in \mathbf{I_{rt}}$, each dependent on market m, time slice t and year y.

Similar to the case of road transport, any demand for heat defined in the end-use sectors is seen by the heat module, which is optimized such that the heat supply must equal the exogenously-given useful energy for heat aggregated over the end-use sectors (see the right-hand side of Figure 1). Only the residential and commercial, industry and agriculture sectors are assumed to exhibit heat demands, i.e., it is not possible for another module to have an endogenous heat demand to use as a secondary energy source. However, as explained in Section 2.4, including thermal storage in the model allows for additional flexibility and may enable heat production to exceed the exogenously-given demand within a single time slice. As such, an endogenous demand emerges within the heat module to keep equilibrium at a given point in time. This is shown in the following equation,

$$\sum_{s\neq et,trans} dh_{m,s,t,y} + \sum_{s=et} \mathbf{ec}_{f,f1,m,s,t,y}\bigg|_{f,f1=heat} = \sum_{i} \mathbf{g}_{i,m,t,y}\bigg|_{i\in\mathbf{I_{ht}}} \qquad \forall m,t,y \tag{2}$$

where $dh_{m,s,t,y}$ represents the exogenous heat demand summed over all sectors s except transport ($trans$) and energy transformation (et) and $\mathbf{g}_{i,m,t,y}$ the generation from heat technologies $i \in \mathbf{I_{ht}}$ in market m, time slice t and year y. The term $\mathbf{ec}_{f,f1,m,s,t,y}$ on the left-hand side of Equation (2) accounts for any heat infeed, i.e., $f, f_1 = heat$, into a thermal storage that occurs as a part of energy transformation (i.e., $s = et$), which may then be offered as heat generation in a future time slice.[13]

For the electricity market module, however, the definition of demand is far more complex. Unlike the road transport and heat modules, the exogenously-given demand for electricity as useful energy in the end-use sectors makes up only part of the total demand. In fact, some end-use sectors are defined to include

[13]For simplicity, storage infeed is depicted as energy consumption (**ec**) and discharge as generation (**g**).

an exogenous demand for electricity as a secondary energy source in order to account for energy conversion that can not be covered by investments in technologies within the modules.[14] These include, for example, electricity consumption from trains, busses and two-wheelers in the transport sector[15] as well as process heating in the industry sector and mechanical processes in the agriculture sector. The combination of useful (i.e., lighting, appliances, and internet) and secondary electricity demand in the end-use sectors is then seen by the electricity market module as an exogenous demand parameter.

Yet, analogous to the modified equilibrium condition developed in Helgeson and Peter (2020), the exogenous demand presents the minimum demand that needs to be supplied by the module. Apart from the exogenously-given demand, an endogenous demand component may arise as a result of the investment and dispatch decisions in the ptx, heat and/or road transport modules, as indicated by the yellow lines in Figure 1. In addition, similar to thermal storage in the heat module, a further electricity demand may arise within the electricity market module itself, e.g., via the charging of battery storage in a specific time slice. As such, the equilibrium condition for the electricity market module then reads

$$\sum_{s \neq et} l_{m,s,t,y} + \sum_{s=et,trans} \mathbf{ec}_{f,f1,m,s,t,y} \Bigg|_{f,f1=elec} = \sum_{i} \mathbf{g}_{i,m,t,y} + \sum_{n} \mathbf{k}_{m,n,t,y} \qquad \forall m,t,y \tag{3}$$

where the electricity demand includes both the exogenous demand for useful and secondary energy $l_{m,s,t,y}$ summed over all sectors except for energy transformation (i.e., all end-use sectors) as well as any endogenous electric energy consumption (i.e, $\mathbf{ec}_{f,f1,m,s,t,y}$ for $f, f1 = elec$) within the energy transformation sector et and transport sector $trans$ in market m, time slice t and year y. The latter summation on the left-hand side corresponds to the aggregated, endogenous electricity demanded by technologies in the electricity market, ptx, and heat modules (i.e., energy transformation sector) as well as the road transport module.

The right-hand side of Equation (3) defines the electricity supply, which may be either generated by technologies i within market m ($\mathbf{g}_{i,m,t,y}$) or traded between markets m and n via cross-border net transfer capacities ($\mathbf{k}_{m,n,t,y}$). More specifically, the technologies i responsible for providing electricity may belong to the electricity market module (i.e., a standard electricity generator) or may be from a different module, e.g, an electric vehicle (i.e., vehicle to grid) in the road transport module or a combined heat and power (CHP) system from the heat module, as highlighted by the bidirectional yellow arrows in Figure 1. Furthermore,

[14]Within this work, the term 'secondary energy' is used to denote an energy carrier that is to be consumed by an end consumer to be converted into another energy type (e.g., electricity as a secondary energy for process heating in the industry sector). In this case, secondary energy and final energy are assumed to be synonymous, as transportation losses within the individual countries are not accounted for in DIMENSION. For more information on different types of energy, see `https://ourworldindata.org/energy-definitions`.

[15]Although busses and two-wheelers may fall under the category of road transport, only private passenger, light-duty and heavy-duty vehicles are considered in the road transport module. Therefore, in order to simplify notation, all other types of transport are labelled as non-road.

positive flexibility[16] may be provided as a result shifting short-term demand from one time period to another. This may be done by combining an electricity-consuming technology with a storage, e.g., a heat pump together with a thermal storage in the heat module or an electrolysis system together with a hydrogen storage in the ptx module, to allow for greater load flexibility. Another similar option considered in the model is demand-side management (DSM), in which investments in, e.g., smart meters or other management systems may allow for certain industry processes or household appliances to shift operation relative to electricity market conditions.[17] The complex interdependence between electricity supply and demand allows for all electricity consumers and suppliers to simultaneously be faced with a single, endogenous electricity price[18] within each country and time slice, given by the first-order condition (i.e., scaled marginal) of Equation (3).

The final module, the ptx module, is only exposed to an endogenous demand. Analogous to the extensions in Helgeson and Peter (2020), a demand for ptx fuels[19] may arise as the need for zero-carbon and carbon-neutral alternatives grows, i.e., to lower emissions in dispatchable electricity generation, heat production or road transport (see Figure 1). Yet within this work, the endogenous link to the ptx module is extended to fuel consumption beyond the modules, as explained in the following subsection.

2.2. Integrating fuel consumption beyond of the scope of the modules

One major challenge of this research lies in accounting for as much of the European energy consumption and emissions cycle as possible. As such, whereas the electricity market, road transport and heat modules are capable of endogenously supplying the use of electricity, road transport and heat, respectively, there exists a greater energy demand that, prior to this work, was not included in the model. More specifically, as touched upon in Section 2.1 in regards to the electricity market module, not all end-use sectors are compatible with an endogenous, model-based optimization of the investment decision. A classic example is the industry sector, which is characterized by a copious amount of heterogeneous energy conversion technologies whose investments may not necessarily coincide with the cost-minimizing solution.[20] Another example is rail or

[16] Within this work, positive flexibility refers to an additional energy supply, and negative flexibility refers to an additional energy demand.

[17] Although not explicitly depicted in Figure 1, the yellow bidirectional arrow between the electricity market module and the final use sectors indicate how the exogenously-defined electricity demand may be adjusted via DSM to offer short-term flexibility for the electricity market module (see Section 2.3).

[18] Within this analysis, the term "endogenous electricity price" may be understood as the marginal costs of electricity generation or provision (i.e., in the case of storage), equal to the shadow price of the equilibrium condition (Equation (3)). See Helgeson and Peter (2020) for a more thorough discussion of the endogenous electricity price.

[19] Throughout this work, the term 'ptx fuels' is used to refer to a broad spectrum of energy carriers that are produced via electrolysis, possibly with an additional conversion technology (e.g., Fischer Tropsch). These include ptx hydrogen (synonymous with green hydrogen), ptx liquid hydrogen, ptx methane, ptx LNG, ptx diesel, ptx gasoline and ptx kerosene.

[20] More specifically, private companies within the industry sector may be limited to investing in certain process equipment based on technical restrictions or production-specific requirements as opposed to the least-cost option. By defining an exogenous fuel pathway, future investment decisions can be predefined based on, e.g., the predictions of stakeholders or industry experts.

air travel in the transport sector, where only limited technology options exist and information on costs is often unavailable. In order to circumnavigate the investment decision while still seeking to assess the entire energy system, fuel consumption pathways are defined for the industry and agriculture sectors as well as the transport sector excluding road transport. The fuel consumption pathways define the demand for multiple energy types, depicting a mixture of primary fuels as well as energy carriers. These include a wide range of fuel types such as gasoline, diesel, kerosene, gas, coal, lignite, hydrogen and biosolid for specific applications in three of the four end-use sectors (see the right-hand side of Figure 1). Although the fuel consumption pathways are defined according to the fuel type, the fuel supply is determined according to the concept of substitute fuels, as explained in Helgeson and Peter (2020).[21] As a result, the model may endogenously choose between fossil, bio and ptx alternatives to cover this demand such that

$$df_{f,m,s,t,y}\Big|_{s=ind,trans,agr} = \sum_{f1} \mathbf{sf}_{f,f1,m,s,t,y}\Big|_{s=et} \qquad \forall m,t,y \quad \text{and} \quad f,f1 \neq elec, heat \tag{4}$$

where $df_{f,m,s,t,y}$ is the exogenous fuel consumption pathway for fuel type f and $\mathbf{sf}_{f,f1,m,s,t,y}$ the supply of substitute fuel $(f, f1)$ in market m, sector s, time slice t and year y. As mentioned above, the left-hand side of Equation (4) only applies to $s = ind, trans, agr$, as the residential and commercial sector is defined only according to the useful energy demand, i.e., electricity and heat use. On the supply side, the energy transformation sector may provide fossil fuels as well as biofuels directly from the market at a given price. In this case, no investment in a conversion technology takes place—only the variable costs of the final fuel use together with the corresponding CO_2 emission factors are taken into account. However, if the model chooses to replace, e.g., a fossil fuel with a ptx alternative, an endogenous investment and dispatch decision must be made within the ptx module to supply the ptx fuel. As such, the equilibrium constraint for ptx fuels developed in Helgeson and Peter (2020) must be adjusted, i.e.,

$$\begin{aligned}\sum_{i} \mathbf{fp}_{f1,i,m,t,y}\Big|_{i\in\mathbf{I_{ptx}}} &+ \sum_{n} \mathbf{ft}_{f1,n,m,t,y} + \mathbf{ft}_{f1,nonEU,m,t,y} \\ &= \sum_{s=et,trans} \mathbf{ec}_{f,f1,m,s,t,y} + \sum_{n} \mathbf{ft}_{f1,m,n,t,y} \\ &\quad + \sum_{s=et} \mathbf{sf}_{f,f1,m,s,t,y} \qquad \forall m,t,y \quad \text{and} \quad f1 = ptx\end{aligned} \tag{5}$$

with the new variable $\mathbf{sf}_{f,f1,m,s,t,y}$ endogenously defining the supply of ptx substitute fuels (i.e., $f1 = ptx$) to cover the exogenous fuel consumption pathways for the end-use sectors industry, transport and agriculture given in Equation (4). The rest of the demand for ptx fuels depicted on the right-hand side of Equation (5) is

[21] See Helgeson and Peter (2020) for a complete description of how substitute fuels are included in the model.

made up of the endogenous energy consumption ($\mathbf{ec}_{f,f1,m,s,t,y}$) in the energy transformation and transport sectors (i.e., within the electricity market, heat, ptx[22] and road transport modules) as well as any exports of ptx fuels $\mathbf{ft}_{f1,m,n,t,y}$ made to other European markets n in market m, time slice t and year y. The supply of ptx fuels, shown on the left-hand side of Equation (5), is consistent with the corresponding equation in Helgeson and Peter (2020), with $\mathbf{fp}_{f1,i,m,t,y}$ denoting the ptx fuel production from ptx technology i within market m and $\mathbf{ft}_{f1,n,m,t,y}$ and $\mathbf{ft}_{f1,nonEU,m,t,y}$ symbolizing the imports of ptx fuels from other European markets n or from outside of Europe (*nonEU*), respectively, in time slice t and year y. Analogous to the case of electricity, the first-order condition of the ptx equilibrium function, Equation (5), is used to calculate the corresponding endogenous price[23] for each ptx fuel produced within each country and time slice.

Introducing the new equilibrium condition shown in Equation (4) into the model requires that the objective function presented in Helgeson and Peter (2020) also be extended to include the additional variable costs that arise for the fuel supply $\mathbf{sf}$. The discounted total costs TC are now minimized according to

$$\min \quad TC = \sum_{i,m,y} \delta_{i,m,y}\bar{\mathbf{x}}_{i,m,y} + \sum_{i,m,t,y} \gamma_{i,m,t,y}\mathbf{g}_{i,m,t,y} + \sum_{f,m,s,t,y} p_{f1,y}\mathbf{sf}_{f,f1,m,s,t,y}\Bigg|_{f1=conv,bio} \tag{6}$$

where $p_{f1,y}$ is the commodity price and $\mathbf{sf}_{f,f1,m,s,t,y}$ the supply of fossil or bio substitute fuels $f1$ in sector s, market m, time slice t and year y. If a fuel type is consumed by an investment object $i \in \mathbf{I}$ chosen by one of the four modules, i.e., $\mathbf{I} = \mathbf{I_{el}} + \mathbf{I_{rt}} + \mathbf{I_{ptx}} + \mathbf{I_{ht}}$, then these costs are accounted for in the variable costs $\gamma_{i,m,t,y}$ scaled by generation $\mathbf{g}_{i,m,t,y}$.[24] Therefore, to return to the previous example, a switch from a fossil fuel to a ptx alternative would cause a reduction in the supply $\mathbf{sf}$ for $f = fossil$; however, the additional investment costs ($\delta_{i,m,y}\bar{\mathbf{x}}_{i,m,y}$, where δ represents the fixed costs and $\bar{\mathbf{x}}$ the generation capacity) and generation costs for both the ptx technology as well as any necessary electricity provision would increase the first two terms in Equation (6)—which by definition must lead to a decrease in total system costs.

With this extension of the objective function, it is possible to account for the value of the additional flexibility that may arise, e.g., when using ptx technologies to decarbonize certain end-use sectors with a static, rather than dynamic, solution.[25] Furthermore, including exogenous fuel consumption pathways allows for a greater share of energy-related emissions to be taken into account by the model. For example,

[22] The ptx module is capable of having an endogenous demand for ptx fuels in the case of liquefaction, such that the infeed is ptx gas and the outfeed is ptx liquid. See Helgeson and Peter (2020) for more information.

[23] Within this analysis, the term "endogenous price" used in combination with any ptx fuel (e.g., green hydrogen) may be understood as the marginal costs of production of the corresponding ptx fuel, equal to the fuel-specific shadow price of the equilibrium condition (Equation (5)).

[24] For road transport, generation can be understood as the amount of kilometers driven by a certain vehicle technology, equivalent to supply road transport $\mathbf{sr}_{i,m,t,y}$ shown in Equation (1).

[25] In other words, the technology costs associated with the exogenous fuel consumption pathways are not included. As such, an endogenous fuel switch represents a static (i.e., no additional investment needed from end consumer) decarbonization option.

carbon emissions arising from aviation pose a significant challenge in reaching carbon neutrality; however, by considering the kerosene consumption of airplanes in the objective function, the model can then endogenously decide the cost-minimizing mix of bio and ptx alternatives to replace the fossil fuel.[26]

2.3. Including demand-side management in the electricity market module

The exogenous demand components presented in Sections 2.1 and 2.2, i.e., for useful energy, secondary energy and fuel consumption, can be understood as inelastic, meaning that endogenous changes in, e.g., the electricity or heat prices do not have an effect on the consumption levels defined in the assumptions. This is, of course, a significant shortcoming of linear models, as in reality a reaction in demand to market prices is common economic behavior. In an attempt to account for such effects, the possibility of demand-side management (DSM) is added to the electricity market module to allow for inter-temporal shifts in part of the exogenously-defined electricity demand in certain end-use sectors. More specifically, the electricity consumption of so-called 'white appliances' such as washing machines, dryers and dishwashers in the residential and commercial sector as well as the electricity use for certain industry processes is able to occur flexibly within a pre-defined time frame. As such, DSM presents a further flexibility option that may compete with other electricity-shifting technologies such as storage or electric vehicles.

Within the model, DSM processes are subjected to two separate capacity constraints depending on whether they are offering negative flexibility to the energy system by increasing electricity consumption ($\hat{\mathbf{ec}}$) or positive flexibility to the energy system by reducing electricity consumption ($\check{\mathbf{ec}}$) in a specific time slice t, shown in Equations (7) and (8), respectively.

$$\hat{\mathbf{ec}}_{f,f1,m,s,t,y}\Bigg|_{f,f1=elec} \leq \sum_i \omega_{i,m,t,y}\theta_{i,m,t,y}l^*_{i,m,t,y}\bar{\mathbf{x}}_{i,m,y}\Bigg|_{i\in\mathbf{I_{dsm}}} \qquad \forall m,t,y \quad \text{and} \quad \bar{\mathbf{x}} \leq \bar{X} \tag{7}$$

$$\check{\mathbf{ec}}_{f,f1,m,s,t,y}\Bigg|_{f,f1=elec} \leq \sum_i \sigma_{i,m,t,y}\theta_{i,m,t,y}l^*_{i,m,t,y}\bar{\mathbf{x}}_{i,m,y}\Bigg|_{i\in\mathbf{I_{dsm}}} \qquad \forall m,t,y \quad \text{and} \quad \bar{\mathbf{x}} \leq \bar{X} \tag{8}$$

The electricity consumption in time slice t of year y is then equal to the electricity consumption in market m and sector s before DSM ($\bar{\mathbf{ec}}_{f,f1,m,s,t,y}$) corrected by the upward or downward shift resulting from the DSM process, i.e.,

$$\mathbf{ec}_{f,f1,m,s,t,y} = \bar{\mathbf{ec}}_{f,f1,m,s,t,y} + \hat{\mathbf{ec}}_{f,f1,m,s,t,y} - \check{\mathbf{ec}}_{f,f1,m,s,t,y} \qquad \forall m,t,y \quad \text{and} \quad f,f1 = elec \tag{9}$$

[26]The reader is referred to Helgeson and Peter (2020) for more information on how the carbon emissions constraint is included in the objective function.

Although not a technology per se, DSM processes are treated in the model as additional investment and dispatch options in the electricity market module and are therefore allocated a specific subset of the technology set $\mathbf{I}$, $i \in \mathbf{I_{dsm}}$.[27] These DSM processes are, by definition, specific to the end-use sector, e.g., the Hall-Héroult process in industrial aluminium production. Only DSM processes affecting the electricity consumption in the residential and commercial as well as industry sectors are considered (i.e., $s = rc, ind$ in Equations (7) - (9)). The load profile of the flexible processes $i \in \mathbf{I_{dsm}}$ before the introduction of DSM is given by the parameter $l^*_{i,m,t,y}$. By installing DSM capacities $\bar{\mathbf{x}}_{i,m,y}$, the electricity demand in time slice t can be increased or decreased within the technical limits of ramping-up (ω) or ramping-down (σ) the process load. A so-called 'feasibility factor' θ accounts for the non-technical aspects that may restrict the use of DSM in a certain time slice t such as, e.g., expected production levels of an industrial good. For example, the model may choose to convert $\bar{\mathbf{x}}$ gigawatts of electric capacity used for clinker production for cement in the industry sector into flexible load by investing in a DSM process (e.g., via an investment in a smart energy management system). Within each time slice, the non-flexible electricity demand for clinker production, i.e., the load profile l^* multiplied by the installed DSM capacity $\bar{\mathbf{x}}$, may now either be increased or decreased by a factor equal to $\omega * \theta$ or $\sigma * \theta$, respectively. The total installed capacity of each DSM process is limited by an exogenously-defined maximum $\bar{X}$, which is determined according to the highest amount of flexible capacity achievable for process i and market m, i.e., the process-specific electricity demand scaled by the total amount of household, commercial or industrial consumers in each country. In the aforementioned example, the maximum capacity $\bar{X}$ would be equal to the total electricity demand for clinker production by all cement manufacturers in the country considered.

By definition, DSM processes are only able to shift consumption within a pre-defined time frame, which may vary significantly depending on the type of consumer. A household, for example, may have to run the dishwasher once within each 24 hours; however, the preparation of pulp for paper production must be completed within a two-hour window. This temporal restriction is accounted for in the model using the following equation

$$\hat{\mathbf{ec}}_{f,f1,m,s,\hat{\mathbf{t}},y}\Bigg|_{f,f1=elec} - \check{\mathbf{ec}}_{f,f1,m,s,\check{\mathbf{t}},y}\Bigg|_{f,f1=elec} = 0 \qquad \forall m,y \text{ and } |\hat{\mathbf{t}} - \check{\mathbf{t}}| \leq T^* \tag{10}$$

such that the additional amount of electricity consumed (i.e., negative flexibility) must be equal to the additional amount of electricity reduced (i.e., positive flexibility) between time slices $\hat{\mathbf{t}}$ and $\check{\mathbf{t}}$ (or vice versa), which in turn must be less than or equal to the maximum shifting period given by T^*. In this case, the time

[27] See Section 3 for more information on the assumptions behind the individual DSM processes.

slices $\hat{\mathbf{t}}$ and $\check{\mathbf{t}}$ are denoted in bold font to indicate that the time slice in which the consumption increase or consumption decrease takes place is endogenously chosen by the model.

As such, the annual consumption levels remain consistent with the exogenous demand for useful electric energy described in Section 2.1. Nevertheless, endogenous adjustments in the hourly load due to the load shifting from DSM processes are implicitly included in the equilibrium condition for electricity via the link between variable $\mathbf{ec}_{f,f1,m,s,t,y}$ in Equation (9) and Equation (3). As a result, the electricity market module is able to benefit from from short-term demand flexibility, which may in turn affect the profitability of investments in other flexibility options.

2.4. Defining the heat module

Introducing heat supply and demand within European is an essential addition to the model as well as a central contribution of the paper at hand. Not only is heat generation responsible for a large share of carbon emissions in Europe, the cross-sectoral nature of, e.g., power-to-heat and CHP technologies means that changes in the heat supply structure could have significant consequences for the future electricity market. Heat pumps or electric boilers together with thermal storage, in particular, could provide both positive and negative flexibility for the electricity system, consuming electricity in times of high renewable generation/low demand and shifting consumption in times of low renewable generation/high demand. Furthermore, the heating market could offer a promising opportunity for green hydrogen and other synthetic fuels to replace fossil gas or oil and lower overall carbon emissions. Yet the use of zero-carbon and carbon-neutral fuels for heat generation may pose an additional challenge for the electricity sector to reliably supply the necessary power-to-x systems. As such, by including the heating market in the investment and dispatch decision of the model, both the least-cost decarbonization pathway for heat production as well as the rebound effects for the entire energy system can be considered.

Analogous to the electricity market, ptx and road transport modules, a new module is developed to simulate the investment in and operation of heat generators and storage. The heat module includes nearly 40 different technologies, differentiated according to four so-called 'heat use types': district heat, individual heating[28], cooling and cooking.[29] An overview of the heating technologies considered as well the corresponding heat use types are shown in Figure 2.

[28]Individual heating refers to decentralized space and water heating as opposed to centralized district heating.

[29]As is the case in the electricity market module, only investments in generation and storage technologies are considered in the heat module. Investments in, e.g., grid infrastructure, efficiency improvements or building envelope refurbishments are outside the model scope.

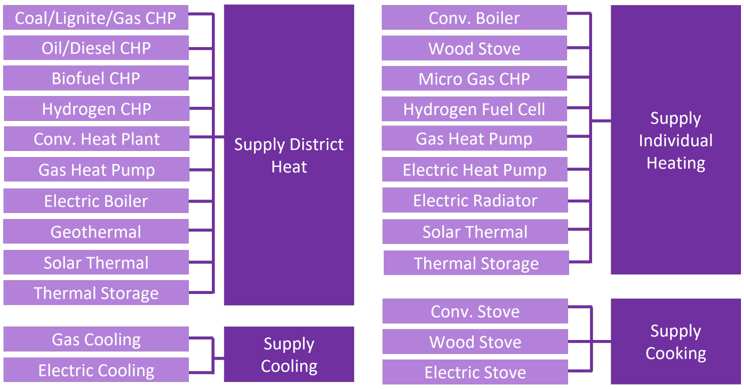

Figure 2: Overview of the heat technologies and heat use types considered in the model

The heat module is structured following the methodology of the electricity market module via a so-called 'top-down approach'.[30] As such, a yearly demand for useful heat is defined for each country (i.e., node) for each model year, which is determined by summing across the exogenously-defined heating needs in the end-use sectors listed in Figure 1. In the case of the heat module, however, the equilibrium condition shown in Equation (2) must hold for each of the four heat use types, meaning that the demand for useful heat defined exogenously in the end-use sectors must be differentiated according to demand for district heat, individual heat, cooling and cooking.[31] The annual heat demand for each heat use type is broken down to the time-step level based on the hourly load profiles assumed for each country and end-use sector (see Section 3.2.3).

