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Broghan Jocelyn Helgeson Cologne, June 2024

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List of Abbreviations

a	Years
AIC	Annualized investment costs
BEV	Battery electric vehicle
bn	Billion
CAES	Compressed air energy storage
CCGT	Closed-cycle gas turbine
CCU	Carbon capture and utilization
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
COMODO	Consumer management of decentralized options
COP	Coefficient of performance
cp.	Compared to
CSP	Concentrated solar power
DAC	Direct air capture
DER	Distributed energy resources
DSM	Demand side management
DSR	Demand side response
El/el	Electricity / electric
eq	Equivalent
EU-ETS	European Emissions Trading System

EUR	Euro
FCV	Fuel-cell vehicle
FIT	Feed-in tariff
FOM	Fixed operation and maintenance
GW_{el} / GW_{th}	Gigawatt (electric / thermal)
H2	Hydrogen
H_2O	Water
HDV	Heavy-duty vehicle
HEV	Hybrid electric vehicle
km	Kilometer
kW_{el} / kW_{th}	Kilowatt (electric / thermal)
kWh_{el} / kWh_{th}	Kilowatt hours (electric / thermal)
LCA	Life cycle analysis
LCOE	Levelized costs of electricity
LDV	Light-duty vehicle
LH2	Liquid hydrogen
Liq	Liquefaction/liquefied
LNG	Liquefied natural gas
m	Million
MILP	Mixed integer linear programming
$MtCO_2eq$	Million tonnes carbon dioxide equivalent
MW_{el} / MW_{th}	Megawatt (electric / thermal)
MWh_{el} / MWh_{th}	Megawatt hour (electric / thermal)
NTC	Net transmission capacity
O_2	Oxygen

OCGT	Open-cycle gas turbine
PEM	Polymer electrolyte membrane electrolysis
PHEV	Plug-in hybrid electric vehicle
PPV	Private passenger vehicles
PtH	Power to heat
PtX / ptx	Power to X (heat, gas, liquid, fuel, chemicals etc.)
PtX CH4	Ptx methane gas
PtX H2	Ptx hydrogen gas
PtX LCH4	Ptx liquid methane
PtX LH2	Ptx liquid hydrogen
PV	Photovoltaic
RES	Renewable energy sources
SOEC	Solid oxide electrolyzer cell
t	Tonne
TAC	Total annual cost
th	Thermal
TTW	Tank-to-wheel
TWh_{el} / TWh_{th}	Terawatt hour (electric / thermal)
VRE	Variable renewable energy
WTT	Well-to-tank
WTW	Well-to-wheel

1. Introduction

1.1. Motivation

The imperative to combat climate change and achieve carbon neutrality by 2050 presents Europe with formidable challenges but also unprecedented opportunities. Although the move from fossil fuels to low and zero-carbon options comes with significant environmental and societal benefits, today it is still heavily contingent on the enforcement of strict decarbonization targets and availability of attractive incentive mechanisms. By subsidizing or penalizing certain technologies or fuels, the merit order of energy options can be shifted such that more climate-friendly options become economically more appealing for both energy providers and end consumers.

Yet defining the appropriate instruments to instigate change is a challenge for many policymakers. From an economic perspective, it is vital that such measures do not hinder competition in the market. Hypothetically speaking, the introduction of an emissions trading system encompassing all carbon emitters, subject to a common reduction target (i.e., quantity cap), would allow each market player to be faced with a single, cross-sectional carbon price. In turn, the technologies and fuel options that succeed would be those with the lowest marginal abatement costs, resulting in a minimization of the total costs of achieving the reduction target. The goal of a carbon-neutral Europe by 2050, which was included in the European Green Deal in 2020, is an example of a policy measure that takes the first step in this direction; however, how this target will be implemented in practice is still unclear.

In reality, enforcing such overarching targets can be challenging. While the accounting of emissions for the energy transformation sector could potentially be done centrally, similar to the European Union Emissions Trading System (EU-ETS), policymakers often struggle to reach the end consumer under certificate schemes. Commonly, governments introduce sector-specific mechanisms such as reduced tariffs or subsidies to incentivize end uses to alter their energy consumption behavior and/or technology choice. However, such bottom-up policies may lead to deviations from the least-cost solution for the energy system as a whole. All in all, the disconnect between the theoretical economic optimum and the currently regulatory practice has the potential to introduce inefficiencies into the market, causing the path to carbon neutrality to be overly slow and costly.

Mathematical models offer a powerful tool to help bridge the gap between the hypothetical and reality. Linear programming, in particular, allows for a systematic evaluation of key decision variables within a constrained solution space, seeking values that optimize the objective function. In the case of energy economics, these methods are often applied to assess the investment and dispatch decisions within certain markets over a period of time under a cost minimization of total system costs. Regulatory instruments, for example, can be introduced as constraints to the optimization problem in order to gain insights into the effectiveness and efficiency of certain mechanisms, usually comparing multiple scenario and sensitivity analyses. In doing so, policymakers are able to better understand the techno-economic consequences of their decisions as well as the types of regulatory triggers needed to achieve a welfare-maximizing result.

The importance of mathematical modeling in the design of regulatory frameworks lies at the heart of the motivation of the thesis at hand. On the one hand, this thesis uses quantitative methods based on linear programming to challenge policymakers into considering a pathway to carbon neutrality in Europe using only a single CO_2 reduction target. In this case, decarbonization and flexibility options compete on a level playing field across sectors and countries to enter and stay in the market. As a result, conclusions can be made on when and how technologies, fuels, countries and sectors transform under a minimization of total system costs, which may help in defining effective policies. On the other hand, complementing the top-down perspective, the thesis examines the investment and dispatch behavior of individual consumers using a mixed-integer linear approach. Here, rather than setting a carbon reduction target, the model takes into account the current incentive mechanisms in place that are meant to encourage consumers to decarbonize their energy use. In doing so, the results help to identify potential shortcomings in the effectiveness of existing regulatory instruments and educate policymakers on the key economic drivers behind consumers' energy decisions. All in all, the quantitative methods developed and assessed within the scope of this thesis should offer a systematic, microeconomic perspective to help guide Europe, and the world, to a greener, more sustainable future.

1.2. Outline and Overview of Thesis

The cumulative dissertation is based[1] on three separate papers, two with co-authors[2] and one written solely by the Ph.D. candidate:

- The Role of Electricity in Decarbonizing European Road Transport — Development and Assessment of an Integrated Multi-Sectoral Model. Joint work with Jakob Peter, *EWI Working Paper 19/01* and published in *Applied Energy.* [Helgeson and Peter, 2020]

[1] The published versions of the three papers listed may vary slightly from the works presented in Chapters 2 - 4, as some minor formatting and wording adjustments were necessary to combine them into a single thesis. It should also be noted that Chapter 2 differs structurally from the publication in *Applied Energy.* More specifically, the Extended Methodology explained in Appendix C in [Helgeson and Peter, 2020] was moved to Section 2.2 in Chapter 2 as the methodology is a central contribution of this thesis and lays the groundwork for the methodology in Chapter 3.

[2] For both papers with co-authors, the authors contributed equally.

- Europe, the Green Island? Developing an Integrated Energy System Model to Assess an Energy-Independent, CO_2-Neutral Europe. *EWI Working Paper 02/24*. [Helgeson, Broghan, 2024]
- Developing a Model for Consumer Management of Decentralized Options. Joint work with Cordelia Frings, *EWI Working Paper 22/05* and under review at *Energy*. Recipient of Theodor-Wessels Prize 2023. [Frings and Helgeson, 2022]

The content presented in the three chapters is strongly related in their research questions as well as quantitative methods. More specifically, the work performed in Chapter 2 lays the groundwork for both Chapters 3 and 4, offering the basis on how to use linear programming to model complex interdependent markets and sector-coupling technologies in an integrated framework. In fact, Chapter 3 is a direct extension of the research in Chapter 2, as the same model is expanded to included a greater number of energy transformation and end use sectors, decarbonization technologies and flexibility options as well an improved data set with refined temporal resolution. Both chapters consider a European scope up to the year 2050. Chapter 4, on the other hand, considers similar research questions regarding decarbonization and flexibility options, but on a much smaller scale: The model developed in Chapter 4 optimizes the energy system for individual consumers, rather than for all of Europe, up to 2040. Nevertheless, the modeling techniques of many of the technologies, constraints and equilibrium conditions remain consistent across all chapters. In any case, the thesis is consistent in its intention to develop quantitative models to investigate the decarbonization and flexibility potential in the provision and consumption of energy in a future low-carbon society.

All three papers benefited from funding from the State of North Rhine-Westphalia. Chapter 2 was partially financed via the research project “Virtual Institute - Power to Gas and Heat” (W041A) through the Ministry of Economic Affairs, Innovation, Digitalization and Energy of the State of North Rhine-Westphalia as well as CEF NRW. Both Chapters 2 and 3 received funding from 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. Finally, funding for Chapter 4 was provided by the European Regional Development Fund (ERDF) together with the Ministry of Economic Affairs, Industry, Climate Action and Energy of the State of North Rhine-Westphalia (MWIDE NRW) obtained through the research project "Virtual Institute Smart Energy in Households" (EFRE-0600037).

In the following subsections, the research questions, methodological approach and key results are summarized for each chapter, followed by a note on the supplementary material.

1.2.1. Overview of Chapter 2, "The Role of Electricity in Decarbonizing European Road Transport — Development and Assessment of an Integrated Multi-Sectoral Model"

Chapter 2 assesses the European road transport sector and the role of electricity as a promising decarbonization option, both to fuel electric vehicles and run power-to-x systems producing synthetic fuels. To understand the economic implications of increased coupling of the road transport and electricity sectors, an integrated multi-sectoral partial-equilibrium investment and dispatch model is developed for the European electricity and road transport sectors, linked by an energy transformation module to endogenously account for, e.g., increasing electricity consumption and flexibility provision from electric vehicles and power-to-x systems. The model is applied to analyze the effects of sector-specific CO_2 reduction targets on the vehicle, electricity and power-to-x technology mix as well as trade flows of power-to-x fuels in European countries from 2020 to 2050.

The results show that, by 2050, the fuel shares of electricity and power-to-x fuels in the European road transport sector reach 37% and 27%, respectively, creating an additional electricity demand of 1200 TWh in Europe. To assess the added value of the integrated modeling approach, an additional analysis is performed in which all endogenous ties between sectors are removed. The results show that by decoupling the two sectors, the total system costs may be significantly overestimated and the production costs of power-to-x fuels may be inaccurately approximated, which may affect the merit order of decarbonization options.

1.2.2. Overview of Chapter 3, "Europe, the Green Island? Developing an Integrated Energy System Model to Assess an Energy-Independent, CO_2-Neutral Europe"

The paper presented in Chapter 3 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.

1.2.3. Overview of Chapter 4, "Developing a Model for Consumer Management of Decentralized Options"

Lastly, Chapter 4 shifts the focus from centralized to decentralized energy provision and the opportunities for distributed energy resources. In deciding how to best serve their long-term energy needs, end consumers face a plethora of investment options together with complex regulatory instruments as well as growing uncertainty regarding, e.g. techno-economic and political developments. Optimization models using linear programming methods are one option to help shed light on possible technology combinations and the economic consequences for end consumers. Yet the existing literature indicates a clear lack of models capable of accounting for high technical, regulatory and economic detail while optimizing investments in multiple future years. Therefore, within this paper, the mixed-integer linear programming model COMODO (Consumer Management of Decentralized Options) is developed to determine the cost-minimal energy provision for end consumers. The model uses its extensive technology catalog to perform an investment and dispatch optimization for multiple years, minimizing total costs over a long-term time horizon while accounting for developments in techno-economic data, regulatory frameworks and energy market conditions. Furthermore, piecewise-linear functions are created to represent costs and subsidies for different systems sizes and for future years.

In order to demonstrate the capabilities of the model developed, an exemplary application is presented to investigate the energy provision of four single-family homes in Germany for the years 2025 to 2045. Three scenarios are designed that build upon each other regarding the amount of information available to consumers and their decentralized energy technologies. The results show a clear preference for gas boilers as a base technology coupled with electric heaters to cover demand peaks. Households with higher demand levels invest in PV systems in 2025, while other households with lower demands either wait until 2040 or do not invest. A sensitivity analysis then examines the effects of higher carbon pricing in the German building sector on the consumer's energy provision. The subsequent increase in the retail gas price leads to households choosing to fully electrify their heat provision, i.e., installing a heat pump combined with thermal storage, PV and an electric heater. On average, these households experience an increase in total costs ranging from 3.5% to 5.4% over the complete time horizon and realize a long-term decrease in annual carbon emissions of up to 80% compared to the analysis with lower carbon pricing. Lastly, this work also presents a novel method of analyzing the marginal costs of electricity and heat provision, revealing a strong correlation between the implicit marginal costs of energy provision and the assumptions on retail energy prices.

1.2.4. Supplementary Material

Supplementary material for Chapters 2, 3 and 4 may be found in Appendices A, B and C, respectively.

2. The Role of Electricity in Decarbonizing European Road Transport – Development and Assessment of an Integrated Multi-Sectoral Model

2.1. Introduction

Preventing severe, pervasive and irreversible impacts of climate change requires rapid carbon emission reduction in all sectors ([IPCC, 2014]). However, European road transport carbon emissions have increased by 22 % since 1990, accounting for a share of 21 % of total European greenhouse gas emissions[3] in 2016 ([EEA, 2018]). European regulations such as fleet targets for the average carbon emission levels for new vehicles is one of the more recent attempts to decarbonize road transport; however, factors such as increasing road transport demand and the continued adoption of fossil-fueled gasoline and diesel motors have counteracted carbon emission reduction efforts ([European Commission, 2019b]). Diversification of the current fuel and vehicle mix using alternatives such as natural gas, hydrogen, biofuels, synthetic fuels and electricity would offer decarbonization opportunities – yet the cost-optimal pathway to a low-carbon fuel mix remains unclear.

Most recently, electricity has gained attention as an energy source capable not only of fueling electric vehicles but also power-to-x (ptx) systems to produce synthetic power-to-x fuels (ptx fuels). More specifically, stand-alone electrolysis or electrolysis coupled with, e.g., methanation or Fischer-Tropsch synthesis can produce zero-carbon and carbon-neutral fuels for the road transport sector (see, e.g., [dena and LBST, 2017]).[4] Yet decarbonizing the road transport sector via electricity results in the road transport and electricity sectors being coupled such that supply and demand become linked across sectors, which may have significant impacts on the future energy system. On the one hand, increased electricity consumption from road transport and ptx systems would require additional electricity generation, which must be produced subject to its own carbon emission reduction regulations ([European Commission, 2014]). In this case, both the marginal cost of electricity generation as well as marginal CO_2 abatement

[3] In CO_2 equivalent.

[4] Zero-carbon fuels refers to fuels with a chemical composition without C-atoms and thus with no carbon emissions associated when burnt. Carbon-neutral fuels, however, generate carbon emissions during combustion, but consist of recycled carbon and thus form part of the carbon cycle (see Section 2.2.1 for a more detailed discussion).

costs of the electricity sector would be influenced by the electricity demand from road transport and ptx systems. On the other hand, linking the road transport and electricity sectors may provide system flexibility since, e.g., electric vehicles or electrolysis may serve as energy storage capacities for the electricity sector (see, e.g., [IEA, 2016a] or [Brown et al., 2018]). Especially in the case of high variable renewable energy (VRE) deployment, power-to-x systems may consume electricity in hours of high VRE supply and very low or even negative electricity prices as well as may offer ptx fuels to generate electricity in times of poor VRE supply and critical demand.

With growing social and political pressure for decarbonization together with an increased interest in synthetic fuels, it becomes vital to understand the economic implications of coupling the road transport and electricity sectors. One common method to assess long-term market behavior is via numerical optimization models, which assume future developments in, e.g., emissions, electricity demand and technologies. However, many current modeling approaches tend to either focus on a single sector or on the energy system as a whole. As such, they either fall short of accounting for cross-sectoral interdependencies or lack granularity in their representation of technologies regarding, e.g., road transport and energy transformation such as power to x. Therefore, the paper at hand seeks to answer the following research questions: i) How can the road transport sector and energy transformation technologies be integrated into an electricity market model, ii) what are the key interactions between the sectors and technologies, and how may these contribute to decarbonization and iii) what is the added value of modeling the electricity and road transport sectors as well as energy transformation processes in an integrated multi-sectoral framework?

Within the scope of Chapter 2, an integrated multi-sectoral partial-equilibrium investment and dispatch model combining the European electricity and road transport sectors is developed. A linear dynamic electricity market optimization model is extended to include both the European road transport sector in a road transport module as well as cross-sectoral conversion technologies such as power-to-x systems, with the x indicating a synthetic gas or fuel, in an energy transformation module. The focus lies not only on creating a detailed technological representation within each module but also on properly accounting for any interconnections between the electricity and road transport sectors as well as energy transformation processes. These include all electricity consumption from electric mobility or from energy transformation as well as ptx fuel flows to the road transport and electricity sectors, both within countries and across borders. Furthermore, the model observes any cross-sectoral emissions, such as upstream emissions in the electricity sector emitted during electricity generation for the road transport sector. Many cross-sectoral technologies such as power-to-x systems may only become competitive if they can be rewarded for their carbon-neutral nature, which is only apparent when considering the complete emissions cycle of the fuel production pathway.

The extended integrated multi-sectoral model is then able to simulate cost-minimal decarbonization pathways for the electricity and road transport sectors in European countries up to 2050. In order to demonstrate the capabilities of the model developed, an exemplary scenario is presented to analyze the effects of sector-specific CO_2 reduction targets on the long-term vehicle, electricity and ptx technology mix in Europe. More specifically, a 90% reduction of carbon emissions by 2050 (compared to 1990) is assumed for the European electricity sector as well as for the national road transport sectors of each country. The model yields the cost-optimal solution, minimizing the total costs of the electricity sector as well as the total costs for the vehicles, fuel use and infrastructure needed to reach the CO_2 reduction goals. The results of the single scenario analysis show that by 2050 the fuel share of electricity and ptx fuels in the European road transport sector reaches 37 % and 27 %, respectively, creating an additional electricity demand of 1200 TWh in Europe. The scenario results provide a basis for understanding the integrated multi-sectoral model, revealing endogenous marginal costs of electricity generation and sector-specific marginal CO_2 abatement costs as well as cross-border trade flows that reflect the cost-optimal decarbonization pathway under integrated sectors.

In order to understand the added value of building complex integrated models, the second part of the analysis applies the model with decoupled sectors, removing all endogenous ties between the modules and allowing each to be optimized independently of one another. Additional electricity demanded by road transport and energy transformation is therefore ignored by the electricity sector. Electricity prices for the road transport module are defined exogenously. The energy transformation module, which is by definition coupled to the electricity sector, is shut off; however power-to-x fuels can be bought by either the electricity or road transport sector at a fixed price equal to the expected production costs. The results show that by decoupling the two sectors, the total system costs may be significantly overestimated and the production costs of ptx fuels inaccurately approximated, which may affect the merit order of decarbonization options. By comparing the model results, conclusions may be made as to the added value of integrated multi-sectoral modeling and the key discrepancies that may occur when performing single-sector analyses.

The paper presented in Chapter 2 is related to two streams of literature. The first relevant stream encompasses research that develops multi-sectoral models covering electricity, road transport and energy transformation. In particular, a large body of literature seeks to extend the MARKAL family of models[5] to include additional sectors and technologies, with a smaller niche addressing electrification of road transport and power-to-x fuels. [Dodds and McDowall, 2014] and [Dodds and Ekins, 2014] extend the MARKAL model to simulate the road transport sector in the UK, with a particular focus on hydrogen consumption. Similarly, [Börjesson and Ahlgren, 2012] develop and integrate a transport module into MARKAL for the Nordic regions in order to asses taxation strategies. Two other MARKAL models, namely TIMES and TIAM, are also often

[5]The MARKAL (Market Allocation) family of models, including GMM, TIMES and TIAM, were some of the first energy system models (early contributions include [Fishbone and Abilock, 1981]). MARKAL and its descendants are widely-applied partial equilibrium, bottom-up, dynamic optimization models that are used to identify the energy system meeting energy service demands with the lowest discounted capital, operating and resource costs ([Loulou et al., 2004], [Dodds and Ekins, 2014]).

seen in literature on coupling the road transport and electricity sectors. Both [Sgobbi et al., 2016] and [Thiel et al., 2016] extend the TIMES model developed in [Simoes et al., 2013] to simulate road transport in Europe with approximately 50 vehicle technologies, assessing decarbonization with hydrogen and electricity, respectively. Studies by [van der Zwaan et al., 2013] and [Rösler et al., 2014] build on the TIAM model described in [Rösler et al., 2011] to perform an integrated assessment of decarbonizing the global and European road transport sector, comparing endogenous CO_2 prices across sectors. Apart from MARKAL-based analyses, other simulations of the electricity and road transport sectors include papers by [Hedenus et al., 2010] and [Krishnan et al., 2014], who build on the models GET 7.0 and NETPLAN, respectively, to determine the future vehicle mix and fuel supply under carbon constraints. More recently, models have been developed by [Colbertaldo et al., 2018] and [Emonts et al., 2019] to carefully examine the interdependencies between the electricity system and hydrogen production (via electrolysis) and distribution for road transport using exogenously-defined power sector scenarios. Alternatively, [Brown et al., 2018] model the power sector endogenously with very high technological and temporal resolution with intricate links to many other sectors; yet only select vehicles are considered in the simulation of the road transport sector.

Although many of the aforementioned studies use modeling techniques to address similar issues to the study at hand, none of the methodologies were found to implement the same level of temporal, spatial and technological granularity. Often only hydrogen production via electrolysis and the direct use of electricity appear to be coupled to the electricity sector, ignoring the production of other ptx fuels. The possibility to use ptx fuels to decarbonize the electricity sector next to the road transport sector is also not taken into account. Furthermore, the dispatch of ptx technologies is often exogenous, i.e., the utilization rate of, e.g., an electrolysis system is exogenously defined while its investments are endogenous. In the model developed in Chapter 2, ptx systems are exposed to developments in the electricity system at a higher temporal resolution than in the models mentioned. Trade flows of ptx fuels were also found to be possible in only a limited number of cases and are never examined in detail. Future electricity generating capacities are also found in many studies to be defined exogenously following sources such as [ENTSO-E, 2015b]. Finally, many studies also choose to consider select decarbonization options for the road transport sector and do not consider the same magnitude of vehicle segments, fuel options and technology types as the analysis presented. As such, the study at hand seeks to contribute to the literature on integrated electricity and road transport sector models by accounting for a wide range of ptx applications and vehicle types, optimizing European electricity capacities and ptx fuel production as well as simulating cost-minimizing trade flows according to endogenous market conditions.