The heat module then invests in the necessary heating capacities within each heat use type in order to cover the exogenously-given demand, as qualitatively shown in Figure 2.[32] The supply from district heat technologies, for example, must cover the demand for district heat summed across all relevant end-use sectors. The supply of the heat technologies shown in Figure 2 can be summarized using the equation

$$\sum_{f1,s} \mathbf{ec}_{f,f1,m,s,t,y}\Big|_{s=et} = \sum_{i} \mathbf{g}_{i,m,t,y}/\eta_{i,m,t} \qquad \forall f,m,t,y \quad \text{and} \quad i \in \mathbf{I_{ht}} \qquad (11)$$

which describes how heat technologies $i \in \mathbf{I_{ht}}$ may generate heat ($\mathbf{g}_{i,m,t,y}$) by consuming a wide range of substitute fuels $f, f1$ ($\mathbf{ec}_{f,f1,m,s,t,y}$) within the energy transformation sector ($s = et$) according to the

[30] The term 'top-down' is used here to mean that the problem is addressed from the perspective of the system as whole, which is a common approach to decrease computational complexity. In doing so, the spatial resolution is set to the country level (i.e., a single node), meaning any characteristics of sub-country regions or individual buildings are not specifically taken into account. This includes any flexibility provided by the absorption of heat from building materials, which may act as a type of thermal storage.

[31] As explained in Section 3.1, all three end-use sectors with heat consumption, i.e. residential and commercial, industry and agriculture, are assumed to exhibit a demand for district heat as well as a demand for individual heat. Only the residential and commercial sector, however, requires energy for cooling as well as demands heat for cooking.

[32] As the heat demand is represented by a single country-specific node, decentralized heating technologies must technically be modeled as aggregated, centralized systems. Nevertheless, the techno-economic assumptions remain consistent with the heat use type, e.g., parameters for smaller decentralized systems are assumed for individual heating (see Section 3.2).

technical thermal efficiency $\eta_{i,m,t}$. As is the case with all energy consumers in the model, the differentiation between substitute fuels is irrelevant for the technology, e.g., a gas boiler can run on fossil gas or on ptx methane without any change in performance. For power-to-heat technologies (i.e., electric boilers, electric heat pumps[33], electric radiators, electric air conditioners and electric stoves), the energy consumption in Equation (11) is solely electric, i.e., $f, f1 = electricity$. This consumption is then implicitly seen by the equilibrium condition for electricity, Equation (3), which ensures that sufficient electricity supply is provided to cover the additional endogenous demand from power-to-heat technologies. Furthermore, for the majority of the heat technologies shown in Figure 2, the technical efficiency $\eta_{i,m,t}$ is constant over all time slices t and markets m. The exception is for heat pumps, whose so-called "coefficient of performance" (COP) heavily depends on several factors including the source temperature and desired flow temperature. In this case, the technical efficiency is defined in an hourly resolution according to the temperature profiles of 57 regions across Europe using the COP equation developed in Frings and Helgeson (2022).

Although not a heat generator per se, Equation (11) also applies to the infeed (i.e., energy consumption) and discharge (i.e., generation) of thermal storage for $f, f1 = heat$ with one minor modification: As this tends to occur at different points in time, the consumption on the left-hand side can depend on t whereas the right-hand side must depend on $(t + \mathbf{t}^*)$, with $\mathbf{t}^*$ representing the temporal shift between the heat being fed into the storage and the heat exiting the storage to be consumed by the end user. In other words, thermal storage may act as an energy consumer in times of over-supply as well as an energy provider in times of heat scarcity.[34] As presented in Figure 2, thermal storage may be introduced in a larger scale for district heating as well as in a smaller size for individual heating within buildings.[35]

In addition to the equilibrium condition shown in Equation (2), heat generators are also subject to a capacity constraint,

$$\mathbf{g}_{i,m,t,y} \leq x_{i,m,t}\bar{\mathbf{x}}_{i,m} \qquad \forall m, t, y \quad \text{and} \quad i \in \mathbf{I_{ht}} \tag{12}$$

which ensures that thermal generation $\mathbf{g}_{i,m,t,y}$ from heat technologies $i \in \mathbf{I_{ht}}$ in time slice t, year y and market m does not exceed the installed capacity $\bar{\mathbf{x}}_{i,m}$ multiplied by a technology-specific availability factor $x_{i,m,t}$. For dispatchable technologies, the availability factor reflects outages due to unplanned maintenance or seasonal fluctuations. For solar thermal technologies, however, the availability factor can be understood

[33] The electric heat pump technology considered in this analysis is an air-to-water system.

[34] As with all heating technologies, the investment in thermal storage takes place for each node, meaning the capacities can be understood as the aggregated storage volume for each country and heat use type. The flexibility provided by the thermal storage is therefore in response to the endogenous price signals for energy within a single price zone.

[35] The modeling of thermal storage is analogous to the modeling of electric storage.

as the hourly production potentials based on the solar resources in 57 regions across Europe.

Whereas Equations (11) and (12) only hold for heat supply, the heat module is also able to provide additional electricity generation to the electricity market module via CHP technologies. Both non-flexible and flexible CHP plants are included for use in district heat supply, whereas non-flexible micro-CHP systems and hydrogen fuel cells[36] may provide individual heating. The electricity generation of non-flexible CHP technologies is defined relative to the amount of heat generation according to a fixed power-to-heat ratio α. For flexible CHP plants, however, the amounts of heat and electricity generation can be adjusted within the bounds of certain technical restrictions. The electricity generation in flexible CHP plants is therefore confined using the following two equations

$$\mathbf{g}^*{}_{i,m,t,y} \;\geq\; \alpha_i \mathbf{g}_{i,m,t,y} \qquad \forall m,t,y \;\text{ and }\; i = CHP \tag{13}$$

and

$$\frac{\mathbf{g}^*{}_{i,m,t,y} + \mathbf{g}_{i,m,t,y}}{\eta_i^* + \eta_{i,m,t}} \;\leq\; \frac{\mathbf{g}^*{}_{i,m,t,y} + \beta_i \mathbf{g}_{i,m,t,y}}{\eta_i^*} \qquad \forall m,t,y \;\text{ and }\; i = CHP, \tag{14}$$

with the former setting the lower bound and the latter the upper bound of total energy generation. More specifically, Equation (13) requires that the electricity generation $\mathbf{g}^*{}_{i,m,t,y}$ be greater than or equal to the heat generation $\mathbf{g}_{i,m,t,y}$ multiplied by the technology-specific power-to-heat ratio α_i.[37] In other words, the minimal electricity generation of a flexible CHP plant is equal to that of a non-flexible one. Equation (14) ensures that the total energy consumption, i.e., the total energy generation of electric ($\mathbf{g}^*{}_{i,m,t,y}$) and thermal ($\mathbf{g}_{i,m,t,y}$) energy divided by the total technical efficiency (i.e., thermal $\eta_{i,m,t}$ plus electric η_i^*), is limited by the energy consumption when generating the maximum amount of electricity possible, which is defined by the usable electricity generation ($\mathbf{g}^*{}_{i,m,t,y}$) plus any losses from heat production due to the so-called 'power loss factor' $\beta_{i,m,t}$ ($\beta_i \mathbf{g}_{i,m,t,y}$) corrected by the electric efficiency (η_i^*). As such, using Equations (13) and (14), the model is able to endogenously determine the optimal cogeneration of heat and electricity for a given market m and in time slice t and year y. Similarly, the capacity constraint for the electricity generation of flexible CHP plants must be refined to account for the power loss factor, i.e.,

$$\mathbf{g}^*{}_{i,m,t,y} \leq x_{i,m,t} \bar{\mathbf{x}}_{i,m} - \beta_i \mathbf{g}_{i,m,t,y} \qquad \forall m,t,y \;\text{ and }\; i = CHP \tag{15}$$

[36] Hydrogen fuel cells are modelled analogously to non-flexible CHP plants as these also provide heat and power simultaneously.

[37] It should be emphasized that the asterisks shown in Equations (13)-(15) are purely illustrative and are only included within this subsection to distinguish the electricity generation from the heat generation of CHP technologies. Within the remainder of this work and in Helgeson and Peter (2020), only a single variable for generation $\mathbf{g}$ exists to denote output of technology i, regardless of the resulting energy carrier.

where the capacity $\bar{\mathbf{x}}_{i,m}$ for technology i equal to flexible CHP plants in given in electric units. Therefore, the total amount of electricity generation is limited not only by the installed electric capacity but by the total amount of heat cogeneration.

Regardless of the technologies chosen by the model, the sum of heat-generating capacities must fulfill a peak demand constraint,

$$dh_{m,peak} \leq \sum_i v_{i,m} \bar{\mathbf{x}}_{i,m} \qquad \forall m \text{ and } i \in \mathbf{I_{ht}} \tag{16}$$

which requires that the total installed thermal capacity, corrected by a capacity value[38] $v_{i,m}$, is greater than an exogenously-given, market-specific peak heat demand $dh_{m,peak}$. Just as with the equilibrium condition, the peak demand parameter is defined according to each heat use type. Peak demand constraints are commonly used in investment models to guarantee that enough secure capacity is built despite a reduced temporal resolution.[39] In the case of heating, including a peak heat parameter ensures that heat generation capacities are dimensioned such that heat demand can be covered even during exceptionally cold winters.

Finally, it should be emphasized that the inclusion of the heating market in a large-scale linear model comes with several caveats. The deployment of district heating technologies, for one, is often determined based on regional characteristics, e.g., the existing distribution infrastructure and surrounding industrial supply and demand. Because of the aggregated nature of the model structure, such characteristics can not be taken into account. Similarly, heat demand and supply for individual buildings within a country must be clustered to depict a single player, which results in a loss of heterogeneity. Furthermore, no assumptions are made regarding the availability of the district heating grid, but rather it is implicitly assumed that sufficient grid is available for the amount of district heating demanded.[40] Lastly, different to electricity, no cross-border exchange of heating is possible, meaning each country must cover its heat demand on its own.

2.5. Extensions in the electricity market, power-to-x and road transport modules

The electricity market, ptx and road transport modules developed in Helgeson and Peter (2020) provide the foundation of the energy system model presented. In order to fulfill the research objective, these modules must also be extended to maximize the endogeneity and flexibility between electricity consumers and generators as well as keep up-to-date with the current and future technology alternatives. In the following, the key updates are summarized according to each of the three modules.

[38] Similar to the availability factor, the capacity value indicates what percentage of the plant's capacity can contribute to security of supply, taking into account plant outages and reliability. Capacity value is sometimes referred to as capacity credit.

[39] A peak demand constraint is also included for electricity. See Helgeson and Peter (2020) for more information.

[40] As such, any developments regarding the expansion of district heating (e.g., an increase in the number of district heating customers) are reflected in the definition of district heat demand over time.

In the electricity market and ptx modules, the main improvements lie in the inclusion of additional technologies. Hydrogen OCGT and CCGT power plants are added as investment options to provide dispatchable electricity generation. Incorporating the possibility of hydrogen-fueled electricity generators in the electricity market module also creates an opportunity for an endogenous demand for green hydrogen, which would then be supplied by the ptx module or by non-European imports. Furthermore, the technologies in the ptx module are further diversified to account for other electrolyzer and methanation technologies. In doing so, the ptx module is able to optimize the investment in and use of alkali, PEM, and SOEC electrolyzers, each of which can be combined with a biological methanation, catalytic methanation or Fischer-Tropsch plant.

With regards to the road transport module, two major enhancements are added: the introduction of driving profiles and the possibility of bidirectional, endogenous charging of electric vehicles. With the first, hourly driving profiles are included for each vehicle segment (i.e., private passenger, light-duty and heavy-duty vehicles) to estimate the number of cars on the road and number of cars parked at a given point in time. This complements the second extension, which allows electric vehicles to act similarly to a battery storage system. Within Helgeson and Peter (2020), electric vehicles were assumed to be solely electricity consumers, demanding just enough electricity necessary to cover their driving needs. As such, electric vehicles were assumed to consume electricity according to exogenous charging profiles and, therefore, were unable to react to endogenous electricity market signals. However, within this work, the modeling of electric vehicles is extended to simulate a mobile battery storage that could offer both positive and negative flexibility for the electricity system via bidirectional charging stations. In order to account for this in the model, the input parameters for electric vehicles must be extended to specify technical characteristics pertaining to, e.g., storage volume, charging and discharging speeds as well as the availability of unidirectional and bidirectional charging stations. Together with the driving profiles, the model can then determine the mobile battery capacity connected to the grid as well as the amount of flexibility the vehicle may offer to the electricity system at a given point in time. As such, the electricity consumption and supply may then be optimized endogenously analogous to a stationary battery storage. This allows electric vehicles to compete with other electricity consumers for low electricity prices as well as offer electricity supply during peak demand hours, as long as the driving demand is covered.

2.6. Drawbacks of the modeling approach

As is the case with any mathematical model, the methodology comes with several key drawbacks. Firstly, linear programming requires that all equations depict linear relationships, which is not always the case in reality. Factors such as investment costs and availability of renewable resources often exhibit non-linear relationships to, e.g., capacity growth[41], and a linearization could lead to an overestimation of the costs or value of the technology (see, e.g., Elberg and Hagspiel (2015) for the example of wind). In addition, especially when minimizing costs, the linear equations often have to be artificially bounded in order to prevent a single solution from dominating the results. For example, both the rate of technology deployment as well as technology replacements (e.g., in the heating and transport sectors) must be exogenously restricted in order to ensure that the transitions are gradual rather than abrupt (e.g., switching out an entire fleet in a single time slice), which is a common way to help calibrate linear models to mimic more realistic outcomes. Of course, the magnitude of such lower and upper limits are hard to determine yet can greatly affect the results. Furthermore, limiting the problem to linear equations makes it nearly impossible to take into account non-linear or non-monetary aspects such as, e.g., consumer preference and acceptance, political interests or non-economic risks for energy producers.

Another major drawback of the DIMENSION model developed are the restrictions regarding the level of technical and economic detail. In fact, due to computational limitations, it is recommended to keep the complexity and number of inputs to a minimum in order to limit the size of the solution matrix. In doing so, it is often the case with linear programming that certain information or details must be omitted or simplified. This is especially apparent when considering the model's level of temporal, technical or spatial resolution: For example, by restricting the spatial resolution to a single node per country, regional heterogeneity in regards to, e.g., demand or supply potentials can not be taken into account. As a result, high-level assumptions must be made for, e.g., domestic renewable potentials that may deviate from reality. In turn, the aggregated nodes combined with the linearity in the investment decisions make it difficult to consider individual consumers, suppliers or buildings without drastically impacting computational time and power. Similarly, the "copper-plate" nodal approach also limits the amount of detail that can be included regarding the electricity grid. In fact, aside from cross-border net transmission capacities (NTCs)[42], no domestic grid capacities are taken into account. Especially when assessing flexibility options, the distribution grid plays a critical role in the techno-economic feasibility of decentralized technologies such as, e.g., heat pumps or electric vehicles.

On a similar note, a further simplification can be seen in the assumptions on demand. As depicted in Figure 1, the model's solution space is bounded by a list of exogenous demands in the residential and commercial, industry, agriculture and transport sectors. By definition, these demands must be completely covered regardless of the cost to the consumer, which is another key deviation from reality: Within the

[41] In other words, the doubling of capacity does not, in reality, necessarily result in a doubling of, e.g., investment costs or available renewable potentials.

[42] The availability of NTC capacities are exogenously assumed and therefore not optimized.

energy system, demand is often observed to be elastic, meaning that a change in the price of a good should lead to a change in the demand. For example, if the costs of heating become too expensive, than the user will seek to reduce their heating needs. Similarly, a skyrocketing price for green hydrogen may drive the industry sector to switch to another, less expensive decarbonization option or even force certain industries to move outside of Europe. Yet in the model, failure to cover the complete exogenously-defined demand would render the model infeasible. Nevertheless, while the outer boundary is restricted by inelastic demand, the model does allow for a certain degree of elasticity in the demand for electricity or for substitute fuels due to the introduction of the endogenous energy consumption in the equilibrium conditions.[43]

Lastly, the micro-economic approach considered in this paper ignores macro-economic aspects such as tax and rebound effects from other non-energy related sectors. Finally, it should go without saying that the fundamental assumption of an omniscient social planner with perfect foresight makes it difficult to draw comparisons to reality. The ability of the model to concoct a coordinated solution over multiple years, countries, market players and sectors allows the model to present a solution that gravely simplifies the political, social and cultural challenges of decarbonizing Europe's future energy system.

3. Application of the energy system model

Within this section, an exemplary application is performed in order to demonstrate the capabilities of the energy system model developed in this paper. Section 3.1 presents the motivation and framework behind the two scenarios that are examined in the application. The corresponding data and assumptions are presented in Sections 3.2. Lastly, the results of the base scenario are discussed in Section 3.3 and a comparison between the two scenarios is made in Section 3.4.

3.1. Scenario definitions

In order to address the research questions, a scenario framework must be designed in such a way to maximize the competition within and across flexibility options and decarbonization technologies. In doing so, it is critical that the restrictions on the investment and dispatch decisions are limited while simultaneously ensuring (i) the energy system is forced to transform, and (ii) transformation can be achieved given the model's investment and dispatch options. To fulfill the first criterion, and in line with the 2020 European Green Deal from European Commission (2019), a reduction in so-called "well-to-wheel" (WTW) CO_2 emis-

[43] See, e.g., Equations (3) and (5).

sions by 55% by 2030[44] and 100% by 2050 (compared to 1990) aggregated across all countries and all sectors in Europe is enforced.[45] Any further country- or sector-specific climate policies are not included in the scenario definition.[46] This simple design of the decarbonization requirements ensures a technology-neutral, cross-sectoral optimization aggregated over a large spatial, technical and sectoral resolution. The second criterion, however, strongly depends on how the spatial boundaries of the model are defined. As described in Section 2, the investment and dispatch decisions of the model are optimized within the 28 European countries, meaning that any costs accrued outside of this space are not considered in the objective function. Yet as explained in Helgeson and Peter (2020) and shown in Equation (5), the model does have the option to purchase zero-carbon and carbon-neutral fuels from outside of Europe at an exogenous price equal to the levelized production and distribution costs. While modeling Europe as an island may drive competition in the electricity and energy transformation sectors, allowing lower-cost imports from outside Europe could alter the merit order of flexibility and decarbonization technologies, especially in the end-use sectors.

Therefore, two scenarios are defined that vary slightly in the spatial boundaries of the optimization. The first, a so-called "Green Island Europe" scenario assumes a world in which Europe must reach carbon neutrality on its own. In other words, any zero-carbon or carbon-neutral fuels that are to be consumed in Europe must be produced within Europe.[47] As depicted by its name, the Green Island Europe scenario should mimic a political and regulatory environment where Europe emerges early on as a pioneer in global decarbonization and considers long-term energy independence to be necessary to reach its targets and ensure security of supply. The second, a so-called "Green Importer Europe" scenario, relaxes this assumption to allow for European energy transformation and end-use sectors to purchase green hydrogen and synthetic fuels imported from outside of Europe. In this reality, countries worldwide seek to reduce carbon emissions, driving a global market for zero-carbon and carbon-neutral fuels.

[44] An exogenous carbon price is assumed only for model year 2025, equal to 40.3 €/tCO_2, before the quantity cap comes into force and prices are determined endogenously (i.e., via shadow prices). The carbon price for 2025 is an extrapolation of a carbon price for 2030 equal to 55 €/tCO_2, which was the regulatory value being discussed in light of the "Fit-for-55" Package from the European Commission at the time of this analysis. It should, however, be emphasized that the exogenous value for 2030 is not included in the model.

[45] Although not explicitly described in Section 2, the CO_2 constraint is included in the objective function similar to Helgeson and Peter (2020), i.e., $GHG_{cap,y} \geq \sum_{f,f1,m,s,t} \left(\mathbf{ec}_{f,f1,m,s,t,y}(\kappa_{f1} + \kappa_{f1,upstream}) - \mathbf{ec}_{f,f1,m,s,t} \cdot \kappa_{f1}|_{f1=bio/ptx}\right)$, where $GHG_{cap,y}$ denotes the carbon emissions reduction target in year y and κ the CO_2 factor of substitute fuel $f1$. The equation states that the emissions that are directly emitted during energy consumption corrected by the recycled emissions that arise by consuming synthetic (i.e., ptx) fuels or biofuels must be lower than a given target. In this case, the variable for energy consumption $\mathbf{ec}_{f,f1,m,s,t,y}$ is modified such that the subscripts for fuel $f, f1$ include heat and the subscript for sector s defines a larger selection of end-use sectors as described in Section 2.2.

[46] The research at hand is meant to give a theoretical, academic-based perspective on market dynamics under carbon neutrality and increased competition. As such, including any sector- or technology-specific targets would undermine the research objective.

[47] Theoretically speaking, fossil fuels such as natural gas may still be imported from outside Europe; however, due to strict decarbonization targets, the demand for fossil fuels decreases significantly to levels that could hypothetically be provided within Europe. Therefore, an additional constraint on fossil fuel imports is considered to be futile.

The motivation to design the two scenarios as such is twofold: First, at the time of this paper, the availability of an international market for zero-carbon and carbon-neutral fuels is yet to be established due to, e.g., lack of infrastructure, low market maturity and insufficient global cooperation on decarbonization mechanisms. The emergence of such a market would come along with significant economic challenges, not only for the necessary investments in the transport itself but also to ensure the security of supply. As such, it is interesting to consider a hypothetical extreme situation where non-European imports of zero-carbon and carbon-neutral fuels never become available and to assess the potential consequences for European players in the electricity, energy transformation and end-use sectors. Secondly, restricting the spatial boundary of the optimization to Europe in the Green Island Europe scenario allows for a maximization of competition in the investment decisions, both within and between flexibility options and decarbonization technologies. Under the premise of linear-programming methods, the availability of imports of zero-carbon and carbon-neutral fuels from outside Europe provides a "back-door" solution for the model: Whereas green hydrogen and synthetic fuels produced in Europe require investments in the corresponding electricity generating and fuel producing technologies, imports from outside of Europe can simply be bought and then consumed directly. Therefore, the model will avoid investments as long as the import price of non-European production leads the objective function to lower total costs. In line with the research objective, the decision to first restrict non-European imports is intentional in order to narrow the solution space and increase the complexity of fulfilling the equilibrium conditions under carbon neutrality. A comparison to the second scenario is then key to understand the drivers of the investment behavior and the deviations under relaxed supply restrictions.

It should be emphasized that the scenario definition applied in this analysis is designed to reflect hypothetical political, regulatory and market situations that should no way mimic the current status quo. For example, by applying a single carbon reduction target aggregated over all sectors and countries, it is implicitly assumed that all technologies and end consumers across Europe see the same carbon price. In reality, different end-use sectors, technologies or countries may be subject to a wide range of regulatory instruments or political mechanisms to force emission reduction. But because the paper at hand seeks to understand the competition between decarbonization and flexibility options across Europe, any such individual policies are disregarded to ensure a level playing field. Similarly, an isolation of the European energy system may be considered an impossible and improbable assumption. With political pressure to decarbonize, the emergence of an international market for green hydrogen and synthetic fuels could allow Europe to complement domestic production in first-best locations with imports from countries with low production costs, i.e., high renewable energy resources. Not only would this drive down the price of green hydrogen and synthetic fuels in Europe, but any additional indirect costs of production—namely electricity generation—could be avoided, i.e., outsourced to non-European countries. As non-European investments are outside the scope of the model, investigating a fictitious energy-independent Europe creates a unique market environment that pushes the model's endogeneity to the limit.

3.2. Data and assumptions

3.2.1. Developments in commodity prices, biofuels and emissions factors

Table C.5 in Appendix C.1 gives an overview of the fuel prices assumed in the application. Assumptions on the price developments for oil, coal and gas are taken from the Announced Pledge Scenario from the 2021 edition of the World Energy Outlook from the International Energy Agency (IEA) (2021). Historical, current, and near-term gas prices (through 2025) are taken from Rystad Energy's GasMarketCube.[48] Forecasts for the remaining fuel prices are estimated based on the oil and gas prices, analogous to Helgeson and Peter (2020). It is also assumed that a European market for biofuels will be established in the medium to long term. Market prices for biofuels including biodiesel, biogasoline, bio oil, biogas (low calorific), biomethane (high calorific), biokeresene, bio LNG and biosolid are based on Kampman et al. (2016), Koch et al. (2018), Ruiz et al. (2019), Brown et al. (2020) and European Commission (2021). A maximum potential for biofuel consumption based on assumptions on land use in Europe is included, increasing gradually from 2200 TWh in 2020 to 3490 TWh by 2050 (European Commission (2011)). Furthermore, of this potential, a limit of 932 TWh of biosolid (e.g., wood) and 361 TWh of biogas (high and low calorific) is specified in order to account for the differences in land availability for each feedstock type (Ruiz et al. (2019)). Table C.5 in Appendix C.1 also shows the prices assumed for supplying CO_2 to methanation and Fischer-Tropsch systems via direct air capture (DAC) based on Helgeson and Peter (2020).