The second relevant literature stream focuses on single-sector analyses of the road transport sector and the resulting optimal decarbonization pathways. Many studies assess the penetration of alternative vehicle technologies under certain scenarios (e.g., [Pasaoglu et al., 2016], [Harrison et al., 2016]). [Ou et al., 2013] as well as [Gambhir et al., 2015] simulate the Chinese road transport sector up to 2050 to determine total costs under varying penetration levels of electric or hydrogen fuel-cell vehicles. Applying similar methods to those used in the road transport module developed in this paper, [Romejko and Nakano, 2017] perform a cost minimization for the Polish road transport sector in order to determine endogenous vehicle investments and carbon emissions up to 2030. However, as the models used are decoupled from the energy system, all three papers must assume exogenous prices for all fuels, including electricity. One aim of the study at hand is to gain understanding as to how exogenous assumptions on cross-sectoral parameters may cause the model to deviate from the cost-optimal solution. The assessment of the added value of coupled models, a step that none of the aforementioned studies perform, is another key contribution of this paper.

The remainder of this chapter is organized as follows: In Section 2.2, the underlying methodologies in coupling the electricity market, energy transformation and road transport modules as well as in developing the individual modules are explained in detail. The scenario framework and results of the integrated model are presented in Section 2.3, and the comparison to a decoupled model is made in Section 2.4. Section 2.5 concludes.[6]

2.2. Methodology

One of the main objectives of the research at hand is to develop a consistent, integrated energy system model. The foundation of the work presented is the electricity market model DIMENSION, which has been used in numerous analyses;[7] yet with increasing electrification in synthetic fuel production and road transport, complex interactions arise that cannot be investigated with a single-sector model. In order to account for these multi-sectoral effects, not only do the energy transformation and road transport modules themselves need to be modeled in detail, it is also critical that any interdependencies with the electricity market are also properly simulated.

The remainder of this section is structured as follows: Section 2.2.1 begins by providing an overview of the model developed in this study as well as identifies the key links connecting the individual modules. The main equations, assumptions and parameters for the energy transformation and road transport modules are then given in Sections 2.2.2 and 2.2.3, respectively. For completeness, a short overview of the electricity market module is also included in Appendix A.2.

[6] See Appendix A.1 for a list of nomenclature used throughout Chapter 2.
[7] See, e.g., [Jägemann et al., 2013a], [Knaut et al., 2016] and [Peter and Wagner, 2018].

2.2.1. Developing an integrated multi-sectoral model

Overview of the model

Figure 2.1 presents an overview of the model developed and shows how the individual modules (electricity market, energy transformation and road transport) are connected on the supply side. A key factor of this analysis is that the entire fuel supply chain, from the primary energy source to final fuel consumed, is taken into account. The different fuel types and their production paths can be seen in Figure 2.1.

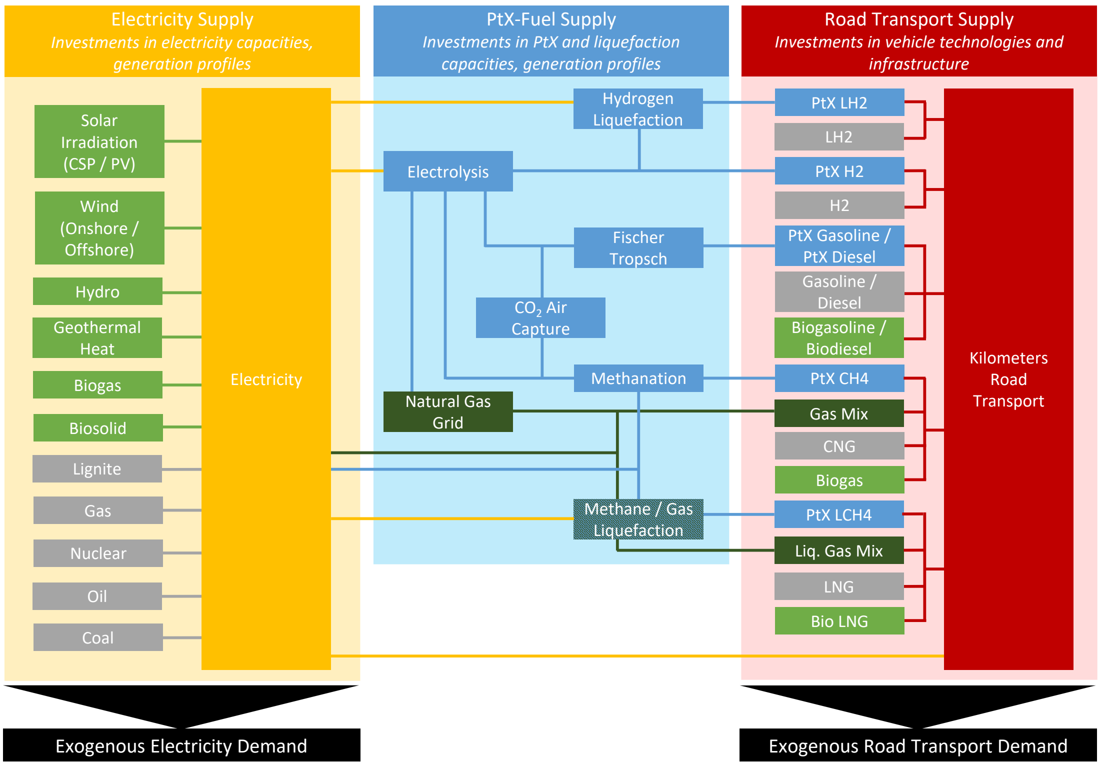

Figure 2.1.: Overview of the model developed for the study presented in Chapter 2. The yellow area indicates the electricity market module, the blue area the energy transformation module and the red area the road transport module.

The electricity market module, as shown in the yellow area of Figure 2.1, is responsible for providing the necessary investments to supply electricity to meet both a country-specific exogenous electricity demand[8] (indicated by the black box) as well as any electricity-consuming technologies in both the energy transformation module (the blue area of Fig. 2.1) or the road transport module (the red area of Fig. 2.1). The yellow lines exiting the yellow area of the electricity market module indicate these electricity

[8]The electricity market module is also subject to an endogenous electricity demand from, e.g., storage or demand side response (see Appendix A.2). For simplification, this is excluded from Figure 2.1.

flows. The green and gray boxes are the renewable/bio and fossil fuels, respectively, that are available to the power plant fleet.[9]

The energy transformation module (the blue area) installs power-to-x as well as liquefaction capacities. The blue boxes in Figure 2.1 show the different ptx processes that are accounted for in the energy transformation module, including electrolysis, CO_2 air capture, methanation, Fischer-Tropsch synthesis as well as hydrogen and methane/gas liquefaction.[10] Endothermic processes such as electrolysis, which splits water into oxygen and hydrogen, and liquefaction require an electricity input from the electricity market module, as indicated by the yellow lines. The blue lines indicate the flow of ptx fuels, which include zero-carbon ptx hydrogen gas (PtX H2) and ptx liquefied hydrogen (PtX LH2) as well as carbon-neutral ptx methane gas (PtX CH4), ptx liquid methane (PtX LCH4) as well as ptx synthetic gasoline (PtX Gasoline) and ptx synthetic diesel (PtX Diesel).[11] The dark green boxes and lines depict the production of a gas mixture (Gas Mix), created by feeding in zero-carbon hydrogen from the electrolysis system into the existing natural gas grid.[12] The resulting gas mixture is equivalent to a low-carbon substitute for fossil natural gas and can also be liquefied via methane/gas liquefaction to provide a low-carbon alternative to fossil liquefied natural gas (Liq. Gas Mix). The energy transformation module is not subject to an exogenous demand but rather optimizes its supply according to the other modules, meaning that ptx fuels can either be supplied back to the electricity market module (i.e., as ptx methane or gas mix for electricity generation) or to the road transport module to be used in a wide range of vehicle technologies.

The road transport module invests in vehicle technologies as well as infrastructure to cover an exogenous demand for road transport (indicated by the black box), varying across countries and years. In the model, the equilibrium condition is defined in annual vehicle kilometers, which in turn defines an energy demand based on the vehicle's motor type and specific fuel consumption. As indicated by the red lines, a single vehicle technology may consume multiple fuel types, as explained in Section 2.2.1. In addition to ptx fuels (blue and dark green boxes), the road transport module may also purchase fossil fuels (gray boxes) such as gasoline, diesel, natural gas (CNG), liquefied natural gas (LNG), hydrogen gas (H2) and liquefied hydrogen (LH2) from natural gas reformation as well as biofuels (light green boxes) such as biodiesel, biogasoline, biogas

[9] Investments in nuclear power are only allowed in countries with no existing nuclear phase-out policies. Investments in carbon capture and storage (CCS) technologies are not allowed due to a general lack of social acceptance in European countries.

[10] Unlike the other processes presented, CO_2 air capture is not modeled as an investment object but rather assumed to be available at a feedstock price equal to the average costs of CO_2 air capture (see Section 2.2.2).

[11] The upstream emissions from the electricity generation used as input for the ptx production processes are accounted for within the electricity market emissions. Therefore, the zero-carbon and carbon-neutral properties hold with respect to the sector in which the fuel is used, irrespective of how the electricity was generated in the first place. See Section 2.2.1 for a detailed discussion.

[12] The existing natural gas grid is not modeled as an investment object but rather as an energy constraint (see Section 2.2.2).

and bio LNG. Fossil fuels and biofuels can be bought from the global commodity market at a price reflecting both the raw fuel and the fuel production costs.[13] Electricity may also be consumed in the road transport module, which is endogenously supplied by the electricity market module.

The integrated multi-sectoral model optimizes the energy transformation and road transport modules simultaneously with the electricity market module to determine the cost-efficient investment and dispatch strategy for meeting electricity and road transport demand of each country. To this end, accumulated discounted total system costs are minimized subject to regulatory conditions as well as technical constraints such as carbon emission reduction targets[14] or energy balance restrictions. The model allows for an integrated analysis yielding a cost-minimal, welfare-optimal[15] solution across multiple coupled sectors. The spatial scope of the model covers 28 countries, including 26 countries of the European Union as well as Norway and Switzerland.[16] The analyzed time period spans 2015 to 2050 in 5-year steps. For computational tractability, the model applies a reduced temporal resolution based on 16 typical days.[17]

Understanding the structure of the electricity market module

The model developed within the scope of this study is an extended version of the dynamic electricity market model DIMENSION, similar to the integrated problem for investment and operation as presented in, e.g., [Turvey and Anderson, 1977]. It may be interpreted as a social planner problem in which the social planner minimizes total system costs under perfect foresight for investments in generation capacity and the operation of generation and transmission between markets.[18]

As it is often seen in the literature on electricity market modeling, fundamental as-

[13] Costs for oil refining, natural gas reformation, etc. are added as a price markup to the commodity price. Note that such a marginal cost approach does not take into account any sunk costs such as the investment costs for oil refineries. Biofuels are assumed to be traded on a European market, with prices based on the fossil-based equivalent plus a 20 % markup.

[14] 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.

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

[16] See Table A.2 in Appendix A.1 for a complete list of the countries considered in Chapter 2.

[17] In order to represent a full year, the typical days are scaled up by multiplying each typical day with its frequency of occurrence. Each typical day consists of four time slices representing six consecutive hours. The typical days vary according to wind speed, solar irradiance, winter or summer as well as week or weekend day. The authors have chosen this temporal resolution due to restrictions in computational power given the complexity of the multi-sectoral model 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.

[18] The electricity market model DIMENSION will be referred to as the *electricity market module* henceforth. The reader is referred to [Richter, 2011], [Fürsch et al., 2013] and [Jägemann et al., 2013a] for more detailed descriptions of the model DIMENSION, which was developed and has been maintained at the Institute of Energy Economics at the University of Cologne (EWI).

sumptions are necessary to reduce the complexity of the optimization problem. The model at hand assumes inelastic demand due to, e.g., the lack of real-time pricing as well as market clearing under perfect competition. As such, the problem can be treated as a linear optimization, as shown in Equation (2.1). The objective function (2.1a) minimizes total costs TC, i.e., the sum of the fixed costs of generation capacity $\bar{\mathbf{x}}_{i,m}$ and variable costs of generation $\mathbf{g}_{i,m,t}$ of technology i in market m.[19] Investing in additional generation capacities comes with costs of $\delta_{i,m}$ and generation incurs variable costs of $\gamma_{i,m,t}$.

$$\min \quad TC = \sum_{i,m} \delta_{i,m} \bar{\mathbf{x}}_{i,m} + \sum_{i,m,t} \gamma_{i,m,t} \mathbf{g}_{i,m,t} \tag{2.1a}$$

$$\text{s.t.} \quad l_{m,t} = \sum_{i} \mathbf{g}_{i,m,t} + \sum_{n} \mathbf{k}_{n,m,t} \qquad \forall m, t, m \neq n \tag{2.1b}$$

$$\mathbf{g}_{i,m,t} \leq x_{i,m,t} \bar{\mathbf{x}}_{i,m} \qquad \forall i, m, t \tag{2.1c}$$

$$|\mathbf{k}_{m,n,t}| \leq \bar{k}_{m,n} \qquad \forall m, n, t, m \neq n \tag{2.1d}$$

$$\mathbf{k}_{m,n,t} = -\mathbf{k}_{n,m,t} \qquad \forall m, n, t, m \neq n \tag{2.1e}$$

$$l_{m,peak} \leq \sum_{i} v_{i,m} \bar{\mathbf{x}}_{i,m} \qquad \forall m \tag{2.1f}$$

$$GHG_{cap} \geq \sum_{i,m,t} \kappa_i \, \mathbf{g}_{i,m,t} / \eta_{i,m} \tag{2.1g}$$

for technologies $i \in \mathbf{I}$, markets $m, n \in \mathbf{M}$ and time $t \in \mathbf{T}$.

The cost-minimizing objective function is subject to various constraints: The equilibrium condition (2.1b) ensures that supply, i.e., the sum of generation $\mathbf{g}_{i,m,t}$ and electricity exchanges between markets m and n, $\mathbf{k}_{n,m,t}$ and $\mathbf{k}_{m,n,t}$, equals demand $l_{m,t}$. The two capacity constraints (2.1c) and (2.1d) require that generation and transmission are restricted by installed generation and transmission capacities. Equation (2.1e) states that electricity trades from market m to market n are equal to negative trades from market n to market m. The peak capacity constraint (2.1f) requires the sum of generation capacities $\bar{\mathbf{x}}$ weighted by their capacity values[20] $v_{i,m}$ is to be greater than or equal to the market-specific annual peak load $l_{m,peak}$. The peak capacity constraint is typically introduced in long-term investment models that are based on a reduced temporal resolution, e.g., a typical-days approach, to ensure security of supply even when only modeling select hours. Finally, the decarbonization constraint (2.1g) requires the sum of greenhouse

[19] See Table A.1 in Appendix A.1 for a complete list of model sets, parameters and variables used within Chapter 2. Unless otherwise noted, bold capital letters indicate sets, lowercase letters parameters and bold lowercase letters for optimization variables.

[20] The capacity value indicates what percent of the plant's capacity can contribute to security of supply. For conventional power plants, the capacity value may deviate from 100% due to, e.g., unplanned outages or seasonal effects. Variable renewable energy sources have lower capacity values due to a possible lack of production during times of high demand. In the existing literature, capacity value and capacity credit are often used as synonyms. Throughout Chapter 2, the term capacity value is used.

gas emissions[21] of all technologies in all markets to be lower than a certain greenhouse gas cap. The CO_2 emissions are calculated by dividing electricity generation $\mathbf{g}_{i,m,t}$ by the technology-specific efficiency $\eta_{i,m}$ to determine the technology's fuel consumption, which is then multiplied with its fuel-specific carbon emission factor κ_i.

Identifying key links between modules

Within the scope of this research, two additional modules were developed and embedded into the optimization problem shown in Equation (2.1): a road transport module simulating the European road transport sector and an energy transformation module simulating conversion technologies, e.g., power-to-x systems providing fuels to the electricity and road transport sectors.

The complexity of a multi-sectoral model lies within the proper representation of interlinkages between the modules.[22] Within the integrated multi-sectoral model, the electricity market module is still represented by Equations (2.1b) - (2.1f), which now, however, only apply to the set of electricity market technologies $i \in \mathbf{I_{el}}$, i.e., a sub-quantity of the entire quantity of technologies $\mathbf{I} = \mathbf{I_{el}} + \mathbf{I_{rt}} + \mathbf{I_{et}}$ comprising all technologies from the electricity market module, the road transport module and the energy transformation module.

The cost-minimizing objective function (2.1a) is still valid; however it now encompasses technologies from all modules, i.e., $i \in \mathbf{I}$, and thereby represents the core of the integrated modeling approach. The fixed costs $\delta_{i,m}$ include the annuity as well as the yearly fixed operation and maintenance costs of power plants, vehicles and infrastructure as well as ptx and liquefaction systems. The variable costs $\gamma_{i,m,t}$ include fuel costs as well as costs for, e.g., CO_2 air capture and fuel distribution (see Sections 2.2.2 and 2.2.3).

One key link between the modules is achieved via modifying the equilibrium condition (2.1b) in order to account for the endogenous electricity demand from all modules. In addition to the endogenous electricity demand in the electricity market module, e.g., by storage technologies, both the energy transformation module and the road transport module may demand electricity in order to generate ptx fuels (see Section 2.2.2) or fuel electric vehicles (see Section 2.2.3), which in turn must be supplied by the electricity market module. The modified equilibrium condition then reads

$$l_{m,t} + \sum_s \mathbf{ec}_{f,f1,m,s,t}\Big|_{f,f1=elec} = \sum_i \mathbf{g}_{i,m,t} + \sum_n \mathbf{k}_{m,n,t} \tag{2.2}$$

where the electricity demand has both an exogenous component, $l_{m,t}$, and an endogenous component, represented by the electric energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ for $f1 = f =$ electricity, summed over sectors s.

[21] In CO_2 equivalent.

[22] See Figure A.1 in Appendix A.3 for a schematic representation of the key links between the modules.

Another key link between the modules is the endogenous country-specific electricity price. It is implicitly visible to all modules as they are all subject to one common cost-minimizing objective function (2.1a). The endogenous country-specific electricity price is derived from the dual variable of Equation (2.2) and represents the change in total system costs for supplying one additional unit of electricity. The remaining two key links between the modules consist of the endogenous ptx fuels demand and the resulting endogenous ptx fuel price in the energy transformation module: The endogenous ptx fuel demand drives investments in ptx and liquefaction technologies, which in turn determines the implicit ptx fuel prices, discussed in Section 2.2.2.

Introducing substitute fuels

Both the electricity market module and road transport module have a wide range of fuels to choose from when making the investment decision in an electricity generation or vehicle technology. However, some of the fuel choices are substitutes, varying only in, e.g., production costs and upstream carbon emissions. For example, a fuel-cell vehicle running on hydrogen can run both on ptx and fossil-based hydrogen; yet the model must be able to distinguish between the two fuel types as hydrogen from electrolysis differs strongly in terms of production cost and upstream carbon emissions compared to that from natural gas reformation. Moreover, both carbon-based ptx fuels and biofuels are assumed to be carbon neutral, which can only be accounted for if the fuel's production cycle is properly recognized by the model (see Section 2.2.1).

As a result, the concept of substitute fuels is introduced in order to differentiate fuels by how they are produced while still allowing for fuels to be grouped by their type (Table 2.1).[23] It should be noted that for fuels without multiple substitute fuels (e.g., electricity, coal, lignite), f equals $f1$. For simplification, such fuels are omitted from Table 2.1.

Fuel type f	**Substitute fuels** f_1		
Diesel	Diesel	PtX Diesel	Biodiesel
Gasoline	Gasoline	PtX Gasoline	Biogasoline
Gas	CNG	PtX CH4/Gas Mix	Biogas
Liquefied Gas	LNG	PtX LCH4/Liq. Gas Mix	Bio LNG
Hydrogen	H2	PtX H2	
Liquefied Hydrogen	LH2	PtX LH2	

Table 2.1.: Fuel types and the corresponding substitute fuels

[23]It should be noted that the concept of substitute fuels ignores any differences in the chemical composition of the respective fuels. Substitute fuels are thus treated, economically speaking, as perfect substitutes. This assumption is justified in an economic model as long as the fuel-consuming technologies can interchangeably switch between fuels without affecting their performance.

By applying the concept of substitute fuels, not only can each sector's endogenous energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ be determined for a certain fuel type f, but the mix of substitute fuels $f1$ can be simultanously derived, taking into account constraints such as decarbonization targets. As such, in terms of the electricity market model given in Equation (2.1), the energy consumption of power plants in the electricity sector is then defined by

$$\sum_{f1} \mathbf{ec}_{f,f1,m,s,t}\Bigg|_{s=el} = \sum_{i} \mathbf{g}_{i,m,t}/\eta_{i,m} \qquad \forall m,t,f \tag{2.3}$$

For example, the ptx methane consumption of a power plant in the electricity sector $s = el$ of market m is depicted by $\mathbf{ec}_{f,f1,m,s,t}$ with $f =$ gas and $f1 =$ ptx methane. The electricity consumption of, e.g., a pump storage is denoted by $f1 = f =$ electricity.

Accounting for upstream emissions and the carbon cycle

Carbon emissions from combustion processes are based on the carbon content of the respective fuel, i.e., a fuel-specific carbon emission factor κ_{f1}. For non-carbon fuels such as electricity or hydrogen, this value is equal to zero. Fuel-specific upstream carbon emissions, on the other hand, include emissions from fuel extraction and transformation and are accounted for by a fuel-specific upstream carbon emission factor $\kappa_{f1,upstream}$.[24] For fossil fuels and biofuels, this includes carbon emissions generated during fuel production and conditioning at the source, fuel transformation at the source, transformation near market and conditioning and distribution ([Edwards et al., 2014]).[25] It should be noted that the upstream emissions of electricity as an input fuel for, e.g., electric vehicles or ptx processes are accounted for in the electricity market module. Thus, the upstream emissions of ptx fuels produced in the energy transformation module consist only of emissions resulting from the distribution of the final fuel from the central ptx system to the consumer. The fuel-specific carbon emission factors and upstream carbon emission factors are shown for each substitute fuel in Table A.3 of Appendix A.4.

The carbon emissions $\mathbf{em}_{m,s}$ from sector s in market m are then defined by

$$\mathbf{em}_{m,s} = \sum_{f,f1,t} \mathbf{ec}_{f,f1,m,s,t}(\kappa_{f1} + \kappa_{f1,upstream}) \qquad \forall m,s \tag{2.4}$$

In order to account for the carbon cycle of carbon-neutral fuels such as biofuels or ptx fuels (discussed in detail in Section 2.2.2), a carbon capture variable $\mathbf{cpt}_{m,s}$ is introduced

[24] Note that the carbon emission factor from combustion processes κ_{f1} is equal for fuel f and its substitute fuels $f1$, assuming the fuels are perfect substitutes. The upstream carbon emissions factor $\kappa_{f1,upstream}$ however varies for different substitute fuels $f1$.

[25] Upstream emissions differs from a Life Cycle Analysis (LCA), as it does not consider energy and emissions involved in building facilities and the vehicles, or end of life aspects.

and defined as

$$\mathbf{cpt}_{m,s} = \sum_{f,f1,t} \mathbf{ec}_{f,f1,m,s,t}\ \kappa_{f1}|_{f1=bio/ptx} \qquad \forall m,s \qquad (2.5)$$

Thereby, it is assumed that the entire carbon content of the biofuels or ptx fuels, represented by κ_{f1}, is captured from air either by natural carbon bonding via biomass photosynthesis or by a direct air capture process (DAC) (see Section 2.2.2). As such, a closed carbon cycle is formed, allowing the corresponding fuel to be considered 'carbon neutral'.

A generalized formulation of the decarbonization constraint (2.1g) in Equation (2.1) reads then as

$$GHG_{cap,s} \geq \sum_{m}(\mathbf{em}_{m,s} - \mathbf{cpt}_{m,s}) \qquad \forall s \qquad (2.6)$$

It should be noted that for carbon-neutral fuels, i.e., biofuels and ptx fuels, the emissions κ_{f1} cancel out in Equation (2.6); however, this does not hold true for any upstream emissions $\kappa_{f1,upstream}$. Furthermore, the sum on the right-hand side of Equation (2.6) has to be adjusted depending on the definition of the decarbonization target, which can be either, e.g., a multi-national sectoral target, a national sectoral target or a national multi-sectoral target.

2.2.2. Simulating energy transformation

The energy transformation module simulates the investment in as well as energy consumption and production volumes of energy conversion technologies in order to serve, among others, the electricity and road transport sectors. Within the scope of this analysis, the module endogenously reacts to developments in the electricity market (i.e., increased VRE production) as well as the demand for ptx fuels in the electricity and road transport modules, which may be necessary to achieve, e.g., decarbonization targets. This section seeks to introduce the conversion technologies considered as well as provide key details on how the ptx fuel supply is modeled. Further explanation is then provided on how the conversion technologies are linked to the electricity market module.

Power-to-x, liquefaction and carbon neutrality via CO_2 air capture

The ptx conversion technologies, analogous to the electricity generation technologies, are investment objects with defined techno-economical parameters that vary across vintage classes. These technologies include alkaline and PEM electrolysis, catalytic methanation and Fischer-Tropsch synthesis. Key techno-economic assumptions for each ptx investment object considered in the energy transformation module including investment costs, fixed operation and maintenance costs (FOM), efficiency and technical lifetime can be found in Table A.4 in Appendix A.4. Plants to liquefy gaseous hydrogen or natural gas are also taken into account in the energy transformation module. Analogous to ptx systems, liquefaction plants are modeled as investment objects. The techno-economic assumptions for the liquefaction plants may be found in Table A.5 in Appendix A.4.

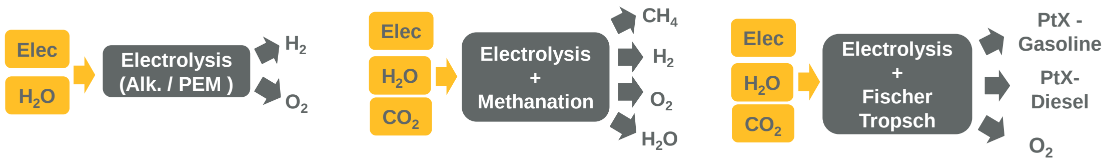

Figure 2.2.: Inputs and outputs of ptx processes

Figure 2.2 gives an overview of the relevant input and outputs for each ptx technology modeled in this analysis. The hydrogen gas produced in electrolysis can either be sold directly or be stored to successively produce methane via catalytic methanation or hydrocarbons via Fischer-Tropsch synthesis. Alternatively, ptx hydrogen may be mixed with natural gas in the existing gas grid infrastructure up to a certain threshold which depends on the design and certification of end appliances. An upper limit of 10 vol-% of the natural gas grid is assumed for hydrogen feed-in.[26] It should be noted that, as shown in Figure 2.2, an electrolysis system produces oxygen as by-product. As such, in addition to selling ptx fuels, the energy transformation module also sells oxygen to an exogenously-defined market at an exogenous price, increasing the profitability of ptx systems.[27] Detailed descriptions of the energy transformation processes can be found in Appendix A.4.2.

As previously stated, the ptx fuels produced in the energy transformation module are assumed to be either zero-carbon or carbon neutral. Upstream emissions aside, hydrogen fuel produced from electrolysis is by definition carbon-free as electricity splits water into oxygen and hydrogen. Technologies such as methanation and Fischer-Tropsch synthesis, however, produce carbon-based fuels that, via combustion, will emit carbon dioxide into the atmosphere. Yet these ptx fuel production processes require carbon dioxide together with hydrogen as an input in order to create carbon-based ptx methane or ptx gasoline and ptx diesel (see Figure 2.2). The classification carbon neutral depends on the origin of the carbon fed into the ptx processes. More specifically, if the carbon stems from a fossil-based origin, the eventual release of carbon dioxide during the ptx fuel combustion

[26] In the future, it is expected that gas turbines, motors and consumer appliances will be able to function under higher shares of hydrogen gas. However, the authors have chosen 10 vol-% as an average in order to account for a wide range of older and newer technologies. In order to set the limit in the model, the national gas demand is used as a proxy for gas grid size in each respective country.

[27] An oxygen price of 0.07 EUR/cubic meter is assumed based on [Brynolf et al., 2018]. The country-specific upper limit for oxygen sales is estimated based on industry data for Germany ([VCI, 2014]) and for the other European countries scaled according to GDP ([Eurostat, 2017]), whereby only 25 % of a country's oxygen demand is assumed to be able to be provided by electrolysis.

process cannot be regarded as carbon neutral.[28] If, however, the carbon is based on air capture either from biomass photosynthesis or a technical direct air capture process, the CO_2 is recycled, resulting in a carbon-neutral process being part of a carbon cycle. In this work, it is assumed that the carbon required for ptx fuel production stems from CO_2 extracted from the atmosphere via direct air capture.[29]

Key aspects of modeling the supply of ptx fuels

The equilibrium condition for ptx fuels ensures that the ptx fuel production, $\mathbf{fp}_{f1,i,m,t}$, within each country m in addition to any ptx fuel trade $\mathbf{ft}_{f1,n,m,t}$, i.e., ptx fuels being imported into country m from other EU countries n or from outside of Europe, $\mathbf{ft}_{f1,nonEU,m,t}$, is equal to the amount of ptx energy consumption in country m, $\mathbf{ec}_{f,f1,m,s,t}$, plus ptx fuel exports from country m to country n, $\mathbf{ft}_{f1,m,n,t}$:

$$\begin{aligned} &\sum_i \mathbf{fp}_{f1,i,m,t} + \sum_n \mathbf{ft}_{f1,n,m,t} + \mathbf{ft}_{f1,nonEU,m,t} \\ &\qquad = \sum_s \mathbf{ec}_{f,f1,m,s,t} + \sum_n \mathbf{ft}_{f1,m,n,t} \qquad \forall m,t,f,f1 \end{aligned} \tag{2.7}$$

This equilibrium condition holds for all liquid fuels $f1$ produced by ptx technologies i such as ptx gasoline, ptx diesel, ptx liquefied hydrogen, ptx liquid methane and liquefied gas mix.

The gaseous ptx fuels, namely ptx hydrogen, ptx methane and gas mix, are subject to a slightly modified equilibrium condition in order to account for any ptx hydrogen that is injected into the natural gas grid. Similar to Equation (2.7), the equilibrium conditions for gaseous ptx fuels are

$$\begin{aligned} &\sum_i \mathbf{fp}_{PtXH2,i,m,t} + \sum_n \mathbf{ft}_{PtXH2,n,m,t} + \mathbf{ft}_{PtXH2,nonEU,m,t} \\ &\qquad = \sum_s \mathbf{ec}_{H2,PtXH2,m,s,t} + \sum_n \mathbf{ft}_{PtXH2,m,n,t} \\ &\qquad\quad + \mathbf{ffi}_{PtXH2,m,t} \qquad \forall m,t \end{aligned} \tag{2.8}$$

$$\begin{aligned} &\sum_i \mathbf{fp}_{PtXCH4,i,m,t} + \sum_n \mathbf{ft}_{PtXCH4/GasMix,n,m,t} + \mathbf{ft}_{PtXCH4,nonEU,m,t} + \mathbf{ffi}_{PtXH2,m,t} \\ &\qquad = \sum_s \mathbf{ec}_{Gas,PtXCH4/GasMix,m,s,t} + \sum_n \mathbf{ft}_{PtXCH4/GasMix,m,n,t} \qquad \forall m,t \end{aligned} \tag{2.9}$$

[28]Note that carbon from fossil-based carbon capture and utilization (CCU) is, while relieving the first combustion process from its carbon emissions, still fossil-based carbon. Thus, it does not qualify for production of carbon-neutral ptx fuels, as this would entail double counting.

[29]The CO_2 feedstock prices from air capture are assumed to reduce from 300 EUR/tCO_2 in 2020 to 84 EUR/tCO_2 in 2050 ([Sanz-Pérez et al., 2016]), as shown in Figure A.2 in Appendix A.5.

with the extra variable ptx fuel feed-in $\mathbf{ffi}_{PtXH2,m,t}$ indicating the amount of ptx hydrogen injected into the natural gas grid. In Equation (2.8), the ptx hydrogen into grid contributes to the hydrogen demand, whereas in Equation (2.9) it becomes part of the gas supply. Apart from being fed into the natural gas grid ($\mathbf{ffi}_{PtXH2,m,t}$), ptx hydrogen can be directly used in sectors such as road transport or sent to a liquefaction plant in order to produce ptx liquefied hydrogen ($\mathbf{ec}_{H2,PtXH2,m,s,t}$). Ptx methane, analogous to ptx hydrogen, can be either fed into the natural gas grid or liquefied, represented by each sector's energy consumption ($\mathbf{ec}_{Gas,PtXCH4/GasMix,m,s,t}$).[30]

As shown in Equations (2.7), (2.8) and (2.9), ptx fuels can either be traded between European countries or bought from outside of Europe, e.g., from North Africa. Inner-European import and export volumes via trucks are determined endogenously, being subject to tanker transport costs relative to delivery distance.[31] As the model does not cover investments outside Europe, an exogenous ptx fuel import price is calculated based on the expected production and distribution costs of ptx fuels at a typical location in North Africa.[32] For the recycled carbon supply for ptx diesel, ptx gasoline and ptx methane production outside of Europe, CO_2 air capture is assumed and included in the production costs. Ptx fuels from European production are not permitted to be exported outside Europe.

Linking the energy transformation module to the electricity market and road transport modules

One key link between the energy transformation and electricity market module is the demand of electricity by power-to-x and liquefaction systems to produce gaseous and liquid ptx fuels, determined endogenously. The electric energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ of the energy transformation module is defined as

$$\sum_{f1} \mathbf{ec}_{f,f1,m,s,t} \Bigg|_{f,f1=elec} = \sum_{i} \mathbf{fp}_{f1,i,m,t} / \eta_{i,m} \qquad \forall m,t \qquad (2.10)$$

where the factor $\eta_{i,m}$ represents the efficiency of the ptx or liquefaction system, i.e., the ratio of fuel output to electricity input. This equation holds also for methanation and Fischer-Tropsch systems, as they are modeled as integrated systems with integrated efficiencies (see discussion in Appendix A.4.2). Equation (2.10) together with Equation (2.2) then defines the link between the electricity market module and the energy transfor-

[30] Note that liquefaction plants use gaseous ptx hydrogen and ptx methane as input, representing an energy consumption of the energy transformation module in Equations (2.8) and (2.9).

[31] The transport costs are derived based on km-specific transport costs and the distance between capital cities as a proxy, see Table A.6 in Appendix A.4.

[32] The production costs include the investment and FOM costs of the ptx systems as well as the variable costs, i.e., the electricity price, calculated as the LCOE of a hybrid onshore wind and photovoltaics plant in North Africa.

mation module, integrating the endogenous electricity demand. Short-term drops in the electricity price, for example, may cause ptx systems to ramp up their production and, in turn, their electricity demand. On the other hand, deep decarbonization of sectors, e.g., the road transport sector, may drive the demand for ptx fuels upwards, increasing electricity consumption. Greater electricity consumption requires greater investments in generation capacities, raising total system costs of the electricity sector and, therefore, driving the endogenous electricity price upwards.

Analogous to the endogenous electricity price, the endogenous ptx fuel price represents another key link, which is implicitly visible to all modules as they are subject to one common cost-minimizing objective function. More specifically, for every unit of increased ptx fuel consumption in country m or export to another country, an additional unit of ptx fuel has to be produced in country m or imported from another country or from outside of Europe. The resulting increase in total system costs can be understood as the marginal price of that unit of additional fuel production. Thus, the endogenous market-specific ptx fuel price can be derived from the dual variables of the equilibrium conditions (2.7), (2.8) and (2.9) and represents the change in total system costs for supplying one more unit of ptx fuel.

Another key link between the energy transformation module and the electricity market and road transport modules is the endogenous ptx fuel demanded by the electricity and road transport sectors, defined via the energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ for $f1$ = ptx fuels as part of the ptx fuel equilibrium conditions (2.7), (2.8) and (2.9). As such, the model has the option to decarbonize the electricity and road transport sectors using, e.g., a carbon-neutral ptx methane gas or a low-carbon natural gas and ptx hydrogen gas mix.

2.2.3. Simulating the European road transport sector

A key contribution of this analysis lies within the detailed modeling of the European road transport sector and the representation of interlinkages with the electricity market and energy transformation modules. The road transport module invests in vehicle technologies as well as infrastructure to cover an exogenous demand for road transport. The choice of vehicle technology, in turn, drives the fuel demand for the road transport sector, being supplied by the electricity market module and the energy transformation module. In the following, the relevant parameters and assumptions as well as equations are presented in detail. Furthermore, key variables and equations linking the road transport module to the electricity market and energy transformation modules are summarized.

Vehicle segments, vehicle technologies, fuels and infrastructure

Modeling the European road transport sector requires a detailed dataset to define parameters, which are categorized according to those that vary across vehicle segment, vehicle technology and fuel type.

The road transport sector is divided into three vehicle segments: private passenger vehicles (PPV), light-duty vehicles (LDV) and heavy-duty vehicles (HDV).[33] Similar to the approach for the electricity sector, technologies are defined for each of these vehicle segments; however, in the case of road transport, technologies can be understood as motor types. The vehicle technologies considered include gasoline motors, gasoline hybrids, diesel motors, diesel hybrids, natural gas motors, natural gas hybrids, battery electric vehicles (BEVs) and fuel-cell electric vehicles (FCVs). Hybrid vehicles (gasoline, diesel, natural gas) are represented by mild hybrids (HEVs) and plug-in hybrids (PHEVs). The existing technology mix in each country for 2015 as well as any recent growth in, e.g., electric vehicles between 2015 and 2017 is defined exogenously.[34] PPVs and LDVs are available for any fuel in Table 2.1 except for liquefied natural gas and liquefied hydrogen, which can solely be consumed by HDVs. HDVs have a variety of liquid fuels available, although gasoline is not assumed to be an option for heavy transport. Similarly, gaseous fuels such as hydrogen and gas are not available for HDVs in the road transport module due to lower energy densities and, as such, lower driving range ([DLR et al., 2010], [Bünger et al., 2016]).

As in the electricity market module, vintage classes are defined for each vehicle technology such that new investment objects are made available in future years to account for, e.g., cost degressions and technological innovations. One key cost component for vehicles is the investment cost or purchase price, with the values for PPVs, LDVs and HDVs shown in Tables A.7 - A.9 in Appendix A.4. The costs of vehicle technologies vary greatly not only according to the motor type but also across vehicle segments. This also holds true for fuel consumption, with values differing not only between, e.g., a diesel vehicle and a FCV but also between a passenger vehicle and a heavy-duty vehicle (see Tables A.13 - A.15 in Appendix A.4). As a result, under a sector-specific decarbonization target for the road transport sector, different vehicle technologies will compete not only within their segment (e.g., diesel PPV vs. FCV PPV) but also against the CO_2 abatement costs of the other segments (e.g., FCV PPV vs. FCV HDV).

In addition to investments in vehicle technologies, the model also endogenously builds the accompanying refueling or charging station infrastructure, depending on the fuel type. Just as in the other modules, infrastructure is an investment object with capital, FOM and variable costs.[35] Apart from refueling and charging station infrastructure costs, the distribution costs to the refueling or charging station is also taken into account and shown in Table A.16 in Appendix A.4.

As explained in Section 2.2.1, substitute fuels are defined as subsets to the fuel types and are priced according to how they were produced. Fossil-based hydrogen, CNG, LNG,

[33] Light-duty vehicles are considered to weight less than 3.5 tonnes, heavy-duty vehicles more than 3.5 tonnes. Motorbikes, scooters and bicycles are excluded from this analysis, as are buses.

[34] Based on [European Commission, 2016a], [KBA, 2017], [IEA, 2016a], [CBS, 2015], [Statistics Sweden, 2017], [Statistics Norway, 2017], [Bundesamt für Statistik, 2017], [ZSW, 2017] and [Department of Transport, 2017].

[35] Any additions or reinforcements to the electricity grid are not considered in this analysis.

gasoline and diesel as well as biogas, bio LNG, biogasoline and biodiesel are assumed to be available at global market prices. The fuel costs reflect not only the raw fuel prices but also additional production costs such as, e.g., natural gas reformation and oil refining. The price for electricity-based fuels, e.g. ptx gas, ptx diesel, etc., as well as the electricity price for BEVs and PHEVs are endogenously determined together with the electricity market and energy transformation modules.

Key aspects of modeling road transport and its infrastructure

The road transport module invests in vehicle technologies as well as infrastructure to cover an exogenous demand for road transport. The underlying equilibrium condition requires the exogenous demand road transport $dr_{m,t}$ to be covered by supply road transport $\mathbf{sr}_{i,m,t}$ summed over all vehicle technologies $i \in \mathbf{I_{rt}}$:

$$dr_{m,t} = \sum_i \mathbf{sr}_{i,m,t} \qquad \forall m, t \tag{2.11}$$

The demand for road transport $dr_{m,t}$ defines the annual kilometers driven within each vehicle segment in each country up to 2050 (Tables A.10 - A.12 in Appendix A.4). Investments in vehicle technologies therefore supply the kilometers $\mathbf{sr}_{i,m,t}$ needed to serve demand based on a vehicle's annual driving distance, assumed to be 13'800 km for PPVs, 21'800 km for LDVs and 70'000 km for HDVs.[36] A single FCV PPV, for example, can supply 13'800 km of zero-carbon driving to a country's yearly demand for road transport. Large differences in yearly driving distance affect the vehicle lifetime, assumed to be 15 years for PPVs and 10 years for LDVs and HDVs. Such characteristics may influence the results as technologies in one vehicle segment must be replaced more often than others (e.g., FCV HDV vs. FCV PPV). In order to prevent a single technology from dominating the market from one time period to the next, maximum yearly adoption rates are defined, limiting the share of new registrations in the vehicle fleet in a single time period.[37]

Carbon emissions and emission reductions in the road transport sector are accounted for as described in Section 2.2.1. Thereby, both direct and upstream emissions are accounted for via the decarbonization constraint (2.6), which also applies to the road

[36] Assumptions on annual driving distance and vehicle lifetimes are based on [EWI et al., 2014], [European Commission, 2016a], [McKinsey, 2010], [KBA, 2017], [Rhenus Logistics, 2007], [Knörr et al., 2012] and [Papadimitriou et al., 2013].

[37] The upper bounds for the short term are taken from current data on new vehicle registrations and vary between 1.8 % and 4.8 % per year for a single vehicle technology. For the long term, they are assumed to increase up to 6.6 %. The values are the same across vehicle technologies but vary across vehicle segments due to discrepancies between segment fleet sizes. These maximum adoption rates were set in order to best allow for an exponential deployment curve for new technologies. Note that the condition may become binding under strict decarbonization targets.

transport sector.[38]

Linking the road transport module to the electricity market and energy transformation modules

The fuel demanded, or energy consumed, by the road transport sector is determined endogenously based on the cost-optimal vehicle and infrastructure investments to cover the total demand for road transport per vehicle segment. The energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ by fuel type f for the road transport sector $s = rt$ is determined by the sum over supply road transport divided by the vehicle efficiencies $\eta_{i,m}$ for all vehicles i of the respective fuel type:

$$\sum_{f1} \mathbf{ec}_{f,f1,m,s,t} \Bigg|_{s=rt} = \sum_{i} \mathbf{sr}_{i,m,t} / \eta_{i,m} \qquad \forall m, t, f \qquad (2.12)$$

with vehicle efficiency $\eta_{i,m}$ being the inverse of vehicle fuel consumption and $i \in \mathbf{I}_{rt}$.