The assumptions on direct and upstream carbon emissions are shown in Table C.6 of Appendix C.1. Data on the direct emissions resulting from the final energy conversion process, i.e., 'tank-to-wheel' (TTW) emissions, are taken from the info sheet provided by BAFA (2019). As explained in Helgeson and Peter (2020), carbon-based ptx fuels and biofuels are assumed to be carbon neutral, as any direct emissions are assumed to be recycled into the methanation or Fischer-Tropsch system or consumed via photosynthesis (see Footnote 45). Estimations of 'well-to-tank' (WTT) (i.e., upstream) emissions are based on the most recent publication of the "JEC Well-to-Wheel Analysis" by Prussi et al. (2020) from the Joint Research Center of the European Commission together with the research from Helgeson and Peter (2020). Contrary to the

[48]See `https://www.rystadenergy.com/energy-themes/commodity-markets/gas-lng/gas-market-cube/`.

assumption in Helgeson and Peter (2020), the WTT emissions in this analysis are assumed to change over time to account for, e.g., the growing social and financial pressure to reduce upstream carbon emissions. As such, it is assumed that the 2019 WTT emission values shown in Table C.6 of Appendix C.1 for ptx fuels and biofuels stay constant until 2025 and then decrease linearly up to 2045, at which point it is assumed that all upstream emissions for carbon-neutral energy carriers have been eradicated. Another novelty of this work is the inclusion of waste as a fuel, whose definition evolves over the model horizon. In the short term, waste is assumed to be primarily recycled oil-based, petroleum byproducts; however, by 2045, only bio-based waste is available. As such, analogous to ptx fuels and biofuels, the emissions for waste are also assumed to decrease linearly between 2025 and 2045. It should also be noted that any form of carbon capture and storage (CCS) is not considered in this analysis.[49]

3.2.2. Techno-economic assumptions within the modules

Techno-economic data on the power generation and storage technologies in the electricity market module are taken from "The POTEnCIA Central Scenario" study by Mantzos et al. (2019) from the Joint Research Center of the European Commission as well as dena et al. (2021) and Helgeson and Peter (2020) (see Table C.7 in Appendix C.2). Investment costs are annualized according to an interest rate of 8% for all electricity generators and storage, except for rooftop PV with 4% (see dena et al. (2021)). Information on the existing power plant fleet in Europe also comes from the POTEnCIA scenario developed by Mantzos et al. (2019), whose assumptions are in turn based on Eurostat data, as well as from the EWI power plant database based on Platts (2016). For renewable electricity generators, minimum expansion pathways from the Global Ambition Scenario of the 2021 edition of the "Ten Year Network Development Plan" (TYNDP) from ENTSO-E (2021) are set for all model years until 2050 to ensure that a minimum level of capacity is realized, consistent with existing targets in the individual countries (as of 2020). The assumptions on the developments in cross-border net transmission capacities (NTCs) are also adopted from the same TYNDP scenario in ENTSO-E (2021). In addition, the assumptions on the RES potentials in Europe are a key factor for the achievement of the climate targets in the model. In the Green Island Europe scenario described in Section 3.1, it is assumed that the installed capacities in Europe for PV, onshore wind and offshore wind can not exceed 1954 GW, 1576 GW and 2792 GW, respectively, over the complete model horizon. These upper limits are estimated in Schmidt et al. (2016) and dena et al. (2021) based on the maximum available

[49]The decision to disregard CCS is twofold: First, at the time of this research, CCS lacks both social and political support, making its future uncertain. Second, by forbidding the model to offset carbon emissions via CCS, a greater strain is placed on the flexibility and decarbonization technologies, which better fits to the research questions outlined in Section 1.1.

area per technology type. Hourly renewable generation profiles for wind and PV are based on MERRA data (DISC (2016)) from 2015 for 57 regions in Europe according to the clustering algorithm explained in Appendix B. Country-specific hourly run of river generation profiles are taken from Paardekooper et al. (2018). In addition, hourly generation profiles for solar thermal as well as hourly COP profiles for heat pumps are estimated using MERRA weather data (DISC (2016)) from 2015 for 57 regions in Europe using the methods developed by Frings and Helgeson (2022) and the clustering algorithm explained in Appendix B.

Besides electricity generation and storage technologies, assumptions on DSM processes are also included in the electricity market module. Within this work, four industrial processes are presumed to be particularly compatible with DSM, including the Hall-Héroult process in aluminum production, clinker production in cement manufacturing, the membrane process in chlorine production and pulp preparation in the paper industry. A selection of the input data for the industrial DSM processes is provided in Tables C.8 and C.9 in Appendix C.2.[50] The costs shown in Table C.8 in Appendix C.2 reflect the investment and operation of a smart management system as well as any hardware that needs to be added to the production site to allow for load flexibility. Furthermore, as explained in Section 2.3, each industrial DSM process is subject to a maximum potential equal to the total electric capacity that would be reached if every producer of aluminum, cement, chloride and paper in a certain country invested in the corresponding DSM process. Process-specific prognoses for electricity capacities for each country are taken from the POTenCIA scenario developed by Mantzos et al. (2019). The aggregated values over all countries considered up to 2050 in this application can be found in Table C.12 in Appendix C.2.

In the case of the residential and commercial sector, six household types are defined with varying levels of annual electricity demand and numbers of residents. Assumptions are then made on the amount of electric capacity for DSM-compatible white appliances, i.e., refrigerators, washing machines, dishwashers and dryers, installed in each household (see, e.g., Frondel et al. (2015) and Mantzos et al. (2019)). Based on this information, the annual fixed costs can then be estimated according to the costs for smart meters presented in Bundesnetzagentur (2017). As can be seen in Table C.10 in Appendix C.2, only FOM costs are included in the model to account for the fee charged by an electricity provider for the installation and use of a smart meter, which would be necessary to enable DSM.[51] Using the estimations provided in the POTenCIA scenario from Mantzos et al. (2019), the total MW of white appliances installed in all households

[50] The conceptualization and parameterization of the industrial DSM processes benefited greatly from collaboration with other project partners during the research project "Virtual Institute—Power to Gas and Heat". More information can be found in the final project report Virtuelles Institut (2022).

[51] It is therefore implicitly assumed that the appliances are capable of exchanging information with the smart meter and adjusting their load. As such, no additional costs are included for the replacement or enhancement of the existing appliances.

in each country up to 2050 is set as the maximum DSM potential, as shown in Table C.12 in Appendix C.2. The household types are then used to estimate the costs and ramping capabilities of household DSM in each country, which is done by assigning a household type to each country according to their average annual electricity consumption of the households and average number of persons per household. A similar method is used for commercial consumers, in this case using two types with either smaller or larger electricity consumption. However, in the case of commercial consumers, only cooling processes are assumed to be DSM-compatible. The assumptions on ramping factors and smart meters costs as well as the potentials in Europe for the two commercial consumer types are presented in Tables C.11 and C.12 in Appendix C.2.[52]

For the heat module, a completely new data set is conceptualized and designed for each heat use type, as summarized in Tables C.13-C.15 in Appendix C.2. Large-scale CHP technologies are assumed to be flexible cogeneration plants that both sell electricity to the spot market as well as provide district heating to the residential and commercial, industry and agriculture sectors.[53] Similar to the electricity generators, the data for CHP technologies also stems from sources such as dena et al. (2021), Platts (2016) and Mantzos et al. (2019). Techno-economic assumptions on non-CHP, 'heat-only' technologies are based on a wide range of studies and industry data including the "Heat Roadmap Europe 4" from the European Commission (see Paardekooper et al. (2018)), IRENA (2017), Mantzos et al. (2019) as well as data from the COMODO model developed in Frings and Helgeson (2022) and the catalogs of technology data provided by Energinet and Danish Energy Agency (2019). As touched upon in Section 2.4, individual heating technologies along with cooling and cooking systems are assumed to be decentralized generators located in buildings such as, e.g., households or industrial production facilities. Although accounting for the spatial granularity is impossible without modeling a distribution grid, the parameter values shown in Tables C.14 and C.15 are selected to represent smaller-scale systems (see, e.g., Frings and Helgeson (2022)). Moreover, the investment costs of centralized district heating technologies are annualized assuming an interest rate of 8%, whereas smaller systems for individual heating, cooling and cooking are faced with an interest rate of 4% (see dena et al. (2021)). The existing CHP capacities as well as heat generation mixes in each European country are also derived from the POTEnCIA scenario developed in Mantzos et al. (2019), whose assumptions are based on Eurostat data. In addition, hourly generation profiles for solar thermal as well as hourly COP profiles for heat pumps are estimated using MERRA weather data (DISC (2016)) from 2015 for 57 regions in Europe using the methods developed by Frings and Helgeson (2022) and the clustering algorithm explained

[52] As can be observed in Table C.12 in Appendix C.2, it is assumed that DSM is only possible in the residential and commercial sector from the year 2031 onward, once smart meter programs begin to roll out in many European countries.

[53] A power-to-loss ratio β equal to 0.286 is assumed for all CHP district heat technologies (see Equations (14) and (15) in Section 2.4).

in Appendix B. Country-specific expansion potentials for geothermal and solar thermal are also introduced based on, e.g., Schmidt et al. (2016), Weiss and Biermayr (2009) and ETIP-DG et al. (2018).

The assumptions for the ptx module build upon those made in Helgeson and Peter (2020). Data on investment costs, efficiencies and lifetimes were updated according to, e.g., IEA (2019), Kreidelmeyer et al. (2020) and dena et al. (2021). Furthermore, two new technologies are considered in the PtX module: SOEC high temperature electrolysis and biological methanation.[54] As such, the model may choose from three electrolysis systems, i.e., Alkali, PEM and SOEC, which may produce gaseous or liquid green hydrogen on their own or may be integrated with another system, i.e., either a catalytic methanation or biological methanation to produce gaseous or liquid synthetic methane or a Fischer-Tropsh system to produce synthetic diesel, gasoline, kerosene or oil. In order for gaseous fuels to liquefied, an investment in a liquefaction system is required. Tables C.16 and C.17 in Appendix C.2 give an overview of the techno-economic assumptions for the ptx and liquefaction technologies included in this analysis. It should be noted that the investment costs for all ptx technologies include a hydrogen storage as well as any additional infrastructure needed to integrate an electrolyzer with another ptx system (e.g., CO_2 storage). The capital costs of all investment objects in the ptx module are assumed to be annualized using an interest rate of 8% (dena et al. (2021)). Moreover, as implemented in Helgeson and Peter (2020), green hydrogen and synthetic fuels may also be traded between European countries. Table C.18 in Appendix C.2 provides the relevant cost information on the cross-border transport.

Finally, analogous to the ptx module, the assumptions of the road transport module also stem from previous research. However, in this case, the cost assumptions for vehicles and road transport infrastructure as well as the fuel consumption factors are taken directly from Helgeson and Peter (2020) for this analysis and are therefore omitted from Appendix C.2.[55] The existing vehicle fleets are updated for the base year 2018 using ACEA (2018), Norway (2020) and BFS (2020), and the interest rates used to calculate the annualized investment costs are adjusted to 4% for private passenger vehicles and 8% for light-duty vehicles, heavy-duty vehicles as well as road transport infrastructure (see dena et al. (2021)). Furthermore, extensive research must be conducted to account for the flexibility potential of electric vehicles in the model. As mentioned in Section 2.5, driving profiles are included in the model to estimate the share of parked and moving vehicles on the road in a given hour in a given country. Data from the studies by Nobis and

[54]The techno-economic data for these technologies benefited from collaboration with other project partners during the research project "Virtual Institute—Power to Gas and Heat". More information can be found in the final project report Virtuelles Institut (2022).

[55]Detailed data tables on the techno-economic data for all vehicles segments and infrastructure are presented in the appendix of Helgeson and Peter (2020).

Kuhnimhof (2018) and Ecke et al. (2020) are used to create hourly driving profiles for each vehicle segment, shown in Figure C.2 in Appendix C.2. In doing so, the endogenous results on the number of electric vehicles can be differentiated into cars that are capable of being connected to the grid and cars that are in motion. By making assumptions on additional technical characteristics of electric vehicles, e.g., battery volume, charging and discharging speeds (i.e, charging station capacities) and the availability of charging stations[56], the potential of electric vehicles to offer positive or negative flexibility in a specific time slice can be determined. Lastly, an additional parameter is included that dictates the share of charging stations that are capable of providing bidirectional electricity flows, i.e., vehicle-to-grid, in a given year. Table C.19 and Figure C.2 in Appendix C.2 give an overview on the assumptions pertaining to electric vehicle charging.

3.2.3. Exogenous demand levels and load profiles

As explained in Sections 2.1 and 2.2, the end-use sectors are characterized by exogenous demands that are then fed into the equilibrium conditions of the individual modules. One challenge of the analysis at hand is the development of consistent, plausible pathways for useful and secondary energy as well as the implementation of an hourly structure for each demand type. In order to minimize discrepancies in the scenario definition, the POTenCIA scenario developed by Mantzos et al. (2019) is used as the main source to define the demand levels for the following consumption types for each year and country up to 2050: annual district heating demand (TWh_{th}) for space and water heating in the residential and commercial, industry and agriculture sectors; annual district heating demand (TWh_{th}) for steam for process heat in the industry and agriculture sectors; annual individual (i.e., non-district) heat demand (TWh_{th}) for space and water heating in the residential and commercial, industry and agriculture sectors; annual cooling demand (TWh_{th}) for air conditioning in the residential and commercial sector; annual cooking demand (TWh_{th}) in the residential and commercial sector; annual electricity demand (TWh_{el}) for lighting, appliances, and IT in the residential and commercial, industry and agriculture sectors; annual electricity demand (TWh_{el}) for mechanical energy and process heat in the industry and agriculture sectors; annual electricity demand (TWh_{el}) for trains, two-wheelers and busses in the transport sector; annual fuel consumption ($TWh_{th)}$ for airplanes, trains, two-wheelers and busses in the transport sector; annual vehicle demand (billion vehicle-km.) per vehicle segment.[57] The pathway for fuel consumption in the industry sector (TWh_{th}) for Germany

[56]The availability of charging stations can be understood as the probability that a charging station is located where the car is parked and that the charger is available. An hourly profile is created using data from, e.g., Bamberg et al. (2020) and varies over the years as the availability of charging stations increases.

[57]It should be noted that the values for the annual energy demand are defined to account for developments in, e.g., energy efficiency, the number of consumers, changes in consumer structure, etc. For more information on the assumptions behind the demands listed here, see Mantzos et al. (2019).

is taken from dena et al. (2021), which is then used to estimate the demand pathways for all other countries based on, e.g., the domestic value-added for each industry branch given in Mantzos et al. (2019). The values of the aforementioned parameters are depicted graphically in Appendix C.4.

The exogenously-defined demand levels must then be broken down into hourly values, which is done using hourly load profiles for each sector-specific application. The following data sets are taken from the "Heat Roadmap Europe 4" study of the EU Commission by Paardekooper et al. (2018) for each country: hourly demand structure for space and water heating for residential and commercial, industry and agriculture sectors; hourly demand structures for cooling in the residential and commercial sector; hourly electricity load profile for lighting, appliances and IT in the residential and commercial, industry and agriculture sectors. Consistent with the weather data, the demand profiles are developed based on historical data from the year 2015. For industry processes, a constant load profile is assumed. Furthermore, the annual electricity and fuel consumption for air, rail, busses and two-wheelers is divided evenly over the year[58], and the road transport driving distance is multiplied by the driving profiles explained in Section 3.2.2. Finally, cooking load profiles are taken from the balance group coordinator AGCS (2020) and set equal for all countries.

3.2.4. Allowing for green hydrogen and synthetic fuel imports from outside Europe

In the Green Importer Europe scenario, a single import price is estimated for each available fuel import for each model year, as shown in Table C.21 in Appendix E. In doing so, the Global Hydrogen Cost Tool developed by Brändle et al. (2020) is used to estimate the weighted average of hydrogen production costs across Algeria, Egypt, Libya, Morocco and Tunisia.[59] Among others, one benefit of the cost tool is the detailed modeling of the availability of renewable energy resources in each country. In fact, Brändle et al. (2020) estimate the theoretical potentials of onshore and offshore wind as well as PV not only on the country level, but for so-called 'resource classes' relative to a renewable generator's capacity factor[60]. As such, the tool is able to approximate the hydrogen production costs at the best (e.g., class 1) and worst (e.g., class 4)

[58] It is implicitly assumed that sufficient fuel storage is available such that the demand level is the same in all time slices.

[59] The non-European import prices are estimated based on the North African region for several reasons. The first is to ensure consistency with the Green Island Europe scenario, which assumes that gaseous fuels such as hydrogen and methane are transported within Europe via existing (retrofitted) pipelines. This assumption can also be applied to imports from North African countries, which are already well-connected with the European gas infrastructure. Second, the aim of this second scenario is to understand the consequences of relaxing the strict requirement enforced in the Green Island Europe scenario of energy independence. As such, a single price per fuel type is assumed to be sufficient to draw conclusions for this analysis. However, production costs of green hydrogen may differ greatly depending a country's renewable energy resources as well as proximity to demand centers (see Brändle et al. (2020)). Therefore, choosing countries such as those in North Africa with relatively uniform solar and wind conditions as well as transport distances to Europe may reduce discrepancies when building a weighted-average of hydrogen production costs. A detailed cost analysis of global imports of green hydrogen and synthetic fuels is beyond the scope of this paper.

[60] The capacity factors are determined via an optimization model that accounts for regional weather conditions as well as the techno-economic characteristics of the different renewable energy generators (see Brändle et al. (2020)). The resulting capacity factors within each country are then clustered to form the resource classes for each renewable energy generation technology

locations for each renewable energy generator type in each country.[61] The theoretical potentials for selected resource classes are used as weights in determining a single average import price for green hydrogen. The hydrogen production costs as well as the corresponding theoretical potentials for each resource class and country considered are given in Table C.20 in Appendix E. The weighted-average of the hydrogen production costs are used to calculate the import prices for the other synthetic fuels including ptx methane, ptx gasoline, ptx diesel, ptx oil and ptx kerosene. In doing so, a production price is calculated using the techno-economic assumptions for the methanation and Fischer-Tropsch systems used in the Green Island Europe scenario (see Tables C.16 and C.17 in Appendix C.2).[62] Furthermore, it is assumed that synthetic fuels may be imported after the year 2030, whereas green hydrogen will become available from 2035 onward.[63]

3.3. Results of the Green Island Europe scenario

The scenario results presented in this subsection help to gain insights on how cross-sectoral, technology-open competition could look like under strict CO_2 abatement and within the boundaries of the countries considered. In doing so, the first two research questions presented in Section 1.1 are addressed, namely how decarbonization technologies, flexibility options and electricity-based fuels may compete in order to achieve a carbon-neutral energy system within Europe at minimal cost.

The first element to consider is the carbon abatement pathway chosen by the model, which is shown on the left-hand side of Figure 3. Between 2019 and 2030, a drastic reduction is seen in the carbon emissions from European electricity generation (-76%), which can be explained by the shift from fossil-based to renewable-based generation shown in the left-hand side of Figure 6 at the end of this subsection. Within the same time frame, heat generation also experiences significant decarbonization (-72%) as a growing share of renewable electricity is used for heat generation. In fact, the heat module developed in this study finds 77% of heat generation in Europe is supplied by electricity-consuming heating technologies in 2030 compared to 19% in 2019. As can be seen on the right-hand side of Figure 4 as well as Figure D.6 in Appendix D, the major driver of electrification is the rapid adoption of decentralized electric heat pumps in buildings: Between 2019

[61] The cost tool from Brändle et al. (2020) can be configured for two scenario types, baseline and optimistic. The optimistic scenario was found to be most consistent with investment costs of renewable energy technologies and electrolyzers assumed for the European countries in the first analysis (see Appendix C.2). As such, the optimistic scenario estimations for the hydrogen production costs at the best available locations (i.e., highest resource class in a given country) were selected. This does not hold true for PV technologies, which were assumed by Brändle et al. (2020) to be significantly less capital intensive. In order to correct this discrepancy, only the hydrogen production costs from the worst PV resource classes (i.e., class 4) were included in the calculation. Apart from scenario types, the tool may also be adjusted to account for different infrastructure assumptions to include the transport costs relative to the transport distance (see Brändle et al. (2020)). For this analysis, retrofitted gas pipelines are assumed. Furthermore, Germany was chosen as a proxy destination due to its central location in Europe.

[62] To estimate the production costs, 4000-5000 full load hours are assumed for the methanation and Fischer-Tropsch systems.

[63] The availability of green hydrogen imports is assumed to be delayed due to necessary infrastructure retrofits.

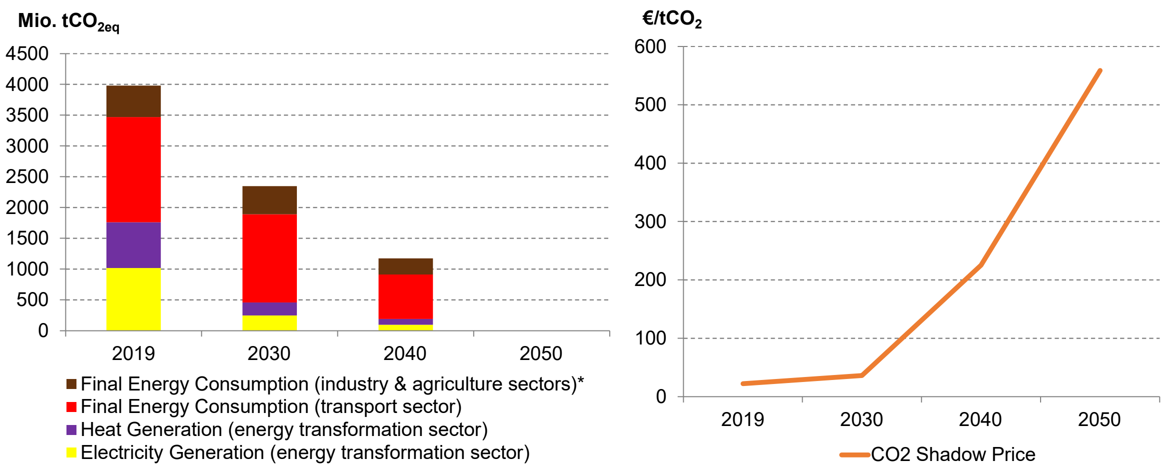

Figure 3: Results on the decarbonization pathway (left) and CO_2 shadow prices (from 2030 onwards) in Europe up to 2050 in the Green Island Europe scenario

and 2030, the installed capacity increases 3.6-fold from 48 GW_{el} (i.e., 190 GW_{th}) to 174 GW_{el} (i.e., 688 GW_{th}), reaching nearly 3300 TWh_{th} of heat generation in 2030 as a result from attractive COPs. District heat experiences a similar trend, albeit in a more gradual manner, transitioning from fossil-based generation to electric heating (see the left-hand side of Figure 4).

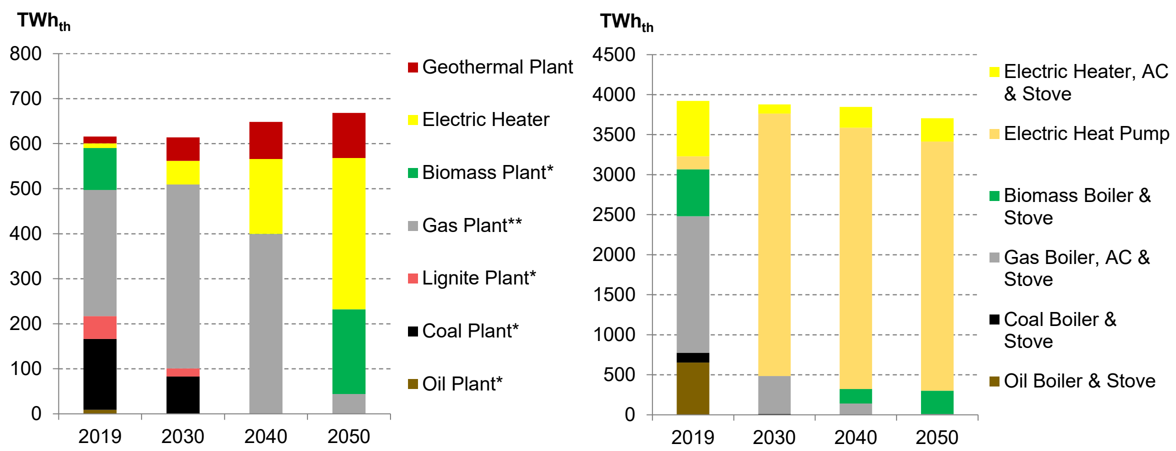

Figure 4: Results on heat generation from district heat generators (left) and from individual heating, cooking and cooling (AC) technologies (right) in Europe up to 2050 in the Green Island Europe scenario, * indicates that both CHP and heat-only plants are included, ** indicates that CHP, heat-only and gas heat pumps are included

Despite a significant transformation of the electricity and heat generation, the 41% decrease in total emissions between 2019 and 2030 results in a relatively modest change in the shadow price[64] for CO_2 in

[64]The term 'shadow price' for CO_2 refers to marginal value of the equation restricting carbon emissions relative to the exogenous decarbonization target as given in the scenario definition. It reflects the costs for the final unit of carbon abatement in order to fulfill the emissions constraint. See Footnote 45 as well as Helgeson and Peter (2020) for a more thorough description of the emissions constraint in the model.

Europe from 22 €/tCO_2 in 2019 to 36 €/tCO_2 in 2030, shown in the right-hand side of Figure 3. As such, it can be concluded that the electrification of heat generation over the next decade may lead to significant reductions in CO_2 emissions at comparatively low marginal abatement costs. After 2030, on the other hand, the CO_2 price increases significantly once more favorable opportunities for carbon reduction have been largely exhausted. Marginal abatement occurs in the transport sector as well as in the industry and agriculture sectors, with the former reducing its CO_2 emissions by 50% and the two latter reducing by 43% between 2030 and 2040. The results of the annual energy consumption for these sectors are shown in Figure 5: In the transport sector, electricity begins to displace fossil diesel and gasoline; and in industry and agriculture, a gradual transition to hydrogen as an alternative to fossil fuels creates an opportunity to reduce carbon emissions via green hydrogen.[65]

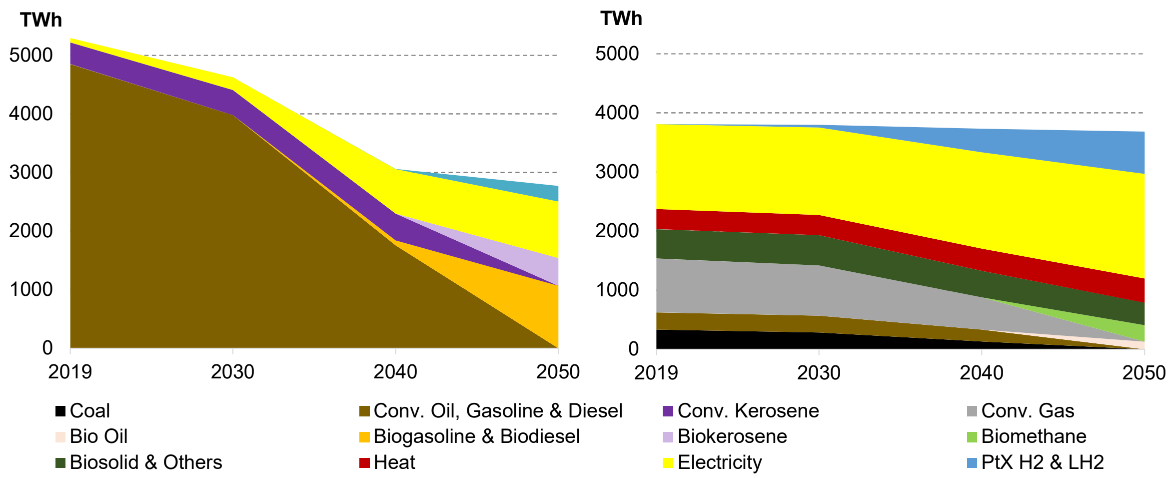

Figure 5: Results on final energy consumption in the transport sector (left) and industry and agriculture sectors (right) in Europe up to 2050 in the Green Island Europe scenario

With the transport sector still emitting 42% of its 2019 emissions level in 2040, the last decade of carbon abatement revolves primarily around transitioning to carbon-neutral mobility. As can be seen in Figures 3 and 5, rapid reduction in CO_2 emissions is driven by the switch to green hydrogen and biofuels in road transport, aviation and shipping. More specifically, as can be drawn from the results shown in Figure D.8 in Appendix D, the road transport module chooses to invest in a European vehicle fleet that, by 2050, reaches a share of 53% electric vehicles, 10% hydrogen fuel cells and 37% combustion engines running on

[65]It should be emphasized that, for the industry and agriculture sectors, the consumption levels of each fuel type are given exogenously (see Section 2.2). The model does decide endogenously which substitute fuel is consumed, i.e., whether a fossil, bio- or ptx variation is used. For transport, the investment and operation of all vehicles is done by the road transport module, which results in an endogenous fuel consumption. The remaining energy consumption the in transport sector is defined exogenously analogous to the industry sector.

biofuels. The industry and agriculture sectors also begin consuming biofuels in 2050, replacing fossil oil with bio oil and natural gas with biomethane. Biomass and biosolids are also used for heat generation, which are first pushed out of the market before reemerging in 2040 once the upstream emission factor has declined (see Section 3.2.1). The economic consequence of reaching carbon neutrality in 2050 is reflected in the peak marginal abatement costs given by the model: As shown on the right-hand side of Figure 3, the cross-sectoral, European CO_2 shadow price doubles from 225 €/tCO_2 in 2040 to 559 €/tCO_2 in 2050.

The second element to consider is the change in the structure and magnitude of electricity supply and demand. As shown on the left-hand side of Figure 6 as well as in Figure D.5 in Appendix D, a tripling of wind and solar capacities in Europe between 2019 and 2030 leads to about 50% of the total electricity supply being provided by intermittent renewable electricity sources in 2030. While this drives significant decarbonization in electricity generation, as explained above, it also creates challenges in maintaining system stability. As such, the model's decision to convert intermittent renewable generation into heat not only serves to reduce emissions in heat generation but also offers flexibility for the electricity market. More specifically, the heat pump capacities shown in Figure D.6 in Appendix D are coupled with 52 GW_{th} of thermal storage to allow for the temporal decoupling of heat generation and consumption.[66] The same holds true for the transport sector, as a small but significant influx of electric vehicles is able to act as battery storage and offer flexibility. As a result of a more flexible system, the dispatchable electric capacity aggregated over gas, lignite and coal generators is able to be reduced by nearly 50% between 2019 and 2030—despite the 484 TWh_{el} increase in electricity consumption, as depicted on the right-hand side of Figure 6. A similar trend is continued between 2030 and 2050, with expansion of renewable electricity generators taking place hand-in-hand with investments in flexibility options. Within this time frame, electricity consumption doubles in order to reach carbon neutrality by 2050, at which point the share of intermittent renewable electricity generation reaches 70% alongside generation from hydro plants (11%), nuclear (8%), geothermal (6%) and hydrogen power plants (4%). As such, only a small amount of dispatchable capacity is available to to provide backup generation, which in turn speaks to the flexibility of the energy system. The right-hand side of Figure D.5 in Appendix D demonstrates how both electricity storage and DSM increase their capacities post-2030 to help keep equilibrium via shifting of electricity supply and demand. Electric vehicles also continue to expand their market presence long term, replacing diesel heavy-duty vehicles with electric trucks with large battery volumes and, as such, high flexibility potentials (see Figure D.8 in Appendix D).

Finally, the simultaneity of impending carbon neutrality, increasingly intermittent electricity supply,

[66] Thermal storage is omitted from the figures.

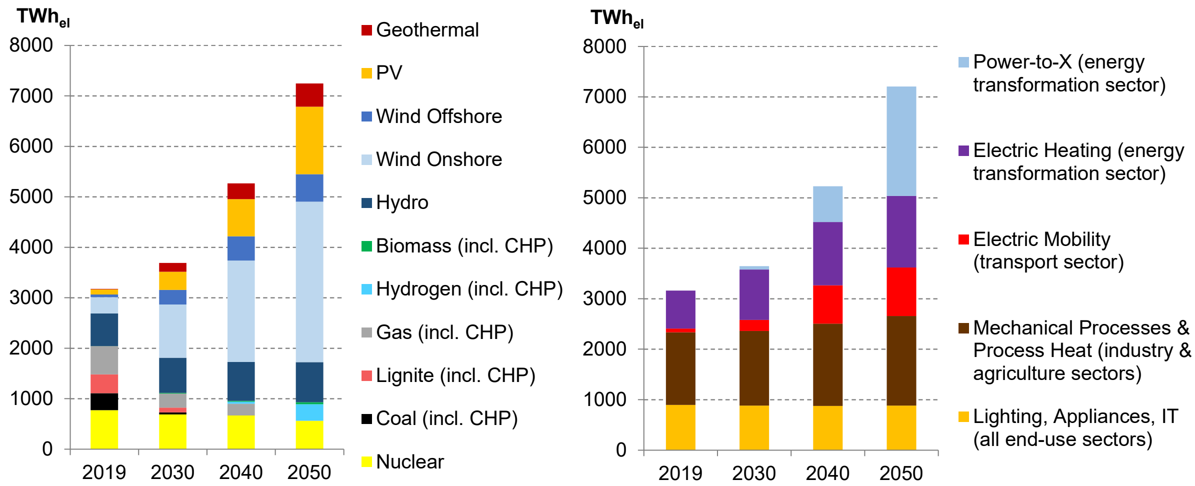

Figure 6: Results on electricity generation (left) and consumption (right) in Europe up to 2050 in the Green Island Europe scenario

growing hydrogen demand in the industry sector and decreasing capital costs of hydrogen-consuming and ptx technologies drives the ptx module to invest in over 500 GW_{el} of electrolyzer capacity between 2030 and 2050, producing 1528 TWh_{th} of green hydrogen in 2050 (see Figure D.7 in Appendix D). As such, an extensive market emerges throughout Europe, with green hydrogen being produced and exported by countries with high shares of wind generation such as Sweden and Finland, with production volumes of 240 TWh_{th} and 113 TWh_{th}, respectively, as well as countries with high solar irradiation levels such as Spain and Italy, each with around 200 TWh_{th} of production. As depicted in Figures 5 and 6, green hydrogen is then used in the industry sector as well as for electricity generation and fuel-cell vehicles, consuming 50%, 38% and 12% of the European production in 2050, respectively. For electricity supply, the demand for green hydrogen translates to an additional 2167 TWh_{el} in 2050. All in all, carbon neutrality in an energy-independent Europe leads to an overall increase in electricity consumption of over 4000 TWh_{el} in Europe between 2019 and 2050.

The results of the Green Island Europe scenario are comparable with the decarbonization pathways seen in other scenario analyses on the European level. For example, considering the most recent study released from the European Commission in August 2023[67], the direct use of electricity is the predominant source of decarbonization in 2050. As can be seen on the right-hand side of Figure 6, round 5000 TWh_{el} of electricity is consumed by non-ptx processes in 2050 compared to 4811 TWh_{el} in the study by the European

[67]See European Commission. Directorate General for Energy. and Fraunhofer Institute for Systems and Innovation Research. (2023).

Commission.[68] However, the studies do diverge when it comes to the development aside from electricity consumption: Whereas the study from the European Commission expects over 3000 TWh_{th} of green hydrogen consumption in 2050, the results of the Green Island Europe scenario indicate a green hydrogen demand equal to half that, roughly 1500 TWh_{th} (see Figure D.7 in Appendix D). The delta seen in the Green Island Europe scenario is covered by biofuels, which contribute significantly (i.e., circa 4000 TWh_{th}) to decarbonization primarily in the transport, heating, industry and agriculture sectors in 2050. In comparison, the study by the European Commission only expects roughly 500 TWh_{th} of biomass consumption in 2050.[69] As a result of the increased demand for green hydrogen, the electricity generation in the European Commission's study exceeds 9000 TWh_{el} compared to a little over 7000 TWh_{el} in the Green Island Europe scenario (see Figure 6). Yet interestingly, whereas the restriction on non-European trade of green hydrogen and synthetic fuels is an exogenous boundary condition of the Green Island Europe scenario, the study from the European Commission finds that imports of hydrogen via pipeline from North Africa are not cost competitive compared to domestic European production. In fact, the studies are similar in their results regarding where green hydrogen is produced and what countries are the biggest exporters and importers: Electrolysers are installed closest to locations with highest renewable potentials (e.g., the Nordics), whose product is then transported to the demand centers (e.g., Germany, Belgium and the Netherlands). The trade flows are described in detail in the following subsection.

3.4. Comparison of selected results of the Green Island Europe and Green Importer Europe scenarios

Similar to the Green Island Europe scenario, the results of the Green Importer Europe scenario indicate a clear preference for the direct use of electricity to reduce CO_2 emissions in the short to medium term. As such, the two scenarios paint a consistent picture in terms of the electrification of heat generation and road transport. Even between 2030 and 2040, the availability of zero-carbon and carbon-neutral fuels from outside of Europe does not lead to a significant shift in the investment decisions compared to the Green Island Europe scenario. By 2050, however, the emergence of a demand for green hydrogen to provide zero-carbon, dispatchable electricity generation as well as to displace fossil fuels in the industry and transport sectors creates an opportunity for competition between European and non-European supply. As a result, the production of green hydrogen in Europe in 2050 decreases from 1528 TWh_{th} in the Green Island Europe

[68] The discrepancy most likely arises from the difference in the developments in the end-use sectors: The study at hand sees a massive electrification in, e.g., heating in Europe by 2050, whereas the study from the European Commission assumes exogenously that a share of such energy needs are covered by synthetic oils and gases in the long term.

[69] The scenario definitions in the European Commission's study exogenously assume that biomass is to play no particularly strong role in Europe in 2050.

scenario to 1282 TWh_{th} in the Green Importer Europe scenario, with Europe importing 304 TWh_{th} of non-European green hydrogen. Consistent with the results of the Green Island Europe scenario, nearly half of all green hydrogen demanded in Europe is consumed by the industry sector, with the dominant industry player Germany requiring 185 TWh_{th} of green hydrogen (i.e., 12% of European green hydrogen demand) for industrial use in 2050 (see Figures E.11-E.13 in Appendix E).[70] Surprisingly, non-European imports of other synthetic fuels are not seen in the optimal solution of the Green Importer Europe scenario, as green hydrogen and biofuels remain the more predominant carbon-neutral choices in 2050. As such, while the availability of zero-carbon and carbon-neutral non-European imports has an affect on the hydrogen supply mix, it does not drive a significant change in the cost-minimizing long-term investment decisions with regards to, e.g., technologies that consume gas or oil derivatives. Furthermore, the cross-sectional European CO_2 shadow prices in all years remain more or less unchanged across scenarios, with the long-term, price-setting marginal abatement in both scenarios occurring via the consumption of biofuels.[71]

The ability of countries to cover some of their hydrogen demand with green hydrogen imports from outside Europe leads to a reduction in the trade flows within Europe. Figure 7 shows the net imports of green hydrogen within Europe in the Green Island Europe (green columns) and Green Importer Europe (orange columns) scenarios as well as the import volumes of green hydrogen from outside of Europe in the Green Importer Europe scenario (grey columns).[72] Five countries are found to consume imports of green hydrogen from outside Europe, namely Germany (215 TWh_{th}), Belgium (53 TWh_{th}), France (21 TWh_{th}), Ireland (9 TWh_{th}) and the Netherlands (4 TWh_{th}), with the majority of these countries requiring relatively large volumes of green hydrogen for their respective industry sectors (see Footnote 70) as well as for electricity generation (see Figures E.12 and E.13 in Appendix E). As a result, these countries lower their imports of European-produced green hydrogen as more economical supply options from outside Europe become available. In turn, the overall reduction in the demand for European-produced green hydrogen leads to a greater concentration in the European countries providing exports within Europe. More specifically, a handful of countries including Sweden, Norway, Finland, Lithuania, Romania and Hungary makes up 85% of European exports in the Green Importer Europe scenario as opposed to 70% in the Green Island Europe scenario. As such, smaller, more expensive producers located in countries with less attractive or less available renewable resources are pushed out of the market, allowing for consumers to benefit from lower hydrogen

[70] Once again, it should be emphasized that the assumption for hydrogen demand in the industry sector is given exogenously according to the fuel consumption pathways described in Section 2.2 and shown in Figure C.4 in Appendix C. As green hydrogen is the only zero-carbon / carbon-neutral option considered in the model to decarbonize hydrogen consumption, the results should be interpreted with the exogenous pathway for the industry sector in mind.

[71] Additional comparisons of scenario results available in Appendix E.

[72] A list of the abbreviations used for the country names is given in Table A.3 in Appendix A.

prices in Europe (see Section 4). Spain and Poland, for example, actually switch from green hydrogen exporters to green hydrogen importers, as the neighboring countries Portugal and Lithuania, respectively, can take advantage of strong wind resources to lower green hydrogen production costs. All in all, total European export volumes fall by 28% due to the reduced demand for European-produced green hydrogen that is induced by the availability of green hydrogen from outside of Europe. In addition to the export countries, the results show that a selection of the countries who import green hydrogen from outside of Europe (i.e., Germany, France and Ireland) also ramp down their domestic, more expensive production.

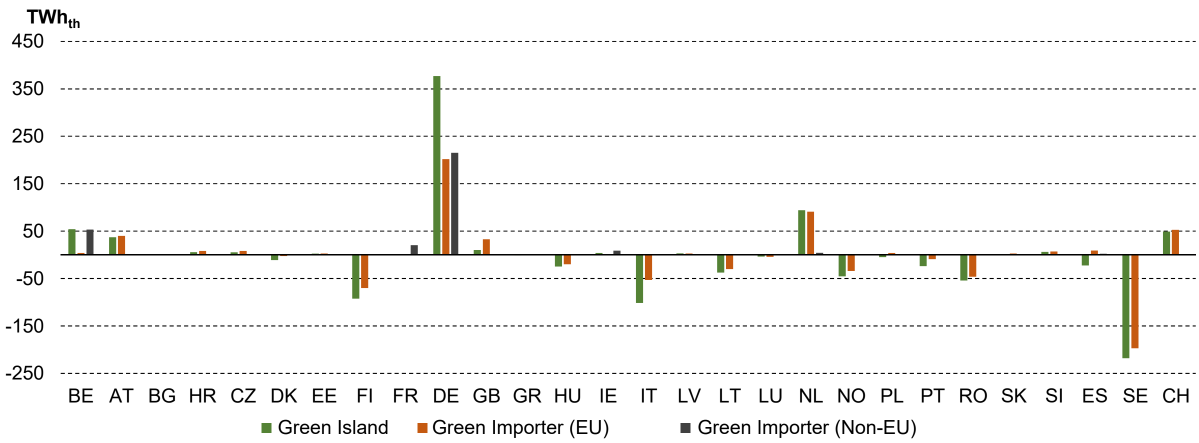

Figure 7: Net imports of green hydrogen produced within Europe in the Green Island Europe scenario and Green Importer Europe scenario as well as imports from outside Europe in the Green Importer Europe scenario in 2050

The 16% reduction in green hydrogen production within Europe has direct consequences for the electricity market. Consistent with the results of the Green Island Europe scenario, 70% of the electricity generation mix in Europe in 2050 is provided by wind and solar generators in the Green Importer Europe scenario, driven by the goal of long-term carbon neutrality. As explained in Section 1.1, a high share of intermittent renewable generation in the electricity market requires sufficient flexibility options to balance short-term discrepancies between electricity supply and demand. Therefore, although the decrease in domestic green hydrogen production is equivalent to savings of 326 TWh_{el}, the electricity consumption in the Green Importer Europe scenario is found to be only 154 TWh_{el} less than in the Green Island Europe scenario. As such, the ramping down of European stand-alone electrolysis systems in the Green Importer Europe scenario creates an opportunity for other flexibility options to benefit from the increased availability of hours with high intermittent generation and, in turn, lower electricity prices. High-temperature electrolysis integrated with a Fischer-Tropsch system is one technology that emerges in the Green Importer Europe scenario, responsible for 130 TWh_{el} of the additional electricity consumption compared to the Green Island Europe Scenario. More specifically, as illustrated in Figure E.9 in Appendix E, several high-renewable countries whose exports of green hydrogen are pushed out by non-European imports decide to substitute the production of hydrogen with the production of synthetic kerosene. In this case, the increase in the availability of low-cost intermittent renewable electricity allows these countries to produce ptx kerosene at prices lower than the bio alternative (i.e., as seen in the Green Island Europe scenario), with the resulting production of 80 TWh_{th} used to decarbonize aviation. Yet the increase in the availability of lower-cost electricity is found to be beneficial for another flexibility option: As depicted in Figure E.10 in Appendix E, electric heat generators ramp up electricity consumption by a total of 42 TWh_{el} over roughly two-thirds of the countries. In fact, a handful of countries with only minimal amounts of ptx capacities actually increase their overall electricity consumption as a result of increased electrification in heating. Nevertheless, despite shifts in the type of electricity consumers, the total electricity consumption in the majority of countries is decreased once non-European imports of green hydrogen enter the market, as shown in Figure E.14 in Appendix E.[73]

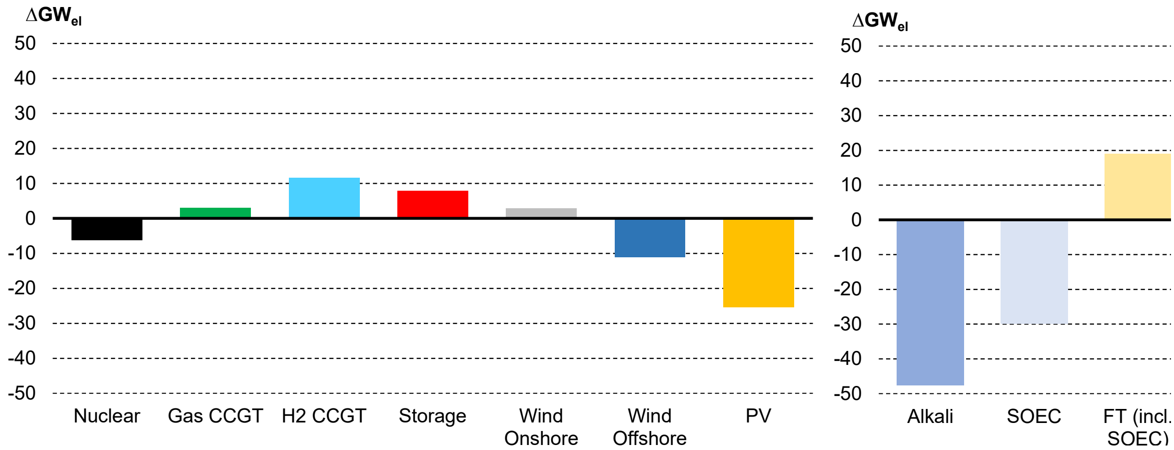

Figure 8: Difference in installed capacities of electricity generation and storage technologies (left) and ptx technologies (right) in 2050 in the Green Importer Europe scenario compared to the Green Island Europe scenario

The change in the electricity consumption levels leads to deviations in the investment decisions regarding the installed capacities of electricity generators in 2050, as shown in Figure 8.[74] Aggregated across all electricity generating technologies and countries, the installed capacity in 2050 in the Green Importer Europe scenario is found to be 26 GW_{el} less than in the Green Island Europe scenario. Technologies including PV,

[73]Similar to the case of hydrogen described in Footnote 70, it is important to note that ca. 35% of the European electricity demand in 2050 is defined exogenously via the fuel consumption pathways for the industry, agriculture and residential and commercial sectors as well as non-road transport described in Section 2.2 (see Figure 1 and Figure C.3 in Appendix C). Furthermore, assumptions on, e.g., technical lifetimes and replacement rates for technologies within the end-use sectors defined exogenously in the model may restrict to what extent the electricity market can react to a change in the scenario definition.

[74]Any comparative results shown in this subsection are taken from the perspective of the Green Importer Europe scenario, i.e., results of the Green Importer Europe scenario minus the results of the Green Island Europe scenario.

offshore wind and nuclear see lower levels of installed capacity in the Green Importer Europe scenario, whereas the capacities of gas and hydrogen power plants is increased. As such, the reduced need for electricity input for ptx processes allows the model to avoid investing in renewable electricity generation technologies in sub-par locations. For example, as shown in Figure E.15 in Appendix E, the installed capacity of PV systems in 2050 in Scandinavian countries is more than 50% lower and in Estonia and Ireland nearly 90% lower than in the Green Island Europe scenario; and France, Germany and Poland see less installed capacity of offshore wind. Furthermore, the availability of comparatively low-cost green hydrogen imports from outside Europe makes hydrogen power plants more economical. Several countries including Belgium, Austria, Croatia, Estonia, Latvia and the Netherlands actually choose to install hydrogen CCGT instead of gas CCGT for backup capacity in the Green Importer Europe scenario. These shifts are also reflected in the changes in the countries' generation mix, illustrated in Figure E.16 in Appendix E. In fact, this change to the electricity market is the main driver behind why the total consumption of green hydrogen in Europe actually increases by 58 TWh_{th} in the Green Importer Europe scenario compared to the Green Island Europe scenario (see E.17 in Appendix E).

Finally, as explained above, the reduction in electricity consumption for ptx processes allows for other flexibility options to increase their market penetration. Storage is another flexibility option that is able to take advantage of the situation, increasing installed capacity by 8 GW_{el} in the Green Importer Europe scenario. Countries such as Great Britain (+3 GW_{el}) and Finland (+2 GW_{el}) make up a large share of this difference, using storage —rather than electrolysis—to maximize the consumption of offshore wind generation for the direct use of electricity in, e.g., heat generation. On the other hand, as shown on the right-hand side of Figure 8, the drop in European green hydrogen production results in a decrease in electrolyzer capacity, equal to a difference of 78 GW_{el}. The largest differences are seen in Italy (-12 GW_{el}), driven by a 25% decrease in green hydrogen exports, alongside Great Britain (-11 GW_{el}), Germany (-9 GW_{el}) and France (-9 GW_{el}), who significant reduce domestic production. Finally, nearly 20 GW_{el} of high-temperature SOEC electrolysis integrated with a Fischer-Tropsch system is installed in eleven countries in the Green Importer Europe scenario, compared to just 1 GW_{el} installed in Bulgaria in the Green Island Europe scenario.

4. Welfare analysis of selected market players

To address the third research question, the economic consequences of long-term energy independence in Europe are analyzed for selected individual players. The comparison of the two scenarios presented in Section 3.4 reveals that both green hydrogen producers and consumers as well as electricity generators and consumers appear to be noticeably affected by the decision whether or not to impose long-term energy independence in Europe. As such, following a similar method as described in Schlund and Schönfisch (2021), the differences in the average[75] producer surplus, consumer surplus and total welfare across scenarios for green hydrogen producers and consumers (in €/MWh$_{\mathrm{th}}$) as well as electricity generators and consumers (in €/MWh$_{\mathrm{el}}$) across Europe are evaluated in the following. The key results are summarized in Table 1. A detailed description of the country-specific results can be found in Appendix F.