One key link between the road transport module and the electricity market module is the direct use of electricity as a fuel for electric vehicles, i.e. PHEVs and BEVs. Combining Equations (2.12) and (2.2) is how the endogenous electricity demanded by electric vehicles, $\mathbf{ec}_{f,f1,m,s,t}$ for $f1 = f =$ electricity, is accounted for in the electricity market module.[39] The endogenous electricity price represents another key link.

The key links between the road transport module and the energy transformation module are represented by the endogenous ptx fuel price and the ptx fuel demand of the road transport sector, i.e. its energy consumption $\mathbf{ec}_{f,f1,m,s,t}$ for $f1 =$ ptx fuels, as defined in Equation (2.12), which directly feeds in the ptx fuel equilibrium conditions (2.7), (2.8) and (2.9). For example, under increased decarbonization targets, one option to decarbonize may be to displace carbon-heavy fossil fuels with ptx fuels. The increase in electricity consumption due to ptx fuel production is then accounted for via the energy transformation module and the electricity market module.

[38] Literature on the road transport sector often uses the concept of well-to-tank (WTT), i.e., the carbon emissions released during fuel production, and tank-to-wheel (TTW) emissions, i.e., the carbon emissions released upon combustion in the vehicle. In this analysis, the fuel-specific upstream carbon emission factor $\kappa_{f1,upstream}$ is analogous to the WTT emission factor in the road transport sector, whereas the fuel-specific carbon emission factor κ_{f1} is analogous to the TTW emission factor from vehicles. The road transport module therefore follows an approach, which is equivalent to a well-to-wheel (WTW) approach.

[39] For electric vehicles, exogenous hourly charging profiles are applied. Three types of charging stations are simulated: private (e.g., households), semi-private (e.g., workplace) and public (fast charging). Private charging is assumed to take place mostly during evenings, whereas semi-public charging occurs primarily in daytime hours on weekdays. Public charging is possible at any hour but assumed to be less common than private and semi-private charging options (see, e.g., [BAST, 2015] and [DLR, 2015]). PHEV are assumed to follow the same charging profiles; however, PPVs are assumed to run 67 % and LDVs 50 % electric (see [Kelly et al., 2012]).

2.3. Application of the integrated model

In order to demonstrate the capabilities of the integrated model developed, an exemplary single scenario analysis is performed. The goal is to simulate the future European electricity-, road transport- and ptx-technology mix under sector-specific decarbonization targets and examine the role of electricity in achieving emission reductions. Within this section, first the scenario framework is presented (Section 2.3.1), followed by key results for the road transport sector (Section 2.3.2). The section ends with a discussion on the production of ptx fuels and how equilibrium is reached via the trading of ptx fuels throughout Europe (Section 2.3.3). The results for the European electricity sector are shown in Appendix A.6.

2.3.1. Scenario framework

The CO_2 constraint in the electricity market module covers cumulative emissions from electricity generation across all European countries, regardless of the sector that uses the electricity. In the scenario at hand, the aim is to reduce not only the direct emissions from, e.g., the burning of fossil fuels but the upstream emissions as well. Within the electricity market module, upstream emissions may result from, e.g., coal mining or biofuel production. Historical data on European greenhouse gas emissions is taken from the European Environmental Agency ([EEA, 2017]).[40] For 2020, an emission reduction of 24 % compared to 2005 emission levels is set for the European electricity sector.[41] Furthermore, the scenario requires that emissions decline by 43 % compared to 2005 emission levels by 2030 and 90 % compared to 1990 by 2050. All percent values are based on official reduction targets formulated by [European Commission, 2014].

For the road transport sector, the CO_2 constraint is implemented as a percentage reduction of CO_2-equivalent emissions emitted not for Europe as a whole, but rather for each individual European country. Whereas policies to decarbonize the electricity sector tend to be regulated on the European level (e.g., via instruments such as the EU-ETS), the road transport sector is assumed in this scenario to be overseen nationally. The decarbonization target for the road transport sector applies to both the TTW and the WTT emissions. Historical emissions data is based on the [EEA, 2017] and [UBA, 2017].[42] National reduction targets for the road transport sector are based on the Effort Sharing Decision of the European Commission for 2020 [European Commission, 2009] and 2030 [European Commission, 2016b] for each European member state and can be found in Table A.17 of Appendix A.5. For 2050, CO_2 emissions in the transportation sector are to be reduced by 90 % compared to 1990 values in every country, consistent

[40]Historical values were adjusted to account for upstream emissions.

[41]The European 2020 Climate & Energy Package outlines a 21 % reduction relative to 2005 emission levels [European Commission, 2014]. However, latest developments and discussions have shown that this target is likely to be surpassed and was therefore adjusted accordingly in the model.

[42]Historical values were adjusted to account for the WTT emissions.

with the electricity sector target. The energy transformation module is not subject to a CO_2 reduction target. The produced zero-carbon and carbon-neutral ptx fuels, however, contribute to the targets imposed on the electricity and road transport sectors, depending on the sector in which the fuels are consumed. In addition to CO_2 constraints, the modeled scenario inhibits the energy transformation module from importing ptx fuels from outside of Europe.[43]

The fuel price assumptions for the scenario are based on a global commodity market at a price reflecting both the raw fuel and the fuel production costs (see Figure A.2 in Appendix A.5). All other parameters are defined as described in Section 2.2.

2.3.2. Scenario results for the European road transport sector

The vehicle mix cumulated over all European countries is shown in Figure 2.3. The introduction of a country-specific sectoral decarbonization target in road transport drives an almost immediate alteration to the current vehicle mix. Hybrid (HEV) gasoline and diesel engines emerge as a short-term option to replace their fully internal combustion-powered counterparts. Furthermore, vehicles running on natural gas and electricity also show accelerated growth, with varying penetration levels across segments.

For the PPV segment, a mix of hybrid and internal combustion-powered vehicles running on compressed natural gas (CNG) dominate new vehicle investments in the short term. Starting in 2035, the model begins to maximize BEV deployment alongside continued investments in natural gas hybrids. HDVs also use natural gas to jump-start decarbonization, introducing internal combustion-powered trucks in 2020 and hybrid trucks in 2030 that run on liquefied natural gas (LNG) to push out their diesel counterpart; however, diesel HEVs remain in the vehicle mix through 2050. It is not until after 2040 that electric vehicles also begin to break through in the HDV segment, growing quickly to a 25 % share of HDVs by 2050. LDVs, on the other hand, begin to maximize the deployment of electric vehicles early on, reaching upper bound adoption rates already in 2025. Natural gas LDVs help the remaining share to decarbonize, first via internal combustion-powered vehicles and then via plug-in hybrids. Hydrogen FCVs emerge in the LDV segment in 2045 and in the PPV and HDV segments in 2050, as the CO_2 bound becomes more and more restrictive.

Figure 2.4 provides further information about the fuel type consumed by the road transport sector.[44] The amount of fossil gasoline and diesel consumed in the road trans-

[43] The goal of the analysis is to maximize the endogeneity of the model. Any exogenous decarbonization options such as ptx fuel imports from outside EU at fixed import costs may weaken the effects of the endgenous model output. Therefore, only endogenous investments in ptx and liquefaction capacities within Europe are allowed.

[44] The results for the infrastructure follow the developments shown in Figure 2.4, as investments in infrastructure are made independent of vehicle segment and instead serve the total vehicle demand according to fuel type. A detailed discussion of the infrastructure results is omitted from this study as the focus lies primarily on the interdependencies between the modules rather than the individual module results.

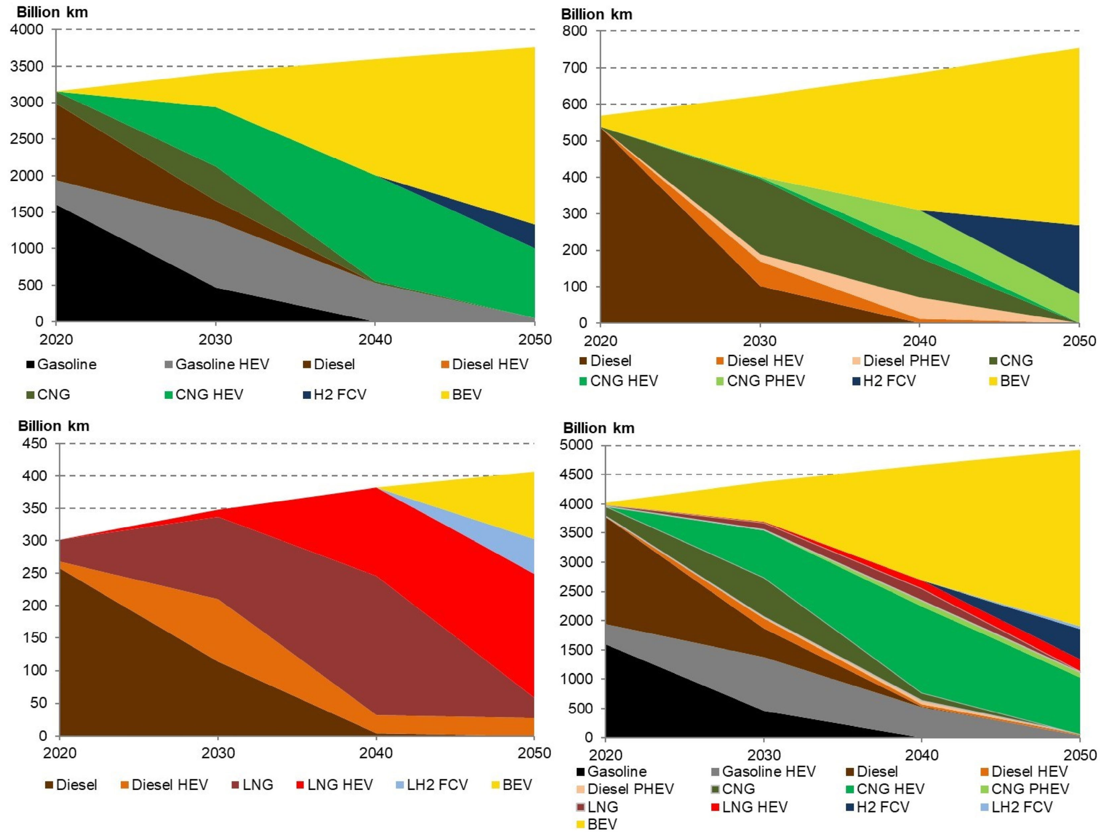

Figure 2.3.: EU vehicle mix up to 2050 for PPVs (top left), LDVs (top right), HDVs (bottom left) and all vehicles (bottom right)

port sector decreases by 46 % and 60 %, respectively, between 2020 and 2030. Within this decade, the amount of fossil CNG and LNG, on the other hand, increases ten-fold to account for over 40 % of all fuels consumed in 2030. As the techno-economic characteristics of the vehicles do not drastically differ from one another, the switch from gasoline and diesel to natural gas is driven primarily by comparatively lower well-to-wheel CO_2 emissions as well as cheaper fuel prices. The reduction in non-hybrid gasoline and diesel engines as well as gains in vehicle efficiency drive the total fuel consumption downwards.

Non-fossil fuels mostly enter the market between 2030 and 2050 as a result of the long-term country- and sector-specific 90 % CO_2 reduction targets. Most notable is the increase in electricity, accounting for 570 TWh or 37 % of total fuel consumption in the European road transport sector in 2050. Restrictions in new vehicle deployment via maximum adoption rates are binding for BEVs in the PPV and LDV segments relatively early on, which constrains the amount of electricity that can be directly consumed. As such, in order to reach the decarbonization targets, other low-carbon fuels must play a role. In particular, ptx fuels emerge from 2040 onwards, primarily for use in the HDV segment: First as liquefied gas mix and then together with ptx liquefied hydrogen (PtX

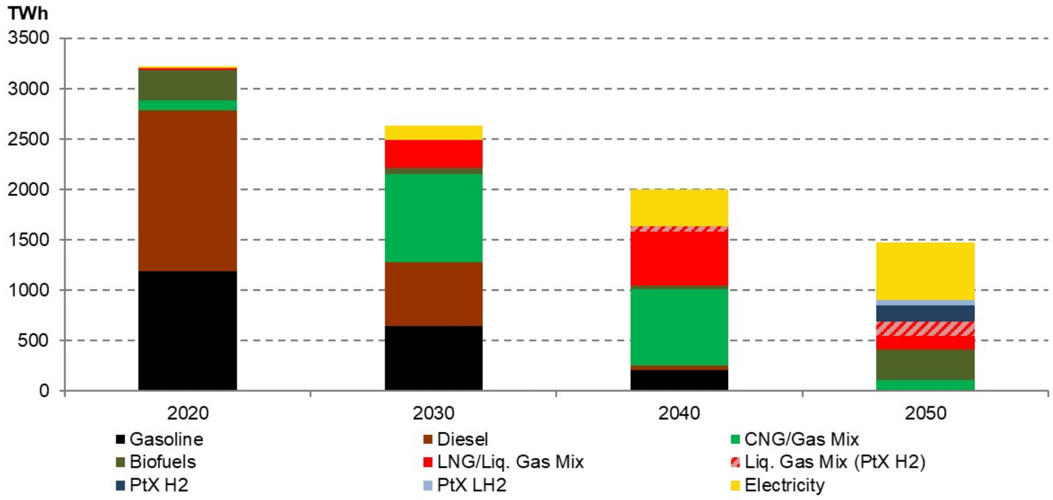

Figure 2.4.: Fuel consumption in the road transport sector in Europe in 2020, 2030 and 2050 in the coupled model

LH2) and ptx diesel.[45] In fact, in 2050, over 55 % of ptx fuels sold to the European road transport sector is consumed by HDVs. The remaining ptx fuels are in the form of ptx hydrogen gas (PtX H2) and ptx gasoline, consumed by the PPV and LDV segments. In total, the fuel share of ptx fuels in the European road transport sector reaches 27 % by 2050. At this point, fossil as well as biogasoline and biodiesel are completely excluded from the fuel mix. Biogas, on the other hand, makes up a 20 % share of total energy use.

Table A.18 of Appendix A.6 shows the corresponding marginal CO_2 abatement costs for the road transport sector in each country for each model year. The countries with higher road transport demand and stricter CO_2 reduction targets in 2030 exhibit non-zero marginal CO_2 abatement costs in all years. A handful of other countries, however, appear to have zero costs for CO_2 abatement in several years up to 2040, i.e., the investments in lower-carbon vehicles and/or fuels are cost-efficient without any price signal from a binding CO_2 constraint. This holds particularly true for countries with higher shares of PPV and LDV demand, as the short-term switch to natural gas and electric cars/vans is cost competitive and thus appears to displace enough carbon emissions to undercut the decarbonization targets. Countries with higher shares of HDV demand, like Belgium, Poland and Spain, reveal some of the highest marginal CO_2 abatement costs in 2040 due to the consumption of liquefied gas mix, which is necessary to reach their sectoral decarbonization target. Because trucks have a higher fuel consumption and longer annual driving distance, the HDV segment in these countries is responsible

[45]The striped areas in Figure 2.4 indicate the share of the gas mix that is decarbonized by ptx hydrogen gas. For example, in 2050, the liquefied gas mix consists of a share of 140 TWh that is decarbonized via ptx hydrogen gas feed-in (red striped area) and a share of 140 TWh liquefied natural gas (red area). For the years without any striped areas, the gas mix is completely fossil. For more information on the assumptions underlying the concept of gas mix, see Appendix A.4.2.

for a larger share of the emissions. By switching from fossil LNG to low-carbon liquefied gas mix, the model can significantly reduce emissions without a major reinvestment in new vehicle technologies but rather maintaining (and adding to) the existing LNG and LNG hybrid HDV fleet.

By 2050, the country-specific marginal CO_2 abatement costs in the road transport sector in every country reach levels around 500 EUR/tCO_2 as the European-wide production and consumption of ptx fuels in all segments, especially the HDV segment, becomes necessary to reach the 90 % reduction target. Investments in FCV HDVs (with ptx liquefied hydrogen) and BEV HDVs as well as FCVs (with ptx hydrogen gas) in the PPV and LDV segments in 2050 also add to the comparatively high marginal CO_2 abatement costs of the road transport sector.

2.3.3. Supplying ptx fuels in an integrated modeling framework

Decarbonization of the road transport sector appears to create a demand for ptx fuels that must be supplied by either the countries themselves or imported from another European country. As such, a country's electricity market conditions (e.g., endogenous electricity demand, electricity generation mix, NTC constraints) as well as ptx fuel production conditions (e.g., endogenous electricity price, natural gas grid capacities, ptx fuel transport costs) will affect not only how their own road transport sector is decarbonized but whether they supply ptx fuels to or demand ptx fuels from other countries.

A deeper analysis of the ptx investment behavior provides insight into the cost-minimal supply of ptx fuels. Figure A.5 in Appendix A.6 shows the development of ptx installed capacities and production across Europe between 2030 and 2050. As can be seen in the figure, investments in ptx first begin to take hold in 2040, with 22 GW electrolysis systems and 400 MW natural gas liquefaction plants. The hydrogen produced from the electrolysis systems (60 TWh) is completely fed into the natural gas grid to produce a low-carbon gas mixture, which is then liquefied (Liq. Gas Mix). The demand for liquefied gas mix in 2040 is driven by the need to decarbonize the fuel consumption in Belgium, Poland and Spain – the three countries with the highest share of HDVs. These three countries both consume their own gas mix production as well as import additional gas mix (via the natural gas grid) and liquefied gas mix (via tankers) to cover their ptx fuel demand. The two largest exporters of gas mix are France and Great Britain, who continue to have significant amounts of nuclear generation in 2040 next to large amounts of VRE. In addition, along with the third largest exporter Germany, these countries profit from large natural gas grid capacities available to feed-in ptx hydrogen gas as well as low transport costs due to the close proximity to the importing countries.

By 2050, the decarbonization targets in the road transport sector have driven every European country to both produce as well as consume ptx fuels. As shown in Figure A.5 in Appendix A.6, 114 GW_{el} of electrolysis systems and 3 GW_{el} of hydrogen and natural gas liquefaction plants are installed across Europe to produce hydrogen gas that is directly consumed (161 $\mathrm{TWh_{th}}$), directly liquefied (56 $\mathrm{TWh_{th}}$) or fed into the natural gas grid (140 $\mathrm{TWh_{th}}$) and eventually liquefied. In addition, 12 $\mathrm{GW_{el}}$ of integrated electrolysis/Fischer-Tropsch systems are installed to produce ptx gasoline (16 $\mathrm{TWh_{th}}$) and ptx diesel (33 $\mathrm{TWh_{th}}$).

The ptx-fuel flows in 2050 are shown in Figure 2.5, with red indicating exporting countries and blue importing countries. In addition, Table A.19 in Appendix A.6 provides key country-level results for 2040 and 2050 including the marginal costs of electricity generation as well as the average input electricity price for the electrolysis and integrated Fischer-Tropsch systems.[46]

The map on the left-hand side shows the trading of gas mix, i.e., ptx hydrogen gas mixed into the natural gas grid. Although Poland has significantly lower marginal costs of electricity generation than Italy in 2050, the lack of sufficient natural gas grid capacity combined with growing pressure to reduce emissions from its HDV segment result in large import volumes of gas mix. Investing in methanation systems locally, which would be a possible alternative to trading gas mix, does not appear in the cost-optimal solution due to the lower methanation efficiency and resulting higher costs. The model maximizes the feeding-in of ptx hydrogen into the natural gas grid, and, as such, reaches the hydrogen feed-in limit for gas mix in Europe.

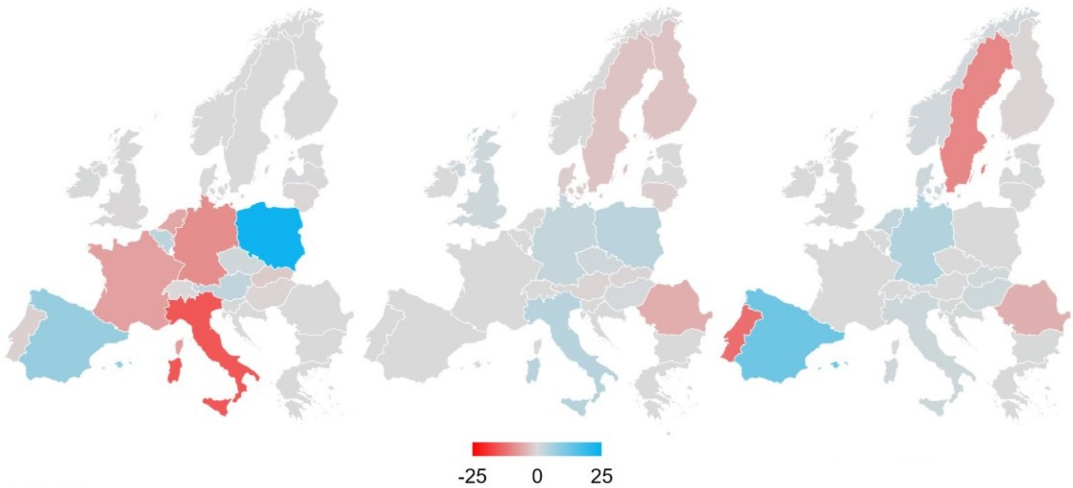

Figure 2.5.: Net imports and exports of gas mix (left), ptx liquefied hydrogen (middle) and ptx diesel (right) in $\mathrm{TWh_{th}}$, with positive values in blue indicating net import and negative values in red indicating net export

As a result, more fuels and/or vehicle technologies to reduce emissions are required to

[46] The average input electricity price is calculated for each ptx technology by summing the marginal costs of electricity generation across all hours in which the ptx system produces fuel and then dividing by the respective number of hours. By definition, an average input electricity price only exists if the ptx system is in operation.

reach the sector-specific decarbonization targets. With the maximum adoption rates for all BEVs, including the HDV segment, have been reached by 2050, the next cost-optimal decarbonization option that emerges in the road transport sector is the consumption of ptx liquefied hydrogen in fuel-cell trucks (FCV HDVs). In fact, all countries invest in FCV HDVs up to their maximum adoption rates during the five-year period between 2045 and 2050, creating a European-wide demand for ptx LH2. As shown in the middle map of Figure 2.5, several countries import significant (>1 TWh_{th}) amounts of ptx LH2 including Czech Republic, Germany, Great Britain, Italy and Poland. The three major exporters include Romania, Sweden and Finland, who not only have significant levels of VRE generation but nuclear generation as well. These effects drive the marginal costs of electricity generation in these countries downwards, lowering the average electricity input price of ptx hydrogen production to 33, 21 and 14 EUR/MWh, respectively (Table A.19). The liquefaction of hydrogen, in particular, is an energy-intensive process and, as such, requires a large number of hours with very low electricity prices in order to be profitable. Despite the additional costs of transporting LH2, the exporting countries are able to supply the importing countries with ptx LH2 at lower cost than the countries would pay in producing the fuel themselves.

Binding adoption rates also for FCV HDVs however drive the need for an additional decarbonized fuel to enter the market, namely ptx diesel. Analogous to ptx LH2, ptx diesel is produced in select countries with profitable ptx conditions and then exported throughout Europe. The right-hand side of Figure 2.5 shows the corresponding trade flows. Fischer-Tropsch synthesis is, compared to electrolysis, significantly less efficient and, therefore, is only exported by the four countries with the lowest marginal electricity generation costs: Portugal, Sweden, Romania and Finland. As shown in Table A.19 in Appendix A.6, the Fischer-Tropsch systems in these countries have an average input electricity price ranging from 47-54 EUR/MWh, similar to their marginal costs of electricity generation. The greatest importer is Spain, who imports over 90 % of its ptx diesel consumption (12 TWh_{th}) from Portugal in order to decarbonize its large HDV fleet. The other producers export small amounts of ptx diesel to fourteen countries across Europe.

Lastly, having exhausted the cost-optimal decarbonization options for the HDV segment, the model chooses to supply the PPV and LDV segments with ptx hydrogen gas by ramping up investments in fuel-cell vehicles in all countries. Convergence in decarbonization targets to 90 % reduction and similar price-setting abatement technologies result in converging marginal CO_2 abatement costs for the road transport sectors in 2050, as shown in Table A.18 in Appendix A.6. Due to very high transport costs of gaseous hydrogen, however, no trading of ptx hydrogen takes place. In other words, all countries supply and consume their own ptx hydrogen, despite significant differences in ptx production costs across countries. The share of ptx hydrogen of total fuel consumption ranges from 3 % (Germany) to 20 % (Ireland); however the maximum adoption rates are never reached. As a by-product of Fischer-Tropsch synthesis, the four exporters of ptx diesel also export small amounts of ptx gasoline for the PPV segments to the neighboring countries with the lowest transport costs, i.e., Spain, Bulgaria, Norway and Denmark.[47]

2.4. Understanding the value of integrated models

Developing and applying an integrated model of this kind can be complex, requiring long computation times and intensive evaluation of the results and their implications. It is not uncommon to question whether such models are more valuable than single-sector or decoupled multi-sectoral models. The model created in this study addresses fundamental economic questions that, given a single market or multiple decoupled markets, could possibly be solved with, e.g., an analytical model. Yet the introduction of multiple coupled markets with integrated demands, substitute fuels across different fuel types, endogenous prices as well as trade possibilities requires that computer-based methods such as linear programming be used to account for the complexity of the coupling of the electricity sector to other sectors.

To provide a quantitative inclination of the added value of the integrated multi-sectoral model at hand, in the following, the results of the integrated model are compared to the results of a model run in which the modules are decoupled and the single sectors optimized independently of one another. In the decoupled model, all endogenous links between the modules are instead fed into the model exogenously. The logic and assumptions behind the exogenous parameters are explained in Section 2.4.1. The results are then compared to the coupled model in Section 2.4.2, with particular focus on key indicators such as CO_2 and electricity prices.

2.4.1. Decoupled versus coupled modules

In order to decouple the model, the endogenous links between the electricity market, road transport and energy transformation modules, i.e. the endogenous demands for electricity and ptx fuels, are broken such that each module stands on its own with its own exogenous inputs. As a result, the electricity market module invests in the cost-minimal electricity generation mix in order to cover its own demand, ignoring any additional electricity demand from electric vehicles or ptx technologies, just as in the original DIMENSION model. The road transport module can, nevertheless, invest in electric vehicles, resulting in an electricity demand; however, analogous to the fossil fuels, the module buys the electricity at an exogenous price.[48] The energy transformation module is shut off in order for the electricity and road transport sectors to be independent of one another. Ptx fuels can, however, be bought by the electricity and road transport

[47] Fischer-Tropsch systems produce a wax (hydrocarbon mixture) that can be upgraded into different fuels. Within the scope of this study, it is assumed that for every unit of ptx diesel, nearly one half unit of ptx gasoline is produced ([Becker et al., 2012]). See Appendix A.4.2 for more information.

[48] In this analysis, the exogenous electricity price is based on the LCOE of onshore wind generation, accounting for decreasing capital costs and technological improvements (see Figure A.6 in Appendix A.7).

sectors at an exogenous price, just as is the case with supplying electric vehicles.[49] Gas mix and liquefied gas mix, the result of feeding ptx hydrogen gas into the grid, is not considered in the decoupled case because the link between hydrogen production and gas mix demand cannot be quantified without the energy transformation module. Furthermore, no trading occurs as there is one single European market price for ptx fuels assumed. The exogenous ptx fuel prices as well as the exogenous electricity price for the road transport sector are shown in Figure A.6 in Appendix A.7.

2.4.2. Identifying the added value of integrated multi-sectoral models

Figure 2.6 depicts the European electricity demand and electricity generation mix for the coupled and decoupled models in 2050 as well as the developments in marginal electricity generation costs and marginal CO_2 abatement costs in the electricity sector across Europe up to 2050. As expected, the electricity generation levels in the decoupled case are significantly lower (1300 TWh) than in the coupled case, as the additional electricity demand from the road transport and energy transformation modules (1200 TWh), indicated by the striped columns, and additional storage demand (100 TWh) is not accounted for.[50] The increase in electricity generation for the additional demand in the coupled model is mainly based on onshore wind and PV due to the identical decarbonization constraint.

The prices on the right side of Figure 2.6 also reflect these developments, with the dashed lines indicating the values from the decoupled model. Because the modules are optimized independently of one another, the endogenous electricity price in the decoupled case only reflects the cost of supplying the demand within the electricity market module. While the difference in marginal electricity generation costs is negligible until 2030 due to limited demand increase, from 2040 onwards, the additional electricity demand from the road transport and energy transformation module results in higher marginal electricity generation costs. This is mainly due to fixed decarbonization targets subject to an increasing electricity generation. In 2050, the marginal electricity generation cost delta between the decoupled and coupled model is 16 EUR/MWh on average across all EU countries. The exogenous electricity price assumption for the road transport sector and the ptx fuel production, being based on the LCOE of wind onshore, underestimates the endogenous marginal electricity generation costs of the coupled model by 5 EUR/MWh on average across Europe. Analogous to the marginal electricity generation costs, the marginal CO_2 abatement costs for the electricity sector also begin to diverge from 2030 onwards, reaching a difference of 6 EUR/tCO_2 when comparing the coupled to the de-

[49] The price for ptx fuels is determined according to the production costs, taking into account the annualized investment, variable and fixed costs of different ptx technologies. The electricity price assumptions for the ptx processes are – as for electric vehicles – based on the LCOE of onshore wind. The lack of endogenous information means that the ptx technologies can no longer optimize their electricity consumption according to hourly changes in the electricity price.

[50] Any discrepancy between generation and demand in Figure 2.6 is due to transmission losses.

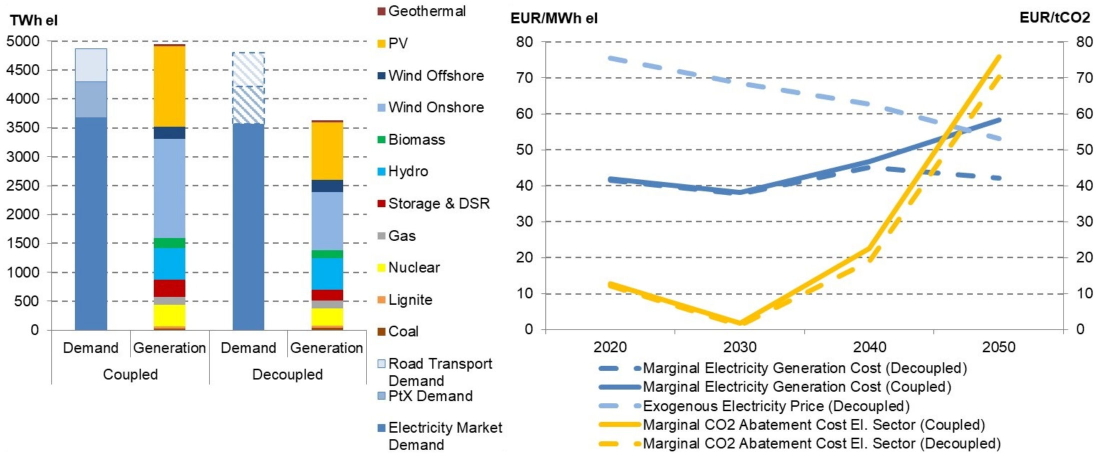

Figure 2.6.: Electricity demand by module and electricity generation by fuel type in Europe in 2050 for the coupled and decoupled model (left); Results of average European marginal electricity generation costs and marginal CO_2 abatement costs for the electricity sector in the coupled and decoupled model, including the exogenous electricity price used by the decoupled road transport and energy transformation modules (right)

coupled model results.[51]

Comparing the results for the road transport sector, both the vehicle technology mix as well as fuel consumption behavior varies, most notably in the trade-off between ptx and fossil fuels. The results for the coupled and decoupled model in 2040 and 2050 are shown in Figure 2.7. In both models, the adoption rates for BEVs reach their maximum yearly values in the long term, leading the direct electricity consumption to be almost identical in both the coupled and decoupled cases. The same holds true for FCV HDVs and PtX LH2 in 2050. Nevertheless, the rest of the fuels show significant discrepancies between the coupled and decoupled cases beginning in 2040. The lack of available gas mix in the decoupled case makes it more expensive to decarbonize LNG and, in turn, drives a decrease in LNG consumption. As such, compared to the coupled case, HDVs in 2040 are supplied by greater amounts of low-cost fossil diesel, which is then balanced out by a growth in biofuel consumption (biogasoline, biodiesel, biogas).

By 2050, carbon-neutral ptx liquid methane (PtX LCH4) displaces much of the fossil LNG at levels equivalent to the decarbonized share of the liquefied gas mix (Liq. Gas Mix (PtX H2)) in the coupled case. Similar to 2040, lower levels of LNG consumption drive higher levels of diesel consumption in the HDV segment, which are, by 2050, entirely made up of carbon-neutral ptx diesel. In the decoupled case, 80 % of all fuel consumption in the HDV segment in 2050 is ptx fuels, compared to the coupled case

[51]As discussed in Appendix A.6.2, the marginal CO_2 abatement costs of the electricity sector sink to 2 EUR/tCO_2 in 2030. Because the model is designed as a social planner problem with perfect foresight, the model anticipates the long-term decarbonization targets with early-on investments in VRE due to limited yearly adoption rates, driving down the marginal CO_2 abatement costs in 2030.

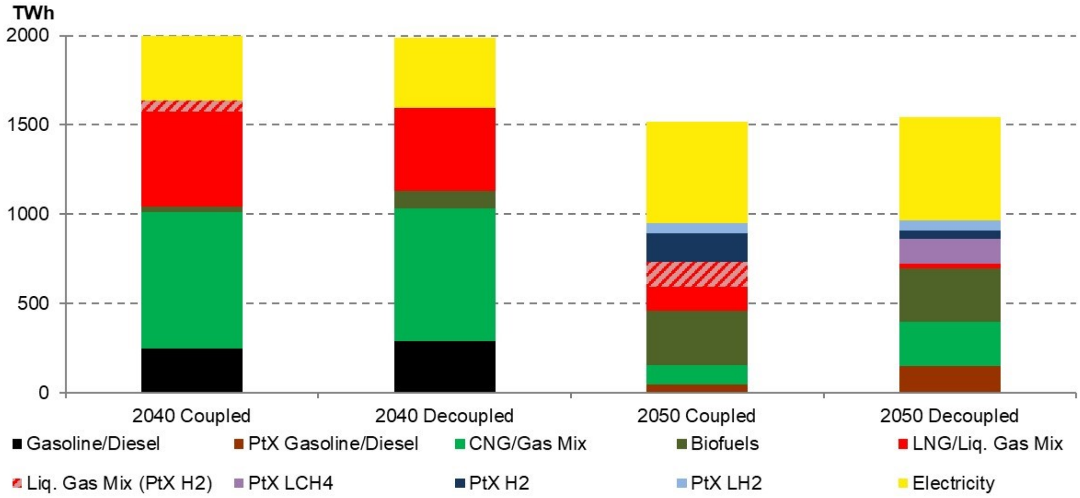

Figure 2.7.: Difference in the fuel consumption in the road transport sector in Europe in 2040 and 2050 between the decoupled and the coupled model

with 60 %. Given the 90 % decarbonization target in 2050, the decoupled model reacts to the increased ptx fuel consumption in the HDV segment by avoiding investments in fuel-cell vehicles, driving a 97 % reduction in FCV PPVs and 50 % reduction in FCV LDVs with an accordingly lower ptx hydrogen consumption.

In sum, the total amount of ptx fuel consumption in the road transport sector is 15 TWh_{th} lower in the decoupled case compared to the coupled case, a discrepancy which arises due to the overestimation of ptx fuel costs in the decoupled case. More specifically, the exogenous electricity price used in estimating the production costs of the ptx fuels is a constant value that does not react to hourly changes in electricity market conditions. In the coupled model, however, the ptx systems can reduce their production costs by consuming electricity at times of low marginal costs of electricity generation. In the coupled case, for example, electrolysis operators pay on average across Europe 38 EUR/MWh for their electricity input in 2050 — an average of 15 EUR/MWh less than the exogenous price assumed in the decoupled case (see Table A.19 in Appendix A.6). As a result, the production costs of ptx hydrogen are overestimated in the decoupled case. The average EU input electricity price for ptx diesel, on the other hand, only differs by 2 EUR/MWh, which yields similar production costs for ptx diesel across models.

Furthermore, endogenous electricity consumption of the ptx systems yields a significant price spread between the production costs of ptx hydrogen and ptx diesel in the coupled case. The decoupled case, on the other hand, does not take the differences in electricity input prices across ptx systems into account and, as such, exhibits a smaller price spread between ptx hydrogen and ptx diesel. This change in ptx fuel price spreads drives a change in the merit order of decarbonization options: low-cost diesel hybrid (HEV) HDVs fueled with ptx diesel appears to jump ahead of high-cost fuel cell LDVs and PPVs fueled with ptx hydrogen in the decoupled model. Thus, in the decoupled model, decarbonization in the HDV segment is stronger, leaving room for reduced decarbonization in the PPV and LDV segments. The overestimation of ptx production costs and the accompanying change in investment behavior has a direct effect on the marginal CO_2 abatement costs of the road transport sector, with an overestimation of approximately 30 EUR/tCO_2 in the decoupled model (see Table A.20 in Appendix A.7).

Overall, the decoupled model overestimates the total system costs in 2050 by 30 billion EUR. The difference in total system costs is a result of the inaccuracy of the estimations for exogenous costs such as electricity and ptx fuel costs compared to the endogenous system costs resulting from the integrated model. In particular, the overestimation of electricity input costs for ptx systems due to a disregard of their flexibility potential adds to the increase in total system costs of the decoupled model.

2.5. Conclusion

This analysis introduces and assesses an integrated multi-sectoral partial-equilibrium investment and dispatch model to simulate the coupling of the European electricity and road transport sectors. The focus lies not only on depicting a detailed technological representation within each sector but also on properly accounting for any interconnections resulting from electricity consumption from electric mobility or from energy transformation via power-to-x processes. High technological, spatial and temporal granularity allows for the optimization of European electricity and power-to-x fuel production as well as the simulation of cost-minimizing trade flows according to endogenous market conditions.

The integrated multi-sectoral model is applied for an exemplary scenario to analyze the effects of sector-specific CO_2 reduction targets (-90 % by 2050 compared to 1990) on the vehicle, electricity and power-to-x technology mix in European countries from 2020 to 2050. The results show that both electricity and power-to-x fuels play a key role in decarbonizing the road transport sector, reaching 37 % and 27 % of total fuel consumption in 2050, respectively. The heavy-duty vehicle segment, in particular, demands the majority of power-to-x fuels in Europe, consuming liquefied gas mix, power-to-x liquefied hydrogen and power-to-x diesel that is produced primarily in countries with high levels of variable renewable energy generation such as Portugal and Sweden. Coupling of the electricity and road transport sectors results in 1200 TWh additional electricity demand in Europe, with average marginal costs of electricity generation across Europe reaching 58 EUR/MWh in 2050.

In order to understand the added value of building complex integrated models, the second part of the analysis examines an identical scenario with decoupled sectors, removing all endogenous ties between sectors and allowing each to be optimized independently of one another. Comparison between the two scenario results confirms that quantitative methods that fail to account for the interdependencies between the electricity and road transport sectors may significantly overestimate the total system costs. The flexibility of power-to-x systems, in particular, cannot be taken into account once exogenous annual electricity prices are used. As shown in the decoupled model results, ignoring fluctuations in short-term electricity prices may lead to a miscalculation of the costs of power-to-x fuels, which may affect the merit order of decarbonization options under strict CO_2 reduction targets and thereby result in substantially different technology choices.

The results of the analysis at hand reveal important real-world consequences that may arise from coupling the road transport and electricity sectors. Especially for policymakers, the implications of decarbonizing the road transport sector via power-to-x and electric vehicles can only be fully understood if the developments and rebound effects in the electricity market are taken into account. For example, increased electrification of the road transport sector will have large repercussions for investments in electricity generation capacities. In turn, changes in electricity prices due to increased cross-sectoral electricity demand may greatly affect the profitability for electric vehicle owners or power-to-x system operators. The model at hand may provide valuable insight in understanding such dynamics. Furthermore, the model presented determines the least-cost pathway to achieve deep decarbonization in the European road transport sector. Such a result may help regulators to more efficiently set economic incentives for certain vehicle technologies or infrastructure. In addition, the optimization of power-to-x capacities, generation and trade across Europe may help to reveal which countries could benefit from producing, importing or exporting synthetic fuels in the long term.

In future work, further detailed scenarios and sensitivity analyses could increase the understanding of the robustness of the presented decarbonization pathway. In particular, the effects of behavioral aspects regarding, e.g., the adoption of new technologies, driving patterns or consumer preferences could be investigated. Furthermore, endogenous charging of electric vehicles may be a promising extension. The model could also be extended to simulate additional modes of transport that may contribute to decarbonization such as, e.g., rail. Although excluded from the discussion, the modeling of the infrastructure for the road transport may be improved to include, e.g., electricity grid investments. Additionally, further research efforts could go into the refining of temporal resolution and technological granularity.

3. Europe, the Green Island? Developing an Integrated Energy System Model to Assess an Energy-Independent, CO_2-Neutral Europe

3.1. Introduction

3.1.1. 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 Chapter 2 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 the work from [Helgeson and Peter, 2020] and presented in Chapter 2 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}.

3.1.2. 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] as well as in the Introduction of Chapter 2, 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.[52] 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.[53] 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 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

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

[53] 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.

European Commission[54], 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.[55] 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 this chapter is structured as follows: Section 3.2 provides a detailed overview of the model and the key methodological extensions realized within this work. The following section, Section 3.3, 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 3.4. Section 3.5 concludes.

3.2. Methodology

Within this section, the methodology behind the energy system model is presented in detail.[56] As explained in Section 3.1.2, 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[57] as well as technical constraints including energy balance restrictions. As such, the model is able to determine

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

[55] [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.

[56] See Appendix B.1 for a complete overview of the nomenclature used in the equations presented in this section.

[57] 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.

the cost-minimal, welfare-optimal[58] 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.[59] 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.[60] The typical days are selected according to a clustering algorithm, described in detail in Appendix B.2.

3.2.1. 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[61], the road transport module and the heat module, depicted in Figure 3.1 by the yellow, blue, red and purple boxes, respectively. The basis of the first three modules were developed by [Helgeson and Peter, 2020] and explained in Chapter 2 extensively; therefore, the reader is referred to Section 2.2 for a thorough description. The heat module, however, is a key extension of the model designed in the research at hand and is presented in detail in Section 3.2.4. The black and grey area on the right-hand side of Figure 3.1 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'.

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

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

[59] See Table B.3 in Appendix B.1 for a complete list of countries considered in this analysis.

[60] 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 3.3 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.

[61] The "power-to-x module" referred to within this chapter is equivalent to the "energy transformation module" presented in Chapter 2 as well as in [Helgeson and Peter, 2020]. The name was changed to avoid confusion with the other newly developed modules, which also include technologies that transform energy from one type to another.

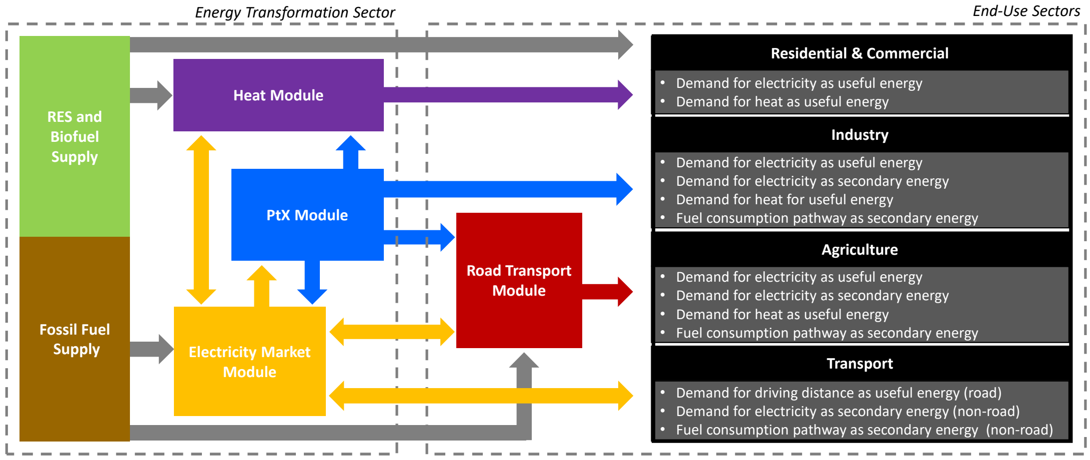

Figure 3.1.: Endogenous energy flows between supply from the modules and demand from the end-use sectors, where the grey arrows depict the flow of renewable energy sources (RES), biofuels or fossil fuels, yellow the flow of electricity, purple the flow of heat, red the flow of road transport and blue the flow of energy carriers produced via ptx processes

an extensive catalog as per the corresponding module name.[62] 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.[63] In the case of useful energy, the exogenously-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 3.1, this module must invest in sufficient vehicle technologies to supply the transport sector with a certain amount of vehicle kilometers. The

[62] 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 3.2.4, 3.2.5 and Appendix B.3.2.