		Green Island	**Green Importer**	**Delta (Imp. - Isl.)**	**Sum (CS + PS)**
Green Hydrogen [EUR/MWh$_{\mathrm{th}}$]	Avg. Consumer Cost	-86.8	-77.3	-	-
	Avg. Consumer Surplus (CS)	-	-	9.5	-
	Avg. Producer Cost	25.2	24.0	-	-
	Avg. Producer Surplus (PS)	-	-	-1.2	-
	Change in Avg. Total Welfare	-	-	-	8.3
Electricity [EUR/MWh$_{\mathrm{el}}$]	Avg. Consumer Cost	-52.3	-47.9	-	-
	Avg. Consumer Surplus (CS)	-	-	4.4	-
	Avg. Producer Cost	34.1	30.6	-	-
	Avg. Producer Surplus (PS)	-	-	-3.5	-
	Change in Avg. Total Welfare	-	-	-	0.9

Table 1: Results of the welfare analysis for the green hydrogen and electricity markets in 2050 across Europe, with average costs (i.e., prices) to consumers shown as negative values

Beginning with green hydrogen, the difference in average consumer surplus is synonymous to the change in a country's endogenous price for green hydrogen, which is a result of the model according to the first-order condition of the equilibrium constraint of the ptx module (i.e., Equation 5) as described in Section 2.2, in the Green Importer Europe scenario relative to the Green Island Europe scenario. Averaging across all countries considered, the demand-weighted endogenous price for green hydrogen in 2050 drops from 86.8 €/MWh$_{\mathrm{th}}$ in the Green Island Europe scenario to 77.3 €/MWh$_{\mathrm{th}}$ in the Green Importer Europe scenario —which is 0.8 €/MWh$_{\mathrm{th}}$ below the exogenous price assumed in 2050 for green hydrogen imports from outside Europe shown in Table C.21 in Appendix C.[76] In fact, it can clearly be seen in Figure F.19 in Appendix F that consumers in the year 2050 across all European countries benefit from allowing imports of green hydrogen from outside Europe, indicated by the unanimously positive difference in the average consumer surplus in the Green Importer Europe scenario compared to the Green Island Europe scenario.

The comparably significant gains in average consumer surplus can be interpreted as a direct result of the scenario definition, as the exogenous price assumed for green hydrogen imports from outside Europe serves

[75]As explained in Schlund and Schönfisch (2021), the average producer or consumer surplus is defined as the absolute surplus in Euro (€) divided by the production or consumption volumes, respectively.

[76]The values of the endogenous prices for green hydrogen in 2050 are shown for each country in Figure F.20 in Appendix F.

as an upper limit for the European consumers' willingness-to-pay for green hydrogen. In other words, the factor driving the change in the results across scenarios is the economic pressure to produce green hydrogen in Europe at an endogenous price below the exogenous price of importing green hydrogen from outside of Europe. If domestic green hydrogen producers fail to dip below this price point, consumers always have the option to increase their consumer surplus in the Green Importer Scenario by buying green hydrogen from the non-European market at a lower price than that of domestic production. As such, the significant difference in the endogenous green hydrogen prices in the Green Island scenario compared to the exogenous non-European import price in the Green Importer scenario preemptively drive the results for the gains in average consumer surplus. For example, countries with the greatest gains in average consumer surplus tend to be those with the highest endogenous green hydrogen prices in the Green Island Europe scenario, namely Ireland, Belgium and Germany with prices of 89.6, 88.9 and 88.6 €/MWh_{th}, respectively (see Figures F.19 and F.20 in Appendix F). Referring to Figure 7, these are also three of the five countries that import from outside of Europe in the Green Importer Europe scenario in order to cover their hydrogen demand for the industry sector as well as for electricity generation (see Figures E.12 and E.13 in Appendix E). On the other hand, the lowest prices for green hydrogen in both the Green Island Europe and Green Importer Europe scenarios are seen in Bulgaria at 62.3 and 58.9 €/MWh_{th}, respectively (see Appendix F).

For European suppliers of green hydrogen, the average producer surplus is calculated as the revenues generated by selling their green hydrogen at the market price corrected by the variable costs needed to produce the green hydrogen, divided by the production volumes. The difference in the average producer surplus, in turn, may be negative or positive depending on how the average revenues and/or average variable costs change across scenarios. As described above, average revenues for green hydrogen producers in all countries decrease as the introduction of non-European green hydrogen imports drives down the endogenous price for green hydrogen. Therefore, mathematically speaking, a difference in the average producer surplus equal to zero across the two scenarios would indicate that the average variable costs, which mostly consist of the costs of electricity consumption, are able to be reduced to the point to fully compensate the average revenue losses accrued from the decrease in the market price for green hydrogen. As shown in Table 1, the results indicate that the green hydrogen producers across Europe that continue to operate in the Green Importer scenario can in fact minimize their losses in average producer surplus to a near-zero value of -1.2 €/MWh_{th}. To counterbalance the rather high losses (11%) in average revenue, green hydrogen producers that stay in the market do so by maximizing their flexibility to take greater advantage of fluctuations in the electricity price. For many, this means ramping down overall production volumes (see Figure E.9

in Appendix E) and, as such, reducing the full-load hours of the electrolysis systems to avoid operation in times of higher electricity prices and less intermittent renewable electricity generation. Hungary, for example, reduces its overall domestic green hydrogen production by 13% and is thus able to operate its electrolysis system at 2540 rather than 2900 full-load hours, enabling Hungarian green hydrogen producers to reduce their variable costs by 11.5 €/MWh_{th}.[77] On average, European producers of green hydrogen are able to save 8.3 €/MWh_{th}, which makes up the entirety[78] of the gains in average total welfare seen in the European green hydrogen market (see Table 1).

Analogous to the case of green hydrogen, electricity consumers are found to reap the benefits of opening up Europe to international green hydrogen trade: The difference in average consumer surplus, which in this case is equal to the savings in the demand-weighted average of the hourly marginal costs of electricity generation (i.e., the electricity price)[79] in the Green Importer scenario compared to the Green Island scenario, is positive in every country (see Figure F.22 in Appendix F).[80] Across Europe, the demand-weighted average electricity price in 2050 decreases by 4.4 €/MWh_{el}, from 52.3 €/MWh_{el} in the Green Island Europe scenario to 47.9 €/MWh_{el} in the Green Importer Europe scenario. The price spreads, as shown in Figure F.23 in Appendix F, range from 36.6 €/MWh_{el} (Portugal) to 65.8 €/MWh_{el} (Switzerland) in the Green Island Europe scenario and 35.4 €/MWh_{el} (Greece) and 61.7 €/MWh_{el} (Switzerland) in the Green Importer Europe scenario. For electricity generators, the average producer surplus can be understood as the total revenues from selling the electricity generated minus the total variable costs of generating the electricity[81], divided by the generation volume. Averaged across all countries considered, the average producer surplus of European electricity generators in 2050 decreases by 3.5 €/MWh_{el}, from 34.1 €/MWh_{el} in the Green Island Europe scenario to 30.6 €/MWh_{el} in the Green Importer Europe scenario.

A similar logic applies to the electricity market as in the green hydrogen market: Price savings for consumers and a reduction in average variable costs for suppliers lead to an increase in total average welfare in the Green Importer scenario compared to the Green Island scenario. However, while the benefits across scenarios for electricity consumers are proportionally similar to those for green hydrogen consumers (i.e., gains of 11% and 9% across scenarios, respectively), electricity generators see losses equal to over 10%

[77]See Appendix F for detailed examples for individual countries.

[78]The average total welfare is equal to the sum of the average consumer surplus and average producer surplus. Within this analysis, the average consumer surplus (i.e., price) and average revenue losses for producers are of equal magnitude, which allows for the change in the average total welfare to be interpreted as the change in the average variable costs of production.

[79]In other words, the first-order condition of the equilibrium condition in the electricity market module weighted by the electricity demand (see Section 2.1). Within this analysis, this may be understood as a market-based electricity price similar to the spot market price.

[80]The values for the demand-weighted averages of the endogenous electricity prices in each country, averaged over all time slices in 2050, are shown in Figure F.23 in Appendix F.

[81]Because carbon neutrality has been reached, electricity generators would be exempt from paying a CO_2 price in 2050.

compared to losses of only 5% for green hydrogen producers. In other words, electricity generators appear to have greater difficulties to reduce their average variable costs and, as such, struggle to recover their losses in average revenue. As a result, the change in average total welfare in the electricity market remains only slightly positive at 0.9 €/MWh$_{el}$ in the Green Importer scenario compared to the Green Island scenario. Referring to Figure F.24 in Appendix F, the country-specific results for the electricity market fluctuate significantly between countries with comparatively high gains in total average welfare (e.g., Norway with +5.5 €/MWh$_{el}$), countries with negligible change in total average welfare (e.g., Finland) and countries with losses in total average welfare (e.g., Croatia with -1.7 €/MWh$_{el}$).[82]

This can be explained by multiple opposing effects exhibited in the electricity market as a result of the changes in the green hydrogen supply mix in the Green Importer Europe scenario. First of all, the availability of lower cost green hydrogen in the Green Importer Europe scenario drives a switch in the choice of dispatchable peak generation from gas turbines running on biofuels to hydrogen CCGT (see Figures E.16 and E.17 in Appendix E), which also explains the increase in hydrogen CCGT capacities shown in Figure 8. As a result, consumer surplus is pushed upwards as the average marginal costs of electricity generation (i.e., prices) are driven downwards. For electricity generators, the fuel switch as well as the overall reduction in electricity demand have a positive effect on the variable costs as they are able to reduce the supply from CCGT running on biofuels, i.e., the most expensive zero-carbon/carbon-neutral dispatchable technology.[83] Nevertheless, both the reduction and shift in the load profile of electrolysis systems described above leads to a lower amount of offshore wind (Δ-46 TWh$_{el}$) as well as PV (Δ-41 TWh$_{el}$) in the Green Importer Europe scenario compared to the Green Island Europe scenario as renewable generation in sub-par locations falls out of the market (see Figures E.16 and E.17 in Appendix E). As such, for electricity generators across Europe, the average variable costs remain more or less unchanged (Δ-0.9 €/MWh$_{el}$) as any financial benefit resulting from the reduction in more expensive dispatchable generation is diluted by the missing volumes of intermittent renewable generation with zero variable costs.

It should be noted that an alternative assumption on the magnitude of the exogenous import price for green hydrogen could drastically effect the results presented. For example, in the year 2040, the average endogenous price of green hydrogen in the Green Importer Europe scenario is equal to 68.0 €/MWh$_{th}$ compared to an exogenous import price of 86.0 €/MWh$_{th}$ (see Table C.21 in Appendix C). As such, it should come as no surprise that the introduction of the availability of non-European green hydrogen imports

[82]See Appendix F for a detailed description of the country-specific results of the welfare analysis for the electricity market.

[83]Approximately 54 TWh$_{th}$ of biofuels are avoided in the 2050 electricity generation mix in the Green Island Europe scenario compared to the Green Importer Europe scenario (see Figure E.17 in Appendix E).

does not cause a noticeable deviation from the Green Island Europe scenario before 2050. If, however, the prices of non-European green hydrogen imports would be exogenously assumed to be lower than those of European production in 2040, the results may be quite different. On the one hand, consistent with the results described above, European green hydrogen producers capable of undercutting the exogenous price will continue to operate. However, on the other hand, it will become increasingly harder to compete as the demand and therefore the endogenous price for green hydrogen increase. As a result, in this alternative scenario, the greater share of green hydrogen consumption in Europe would be covered by non-European imports—far exceeding the 19% share of non-European imports seen in the Green Importer Europe scenario. Depending on the marginal abatement costs in the energy transformation and end-use sectors, a significantly lower exogenous price for green hydrogen could potentially drive further investments in hydrogen-consuming technologies such as hydrogen fuel cell vehicles, hydrogen CHP and hydrogen CCGT, as well as technologies for the decentralized production of hydrogen derivatives such as Fischer-Tropsch and methanation. In turn, more expensive carbon-neutral fuels such as biomass would most likely wean out of the consumption mix, similar to the results depicted above. For the electricity market, less electricity demand from European electrolysis systems would potentially free up opportunities for other flexibility options to take advantage of the large share of intermittent renewable electricity generation and, as such, lower electricity prices. However, flexibility options such as, e.g., electric heating and electric vehicles are limited in the flexibility of their load profiles due to consumer needs and comforts as well as temporal restrictions of storage. Therefore, there would most likely be an increase in the electrification; however, only as long as the electricity-consuming technologies can operate at costs less than or equal to the hydrogen-consuming alternative.

5. Conclusion

The paper at hand offers a quantitative assessment of the transformation of the European energy system in achieving the goal of the European Commission of carbon neutrality in Europe by 2050. In doing so, the investment and dispatch optimization model DIMENSION developed in Helgeson and Peter (2020) is extended to comprise a greater number of sectors and technologies as well as a higher level of endogeneous links between energy supply and demand. More specifically, the complex methodological enhancements to the model serve to evaluate a wider range of flexibility and decarbonization options while also considering a larger share of the costs and CO_2 emissions associated with both the supply and consumption of energy in 28 countries in Europe up to 2050.

The model is applied to examine the cost-minimal pathway for two scenarios with varying spatial boundaries of the optimization, namely the Green Island Europe and Green Importer Europe scenarios: Whereas the consumption of green hydrogen and/or synthetic fuels in the Green Island Europe scenario requires an investment in the necessary power-to-x (ptx) production and electricity generating capacities within Europe, the Green Importer Europe scenario allows for such zero-carbon and carbon-neutral fuels to be available for purchase from outside of Europe at an exogeneously-defined price. By investigating a fictitious energy-independent yet carbon-neutral Europe, a unique market environment emerges that pushes the model's endogeneity to the limit; however, by comparing to a market with the possibility of non-European green imports, key findings can be made regarding the robustness of the investment and dispatch decisions of flexibility and decarbonization options and the economic consequences for selected market players.

The results of the cost minimization in the Green Island Europe scenario show that the model chooses to most rapidly decarbonize the electricity sector, with capacities of wind and solar electricity generation in Europe tripling between 2019 and 2030. Simultaneously, a surge in system flexibility allows for the dispatchable fossil electric capacity to be reduced by nearly 50% despite a 500 TWh_{el} increase in electricity demand as 77% of heat generation in Europe is supplied by electricity-consuming heating technologies in 2030 compared to 19% in 2019. The 41% decrease in total emissions between 2019 and 2030 results in a relatively modest change in the cross-sectional European CO_2 price from 22 €/tCO_2 in 2019 to 36 €/tCO_2 in 2030. By 2050, intermittent renewable electricity generation reaches 70% alongside generation from hydro plants, nuclear, geothermal and hydrogen power plants. Flexibility options such as electricity storage, DSM and electric vehicles expand their market presence, while the more hard-to-abate sectors such as transport and industry experience a rapid shift from fossil fuels to biofuels as well as to green hydrogen. As such, over 500 GW_{el} of electrolyzer capacity is installed between 2030 and 2050, consuming 2167 TWh_{el} of electricity to produce 1528 TWh_{th} of green hydrogen in 2050. As a result, the cross-sectional European CO_2 price rises to 225 €/tCO_2 in 2040 and to 559 €/tCO_2 in 2050. All in all, carbon neutrality in an energy-independent Europe leads to an overall increase in electricity consumption in Europe of over 4000 TWh_{el} between 2019 and 2050.

The second scenario, the Green Importer Europe scenario, reveals a similar decarbonization strategy between 2019 and 2040 to that of the Green Island Europe scenario. By 2050, however, the emergence of a demand for green hydrogen creates an opportunity for the diversification of Europe's hydrogen supply as approximately 300 TWh_{th} of green hydrogen (i.e., 19% of total consumption) is imported from outside of Europe; yet the availability of other carbon-neutral synthetic fuels from outside Europe is not attractive enough to drive a change in the investment decisions in the end-use sectors seen in the Green Island Europe scenario. With a decrease in domestic green hydrogen production of nearly 250 TWh_{th}, the ramping down of stand-alone electrolysis systems in the Green Importer Europe scenario creates an opportunity for other flexibility options to benefit from lower electricity prices, namely high-temperature electrolysis integrated with a Fischer-Tropsch system as well as battery storage and electric heat generators. As a result, the electricity consumption is found to be only 154 TWh_{el} and the installed electric capacity 26 GW_{el} less in the Green Importer Europe scenario than in the Green Island Europe scenario in 2050.

Finally, the difference in average consumer and producer surplus as well average total welfare between the scenarios is examined for the European electricity and green hydrogen markets. The results show that the introduction of the economic pressure to produce green hydrogen in Europe at an endogenous price below the exogenous price of importing green hydrogen from outside of Europe has positive effects for consumers: Averaged across all European countries in 2050, the endogenous price for green hydrogen decreases from 86.8 €/MWh_{th} to 77.3 €/MWh_{th}, and the endogenous electricity price from 52.3 €/MWh_{el} to 47.9€/MWh_{el}, in the Green Island Europe and Green Importer Europe scenarios, respectively. Yet the welfare analysis highlights that an increase in average total welfare is only possible as long as producers/generators are able to reduce their average variable costs beyond the point of simply covering their average revenue losses from the price decrease. In the case of green hydrogen, the results indicate that this is best achieved by reducing the full-load hours of the electrolysis system in order to operate more flexibly and take greater advantage of fluctuations in the electricity price. In doing so, average total welfare for the green hydrogen market is increased by 8.3 €/MWh_{th} in the Green Importer Europe scenario compared to the Green Island Europe scenario. For electricity generators, however, the change in the load profile of green hydrogen producers means that electricity demand in certain hours is lower compared to the Green Island Europe scenario. As a result, the model chooses to reduce supply by decreasing the installed capacity of intermittent electricity generation in sub-par locations. In turn, however, this makes it difficult for electricity generators to reduce their average variable costs as less low-/zero-cost electricity is consumed. Nevertheless, electricity generators are able to take advantage of the reduction in electricity demand as well as increase in hydrogen CCGT capacities by decreasing the supply from the most expensive zero carbon/carbon-neutral dispatchable technology, often CCGT running on biofuels. These two counteracting effects lead to a moderate increase in average total welfare for the electricity market equal to 0.9 €/MWh_{el}.

The model developed as well as the results presented contribute to the discussion surrounding the technical and market implications for Europe in reaching carbon neutrality in 2050. More specifically, the role of flexibility options and the competition between such technologies to balance out the rapid growth of intermittent renewable generation will only continue to gain importance as carbon reduction targets become stricter over time. Especially for policymakers, examining different long-term, cost-minimizing decarbonization pathways of the complete integrated energy system may help to set effective and efficient incentives and regulatory measures across countries and sectors. Nevertheless, as is often the case, the results should be interpreted with care as the model logic as well as the assumptions and scenario definitions deviate strongly from the current and future realities.

The research presented offers a foundation for a wide range of future research and applications. For example, a reexamination of the Green Island Europe and Green Importer Europe scenarios using a high-resolution (e.g., hourly, quarter-hourly, etc.) dispatch setting for, e.g., the model year 2050 would be a relevant extension of the work at hand to better analyze the value of and competition between flexibility options. Similarly, sensitivity analyses to the Green Importer Europe scenario to assess varying import prices from outside of Europe of different zero-carbon and carbon-neutral fuels would help to better understand the robustness of the results. Another interesting sensitivity analysis could assess the robustness of the model under changing pathways for the exogenously-defined end-use sectors, i.e., by varying the fuel consumption mix or demand levels for the industry sector. Moreover, further extensions to the technical scope of the model, e.g., the introduction of options for carbon capture and storage (CCS) and carbon capture and use (CCU), could be beneficial to potentially include so-called 'negative' carbon emissions.

Appendix A. Nomenclature and abbreviations

Throughout the paper, notation as listed in Tables A.1 and A.2 is applied.

Sets		
$f \in \mathbf{F}$		Fuel type ($f1$: Substitute fuels)
$i \in \mathbf{I}$		Technologies (el: electricity generators and storage; ptx: ptx and liquefaction plants; rt: vehicles and driving infrastructure; ht: chp, heat generators and storage; dsm: demand-side management processes)
$m, n \in \mathbf{M}$		Markets
$s \in \mathbf{S}$		Sector (et: energy transformation, rc: residential & commercial; ind: industry; trans: transport; agr: agriculture & other land use)
$t \in \mathbf{T}$		Time ($\mathbf{T}$: time slices)
$y \in \mathbf{Y}$		Model years
Parameters		
l	MWh	Exogenous electricity demand pathway
l^*	MWh	Load of electricity consumers prior to introduction of DSM processes
dh	MWh	Exogenous heat demand pathway per heat use type
dh_{peak}	MWh	Peak heat demand per heat use type
dr	bn. km	Exogenous road transport demand pathway
df	MWh	Exogenous fuel demand pathway
p	EUR/MWh	Commodity prices
σ	-	Maximum decrease in electricity load from flexible DSM processes
ω	-	Maximum increase in electricity load from flexible DSM processes
θ	-	Feasibility factor for DSM processes
T^*	h	Maximum shifting period of DSM processes
x	-	Technical availability factor
$\bar{X}$	MW	Upper limit capacity
v	-	Capacity value
$\bar{k}$	MW	Transmission capacity
α	-	Power-to-heat ratio of CHP systems
β	-	Power loss factor of CHP systems
η	-	Efficiency
η^*	-	Electric efficiency of a CHP system
δ	EUR/MW	Fixed costs
γ	EUR/MWh	Variable costs
κ_{f1}	tCO_2eq/MWh	Fuel-specific emission factor
$\kappa_{f1,upstream}$	tCO_2eq/MWh	Fuel-specific upstream emission factor
GHG_{cap}	tCO_2eq	Greenhouse gas emissions cap
TC	bn. EUR	Discounted total costs

Table A.1: Model sets and parameters

Optimization variables		
$\bar{\mathbf{x}}$	MW	Generation capacity
$\mathbf{g}$	MWh	Generation
$\mathbf{g}^*$	MWh	Cogeneration of electricity in CHP systems
$\mathbf{k}$	MWh	Electricity transmission between markets
$\mathbf{ec}$	MWh	Energy consumption
$\hat{\mathbf{ec}}$	MWh	Increase in energy consumption by DSM processes
$\check{\mathbf{ec}}$	MWh	Decrease in energy consumption by DSM processes
$\bar{\mathbf{ec}}$	MWh	Energy consumption prior to introduction of DSM processes
$\hat{\mathbf{t}}$	h	Time slice of increased load due to DSM processes
$\check{\mathbf{t}}$	h	Time slice of decreased load due to DSM processes
$\mathbf{t}^*$	h	Temporal shift for storage technologies
$\mathbf{sr}$	MWh	Supply road transport
$\mathbf{sf}$	MWh	Supply fuels
$\mathbf{fp}$	MWh	Fuel production
$\mathbf{ft}$	MWh	Fuel trade

Table A.2: Model variables

AT	Austria	FI	Finland	NL	Netherlands
BE	Belgium	FR	France	NO	Norway
BG	Bulgaria	GB	Great Britain	PL	Poland
CH	Switzerland	GR	Greece	PT	Portugal
CZ	Czech Republic	HR	Croatia	RO	Romania
DE	Germany	HU	Hungary	SE	Sweden
DK (East)	Eastern Denmark	IE	Ireland	SI	Slovenia
DK (West)	Western Denmark	IT	Italy	SK	Slovakia
EE	Estonia	LT	Lithuania		
ES	Spain	LV	Latvia		

Table A.3: Country codes

a	Years
BEV	Battery electric vehicle
bn	Billion
CCU	Carbon capture and utilization
CCGT	Closed cycle gas turbine
CHP	Combined heat and power
COP	Coefficient of performance
CNG	Compressed natural gas
CO_2	Carbon dioxide
CSP	Concentrated solar power
DAC	Direct air capture
DSM	Demand-side management
el	Electricity / electric
eq	Equivalent
EUR	Euro
FCV	Fuel-cell vehicle
FOM	Fixed operation and maintenance
GW_{el} / GW_{th}	Gigawatt (electric / thermal)
H2	Hydrogen
HDV	Heavy-duty vehicle
HEV	Hybrid electric vehicle
km	Kilometer
kW_{el} / kW_{th}	Kilowatt (electric / thermal)
kWh_{el} / kWh_{th}	Kilowatt hour (electric / thermal)
LCOE	Levelized costs of electricity
LDV	Light-duty vehicle
LH2	Liquid hydrogen
Liq	Liquefaction/liquefied
LNG	Liquefied natural gas
$MtCO_2$ eq	Million tons carbon dioxide equivalent
MW_{el} / MW_{th}	Megawatt (electric / thermal)
MWh_{el} / MWh_{th}	Megawatt hour (electric / thermal)
NTC	Net transmission capacity
OCGT	Open-cycle gas turbine
PEM	Polymer electrolyte membrane electrolysis
PHEV	Plug-in hybrid electric vehicle
PPV	Private passenger vehicles
PtX / ptx	Power to X (heat, gas, liquid, fuel, chemicals etc.)
PtX H2	Ptx hydrogen gas
PtX LH2	Ptx liquid hydrogen
PtX CH4	Ptx methane gas
PtX LCH4	Ptx liquid methane
PV	Photovoltaics
RES	Renewable energy sources
SOEC	Solid oxide electrolyzer cell
th	Thermal
t	Ton
TTW	Tank-to-wheel
TWh_{el} / TWh_{th}	Terawatt hour (electric / thermal)
WTT	Well-to-tank
WTW	Well-to-wheel

Table A.4: Abbreviations

Appendix B. Defining typical days

The model optimizes both the investment and dispatch decision simultaneously for hundreds of technologies and over many countries and years. Due to limitations in computational capacity, the model size must be reduced in order to allow for the model to solve within an adequate time frame and with the given technical resources. This is often done by limiting the temporal resolution from 8760 hours to a certain number of time slices per year (see, e.g., Nahmmacher et al. (2016)). In doing so, so-called "typical days" are defined in an attempt to identify a pattern in, e.g., the weather or demand conditions that can be simplify 365 different days into a reduced number of reoccurring day types, as shown in Figure B.1.