[63] 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`).

equilibrium condition can then be understood as,

$$\sum_{s} dr_{m,s,t,y}\Bigg|_{s=trans} = \sum_{i} \mathbf{sr}_{i,m,t,y}\Bigg|_{i\in\mathbf{I_{rt}}} \qquad \forall m,t,y \qquad (3.1)$$

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 3.1). 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 3.2.4, 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,

$$\sum_{s\neq et,trans} dh_{m,s,t,y} + \sum_{s=et} \mathbf{ec}_{f,f1,m,s,t,y}\Bigg|_{f,f1=heat} = \sum_{i} \mathbf{g}_{i,m,t,y}\Bigg|_{i\in\mathbf{I_{ht}}} \qquad \forall m,t,y \qquad (3.2)$$

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 (3.2) 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.[64]

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 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.[65] These include, for example, electricity consumption from trains, busses and two-wheelers in

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

[65] 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`.

the transport sector[66] 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], i.e., Equation (2.2) in Section 2.2.1 of Chapter 2, 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 3.1. 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

$$\sum_{s \neq et} l_{m,s,t,y} + \sum_{s=et,trans} \mathbf{ec}_{f,f1,m,s,t,y} \Bigg|_{f,f1=elec} = \sum_{i} \mathbf{g}_{i,m,t,y} + \sum_{n} \mathbf{k}_{m,n,t,y} \quad \forall m,t,y \tag{3.3}$$

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 (3.3) 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 3.1. Furthermore, positive flexibility[67] 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

[66] 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.

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

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.[68] 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[69] within each country and time slice, given by the first-order condition (i.e., scaled marginal) of Equation (3.3).

The final module, the ptx module, is only exposed to an endogenous demand. Analogous to the extensions in [Helgeson and Peter, 2020] described in Chapter 2, a demand for ptx fuels[70] 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 3.1). 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.

3.2.2. 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 3.2.1 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.[71] Another example is rail or air travel in the transport sector, where only limited technology options exist and informa-

[68] Although not explicitly depicted in Figure 3.1, 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 3.2.3).

[69] 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 (3.3)). See Chapter 2 as well as [Helgeson and Peter, 2020] for a more thorough discussion of the endogenous electricity price.

[70] 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.

[71] 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.

tion 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 3.1). 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 Section 2.2.1 of Chapter 2.[72] As a result, the model may endogenously choose between fossil, bio and ptx alternatives to cover this demand such that

$$df_{f,m,s,t,y}\Big|_{s=ind,trans,agr} = \sum_{f1} \mathbf{sf}_{f,f1,m,s,t,y}\Big|_{s=et} \qquad \forall m,t,y \ \text{ and } \ f,f1 \neq elec, heat \tag{3.4}$$

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 (3.4) 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], i.e., Equations (2.7)-(2.9) in Section 2.2.2 in Chapter 2, must be adjusted, i.e.,

$$\begin{aligned}\sum_{i} \mathbf{fp}_{f1,i,m,t,y}\Big|_{i\in\mathbf{I_{ptx}}} &+ \sum_{n} \mathbf{ft}_{f1,n,m,t,y} + \mathbf{ft}_{f1,nonEU,m,t,y} \\ &= \sum_{s=et,trans} \mathbf{ec}_{f,f1,m,s,t,y} + \sum_{n} \mathbf{ft}_{f1,m,n,t,y} \\ &\quad + \sum_{s=et} \mathbf{sf}_{f,f1,m,s,t,y} \qquad \forall m,t,y \ \text{ and } \ f1 = ptx\end{aligned} \tag{3.5}$$

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-

[72] See Table 2.1 in Chapter 2 for an overview of the matching of substitute fuels with their respective fuels types. Important to note that, within this analysis, kerosene was included as an additional fuel type with substitute fuels kerosene, ptx kerosene and bio kerosene.

use sectors industry, transport and agriculture given in Equation (3.4).[73] The rest of the demand for ptx fuels depicted on the right-hand side of Equation (3.5) is 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[74] 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 (3.5), is consistent with the corresponding equations in Section 2.2.2 , 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 (3.5), is used to calculate the corresponding endogenous price[75] for each ptx fuel produced within each country and time slice.

Introducing the new equilibrium condition shown in Equation (3.4) into the model requires that the objective function presented in [Helgeson and Peter, 2020], i.e., Equation (2.1a) in Section 2.2.1 of Chapter 2, 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

$$\min \quad TC = \sum_{i,m,y} \delta_{i,m,y}\bar{\mathbf{x}}_{i,m,y} + \sum_{i,m,t,y} \gamma_{i,m,t,y}\mathbf{g}_{i,m,t,y} + \sum_{f,m,s,t,y} p_{f1,y}\mathbf{sf}_{f,f1,m,s,t,y}\Bigg|_{f1=conv,bio} \tag{3.6}$$

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 $\mathbf{g}_{i,m,t,y}$.[76] 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 (3.6)—which

[73]Equation 3.5 is generalized to apply to all substitute fuels that are considered ptx fuels, including ptx hydrogen, ptx methane (CH4), ptx kerosene, ptx gasoline and ptx diesel. While not explicitly depicted in the equation, the concept of injecting hydrogen into the gas grid in order to create a so-called "gas mix" is still an option in this analysis. See Chapter 2 as well as [Helgeson and Peter, 2020] for the equilibrium equations for ptx hydrogen and ptx CH4 taking into account gas mix.

[74]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 Chapter 2 as well as [Helgeson and Peter, 2020] for more information.

[75]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 (3.5)).

[76]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 (3.1).

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.[77] 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, 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.[78]

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

The exogenous demand components presented in Sections 3.2.1 and 3.2.2, 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 ($\mathbf{\hat{ec}}$) or positive flexibility to the energy system by reducing electricity consumption ($\mathbf{\check{ec}}$) in a specific time slice t, shown in Equations (3.7)

[77] 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.

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

and (3.8), respectively.

$$\hat{\mathbf{ec}}_{f,f1,m,s,t,y}\Bigg|_{f,f1=elec} \leq \sum_i \omega_{i,m,t,y}\theta_{i,m,t,y}l^*_{i,m,t,y}\bar{\mathbf{x}}_{i,m,y}\Bigg|_{i\in\mathbf{I_{dsm}}} \quad \forall m,t,y \text{ and } \bar{\mathbf{x}} \leq \bar{X} \tag{3.7}$$

$$\check{\mathbf{ec}}_{f,f1,m,s,t,y}\Bigg|_{f,f1=elec} \leq \sum_i \sigma_{i,m,t,y}\theta_{i,m,t,y}l^*_{i,m,t,y}\bar{\mathbf{x}}_{i,m,y}\Bigg|_{i\in\mathbf{I_{dsm}}} \quad \forall m,t,y \text{ and } \bar{\mathbf{x}} \leq \bar{X} \tag{3.8}$$

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.,

$$\begin{aligned}\mathbf{ec}_{f,f1,m,s,t,y} =& \bar{\mathbf{ec}}_{f,f1,m,s,t,y} + \hat{\mathbf{ec}}_{f,f1,m,s,t,y} - \check{\mathbf{ec}}_{f,f1,m,s,t,y} \\ & \forall m,t,y \text{ and } f,f1 = elec\end{aligned} \tag{3.9}$$

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 $\mathbf{I}$, $i \in \mathbf{I_{dsm}}$.[79] 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 (3.7) - (3.9)). 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

[79]See Section 3.3 for more information on the assumptions behind the individual DSM processes.

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

$$\hat{\mathbf{ec}}_{f,f1,m,s,\hat{\mathbf{t}},y}\Big|_{f,f1=elec} - \check{\mathbf{ec}}_{f,f1,m,s,\check{\mathbf{t}},y}\Big|_{f,f1=elec} = 0 \quad \forall m,y \ \text{ and } \ |\,\hat{\mathbf{t}} - \check{\mathbf{t}}| \leq T^* \tag{3.10}$$

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 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 3.2.1. 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 (3.9) and Equation (3.3). 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.

3.2.4. 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[80], cooling and cooking.[81] An overview of the heating technologies considered as well the corresponding heat use types are shown in Figure 3.2.

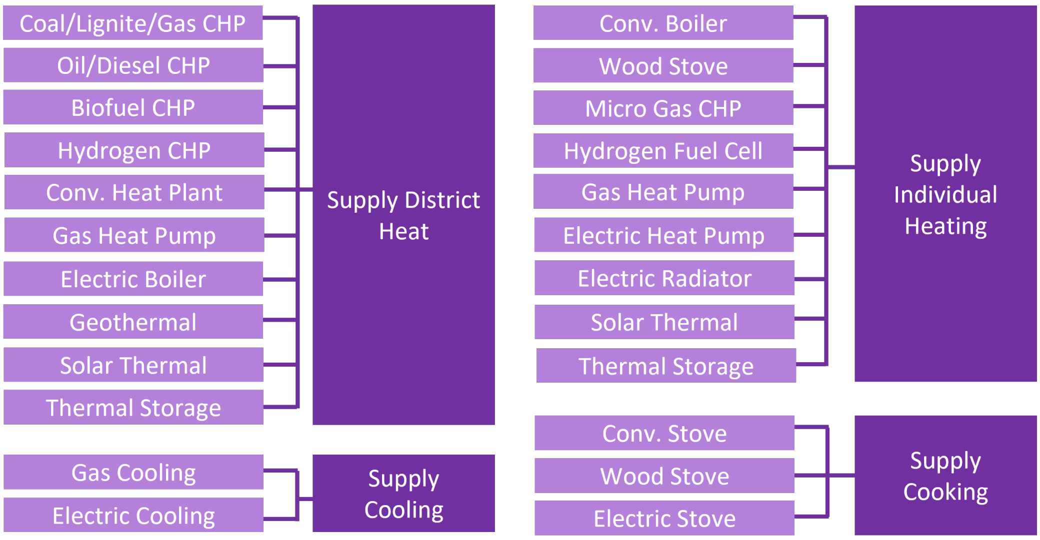

Figure 3.2.: Overview of the heat technologies and heat use types considered in the model

The heat module is structured following the methodology of the electricity market module via a so-called 'top-down approach'.[82] 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 3.1. In the case of the heat module, however, the equilibrium condition shown in Equation (3.2) 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

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

[81]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.

[82]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.

to demand for district heat, individual heat, cooling and cooking.[83] 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 3.3.2).

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 3.2.[84] 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 3.2 can be summarized using the equation

$$\sum_{f1,s} \mathbf{ec}_{f,f1,m,s,t,y} \Big|_{s=et} = \sum_{i} \mathbf{g}_{i,m,t,y} / \eta_{i,m,t} \qquad \forall f, m, t, y \text{ and } i \in \mathbf{I_{ht}} \tag{3.11}$$

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 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[85], electric radiators, electric air conditioners and electric stoves), the energy consumption in Equation (3.11) is solely electric, i.e., $f, f1 = electricity$. This consumption is then implicitly seen by the equilibrium condition for electricity, Equation (3.3), 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 3.2, 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] and presented in Chapter 4.

Although not a heat generator per se, Equation (3.11) 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

[83] As explained in Section 3.3.1, 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.

[84] 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 3.3.2).

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

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.[86] As presented in Figure 3.2, thermal storage may be introduced in a larger scale for district heating as well as in a smaller size for individual heating within buildings.[87]

In addition to the equilibrium condition shown in Equation (3.2), heat generators are also subject to a capacity constraint,

$$\mathbf{g}_{i,m,t,y} \leq x_{i,m,t}\bar{\mathbf{x}}_{i,m} \qquad \forall m,t,y \text{ and } i \in \mathbf{I_{ht}} \tag{3.12}$$

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

Whereas Equations (3.11) and (3.12) 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[88] 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

$$\mathbf{g^*}_{i,m,t,y} \;\geq\; \alpha_i \mathbf{g}_{i,m,t,y} \qquad \forall m,t,y \text{ and } i = CHP \tag{3.13}$$

and

$$\frac{\mathbf{g^*}_{i,m,t,y} + \mathbf{g}_{i,m,t,y}}{\eta_i^* + \eta_{i,m,t}} \;\leq\; \frac{\mathbf{g^*}_{i,m,t,y} + \beta_i \mathbf{g}_{i,m,t,y}}{\eta_i^*} \qquad \forall m,t,y \text{ and } i = CHP, \tag{3.14}$$

with the former setting the lower bound and the latter the upper bound of total energy generation. More specifically, Equation (3.13) 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

[86] 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.

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

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

technology-specific power-to-heat ratio α_i.[89] In other words, the minimal electricity generation of a flexible CHP plant is equal to that of a non-flexible one. Equation (3.14) 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 (3.13) and (3.14), 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.,

$$\mathbf{g}^*{}_{i,m,t,y} \leq x_{i,m,t} \bar{\mathbf{x}}_{i,m} - \beta_i \mathbf{g}_{i,m,t,y} \qquad \forall m, t, y \text{ and } i = CHP \tag{3.15}$$

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,

$$dh_{m,peak} \leq \sum_i v_{i,m} \bar{\mathbf{x}}_{i,m} \qquad \forall m \text{ and } i \in \mathbf{I_{ht}} \tag{3.16}$$

which requires that the total installed thermal capacity, corrected by a capacity value[90] $v_{i,m}$, 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.[91] 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

[89] It should be emphasized that the asterisks shown in Equations (3.13)-(3.15) 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 chapter and Chapter 2, only a single variable for generation $\mathbf{g}$ exists to denote output of technology i, regardless of the resulting energy carrier.

[90] 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.

[91] A peak demand constraint is also included for electricity. See [Helgeson and Peter, 2020] as well as Chapter 2 for more information.

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.[92] Lastly, different to electricity, no cross-border exchange of heating is possible, meaning each country must cover its heat demand on its own.

3.2.5. 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] and presented in Chapter 2 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.

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 Chapter 2, electric vehicles are 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 flexibil-

[92] 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.

ity 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.

3.2.6. 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[93], 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., do-

[93] 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.

mestic 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)[94], 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 3.1, 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 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.[95]

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.

3.3. 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 3.3.1 presents the motivation and framework behind the two scenarios that are examined in the application. The corresponding data and assumptions are presented in Sections 3.3.2. Lastly,

[94]The availability of NTC capacities are exogenously assumed and therefore not optimized.
[95]See, e.g., Equations (3.3) and (3.5).

the results of the base scenario are discussed in Section 3.3.3 and a comparison between the two scenarios is made in Section 3.3.4.

3.3.1. 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, 2019a], a reduction in so-called "well-to-wheel" (WTW) CO_2 emissions by 55% by 2030[96] and 100% by 2050 (compared to 1990) aggregated across all countries and all sectors in Europe is enforced.[97] Any further country- or sector-specific climate policies are not included in the scenario definition.[98] 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 3.2, 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 Section 2.2.2 of Chapter 2 and shown in Equation (3.5), 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.

[96] 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.

[97] Although not explicitly described in Section 3.2, the CO_2 constraint is included in the objective function similar to [Helgeson and Peter, 2020] and the methodology in Chapter 2, 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, comparing to Equations 2.4 and 2.5 in Chapter 2, 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 3.2.2.

[98] 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.

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.[99] 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.

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

[99]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.

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.

3.3.2. Data and assumptions

Developments in commodity prices, biofuels and emissions factors

Table B.4 in Appendix B.3.1 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.[100] 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 B.4 in Appendix B.3.1 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].

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

The assumptions on direct and upstream carbon emissions are shown in Table B.5 of Appendix B.3.1. 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 Chapter 2, 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 97). 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 assumption in [Helgeson and Peter, 2020] described in Chapter 2, 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 B.5 of Appendix B.3.1 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.[101]

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 B.6 in Appendix B.3.2). 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)

[101] 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 3.1.1.

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 3.3.1, 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 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.2. 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], described in Chapter 4, and the clustering algorithm explained in Appendix B.2.

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 B.7 and B.8 in Appendix B.3.2.[102] The costs shown in Table B.7 in Appendix B.3.2 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 3.2.3, 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 B.11 in Appendix B.3.2.

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 B.9 in Appendix B.3.2, only FOM costs are included in the model to account for the fee charged by

[102]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].

an electricity provider for the installation and use of a smart meter, which would be necessary to enable DSM.[103] Using the estimations provided in the POTenCIA scenario from [Mantzos et al., 2019], the total MW of white appliances installed in all households in each country up to 2050 is set as the maximum DSM potential, as shown in Table B.11 in Appendix B.3.2. 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 B.10 and B.11 in Appendix B.3.2.[104]

For the heat module, a completely new data set is conceptualized and designed for each heat use type, as summarized in Tables B.12-B.14 in Appendix B.3.2. 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.[105] 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] (see Chapter 4) and the catalogs of technology data provided by [Energinet and Danish Energy Agency, 2019]. As touched upon in Section 3.2.4, 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 B.13 and B.14 in Appendix B.3.2 are selected to represent smaller-scale systems (see, e.g., [Frings and Helgeson, 2022] as well as the Supplementary Material C for Chapter 4). 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

[103]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.

[104]As can be observed in Table B.11 in Appendix B.3.2, 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.

[105]A power-to-loss ratio β equal to 0.286 is assumed for all CHP district heat technologies (see Equations (3.14) and (3.15) in Section 3.2.4).

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], presented in Chapter 4, and the clustering algorithm explained in Appendix B.2. 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], as described in Chapter 2 and the corresponding Supplementary Material A. 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.[106] 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 B.15 and B.16 in Appendix B.3.2 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] and depicted in Chapter 2, green hydrogen and synthetic fuels may also be traded between European countries. Table B.17 in Appendix B.3.2 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 B.3.2.[107] 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 3.2.5, driving profiles are included in the model to estimate the share of parked

[106] 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].

[107] Detailed data tables on the techno-economic data for all vehicles segments and infrastructure are presented in Supplementary Material A for Chapter 2).

and moving vehicles on the road in a given hour in a given country. Data from the studies by [Nobis and Kuhnimhof, 2018] and [Ecke et al., 2020] are used to create hourly driving profiles for each vehicle segment, shown in Figure B.2 in Appendix B.3.2. 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[108], 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 B.18 and Figure B.2 in Appendix B.3.2 give an overview on the assumptions pertaining to electric vehicle charging.

Exogenous demand levels and load profiles

As explained in Sections 3.2.1 and 3.2.2, 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.[109]

[108]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.

[109]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].

The pathway for fuel consumption in the industry sector (TWh_{th}) for Germany 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 B.3.4.

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[110], and the road transport driving distance is multiplied by the driving profiles explained in Section 3.3.2. Finally, cooking load profiles are taken from the balance group coordinator [AGCS, 2020] and set equal for all countries.

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 B.20 in Appendix B.5. 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.[111] 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

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

[111] 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.

as well as PV not only on the country level, but for so-called 'resource classes' relative to a renewable generator's capacity factor[112]. 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) locations for each renewable energy generator type in each country.[113] 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 B.19 in Appendix B.5. 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 B.15 and B.16 in Appendix B.3.2).[114] Furthermore, it is assumed that synthetic fuels may be imported after the year 2030, whereas green hydrogen will become available from 2035 onward.[115]

3.3.3. 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 3.1.1 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 3.3. Between 2019 and 2030, a drastic

[112]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

[113]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 B.3.2). 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.

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

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

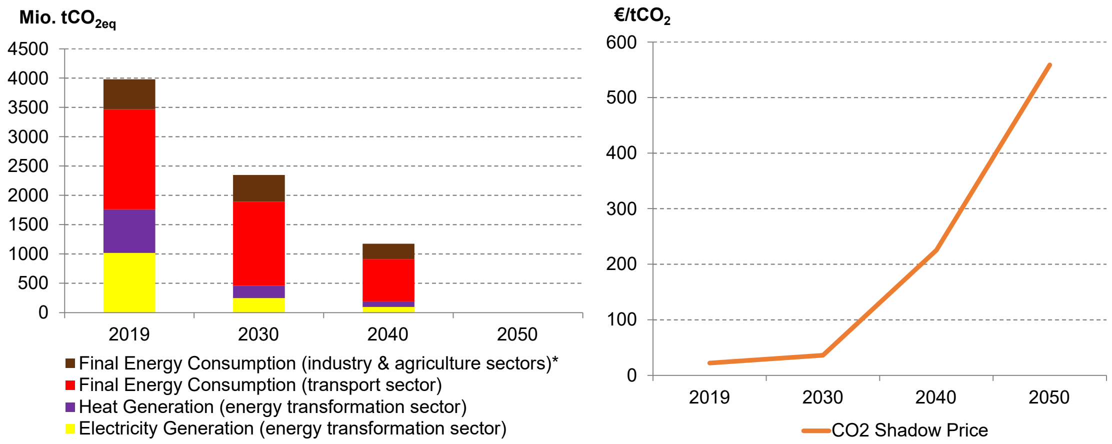

Figure 3.3.: Results on the decarbonization pathway (left) and CO_2 shadow prices (from 2030 onwards) in Europe up to 2050 in the Green Island Europe scenario

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 3.6 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 3.4 as well as Figure B.6 in Appendix B.4, the major driver of electrification is the rapid adoption of decentralized electric heat pumps in buildings: Between 2019 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 3.4).

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[116] for CO_2 in Europe from 22 €/tCO_2 in 2019 to 36 €/tCO_2 in 2030, shown in the right-hand side of Figure 3.3. 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

[116] 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 97 as well as [Helgeson and Peter, 2020] for a more thorough description of the emissions constraint in the model.

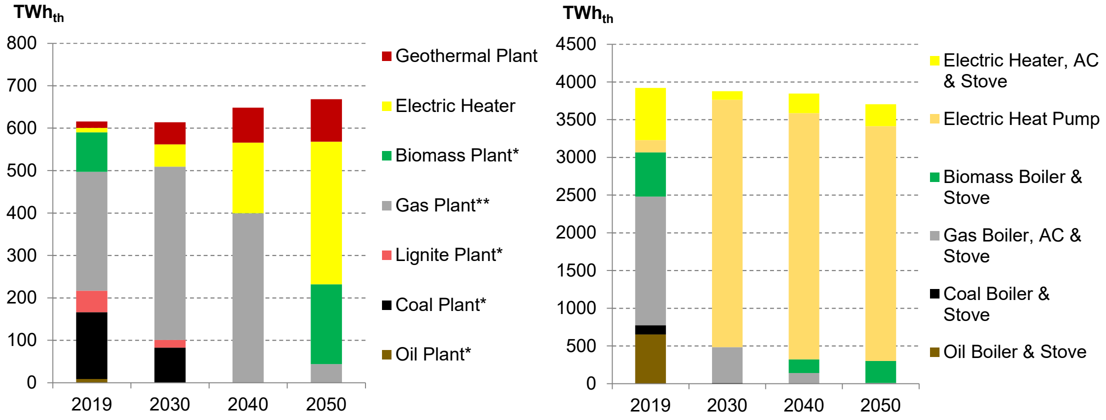

Figure 3.4.: Results on heat generation from district heat generators (left) and from individual heating, cooking and cooling (AC) technologies (right) in Europe up to 2050 in the Green Island Europe scenario, * indicates that both CHP and heat-only plants are included, ** indicates that CHP, heat-only and gas heat pumps are included

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 3.5: 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.[117]

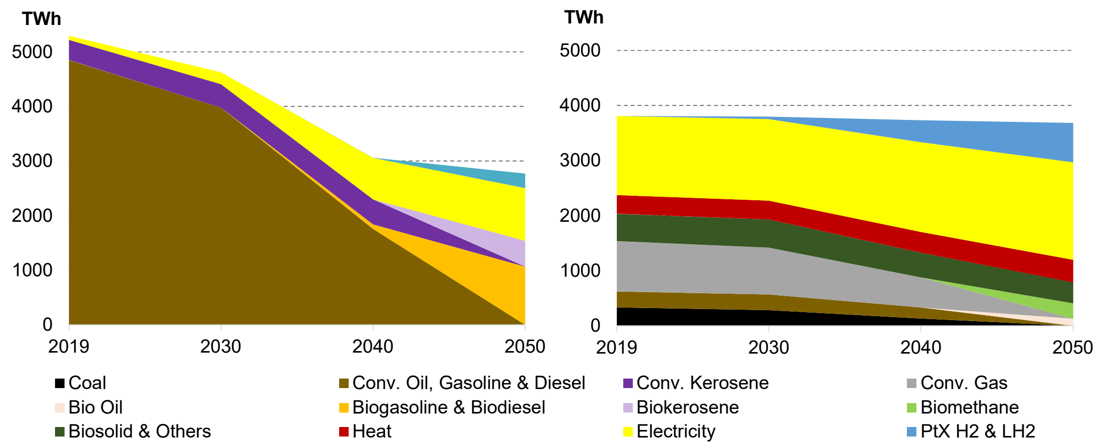

Figure 3.5.: Results on final energy consumption in the transport sector (left) and industry and agriculture sectors (right) in Europe up to 2050 in the Green Island Europe scenario

[117]It should be emphasized that, for the industry and agriculture sectors, the consumption levels of each fuel type are given exogenously (see Section 3.2.2). 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.

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 3.3 and 3.5, 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 B.8 in Appendix B.4, 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 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 3.3.2). 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 3.3, 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 3.6 as well as in Figure B.5 in Appendix B.4, 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 B.6 in Appendix B.4 are coupled with 52 GW_{th} of thermal storage to allow for the temporal decoupling of heat generation and consumption.[118] 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 3.6. 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 B.5 in Appendix B.4 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

[118]Thermal storage is omitted from the figures.

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 B.8 in Appendix B.4).

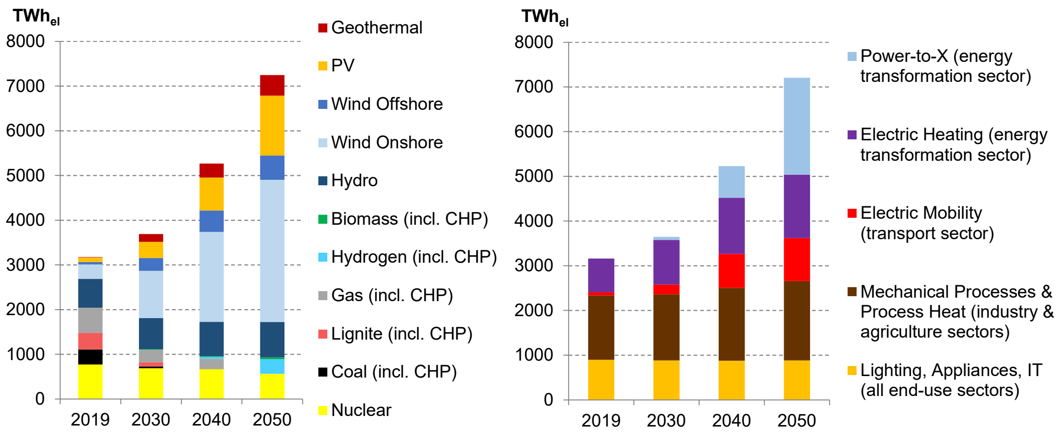

Figure 3.6.: Results on electricity generation (left) and consumption (right) in Europe up to 2050 in the Green Island Europe scenario

Finally, the simultaneity of impending carbon neutrality, increasingly intermittent electricity supply, 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 B.7 in Appendix B.4). 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 3.5 and 3.6, 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[119], the direct use of electricity is the predominant source of decarbonization in 2050. As can be seen on the right-hand side of Figure 3.6, round 5000 TWh$_{el}$ of electricity is consumed by non-ptx processes in 2050 compared to 4811 TWh$_{el}$ in the study

[119]See [European Commission. Directorate General for Energy. and Fraunhofer Institute for Systems and Innovation Research., 2023].

by the European Commission.[120] 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 B.7 in Appendix B.4). 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.[121] 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 3.6). 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.

3.3.4. 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 scenario to 1282 TWh_{th} in the Green Importer Europe scenario, with Europe

[120]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.

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

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 B.11-B.13 in Appendix B.5).[122] 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.[123]

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 3.7 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).[124] 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 122) as well as for electricity generation (see Figures B.12 and B.13 in Appendix B.5). 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 prices in Europe (see Section 3.4). Spain and Poland, for example, actually switch from green hydrogen exporters to green hydrogen importers, as the neighboring countries Portugal and Lithuania, respectively,

[122] 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 3.2.2 and shown in Figure B.4 in Appendix B.3. 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.

[123] Additional comparisons of scenario results available in Appendix B.5.

[124] A list of the abbreviations used for the country names is given in Table B.3 in Appendix B.1.

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.

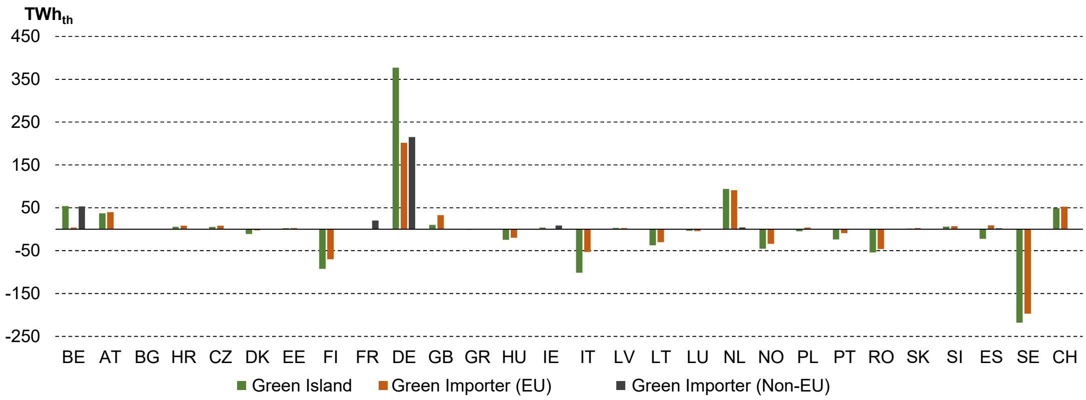

Figure 3.7.: Net imports of green hydrogen produced within Europe in the Green Island Europe scenario and Green Importer Europe scenario as well as imports from outside Europe in the Green Importer Europe scenario in 2050

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 3.1.1, 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 B.9 in Appendix B.5, 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 B.10 in Appendix B.5, 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 B.14 in Appendix B.5.[125]

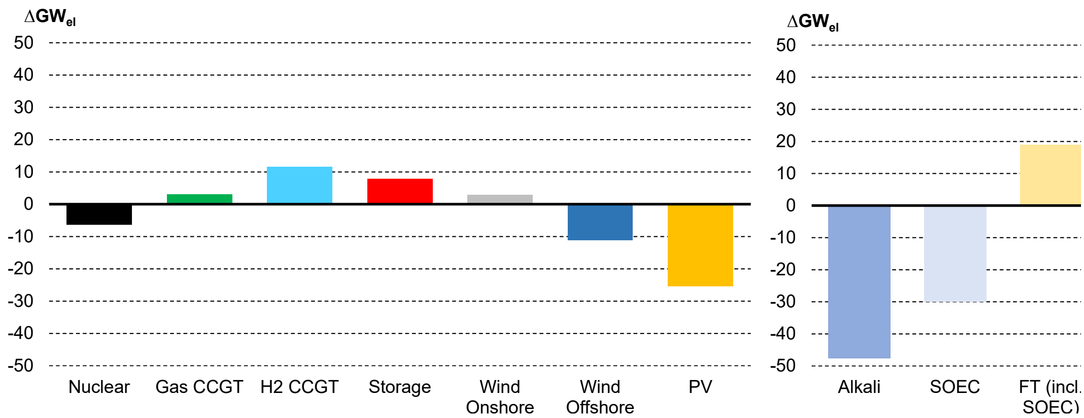

Figure 3.8.: Difference in installed capacities of electricity generation and storage technologies (left) and ptx technologies (right) in 2050 in the Green Importer Europe scenario compared to the Green Island Europe scenario

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 3.8.[126] 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, 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

[125] Similar to the case of hydrogen described in Footnote 122, 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 3.2.2 (see Figure 3.1 and Figure B.3 in Appendix B.3). 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.

[126] 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.

avoid investing in renewable electricity generation technologies in sub-par locations. For example, as shown in Figure B.15 in Appendix B.5, 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 B.16 in Appendix B.5. 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 Figure B.17 in Appendix B.5).

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 3.8, 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.

3.4. 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 3.3.4 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[127] producer surplus, consumer surplus and total

[127] 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.

welfare across scenarios for green hydrogen producers and consumers (in €/MWh_{th}) as well as electricity generators and consumers (in €/MWh_{el}) across Europe are evaluated in the following. The key results are summarized in Table 3.1. A detailed description of the country-specific results can be found in Appendix B.6.

		Green Island	**Green Importer**	**Delta (Imp. - Isl.)**	**Sum (CS + PS)**
Green Hydrogen [EUR/MWh_{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_{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 3.1.: 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 3.5) as described in Section 3.2.2, 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_{th} in the Green Island Europe scenario to 77.3 €/MWh_{th} in the Green Importer Europe scenario —which is 0.8 €/MWh_{th} below the exogenous price assumed in 2050 for green hydrogen imports from outside Europe shown in Table B.20 in Appendix B.3.[128] In fact, it can clearly be seen in Figure B.19 in Appendix B.6 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 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

[128]The values of the endogenous prices for green hydrogen in 2050 are shown for each country in Figure B.20 in Appendix B.6.

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 B.19 and B.20 in Appendix B.6). Referring to Figure 3.7, 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 B.12 and B.13 in Appendix B.5). 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 B.6).

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 3.1, 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 B.9 in Appendix B.5) 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}.[129] On average, European producers

[129]See Appendix B.6 for detailed examples for individual countries.

of green hydrogen are able to save 8.3 €/MWh_{th}, which makes up the entirety[130] of the gains in average total welfare seen in the European green hydrogen market (see Table 3.1).

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)[131] in the Green Importer scenario compared to the Green Island scenario, is positive in every country (see Figure B.22 in Appendix B.6).[132] 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 B.23 in Appendix B.6, 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[133], 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% 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 B.24 in Appendix B.6, the country-specific results for the electricity market fluctuate significantly between countries with comparatively high gains in total

[130] 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.

[131] In other words, the first-order condition of the equilibrium condition in the electricity market module weighted by the electricity demand (see Section 3.2.1). Within this analysis, this may be understood as a market-based electricity price similar to the spot market price.

[132] 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 B.23 in Appendix B.6.

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

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$_{el}$).[134]

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 B.16 and B.17 in Appendix B.5), which also explains the increase in hydrogen CCGT capacities shown in Figure 3.8. 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.[135] 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 B.16 and B.17 in Appendix B.5). 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 B.20 in Appendix B.3). As such, it should come as no surprise that the introduction of the availability of non-European green hydrogen imports 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

[134] See Appendix B.6 for a detailed description of the country-specific results of the welfare analysis for the electricity market.

[135] 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 B.17 in Appendix B.5).

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.

3.5. Conclusion

The paper presented in Chapter 3 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], presented in Chapter 2, 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 in Chapter 3 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.

4. Developing a Model for Consumer Management of Decentralized Options

4.1. Introduction

4.1.1. Motivation and Research Objective

The energy landscape for end consumers has undergone a massive transformation in recent years. In many developed countries, the standard means of energy provision have historically consisted of a centralized electricity supplier paired with decentralized heat generation, typically using a gas or oil boiler. Yet the range of distributed energy resources (DER) available to end consumers has widened over the past decade not only due to technological advancements but also as a result of economic, social and political movements. In Germany, for example, DER such as photovoltaics (PV), micro combined-heat-and-power (CHP) systems as well as heat pumps have been subject to incentive mechanisms, which have in turn driven down the total costs of ownership and increased their market visibility. In addition to a larger selection of affordable technologies, consumers as well as policy-makers have become more aware of the individual carbon footprints associated with energy provision, creating a social and economic pressure to move away from carbon-emitting fossil fuels. As such, consumers may no longer choose the least-cost option based on today's total costs of ownership but may have to also account for uncertainties regarding future energy policies on, e.g., the pricing of different energy carriers or carbon emissions.

Needless to say, the plethora of investment options combined with complex regulatory instruments and growing uncertainty make it difficult for end consumers to decide how to best serve their long-term energy needs. To better understand this conundrum, one method often seen in the existing literature is the use of linear programming methods to identify a least-cost solution over a defined time horizon. Although many of such optimization models have been developed, very few are capable of considering a high level of technological diversity and granularity while also accounting for future economic, regulatory and technical elements. Furthermore, the majority of such models are focused on the investment and operational decisions of today rather than considering how these may change over time. As such, the paper at hand seeks to address the following research questions: (i) How can linear programming methods be used to optimize the investment in and operation of distributed generation and storage technologies for end consumers, (ii) what technological, economic and regulatory aspects must be accounted for in order to model the decisions surrounding end consumers' energy provision, and (iii) how may end consumers design and manage their DER systems to minimize the costs of energy provision over longer time horizons, especially when subject to changes in the technological, economic and regulatory landscape?

Within the scope of Chapter 4, the model "Consumer Management of Decentralized Options", referred to as COMODO, is developed to determine the cost-minimal energy provision for an end consumer or consumer group according to each energy use type (EUT), i.e., electricity, water heating and space heating. The model uses mixed-integer linear programming (MILP) to perform a partial-equilibrium investment and dispatch optimization, accounting for a wide range of distributed generation as well as storage technologies. Apart from a large technology catalog, COMODO is able to account for an extensive amount of policy instruments and financial incentives to more precisely valuate the costs of certain technologies or energy carriers. One unique characteristic of COMODO compared to the existing literature is how the total costs are minimized over the complete, long-term time horizon via a so-called 'dynamic anticipative optimization' ([Cuisinier et al., 2021]). As such, investments in DER technologies are not restricted to one single year but rather are able to be made in multiple model years subject to developments in, e.g., techno-economic data, regulatory frameworks and energy market conditions. In doing so, COMODO not only serves to analyze the profitability of distributed generation and storage technologies but may also help to understand the key economic and regulatory drivers affecting the end consumer's energy investment choices.

In order to demonstrate the capabilities of the model developed, an exemplary application is presented to investigate the investment and energy use decisions of four single-family homes in Germany for the years 2025 to 2045. Three scenarios are considered and then compared: Status Quo, Smart Tech and Smart Market. The scenarios build upon each other sequentially, with the first scenario seeking to resemble current technological and regulatory conditions, i.e., limited information on future weather, demand, costs or price developments. The Smart Tech scenario, on the other hand, allows for technologies to receive information about weather conditions (e.g., renewable generation potential) and demand profiles as well as energy prices and technology costs in future years, which allows technologies to better optimize their sizing and operation as well as the interactions between generators and storages. The Smart Market scenario extends the amount of information available to include transparency regarding current and future electricity market conditions via hourly retail electricity prices. The results show a clear preference for gas boilers as a base technology coupled with electric heaters to cover demand peaks. Households with higher demand levels invest in PV systems in 2025, while other households with lower demands either wait until 2040 or do not invest at all.

A sensitivity analysis then examines the effects of higher carbon pricing in the German building sector on the consumer's energy provision. The subsequent increase in the retail gas price leads to households choosing to fully electrify their heat provision, i.e., installing a heat pump combined with thermal storage, PV and an electric heater. On average, these households experience an increase in total costs ranging from 3.5% to 5.4% over the complete time horizon and realize a long-term decrease in annual carbon emissions of up to 80% compared to the analysis with lower carbon pricing. Lastly, the paper at hand also presents a novel method of analyzing the marginal costs of electricity and heat provision, revealing a strong correlation between the implicit marginal costs of energy provision and the assumptions on retail energy prices.

4.1.2. Literature Review

There exists a large body of literature that develops mathematical models to optimize decentralized energy supply, consumption and storage for single or aggregated consumers. The MILP approach, in particular, has established itself as the method of choice due to its both discrete and continuous nature, allowing for technologies to be selected, sized and switched on/off using binary variables. Table 4.1 gives an overview of reviewed publications that develop or methodologically extend MILP models to optimize the investment in as well as the sizing and operation of decentralized generation and storage technologies.[136] All sources presented in Table 4.1 include objective functions that seek to minimize the total or annual costs of energy provision, which in this case includes at least[137] both electricity and heating.

As illustrated in Table 4.1 and in [McKenna et al., 2017], one key difference among the literature is the technology catalog considered in the respective models and the selected applications. While a handful of papers focus on one specific technology (e.g., [Cano et al., 2014], [Merkel et al., 2015]) or on the dynamics between two technologies such as PV and heat pumps (e.g., [Beck et al., 2017], [Schwarz et al., 2018]), the majority of the publications seek to advance the number of DER types. As is the case with any investment model, the optimal solution depends on the technology options available. As such, one major challenge of modeling DER systems in an economic model lies with the definition of which technologies to consider and how the operation of these technologies can be simulated with high technical complexity, all within computational limits. [Ashouri et al., 2013] and [Liu et al., 2020] are examples of studies that have an unusually vast amount of DER investment options with high levels of technical detail. In particular, the models used in these studies, as well as in others such as [Zhang et al., 2018] and [Rikkas and Lahdelma, 2021], include a dynamic coefficient of performance (COP) function to account for the variable technical efficiency of heat pumps, which is a key factor effecting their economic feasibility.

Alongside the technological scope and technical complexity exists another key distinction between publications: the ability of the models to consider regulatory aspects. Although this highly depends on the country considered, the inclusion of incentive mechanisms in the objective function can greatly affect the profitability of certain technologies. As can be seen in Table 4.1, the majority of publications in this field only consider variable remuneration such as, e.g., feed-in tariffs or direct electricity sales, and ignore the possibility of subsidies or other cost savings via, e.g., alternative tariffs or carbon abatement. [Schütz et al., 2017] is one of the few papers examined that actively investigate the effect of the regulatory environment on the optimal design of DER systems. In doing so,

[136] Papers that optimize the investment in electricity grids (e.g., microgrids) and/or district heating pipelines have been omitted from this literature review as well as from Table 4.1. Furthermore, papers that do not include an investment decision, i.e., papers that only optimize the operation of DER systems, are also not considered.

[137] Some papers in Table 4.1 also consider cooling; however, for the literature selection, it is required that the provision of both electricity and heat are optimized.