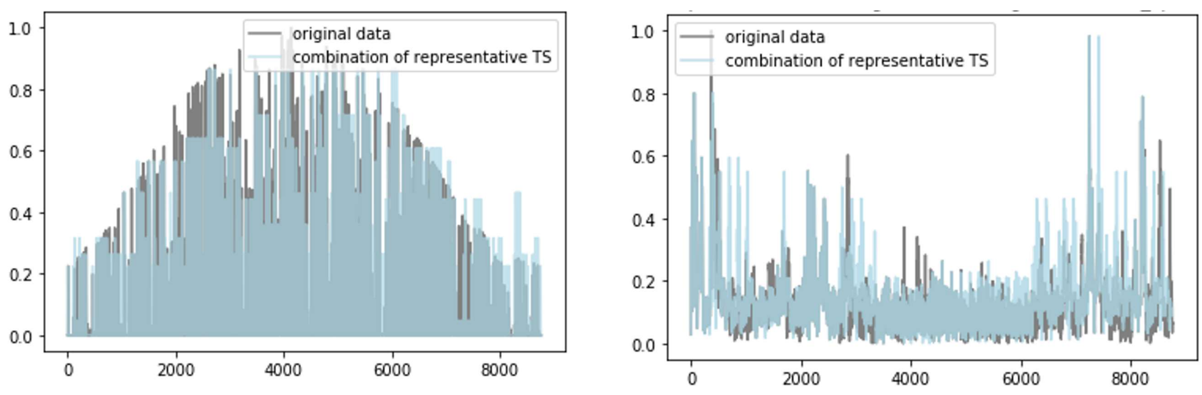

Figure B.1: Illustrative depiction of how data sets with full temporal resolution may be recreated using typical days using the example of solar irradiation (left) and wind speed (right)

Several methods may be applied to create a representative time series. Within this analysis, a clustering tool developed at the Institute of Energy Economics at the University of Cologne (EWI) is used to reduce the yearly resolution to 16 typical days based on wind and solar data sets for the year 2015. The tool was developed based on the methodology presented in Nahmmacher et al. (2016) following a similar 'time slice approach'. In doing so, the data set for solar irradiation and wind speed is separated into four parts according to whether the days occur in summer or winter, on a weekday or weekend. Next, the data is clustered within each of the four groups using a k-means algorithm such that the variance between data values and cluster centers is minimized. The solar and wind data sets are clustered according to four criteria, namely high wind speeds, high solar exposure, low wind speeds and low solar exposure. The resulting 16 typical days are then weighted relative to the number of occurrences, where each calendar day is assigned a corresponding representative day to recreate a full year. The remaining hourly data sets, e.g., electricity and heat demands, coefficient of performance and driving profiles as well as solar thermal, CSP and run-of-river availabilities, are then transformed to representative time series using the same typical days and weights.

Appendix C. Supplementary data and assumptions

Appendix C.1. Assumptions on fuel prices and emissions factors

		2019	**2030**	**2040**	**2050**
Fuel price [€/MWh_{th}]	Oil	36	37	37	36
	Coal	9	10	9	9
	Lignite	4	6	6	6
	Nuclear	3	3	3	3
	Gas	21	21	21	21
	Gasoline	51	52	52	51
	Diesel	49	50	50	49
	Kerosene	45	46	46	45
	LNG	21	21	21	21
	Hydrogen	28	27	27	27
	Liquid Hydrogen	28	27	27	27
	Biomethane (hc)	83	93	93	93
	Biogas (lc)	68	77	77	77
	Bio Oil / Biodiesel / Biogasoline	83	116	116	116
	Biokerosene	83	134	168	168
	Bio LNG	142	160	160	160
	Biosolid	38	53	53	53
Feedstock CO_2 price [€/tCO_2]	CO_2 from DAC	170	142	113	85

Table C.5: Assumptions on price developments for fuels and feedstock CO_2 for ptx applications (based on International Energy Agency (IEA) (2021), Helgeson and Peter (2020), Kampman et al. (2016), Koch et al. (2018), Ruiz et al. (2019), Brown et al. (2020) and European Commission (2021))

Substitute Fuel	Direct (TTW) Emissions	Upstream (WTT) Emissions 2019*	Description Production Cycle
Bio LNG	0.200	0.050	Fermentation, upgrading, liquefaction, distribution
Bio Oil	0.280	0.173	Rape cultivation, rapeseed drying, oil production, distribution
Biodiesel	0.270	0.173	Rape cultivation, rapeseed drying, oil production, biodiesel production, distribution
Biomethane (hc)	0.200	0.034	Fermentation, upgrading, compression, distribution
Biogas (lc)	0.200	0.034	Fermentation, upgrading, compression, distribution
Biogasoline	0.250	0.204	Wheat cultivation, grain drying, storage and handling, ethanol production, distribution
Biokerosene	0.260	0.204	Wheat cultivation, grain drying, storage and handling, ethanol production, distribution
Biosolid	0.250	0.036	Wood plantation & chipping
CNG	0.202	0.027	Natural gas production, distribution, compression
Coal	0.337	0.058	Hard coal provision
Diesel	0.266	0.065	Crude oil production, crude refining, distribution
Gasoline	0.253	0.059	Crude oil production, crude refining, distribution
Hydrogen	0.000	0.322	Natural gas production, stream reforming, pipeline, compression
Kerosene	0.264	0.059	Crude oil production, crude refining, distribution
Liquid Hydrogen	0.000	0.421	Natural gas production, stream reforming, liquefaction, road transport
Lignite	0.381	0.019	Lignite provision
LNG	0.202	0.047	Natural gas production, liquefaction, loading & unloading terminal, road transport
Nuclear	0.000	0.000	Uranium ore extraction, fuel production
Oil	0.294	0.065	Crude oil production, crude refining, distribution
Others/Waste	-**	0.310	Waste and by-products generation (short term: recycled petroleum, long term: bio waste)
PtX CH4	0.202	0.009	Conditioning and distribution
PtX Diesel	0.266	0.003	Conditioning and distribution
PtX Gasoline	0.253	0.003	Conditioning and distribution
PtX H2	0.000	0.034	Conditioning and distribution
PtX Kerosene	0.264	0.003	Conditioning and distribution
PtX LCH4	0.200	0.024	Conditioning and distribution
PtX LH2	0.000	0.013	Conditioning and distribution
PtX Oil	0.294	0.003	Conditioning and distribution

*The upstream emissions are assumed to depend on the year, as the emissions intensity of the production cycles may change over time. A linear reduction is assumed from 2025 onward for waste, ptx fuels and biofuels, reaching zero by 2045.
**The direct emissions are included in the upstream emissions factor to account for changes in the type of waste over time

Table C.6: Description of direct and upstream CO_2 emissions assumed in the application (based on BAFA (2019), Prussi et al. (2020) and Helgeson and Peter (2020))

Appendix C.2. Techno-economic assumptions within the modules

	Investment Costs [€/kW$_{el}$]				FOM Costs	Technical	Technical
	2019	2030	2040	2050	[€/kW$_{el}$*a]	Efficiency [-]	Lifetime [a]
Gas OCGT	534	530	525	517	13	0.39	25
Gas CCGT	860	817	792	788	25	0.62	30
Hydrogen OCGT	2000	636	603	569	13	0.33	25
Hydrogen CCGT	2000	981	924	867	25	0.60	30
Coal	1742	1681	1541	1499	41	0.50	45
Lignite	1862	1806	1676	1637	49	0.46	40
Oil	842	842	842	842	7	0.49	25
Nuclear	3323	3323	3323	3323	107	0.33	60
Geothermal	10303	9268	9031	9026	380	0.10	30
Biogas (lc)	825	821	814	803	120	0.36	20
Biosolid	2577	2556	2451	2225	165	0.41	20
Run of River	5000	5000	5000	4500	12	1.00	100
PV Roof	983	776	624	520	17	1.00	25
PV Base	862	681	547	456	15	1.00	25
CSP	3989	3429	3102	2805	15	0.38	25
Wind Onshore	1133	1036	933	846	13	1.00	25
Wind Offshore	2800	2200	1900	1600	93	1.00	25
Battery Storage	600	450	350	350	15	0.90	15
Compressed Air Storage	1100	950	850	700	9	0.60	40
Hydro Storage	3423	3421	3415	3410	12	1.00	100
Pump Storage	3851	3848	3842	3836	12	0.75	100

Table C.7: Techno-economic assumptions for the technologies included in the electricity market module (based on Platts (2016), Mantzos et al. (2019), Helgeson and Peter (2020) and dena et al. (2021))

	Investment	FOM Costs	Variable Costs	Feasibility Factor [-]			
	Costs [€/kW$_{el}$]	[€/kW$_{el}$*a]	[€/MWh$_{el}$]	2019	2030	2040	2050
Hall-Héroult Process (Aluminium)	400	2.0	115	0.00	0.43	0.71	1
Clinker Production (Cement)	1.5	19.1	200	0.58	0.72	0.86	1
Membrane Process (Chlorine)	0.2	0.1	150	0.87	0.91	0.96	1
Pulp Preparation (Paper)	2.3	2.0	250	0.74	0.83	0.91	1

Table C.8: Cost assumptions and feasibility factors for the DSM processes included in the electricity market module for industrial electricity consumers (estimated within the research project "Virtual Institute—Power to Gas and Heat", see Virtuelles Institut (2022))

	Max. Shift Time Frame [h]	Avg. Capacity Utilization [-]	Full-Load Hours [h]	Ramp-Down Factor [-]	Ramp-Up Factor [-]
Hall-Héroult Process (Aluminium)	48	0.95	8322	0.75	1.25
Clinker Production (Cement)	13	0.72	6263	0.00	0.84
Membrane Process (Chlorine)	4	0.88	7709	0.38	0.95
Pulp Preparation (Paper)	2	0.85	7446	0.00	0.95

Table C.9: Technical assumptions for the industrial DSM processes included in the electricity market module (estimated within the research project "Virtual Institute—Power to Gas and Heat", see Virtuelles Institut (2022))

	Annual Electricity Consumption [kWh/a]	Number of Residents [-]	Ramp-Up/Down Factor [-]	Max. Shift Time Frame [h]	FOM Costs (Smart Meter) [€/kW_{el}*a]
HH1	2900	3	0.947	24	10.1
HH2	4000	2	0.959	24	9.9
HH3	7000	5	0.961	24	19.5
HH4	2000	1	0.959	24	8.5
HH5	3100	2	0.959	24	9.9
HH6	4000	3	0.961	24	8.8

Table C.10: Techno-economic assumptions for DSM processes in the residential and commercial sector for six household types HH1-HH6 (based on, e.g., Frondel et al. (2015), Stromspiegel (2019), Bundesnetzagentur (2017))

	Max. Shift Time Frame [h]	Ramp-Up/Down Factor [-]	FOM Costs (Smart Meter) [€/kW_{el}*a]
Serv1	24	0.1	5.5
Serv2	24	0.1	1.4

Table C.11: Techno-economic assumptions for DSM processes in the residential and commercial sector for two commercial consumers Serv1 and Serv2 (based on, e.g., Bundesnetzagentur (2017))

	2019	2030	2040	2050
Hall-Héroult Process (Aluminium)	3.0	3.1	3.2	3.3
Clinker Production (Cement)	1.4	1.5	1.5	2.2
Membrane Process (Chlorine)	2.4	2.6	2.7	2.8
Pulp Preparation (Paper)	6.8	7.2	7.6	8.1
HH1	0.0	0.0	18.0	35.3
HH2	0.0	0.0	36.8	74.9
HH3	0.0	0.0	5.2	14.1
HH4	0.0	0.0	0.3	0.6
HH5	0.0	0.0	34.5	70.6
HH6	0.0	0.0	9.7	18.6
Serv1	0.0	0.0	9.5	11.1
Serv2	0.0	0.0	8.7	8.5

Table C.12: Assumptions on DSM potentials in Europe in GW_{el} for all DSM processes included in application (based on Mantzos et al. (2019)

	Investment Costs [€/kW]				FOM Costs	Thermal	Electric	Technical
	2019	2030	2040	2050	[€/kW*a]	Efficiency [-]	Efficiency [-]	Lifetime [a]
Coal CHP	2156	2132	2020	1896	54	0.44	0.45	45
Lignite CHP	2257	2235	2136	2027	59	0.40	0.41	45
Gas CHP	1183	1136	1109	1104	41	0.60	0.56	30
Hydrogen CHP	2000	1364	1289	1215	41	0.60	0.56	30
Biogas CHP	1605	1605	1601	1546	130	0.69	0.49	30
Biosolid CHP	2959	2952	2904	2711	175	0.49	0.36	30
Coal Heat Plant	343	343	340	336	9	0.94	-	25
Lignite Heat Plant	343	343	340	336	9	0.94	-	25
Gas Heat Plant	495	474	462	449	7	0.79	-	25
Biosolid Heat Plant	440	420	410	400	34	0.87	-	25
Solar Thermal	463	426	406	386	9	1.00	-	30
Geothermal	2105	2105	2053	2000	11	1.00	-	25
Electric Boiler/Rod	70	60	60	60	1	0.99	-	20
Gas Heat Pump	382	382	341	300	2	0.4-1.6*	-	15
Heat Storage	115	115	115	115	0	0.88	-	40

*Minimum and maximum value of COP across all regions

Table C.13: Techno-economic assumptions for district heating technologies included in the heat module, with CHP and electricity-consuming technologies in electric units and the rest in thermal units (based on Mantzos et al. (2019), dena et al. (2021), Platts (2016), Paardekooper et al. (2018) and Energinet and Danish Energy Agency (2019))

	Specific Investment Costs [€/kW]				FOM Costs	Technical	Technical
	2019	2030	2040	2050	[€/kW*a]	Efficiency [-]	Lifetime [a]
Coal Boiler	247	247	247	247	9	0.96	20
Gas Boiler	258	258	258	258	11	0.97	20
Oil Boiler	329	329	329	329	9	0.96	20
Pellet Oven	368	310	296	282	22	0.88	20
Solar Thermal	718	669	615	561	9	1.00	30
Gas Heat Pump	799	799	749	700	6	0.4-1.6*	20
Electric Heat Pump	984	850	775	700	16	1.1-4.5*	20
Micro Gas CHP	2089	1800	1700	1600	165	0.54 (th) / 0.28 (el)	15
Hydrogen Fuel Cell	2546	2200	1900	1600	65	0.50 (th) / 0.35 (el)	15
Heat Storage	152	152	152	152	0	0.84	30

*Minimum and maximum value of COP across all regions

Table C.14: Techno-economic assumptions on individual heating technologies included in the heat module, with electricity-consuming technologies as well as CHPs having electric units, the rest with thermal units (based on Frings and Helgeson (2022), Energinet and Danish Energy Agency (2019) and Paardekooper et al. (2018))

	Specific Investment Costs [€/kW]				FOM Costs	Technical	Technical
	2019	2030	2040	2050	[€/kW*a]	Efficiency [-]	Lifetime [a]
Air Conditioner Gas	799	799	749	700	6	0.97	15
Air Conditioner Electric	984	850	775	700	16	0.99	15
Coal Stove	50	50	50	50	9	0.96	20
Gas Stove	50	50	50	50	7	0.97	20
Oil Stove	50	50	50	50	9	0.96	20
Wood Stove	50	50	50	50	34	0.88	20
Electric Stove	150	125	113	100	1	0.99	30

Table C.15: Techno-economic assumptions for cooling and cooking technologies included in the heat module, with electric-consuming technologies in electric units and the rest in thermal units (based on Energinet and Danish Energy Agency (2019), Paardekooper et al. (2018) and IRENA (2017))

		Investment Costs [€/kW$_{el}$]				FOM Costs [€/kW$_{el}$*a]		
		2019	**2030**	**2040**	**2050**	**2019**	**2030**	**2040-2050**
Electrolysis	Alkali	534	449	383	337	34	25	20
	PEM	900	698	562	478	61	41	30
	SOEC	1094	828	648	533	75	50	35
Integrated electrolysis-methanation system	Alkali/Catalytic	1439	1285	1150	1031	57	46	39
	PEM/Catalytic	1795	1535	1338	1179	84	63	50
	SOEC/Catalytic	2014	1680	1432	1241	99	72	55
	Alkali/Biological	1518	1320	1186	1067	64	51	43
	PEM/Biological	1871	1570	1375	1216	91	67	54
	SOEC/Biological	2099	1717	1472	1280	107	76	60
Integrated electrolysis-Fischer Tropsch system	Alkali/FT	1918	1766	1630	1491	71	61	54
	PEM/FT	2267	2017	1828	1647	97	77	66
	SOEC/FT	2505	2175	1932	1717	113	87	72
Liquefaction	LH2	1588	761	692	622	67	67	67
	LCH4	5466	5286	5107	4927	178	178	178

Table C.16: Cost assumptions for ptx and liquefaction technologies included in the ptx module (based on Helgeson and Peter (2020), Kreidelmeyer et al. (2020), dena et al. (2021) and IEA (2019))

		Technical Efficiency [el/th]			Technical Lifetime [a]		
		2019	**2030**	**2040-2050**	**2019**	**2030**	**2040-2050**
Electrolysis	Alkali	0.68	0.69	0.71	15	20	25
	PEM	0.65	0.70	0.75	15	20	25
	SOEC	0.73	0.75	0.79	15	20	25
Integrated electrolysis-methanation system	Alkali/Catalytic	0.53	0.54	0.55	15	20	25
	PEM/Catalytic	0.51	0.54	0.58	15	20	25
	SOEC/Catalytic	0.57	0.58	0.62	15	20	25
	Alkali/Biological	0.53	0.54	0.55	15	20	25
	PEM/Biological	0.51	0.54	0.58	15	20	25
	SOEC/Biological	0.57	0.58	0.62	15	20	25
Integrated electrolysis-Fischer Tropsch system	Alkali/FT	0.46	0.48	0.52	15	20	25
	PEM/FT	0.44	0.49	0.55	15	20	25
	SOEC/FT	0.49	0.53	0.58	15	20	25
Liquefaction	LH2	3.53	3.53	3.53	25	25	25
	LCH4	17.37	17.37	17.37	20	20	20

Table C.17: Technical assumptions for ptx and liquefaction technologies included in the ptx module (based on Helgeson and Peter (2020), Kreidelmeyer et al. (2020), dena et al. (2021) and IEA (2019)

Fuel transport costs between European markets [€/(MWh$_{th}$*km)]		
PtX CH4	Pipeline	0.002
PtX LCH4	Tube trailer	0.02
PtX H2	Pipeline (Retrofit)	0.003
PtX LH2	Tube trailer	0.02
PtX Diesel / PtX Gasoline / PtX Oil / PtX Kerosene	Tube trailer	0.01

Table C.18: Assumptions on transport costs for the trading of ptx fuels between European countries (based on Helgeson and Peter (2020) and Brändle et al. (2020))

	Technical Lifetime [a]	Annual Driving Distance [km/a]	Driving trips per day [#]	Battery volume BEVs [kWh$_{el}$]*	Charging speed [kW$_{el}$]*	Adoption Share V2G [-]*
PPV	15	13800	3.52	44-90	22-100	0.05-0.30
LDV	10	21800	8	60-150	100-250	0.05-0.30
HDV	10	70000	9	100-500	250-500	0.05-0.30

*The lower values shown are the assumptions for 2030, the higher values for 2050

Table C.19: Additional assumptions compared to Helgeson and Peter (2020) used to model endogenous and bidirectional charging of electric vehicles in road transport module (based on Nobis and Kuhnimhof (2018), Ecke et al. (2020), European Commission (2020), Wietschel et al. (2019), IEA (2020), Hacker et al. (2015), Altenburg et al. (2017), EAFO (2020) and NPM (2020))

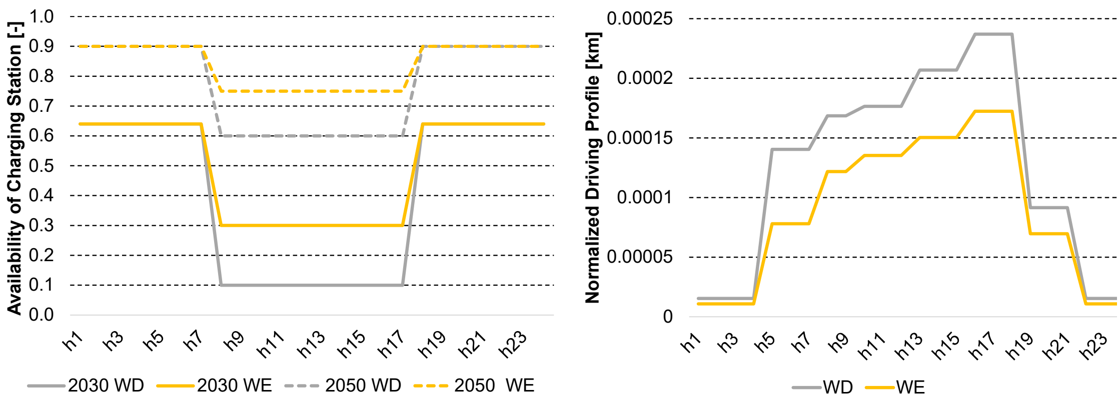

Figure C.2: Hourly availability of charging stations in 2030 and 2050 (left) and hourly driving profiles (right) of private passenger vehicles for a typical weekday (WD) and weekend day (WE) assumed for each country (based on German data sources including Bamberg et al. (2020), Statistisches Bundesamt (2019), Ecke et al. (2020), Nobis and Kuhnimhof (2018) and NPM (2020))

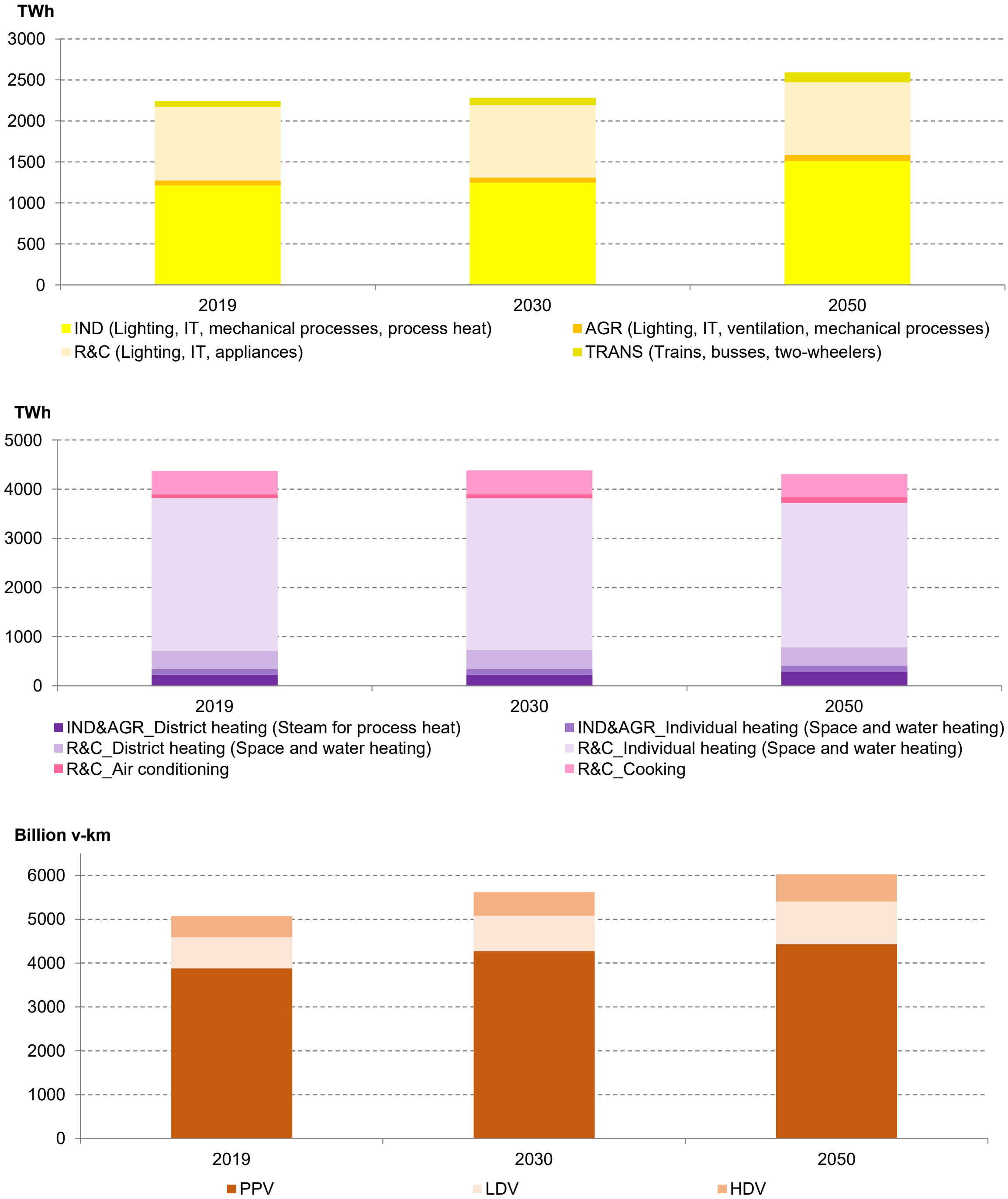

Figure C.3: Assumptions on the development of useful and secondary electricity demand (top), useful heat demand (middle) and useful demand for vehicle kilometers (bottom) in the end-use sectors in Europe up to 2050 (own assumptions based on Mantzos et al. (2019), dena et al. (2021) and Helgeson and Peter (2020))

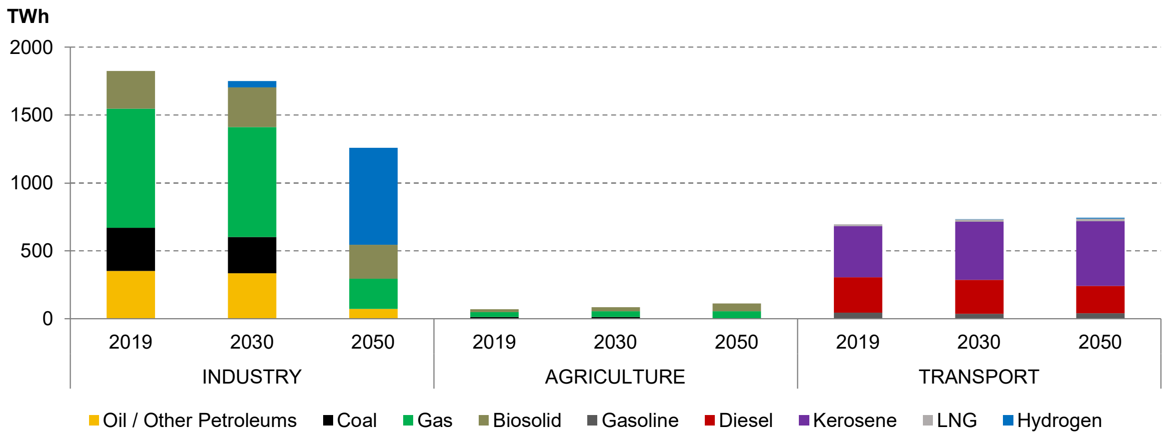

Figure C.4: Assumptions on the development of fuel consumption in the end-use sectors in Europe up to 2050 (own assumptions based on Mantzos et al. (2019), dena et al. (2021))

Appendix C.4. Assumptions on non-European imports for Green Importer Europe scenario

				2040		2050	
Country	**RES Type**	**Resource Class**	**Potential (GW)**	**Capacity Factor**	**LCOH (€/MWh$_{th}$)**	**Capacity Factor**	**LCOH (€/MWh$_{th}$)**
Algeria	PV	4	23965	0.25	56.1	0.25	42.5
Algeria	Onshore	1	68	0.53	67.4	0.50	58.8
Algeria	Offshore	1	1	0.32	128.9	0.30	107.0
Egypt	PV	4	9862	0.26	90.0	0.26	67.5
Egypt	Onshore	2	1697	0.48	118.6	0.46	98.9
Egypt	Offshore	1	33	0.32	169.8	0.31	137.7
Libya	PV	4	15078	0.26	89.8	0.25	67.5
Libya	Offshore	1	20	0.38	141.1	0.37	114.3
Morocco	PV	4	11081	0.26	52.3	0.25	39.1
Morocco	Onshore	1	256	0.61	63.2	0.59	55.2
Morocco	Offshore	1	7	0.49	101.4	0.46	84.6
Tunisia	PV	4	6954	0.25	90.8	0.25	68.2
Tunisia	Onshore	3	572	0.29	145.8	0.27	121.6
Tunisia	Offshore	1	36	0.34	147.8	0.33	119.7

Table C.20: Assumptions on hydrogen production costs according to the theoretical renewable potentials of selected renewable energy technologies in North African countries, extracted from the Global Hydrogen Cost Tool developed by Brändle et al. (2020)

	2035	**2040**	**2045**	**2050**
PtX Hydrogen	-	96.1	86.0	78.1
PtX CH4	215.1	194.4	173.3	155.5
PtX Gasoline, PtX Kerosene	277.3	248.5	222.6	200.5
PtX Diesel, PtX Oil	279.0	250.0	223.9	201.6

Table C.21: Import prices of green hydrogen and synthetic (ptx) fuels from the North African region, calculations based on Brändle et al. (2020)

Appendix D. Supplementary results on the investment decisions and generation amounts of the endogenous modules in the Green Island Europe scenario

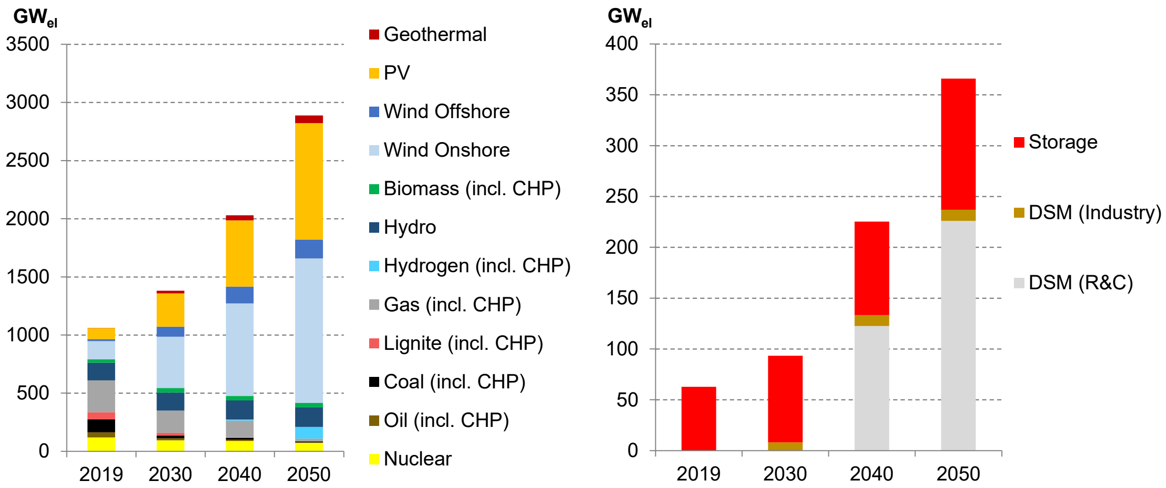

Figure D.5: Results on installed capacities of electricity generators (left) as well as electricity storage and DSM processes (right) in Europe up to 2050 in the Green Island Europe scenario

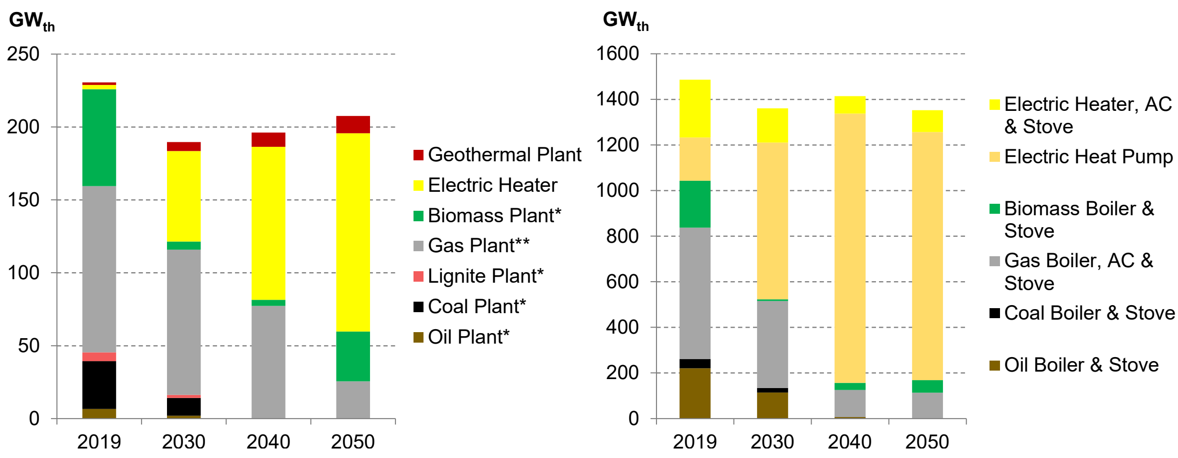

Figure D.6: Results on installed heat capacities of district heat generators (left) and individual heating, cooking and cooling technologies (right) in Europe up to 2050 in the Green Island Europe scenario

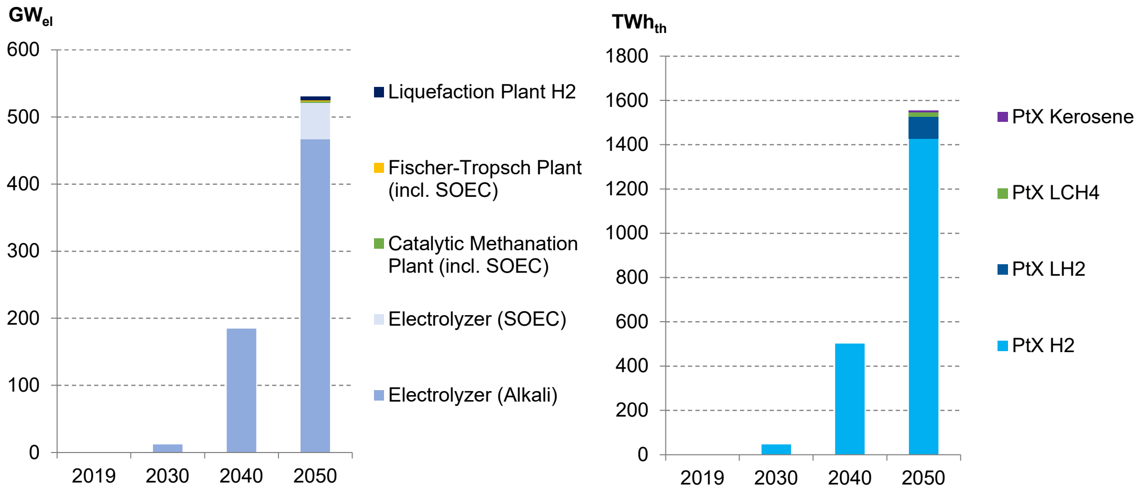

Figure D.7: Results on the installed capacities of ptx technologies (left) and production volumes of green hydrogen and synthetic fuels (right) in Europe up to 2050 in the Green Island Europe scenario

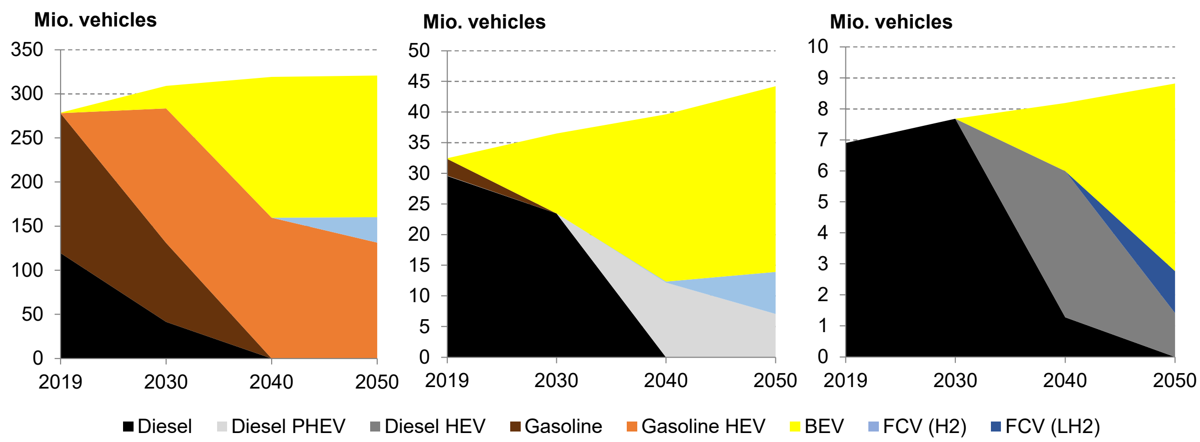

Figure D.8: Results on road transport investments for private passenger vehicles (left), light-duty vehicles (middle) and heavy-duty vehicles (right) in Europe up to 2050 in the Green Island Europe scenario

Appendix E. Detailed comparison of Green Island Europe and Green Importer Europe scenarios

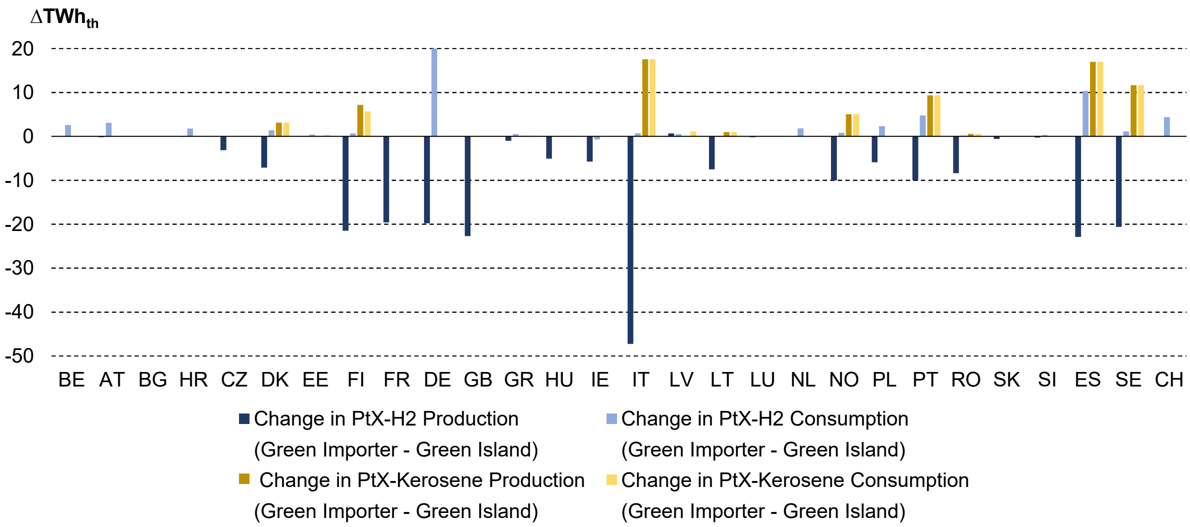

Figure E.9: Change in the resulting green hydrogen (PtX-H2) and synthetic kerosene (PtX-Kerosene) production and consumption in between the Green Importer Europe scenario and Green Island Europe scenario in 2050

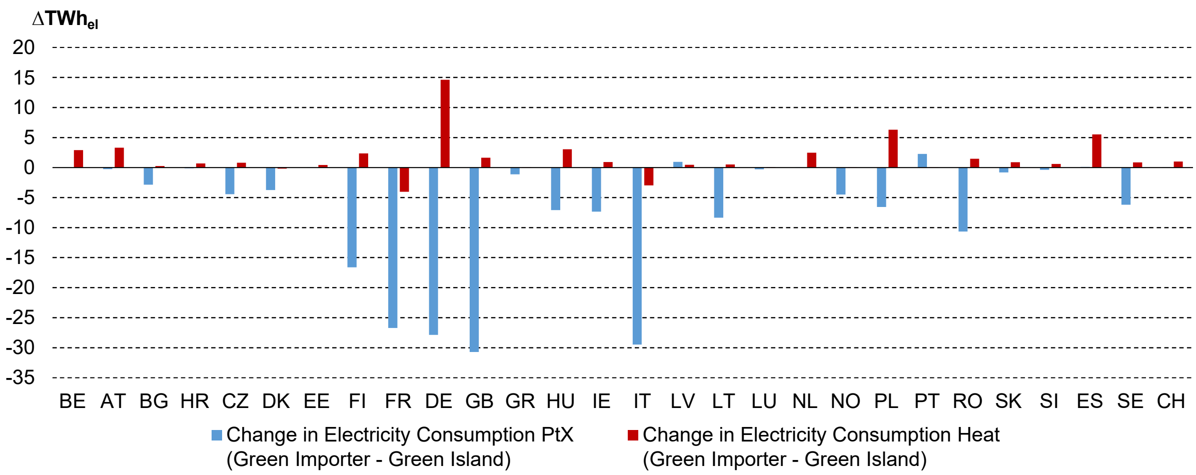

Figure E.10: Change in the resulting electricity consumption from ptx technologies and heaters between the Green Importer Europe scenario and Green Island Europe scenario in 2050

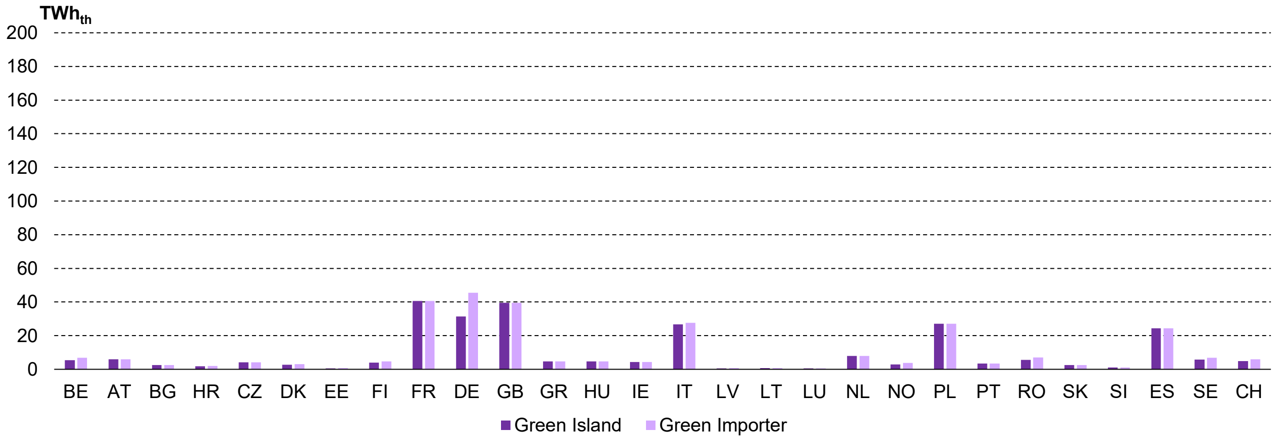

Figure E.11: Results of the consumption of green hydrogen (in TWh$_{th}$) in the transport sector in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

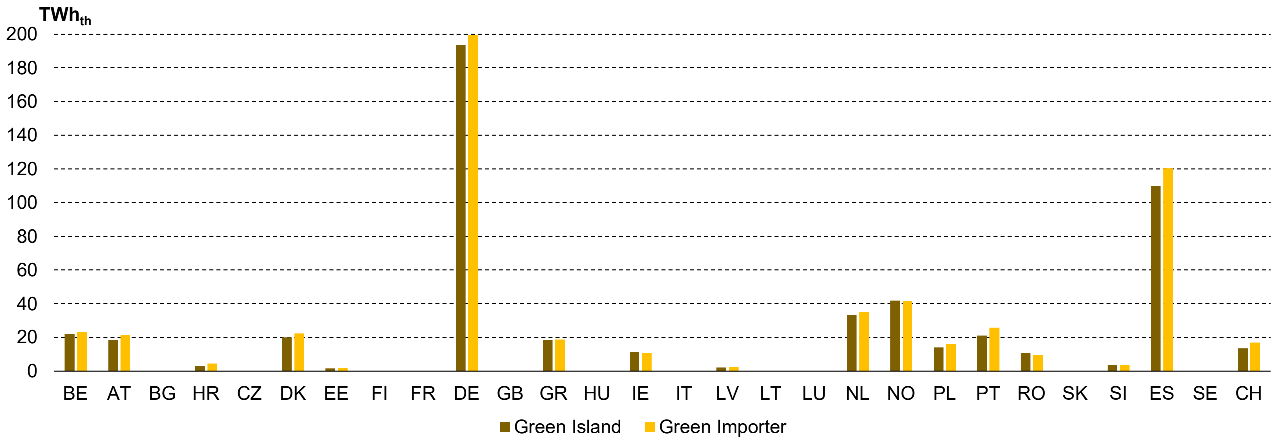

Figure E.12: Results of the consumption of green hydrogen (in TWh$_{th}$) for electricity generation in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

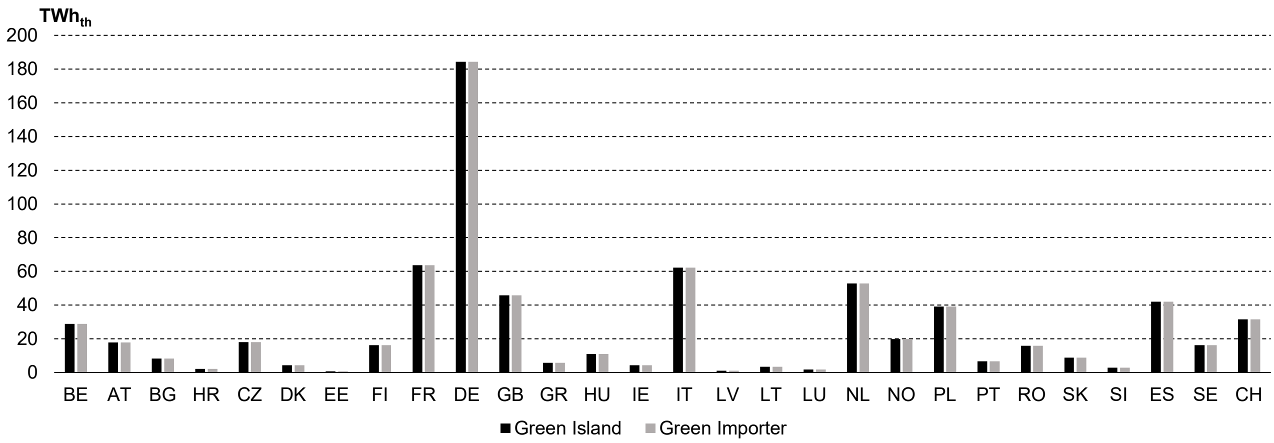

Figure E.13: Results of the consumption of green hydrogen (in TWh$_{th}$) in the industry sector in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

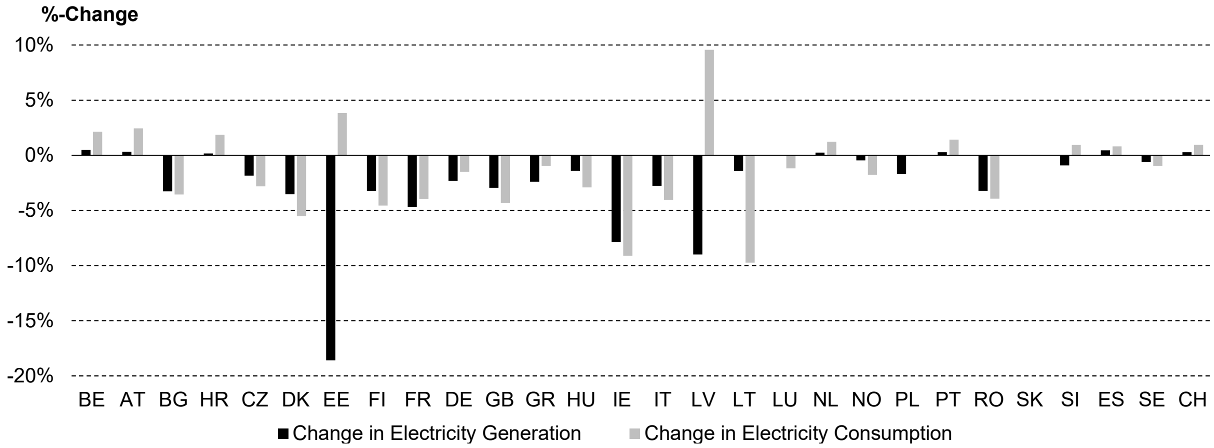

Figure E.14: Change in the resulting total electricity generation and consumption in % between the Green Importer Europe scenario and Green Island Europe scenario in 2050

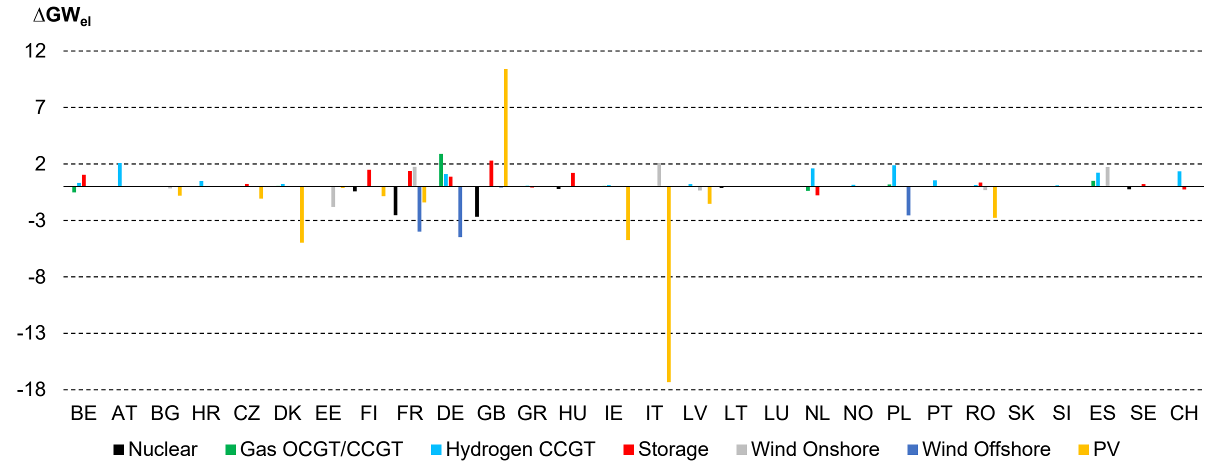

Figure E.15: Change in the resulting installed capacity of electricity generators between the Green Importer Europe scenario and Green Island Europe scenario in 2050

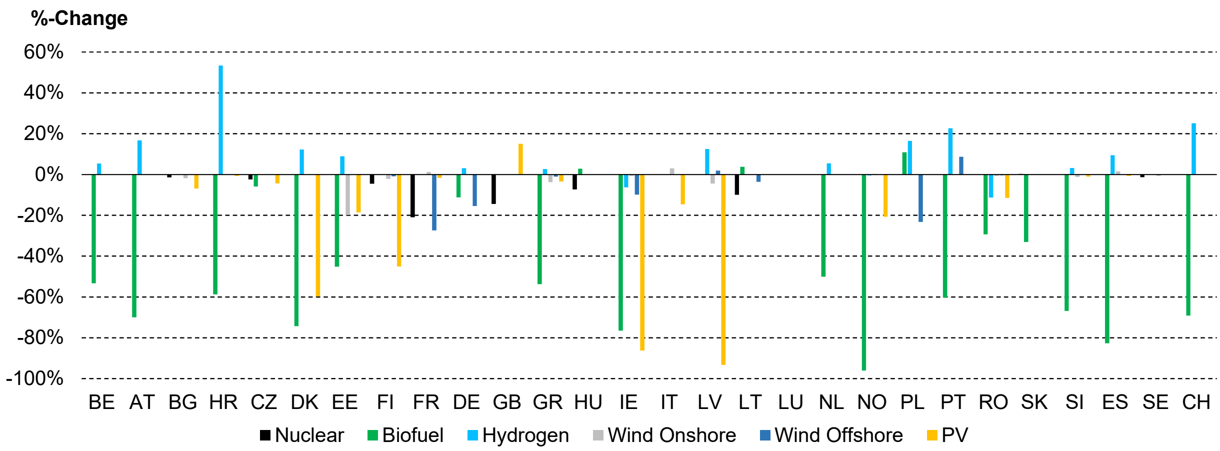

Figure E.16: Change in the resulting electricity generation mix in % between the Green Importer Europe scenario and Green Island Europe scenario in 2050

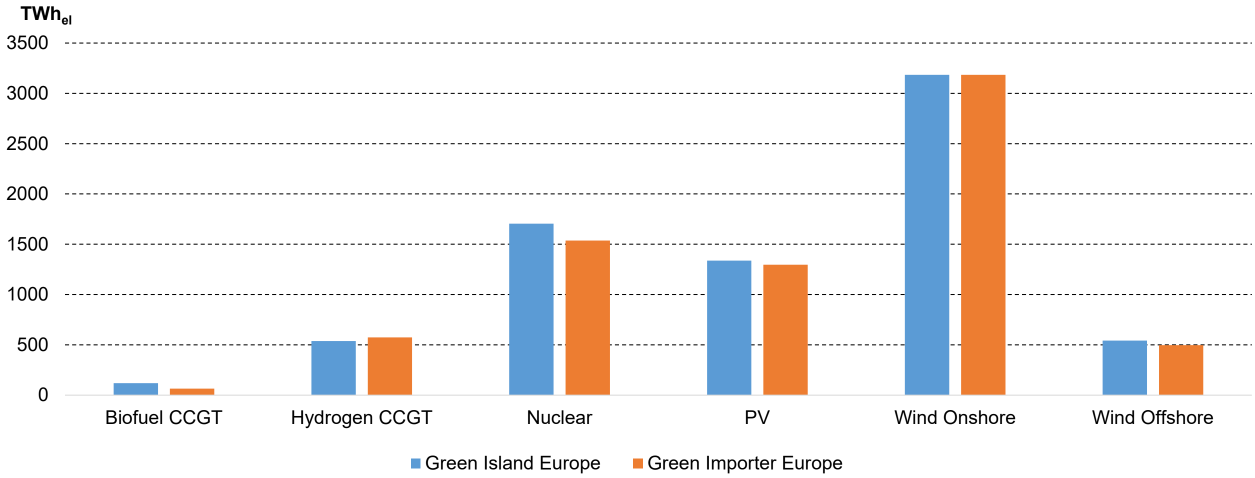

Figure E.17: Electricity generation volumes in the Green Island Europe and Green Importer Europe scenarios in 2050 (hydro and geothermal power not pictured)

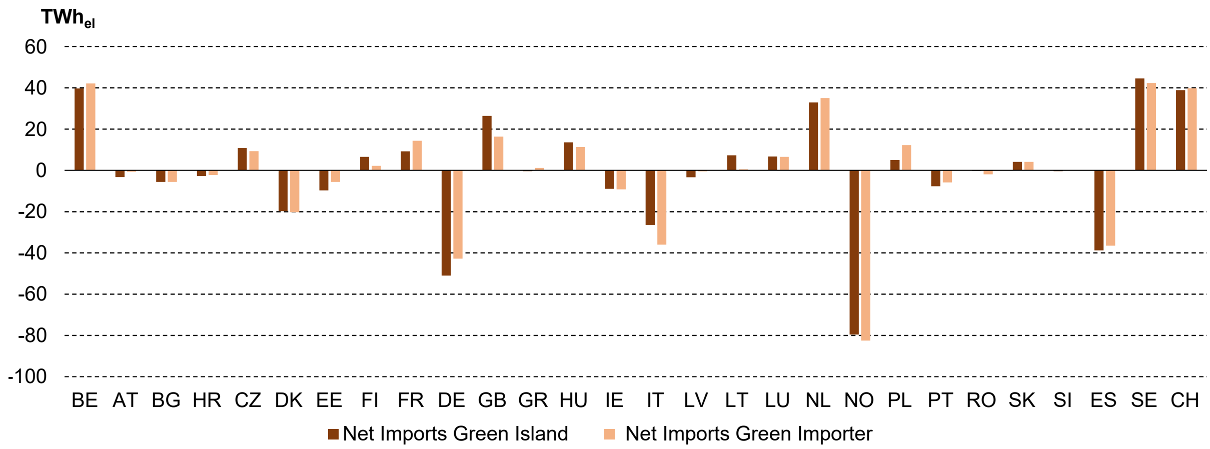

Figure E.18: Net imports of electricity in the Green Island Europe and Green Importer Europe scenarios in 2050

Appendix F. Country-specific results of welfare analysis

Appendix F.1. Investigation on green hydrogen producers and consumers in selected countries

A number of interesting trends can be identified when more closely investigating the differences in the total welfare of the green hydrogen market in selected individual countries. The two countries with the highest change in average total welfare are Lithuania and Hungary, each of whom stand on the list of green hydrogen exporters in both scenarios (see Section 3.4). Like for many other exporters, green hydrogen producers in these countries ramp down the operation of their electrolysis plants to serve a lower demand for European-produced hydrogen in the Green Importer Europe scenario. With both countries exhibiting shares of intermittent renewable electricity generation of over 80%, the reduction in green hydrogen production allows the electrolyzer to run less often and more flexibly to take greater advantage of price fluctuations.[84] As can be seen in Figure F.19, this actually leads to gains in producer surplus in the Green Importer Europe scenario compared to the Green Island Europe scenario, despite the average revenue losses that arise from the decrease in the green hydrogen prices of more than 10 €/MWh_{th}. Yet the decrease in the hydrogen price means consumers benefit from comparably large surplus gains —ranging from four (Lithuania) to nearly seven (Hungary) times more so than their producer counterparts —which then pushes the increase in average total welfare upwards.

The country that appears to be worst off with regards to the difference in average total welfare is Bulgaria, whose electricity mix consists of 30% nuclear and 6% hydro generation combined with 33% PV, 28% onshore wind and 3% offshore wind in both scenarios in 2050. Consistent with the findings in Helgeson and Peter (2020), high shares of inflexible baseload combined with intermittent renewables create the perfect conditions for ptx technologies to produce at absolute minimal costs, which is why Bulgaria sees the lowest endogenous prices for green hydrogen across Europe, equal to 62 €/MWh_{th} and 59 €/MWh_{th} in the Green Island Europe and Green Importer Europe scenarios, respectively (see Figure F.20 in Appendix E). In fact, Bulgaria is the only country to produce all three ptx fuels (i.e., green hydrogen, green methane and synthetic kerosene) in both scenarios. Yet these attractive conditions mean that (i) consumers have little possibility for surplus gains, as prices are already abnormally low and (ii) the average producer actually has to accept an increase in average variable costs in the Green Importer Europe scenario as the pressure to reduce the costs of European green hydrogen production creates additional competition for low-cost electricity across Europe (i.e., the absolute change in producer surplus exceeds the absolute change in consumer surplus). As a result, Bulgaria

[84] More specifically, the full-load hours of electrolysis systems in Hungary and Lithuania decrease from 2900 hours and 3870 hours in the Green Island Europe scenario to 2540 hours and 3625 hours in the Green Importer Europe scenario, respectively.

decreases its capacities in electrolyzers as well as in integrated SOEC-methanation systems, and, in doing so, decrease the electricity consumption for ptx fuel production (see E.10 in Appendix E). Nevertheless, Bulgaria produces the same amount of green hydrogen in both scenarios and consumes it all domestically. Bulgaria is the only country to have a negative change in average total welfare across the scenarios, meaning the Bulgarian green hydrogen market actually benefits from European energy independence under the scenarios considered.

The next two countries with the lowest change in average total welfare for green hydrogen producers in 2050 between the two scenarios are Greece and Portugal. After Bulgaria, these two countries have the lowest endogenous prices for green hydrogen in the Green Island Europe scenario at 83 €/$\mathrm{MWh_{th}}$. Greece, on the one hand, is more or less unaffected by the introduction of green hydrogen imports from outside of Europe due to long transport distances and high domestic renewable resources, namely 37% PV, 32% offshore wind and 19% onshore wind. In the Green Importer Europe scenario, Greece no longer exports 2 $\mathrm{TWh_{th}}$ of its domestic product and instead ramps down its green hydrogen production (-1 $\mathrm{TWh_{th}}$) while also increasing domestic green hydrogen consumption (+1 $\mathrm{TWh_{th}}$). In this case, the average variable production costs remain nearly equal across scenarios, meaning the decrease in average producer surplus can be almost completely explained by the revenue losses accrued from the from the decrease in the green hydrogen price to 77 €/$\mathrm{MWh_{th}}$. Portugal, on the other hand, also reduces its green hydrogen exports by 15 $\mathrm{TWh_{th}}$; however, even though this drives the total domestic production of green hydrogen downwards, Portugal actually installs additional ptx capacities in the Green Importer Europe scenario, namely 2.3 $\mathrm{GW_{th}}$ of integrated SOEC-Fischer Tropsch systems. In turn, the overall production of ptx fuels as well as the electricity consumption from ptx systems slightly increase (see Figures E.9 and E.10 in Appendix E). As such, the average green hydrogen producer is limited in their ability to further reduce their average variable costs in the Green Importer Europe scenario, leading to minimal welfare gains.

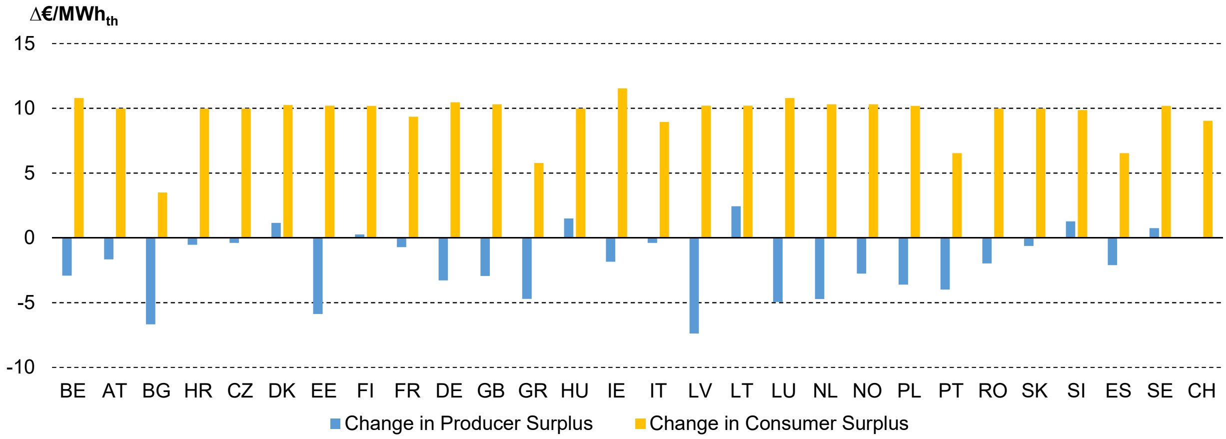

Figure F.19: Differences in producer and consumer surplus for green hydrogen producers and consumers (in €/MWh$_{th}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

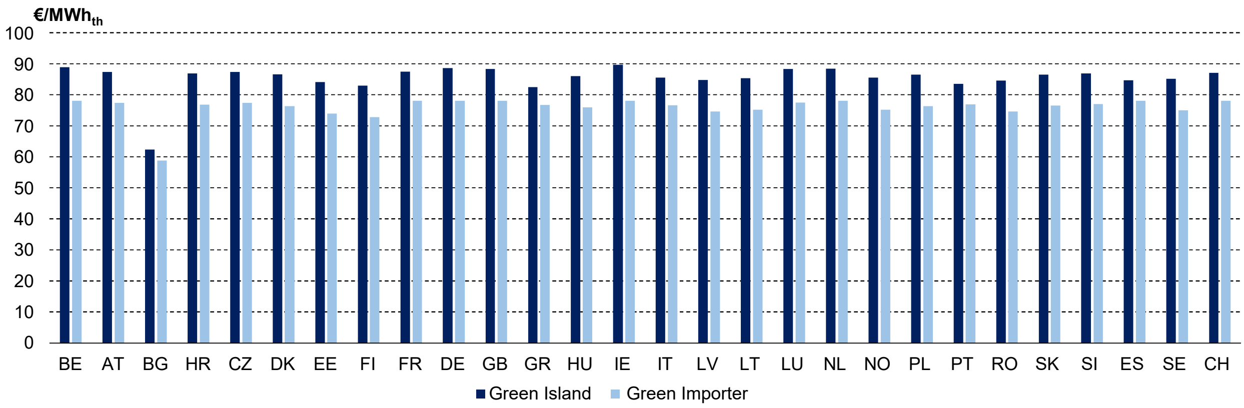

Figure F.20: Results of the endogenous prices for green hydrogen (in €/MWh$_{th}$) produced in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

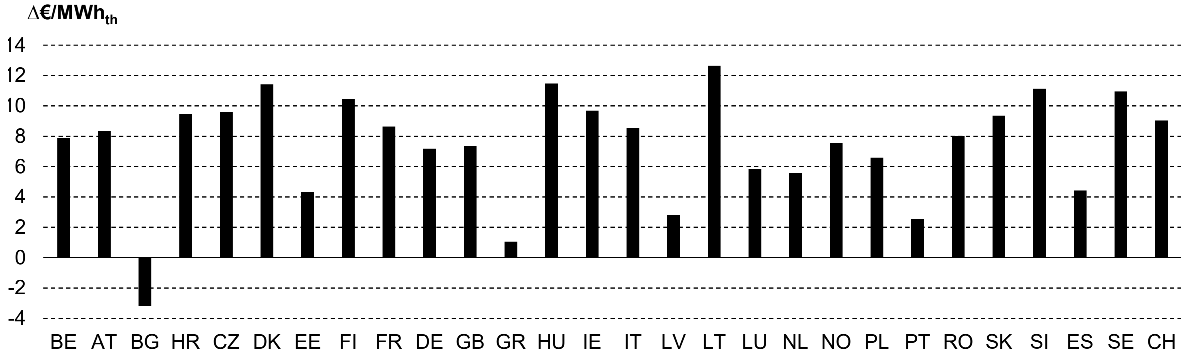

Figure F.21: Differences in total welfare for green hydrogen producers and consumers (in €/MWh$_{th}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

Appendix F.2. Analysis of electricity suppliers and consumers in selected countries

The countries with the highest gains in average total welfare for electricity are found to be Denmark, Norway, Belgium and the Netherlands (see Figure F.24). By definition, this means that these countries are able to reduce the average variable costs of electricity generation in the Green Importer Europe scenario compared to the Green Island Europe scenario, compensating for the losses in average revenues. As discussed in Section 3.4, European exporters of green hydrogen in the Green Importer Europe scenario reduce domestic production as the demand for European-produced hydrogen lessens. For Norway and Denmark, this leads to a decrease in both electricity consumption and generation as less electricity is needed for green hydrogen production and no additional demand for, e.g., heating emerges (see Figures E.10 and E.14 in Appendix E). As a result, electricity generators in Norway and Denmark are able to reduce the use of comparatively expensive biofuels by 96% and 75%, respectively (see Figure E.16 in Appendix E), driving a significant reduction in the variable generation costs and increasing average total welfare. The other two front-runners in total welfare, Belgium and the Netherlands, belong to the short list of countries that choose to purchase green hydrogen from outside of Europe; however, these imports do not affect the domestic production volumes due to the comparatively small electrolysis capacities (< 500 MW_{el}) in these countries. Rather than replacing domestic production, the imported green hydrogen is used to displace biofuels from the electricity generation mix and, as such, reduce the costs of dispatchable electricity production. Furthermore, because of their central location in Europe, these countries are able to benefit from electricity imports from nearby countries with higher renewable resources (e.g., Great Britain) to help cover an increased electricity use for heating (see Figures E.9-E.18 in Appendix E).

On the other hand, the electricity market in six countries experience negative change in total welfare including Estonia, Croatia, Latvia, Bulgaria, Hungary and Poland. In other words, electricity generators and consumers in these countries are better off in the Green Island Europe scenario than in the Green Importer Europe scenario as the increase in average variable costs of electricity generators outweighs any positive effects that consumers may receive as a result of reduced electricity prices. Estonia, in particular, sees significant losses in electricity exports in the Green Importer Europe scenario, which in turn leads to a nearly 20% reduction in electricity generation via the curtailment of PV generation and less onshore wind capacities (see Figures E.14-E.18 in Appendix E). For producers, this results not only in lost revenues from reduced exports and curtailments but also higher average variable costs of electricity production. A similar result can be seen for Latvia, who stops exporting electricity and, in turn, installs only 0.1 GW_{el} of PV capacity compared to 1.7 GW_{el} in the Green Island Europe scenario. Bulgaria and Poland also install less intermittent renewable generation in the Green Importer Europe scenario, and Bulgaria and Hungary reduce their nuclear capacity. Croatia, unlike the others, actually experiences a small increase in electricity generation in the Green Importer Europe scenario to be consumed domestically for heating, as shown in Figures E.10 and E.14 in Appendix E. Yet the lack of flexibility in heat demand creates the need for additional dispatchable capacity, with Croatia choosing to install hydrogen CCGT fueled with green hydrogen imported from Romania. Once again, the resulting increase in the average variable costs for electricity generators leads to the losses in average producer surplus exceeding the gains in average consumer surplus.

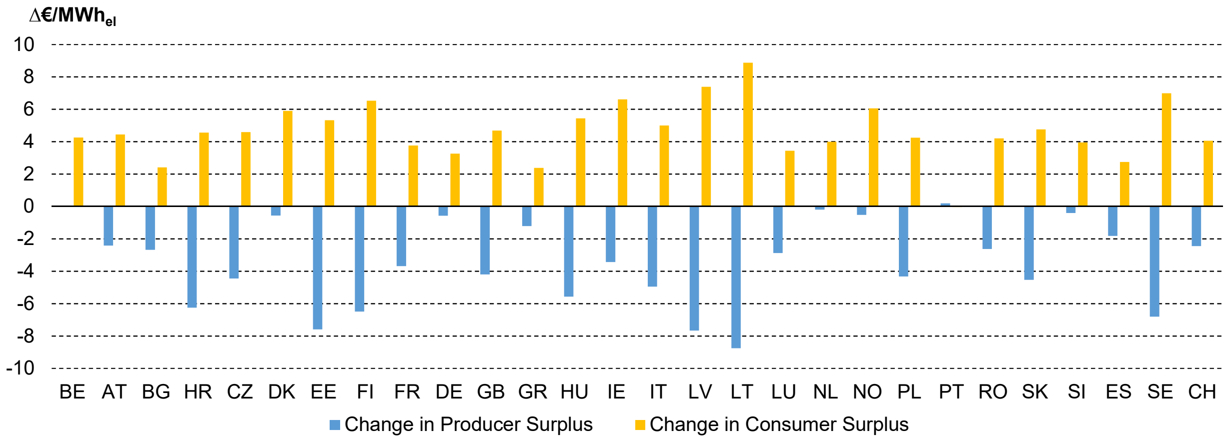

Figure F.22: Differences in producer and consumer surplus for electricity generators and consumers (in €/MWh$_{el}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

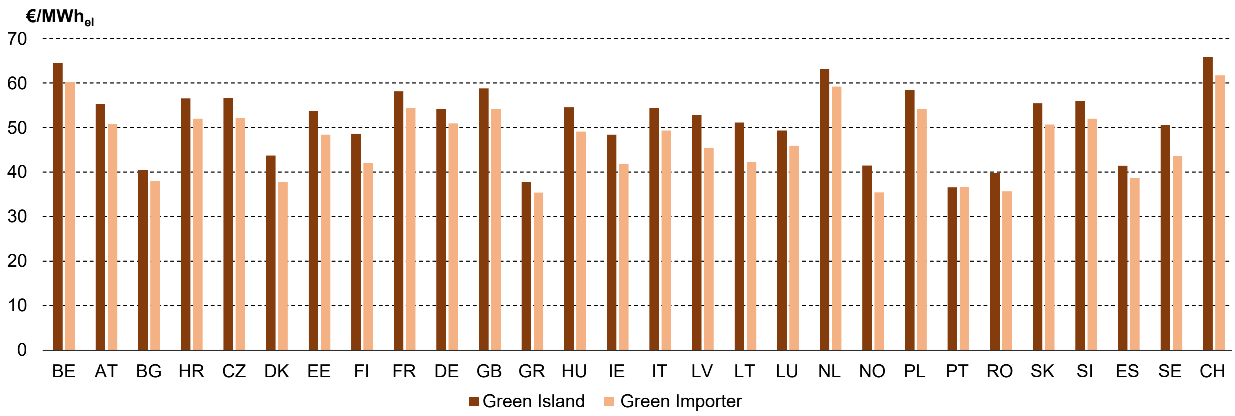

Figure F.23: Results of the endogenous electricity prices (in €/MWh$_{el}$) in the year 2050, equal to the demand-weighted average over all time slices, for each country modeled in the Green Island Europe and Green Importer Europe scenarios

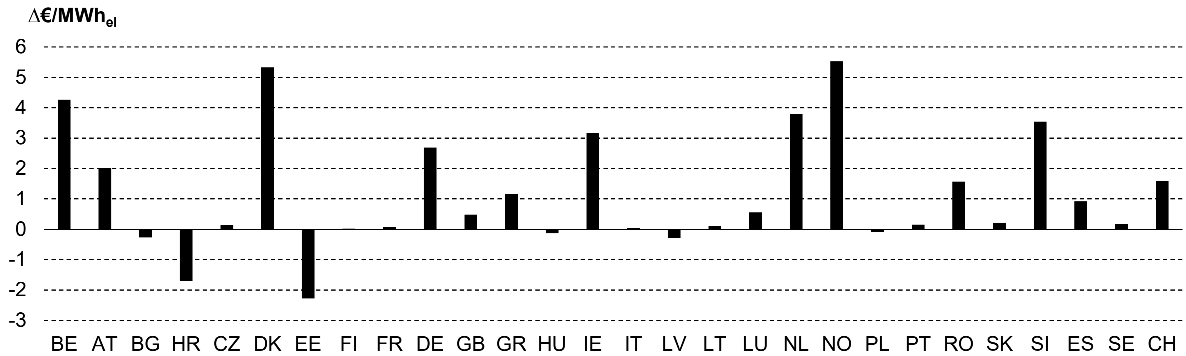

Figure F.24: Differences in total welfare for electricity producers and consumers (in €/MWh$_{el}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

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