Table 4.1.: Overview of reviewed publications in Chapter 4

Source	Energy Use[a]				Investment Technology[b]										COP[c]		Regulation[d]								CF[e]		IOS[f]		GS[g]
	EL	SH	HW	CL	PV	BS	CHP	GB	ST	BIO	EH	HP	TS	OT	C	V	FIT	EMS	OVM	CP	HPT	IS	CO_2	PC	L	PW	1Y	MY	
[Ren and Gao, 2010]	x	x	x	x	x	x	x	x				x	x	x				x				x	x	x		x	x		JP
[Buoro et al., 2012]	x	x	x	x	x		x	x	x			x	x	x	x		x	x	x							x	x		IT
[Ashouri et al., 2013]	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x				x		x	x		x		CH
[Cano et al., 2014]	x	x	x		x												x								x			x	ES
[Stadler et al., 2014]	x	x	x	x	x	x	x	x	x				x	x				x							x		x		AT
[Merkel et al., 2015]	x	x	x				x	x					x				x		x							x	x		UK
[Steen et al., 2015]	x	x	x	x	x	x	x	x	x			x	x	x	x			x							x		x		US
[Beck et al., 2017]	x	x	x		x	x					x	x	x			x	x							x		x	x		DE
[McKenna et al., 2017]	x	x	x		x	x	x	x					x				x		x							x	x		DE
[Schütz et al., 2017]	x	x	x		x	x	x	x	x		x	x	x	x		x	x	x	x		x	x			x		x		DE
[Acha et al., 2018]	x	x	x	x	x	x	x	x						x			x		x				x	x	x		x		UK
[Gabrielli et al., 2018]	x	x	x		x	x		x	x			x	x	x		x	x	x								x	x		CH
[Ma et al., 2018]	x	x	x	x	x	x		x					x	x	x								x		x		x		CN
[Mavromatidis et al., 2018]	x	x	x		x	x	x	x		x		x	x			x	x									x	x		CH
[Schwarz et al., 2018]	x	x	x		x	x						x	x			x	x			x				x	x		x		DE
[Zhang et al., 2018]	x	x	x		x	x					x	x	x			x		x						x	x		x		SE
[Huang et al., 2019]	x	x	x	x	x	x	x	x			x	x	x	x	x										x		x		CN
[Kannengießer et al., 2019]	x	x			x	x	x	x				x	x		x		x	x							x		x		DE
[Alabi et al., 2020]	x	x	x	x	x	x	x	x				x	x	x	x										x			x	HK
[Liu et al., 2020]	x	x	x	x	x	x	x	x	x			x	x	x		x									x		x		CN
[Mavromatidis and Petkov, 2021]	x	x	x		x	x	x	x		x		x	x		x			x							x			x	CH
[Rikkas and Lahdelma, 2021]	x	x	x	x	x	x						x	x	x		x		x						x	x		x		FI
[Petkov et al., 2022]	x	x	x	x	x	x	x	x		x		x	x	x	x			x							x			x	CH
This study	x	x	x		x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x		x		x	DE

[a] EL: Electricity, SH: Space Heating, HW: Hot Water Heating, CL: Cooling

[b] PV: Photovoltaic, BS: Battery Storage, CHP: Combined Heat and Power Gas Engine, GB: Gas Boiler/Gas Condensing Boiler, ST: Solar Thermal, BIO: Biomass Boiler/Stove, EH: Electric Heaters, e.g., Heating Rod or Electric Boiler, HP: Heat Pump, TS: Thermal Storage, OT: Other Technologies that are not listed in the table, which may include, e.g., wind turbines, electrolyzers, fuel cells, flow heaters and/or absorption/electric cooling systems

[c] COP: Coefficient of Performance of Heat Pumps (hourly), C: Constant, V: Variable

[d] FIT: Feed-In Tariff, EMS: Electricity Market Sales, OVM: Other Variable Mechanisms (e.g., market premium, self-consumption fees), CP: Capacity Pricing, HPT: Heat Pump Tariff, IS: Investment Subsidies, CO_2: Carbon Tax, PC: Price Components

[e] CF: Cost Function, L: Linear, PW: Piecewise (considered for at least one technology)

[f] IOS: Investment Optimization Strategies, 1Y: Single-Year (static investment optimization), MY: Multi-Year (dynamic anticipative optimization)

[g] GS: Geographic Scope, JP: Japan, IT: Italy, CH: Switzerland, ES: Spain, DE: Germany, AT: Austria, UK: United Kingdom, US: United States, CN: China, SE: Sweden, HK: Hong Kong, FI: Finland

the authors extend an existing MILP model to include a wide range of German legislation and market characteristics including subsidies for CHP and PV as well as heat pump tariffs. However, the authors provide little information on the assumptions regarding the individual price components assumed for the gas and electricity tariffs. In Germany, for example, retail electricity prices are constructed based on the average spot market bids, grid fees, renewable surcharge and other taxes and fees. By breaking the retail prices down to the individual components, alternative tariff structures such as capacity pricing can be considered. Furthermore, assumptions on the future developments in, for example, the renewable surcharge or carbon taxes can be accounted for in the tariff predictions. As shown in Table 4.1, few studies offer information on price components, with only [Schwarz et al., 2018] including the option of capacity-based pricing in the model.

A third characteristic that varies across the presented literature is the design of the cost function implemented in the model. As is often the case in MILP models, the investment in a technology may not be linear but rather stepwise, as a certain technology may only be available in predefined sizes (e.g., a battery may be bought with 3 kWh or with 7 kWh but not in between). Some of the studies shown in Table 4.1 use a piecewise-linear cost approximation approach to allow for each step to have their own linear cost function. [Ren and Gao, 2010], [Buoro et al., 2012] and [Merkel et al., 2015] are often cited as some of the first to apply a piecewise-linear cost approximation to DER systems in MILP models. More recently, papers such as [Gabrielli et al., 2018] and [Mavromatidis et al., 2018] have increased the level of detail in the cost function, accounting for both fixed (i.e., installation) and variable (i.e., material) investment costs in the piecewise approximation. Yet with the introduction of greater technical complexity, multi-stage investment decisions and higher temporal resolutions, the use of piecewise-linear cost functions may lead to computational issues. As such, many of the most recent publications assume linear capital costs regardless of a technology's size, ignoring effects such as economies of scale. Furthermore, none of the other studies shown in Table 4.1 transfer the concept of piecewise-linear approximation to fixed operation and maintenance (FOM) costs or subsidies, which may also vary non-linearly according to a technology's installed capacity.

Another trend that stands out in Table 4.1 is the general lack of papers that optimize investments over multi-year stages, i.e., such that the consumer may invest in technologies over multiple future time periods. [Cuisinier et al., 2021] refer to this type of optimization as "dynamic anticipative", meaning the model jointly optimizes investment decisions successively for the complete time horizon (i.e., perfect foresight) over evolving data. Although many studies optimize the system costs over the complete system lifetime, the majority of the papers considered perform what [Cuisinier et al., 2021] call "static investment optimization" in which the investment decision occurs in a single stage (e.g., one single year). In fact, only three of the reviewed publications shown in Table 4.1 develop models capable of dynamic-anticipative investments, the earliest of which being [Cano et al., 2014]. In their paper, the authors develop a MILP model to optimize the energy planning in buildings and seek to complement an existing decentralized heating system with PV, with the results showing endogenous investments in PV capacity in three out of the five future years considered. More recently, [Mavromatidis and Petkov, 2021] and [Petkov et al., 2022] address this research gap in the development of their models MANGO and MANGOret, capable of performing dynamic-anticipative investments for a large technology catalog. The former, in particular, optimizes the design of an energy system for a hypothetical urban area assuming a 30-year planning period with six investment stages. However, at the time of this research, the MANGO model omits the possibility of regulatory instruments and their development over time, which may greatly impact future investment decisions.

Lastly, although Table 4.1 highlights the methodological variations in the selected literature, the sources can also be characterized by the unique case studies or scenario analyses that are performed to demonstrate the models' abilities. Yet one interesting finding is the homogeneity of the economic analyses performed. In fact, of the papers that provide economic results, their findings are based on the level values of the output variables, e.g., total annual costs, total investment costs, total operational costs, etc.. Marginal values in the form of implicit or shadow prices, on the other hand, have yet to be evaluated, most likely due to the non-linear nature of MILP models. However, following the methodology provided in [Williams, 1989] and [Williams, 2013], the marginal values of MILP models may be interpreted as shadow prices as long as the optimal MILP solution is then linearized, i.e., the binary variables are set to the optimal solution. In doing so, it is possible to determine the implicit prices for decentralized electricity and heat provision — a task that has yet to be done in the reviewed literature.

4.1.3. Contribution and Paper Structure

In light of the existing literature, the paper at hand seeks to both (i) advance the individual criterion outlined in Section 4.1.2 as well as (ii) offer a unique combination of these criteria not previously seen, emphasized by the distinct combination of x's in the last line of Table 4.1. As such, this work offers several significant contributions within the methodology developed as well as the application performed, in particular:

- The model includes an extensive technology catalog with a comparably large number of generation and storage technologies for space and water heating as well as electricity. The DER systems are modeled with a great deal of technical detail, including the design of an hourly COP profile for heat pumps dependent on regional temperature profiles.
- The cost minimization in COMODO takes into account a wide range of incentive mechanisms including variable remunerations such as feed-in tariffs, market premiums and direct electricity sales as well as investment subsidies. Due to the detailed depiction of the individual price components for electricity and gas, further regulatory aspects such as capacity pricing, heat pump tariffs and carbon taxes may

also be considered.

- The ability of the model to optimize investments in multiple future years, i.e., perform a dynamic anticipative optimization, is a unique characteristic of COMODO. The model therefore requires that assumptions for techno-economic input data be made for each model year for the complete model horizon. This includes detailed assumptions on regulatory and market developments.
- Although several studies have designed piecewise-linear functions for the investment costs of DER for static, single-year optimization, the study at hand uses learning rates to create piecewise-linear cost functions for all future model years. Furthermore, the piecewise-linear approximation approach is also applied to FOM costs as well as investment subsidies, which has also yet to be performed in the reviewed literature.
- To the best of the authors' knowledge, the paper at hand is the first to analyze the future marginal costs of decentralized heat and electricity provision for individual exemplary households in Germany based on a MILP optimization.

The remainder of this chapter is structured as follows: Section 4.2 presents a detailed explanation of the methodology and the model equations. The scenario application and optimization results are given in Section 4.3, including a description and evaluation of the marginal costs of energy provision. The assumptions as well as findings of the sensitivity analysis are also included in Section 4.3. Section 4.4 concludes.

4.2. Model Description

4.2.1. Model Overview

The COMODO model is a mixed-integer problem that uses linear programming methods to minimize the total system costs of supplying energy to a specific consumer or consumer group. Consumers are defined according to criteria such as building type (e.g., single-family home, multi-family home, industry building, etc.), building age, modernization standard, living area, available roof space, number of inhabitants, inhabitants' working schedules and building location. These key criteria, in turn, determine how the consumers are parameterized according to, e.g., their energy demand levels, load profiles, investment options, generation potentials as well as economic and regulatory conditions. The model developed then determines the consumer's private economic optimum in satisfying its electricity as well as space and water heating demands using a partial-equilibrium investment and dispatch optimization. In doing so, COMODO is able to determine the cost-minimal energy provision for a consumer class according to each energy use type (EUT), i.e., electricity, water heating and space heating, over a predefined period of time. Although the model considers individual years, the optimization takes place over the complete time horizon.[138]

In order to cover the consumer's energy needs, COMODO may choose one or multiple investment objects from its extensive DER catalog or may purchase electricity or district heat[139] from the grid. Figure 4.1 gives a schematic overview of the investment objects, available fuels and energy flows that are currently accounted for in the model COMODO, with yellow boxes and lines indicating electricity flow and red indicating heat flows for both space and water heating.

The current DER catalog accounts for 18 distributed generation and storage technologies[140], represented by the grey boxes in Figure 4.1.[141] All technologies are subject to their specific investment and installation costs, operating costs and other fixed costs as well as technical specifications such as efficiency, lifetime and generation potential. Several investment objects require natural gas, oil or wood pellets as input, which can be bought at the local commodity price (see the boxes and arrows in green, black and brown in Figure 4.1, respectively). Others require electricity, which can either be pro-

[138] In other words, the model benefits from perfect foresight.

[139] Although the functional layout of COMODO is designed to include district heat, it is not considered in this analysis and therefore omitted from Figure 4.1.

[140] Currently, these include PV, solar thermal (hot water, combined hot water and space heating), micro-CHP (gas, diesel), fuel cell CHP (gas), gas condensing boiler, gas-fired boiler, gas flow heater, oil condensing boiler, pellet stove, thermal storage, battery storage, electric heater, heat pump (air-to-water, water-to-water, geothermal) and power flow heater. Electric networks and pipelines are not included in the technology catalog as these are excluded as investment objects within the work at hand. This also holds true for investments in building envelope refurbishment.

[141] The model structure allows for the technology catalog to be expanded to include additional electricity or heat production, storage and/or consumption technologies and is in no way limited to the technologies shown in Figure 4.1.

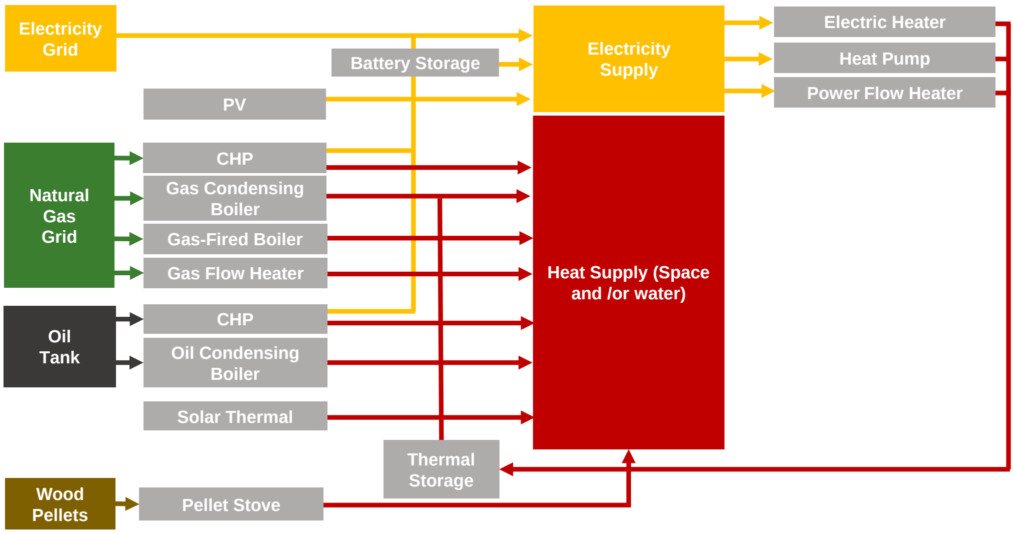

Figure 4.1.: Overview of the energy supply flows and DER systems in the model COMODO, with the yellow boxes and lines indicating electricity, the red boxes and lines indicating heating and grey boxes indicating technologies

duced and supplied by the consumer or bought from the electricity market at the retail price. In the case of PV and solar thermal, the energy input is solar irradiation[142] and depends on the weather conditions in the consumer's region. Weather conditions may also affect other technologies such as heat pumps, whose efficiency may, e.g., decrease in colder temperatures (see Section 4.2.4). Three types of heat pumps are considered in COMODO, namely air-to-water, water-to-water[143] and geothermal[144].

Next to the investment decision, the model also optimizes the resulting consumption, generation and storage-use profiles of the chosen DER systems in order to satisfy demand of all EUTs at each point in time. For example, the decision of the consumer to, e.g., directly consume her own production, store her own production and/or immediately feed-in her own production is simultaneously optimized against the consumer's load, weather conditions, regulatory framework and market signals until the cost-minimizing solution is found. For electricity, demand may be both exogenous and endogenous as the consumer's immediate electricity needs —the exogenous part— may be accompanied by an endogenously-determined heat-driven demand for electric power from, e.g., an electric heater. Space and water heating demands, on the other hand, are defined completely exogenously.[145] The standard temporal resolution of the model is hourly but can be adjusted to account for more (e.g., quarter-hourly) or fewer (e.g., via clustering) time slices.

[142]Not pictured in Figure 4.1.
[143]I.e., including a ground collector
[144]I.e., including vertical drilling
[145]In other words, it is assumed that no technology uses heat as an input energy source. The thermal storage systems are an exception to this assumption, as heat losses can lead to an additional endogenous heat demand.

As emphasized in Sections 4.1.2 and 4.1.3, the model is also able to accommodate current as well as planned or hypothetical regulatory frameworks and energy market conditions relative to the location of the consumer. These include, among others, remuneration mechanisms such as investment subsidies, feed-in tariffs, market premiums and direct sales of distributed generation as well as transparent market signals via, e.g., variable electricity prices. The tariff structure may also be adjusted for either energy (€/kWh) or capacity (€/kW) prices. Further constraints to account for, e.g., emission reduction targets may also be applied. The model can be used to examine future years by adjusting, among others, the regulatory and market conditions as well as the economic and technical assumptions. In doing so, COMODO provides the opportunity to analyze the diffusion of DER systems over time for specific consumer classes or accumulated consumer groups.

4.2.2. Minimizing Total Costs of Meeting Demand

The objective function in COMODO is a minimization of the sum of the individual cost components that consumers[146] face when satisfying their energy needs over a predefined period of time.[147] As shown in Equation (4.1a), these can be broken down into fixed costs ($\boldsymbol{FC}$) and variable costs, which may either be energy-based ($\boldsymbol{EBC}$) and[148]/or capacity-based[149] ($\boldsymbol{CBC}$), for each year y. Furthermore, certain technologies used to supply certain energy use types (EUT) may also be eligible for an energy-based remuneration[150] ($\boldsymbol{EBR}$) via incentive programs, which dampen the consumer's variable costs.[151] Before summing over all modeled years, the annual costs are discounted according to an interest rate i and the starting year y_0.

[146] It is important to note that, in order to simplify the nomenclature, the dependence on the consumer definition has been excluded from the equations. In other words, all the equations shown in Sections 4.2.2, 4.2.3, and 4.2.4 apply to a single or an aggregated group of consumers. More information on the consumer definition may be found in Section 4.3.1.

[147] The period of time is usually defined to be anywhere from a 10-year to 30-year interval.

[148] Both may be possible if, for example, a combination of multiple fuels with different price structures are consumed or if the retail price of an energy use type is made up of a combination of energy-based and capacity-based price components.

[149] Capacity-based costs depend on the size of the consumer's connection to the grid. Per definition, this depends on the energy use type or on the fuel being transported, as infrastructure costs differ for, e.g., electricity or gas (see Equation (4.5)).

[150] Energy-based remuneration is awarded according to energy units (kWh), e.g., feed-in tariffs (see Equation (4.6)).

[151] A complete list of the notations used for all model sets, parameters and variables in Chapter 4 can be found in Appendix C.1. Unless otherwise noted, optimization variables are indicated using bold, uppercase letters.

$$min!\boldsymbol{TC} = \sum_{y} \left[\frac{1}{(1+i)^{(y-y_0)}} \cdot (\boldsymbol{FC}_y + \boldsymbol{EBC}_y + \boldsymbol{CBC}_y - \boldsymbol{EBR}_y) \right] \tag{4.1a}$$

$$\text{s.t.} \quad d_{y,t,EUT} + \sum_{x} [\boldsymbol{XFI}_{y,t,x,EUT} + \boldsymbol{GFI}_{y,t,x,EUT}] = \sum_{x} [\boldsymbol{XS}_{y,t,x,EUT} + \boldsymbol{GS}_{y,t,x,EUT}] + \boldsymbol{GS}_{y,t,EUT=EUT_{demand}} \tag{4.1b}$$

$$\boldsymbol{Q}_{y,x} \geq \boldsymbol{XS}_{y,t,x,EUT} \tag{4.1c}$$

$$q_{grid,EUT} \geq \sum_{x} [\boldsymbol{GS}_{y,t,x,EUT}] + \boldsymbol{GS}_{y,t,EUT=EUT_{demand}} \tag{4.1d}$$

$$cap_{CO_2,y} \geq \sum_{t,f_x,EUT} \left[\left(\sum_{x} [\frac{\boldsymbol{XS}_{y,t,x,EUT}}{\eta_{t,x,EUT}}] + \boldsymbol{GS}_{y,t,EUT=EUT_{demand}} \right) \cdot factor_{CO_2,t,f_x/EUT} \right] \tag{4.1e}$$

Equations (4.1b) - (4.1e) summarize the main constraints of the minimization problem. The first of these equations requires that equilibrium between demand and supply be maintained in every time slice t. In addition to an exogenously-defined energy demand d for each y, t and EUT, an endogenous energy demand may arise from feeding an EUT into a technology (***XFI***) or feeding an EUT into the grid[152] (***GFI***). The exogenous and endogenous demand may be supplied by a decentralized technology x (***XS***) and/or by an energy provider via the grid[153] (***GS***), which may be directly consumed to meet exogenous demand d of an EUT (indicated by the subscript $EUT = EUT_{demand}$[154]) or fed into a technology to store or transform the EUT (indicated by the subscript x). Equation (4.1c) shows the capacity constraint for the DER systems, meaning that the supply ***XS*** can not exceed the installed capacity ***Q*** of a certain technology x for every time slice t and year y.[155] Similarly, Equation (4.1d) limits the amount of energy that can be supplied

[152] Grid feed-in is only possible if a suitable bidirectional grid connection is available to the consumer. Currently, this is most commonly the case for electricity. However, from a technical standpoint, grid feed-in may also be possible for heat.

[153] In this case, grid supply pertains solely to the buying of an EUT, namely electricity or heat, from an energy provider to cover a consumer's energy demand. Grid supply is only possible if a suitable grid connection is available to the consumer.

[154] The subscript $EUT = EUT_{demand}$ is necessary for the notation of variables that describe a direct energy consumption without conversion in a technology x.

[155] Equation (4.1c) holds for $y \in [y_x^*, y_x^* + lt_x]$, where y_x^* indicates the installation year and lt_x the technical lifetime of technology x. If the model chooses to remove the technology before the end of its technical lifetime, ***XS*** would then be equal to zero.

from the grid ($\boldsymbol{GS}$)[156] according to the size of the connection capacity (q_{grid}) for the corresponding EUT, which may vary strongly depending on the consumer definition. The last constraint shown, Equation (4.1e), is only included in the model if a carbon emission reduction target is considered. In this case, total emissions of a single consumer or consumer group are determined by adding the energy consumption of decentralized generation technologies ($\frac{\boldsymbol{XS}_{y,t,x,EUT}}{\eta_{t,x,EUT}}$)[157] to the energy consumed directly from the grid ($\boldsymbol{GS}_{y,t,EUT=EUT_{demand}}$) and then multiplying by the corresponding CO_2 factor. If the energy source of technology x is a fuel f_x[158] such as gas or oil, then the CO_2 factor is equal to the combustion emissions factor ($factor_{CO_2,f_x}$)[159]; however, in the event that an EUT is bought from an energy provider to be used directly ($EUT = EUT_{demand}$) or as an input energy source for technology x, then the CO_2 factor is equal to an average emissions factor of the generation technologies used to produce the respective EUT ($factor_{CO_2,t,EUT}$).[160] The total CO_2 emissions emitted by the consumer are then limited by an exogenously-given target value $CO_{2,cap}$ for year y.

The fixed costs ($\boldsymbol{FC}$) in year y include the annualized investment costs ($\boldsymbol{AIC}$) and fixed operation and maintenance costs ($\boldsymbol{FOMC}$), summed over all technologies installed x,

$$\boldsymbol{FC}_y = \sum_x \Big[\boldsymbol{AIC}_{y,x} + \boldsymbol{FOMC}_{y,x}\Big], \tag{4.2}$$

with

$$\boldsymbol{AIC}_{y,x} = \frac{j_x}{1-(1+j_x)^{-w_x}} \cdot (\boldsymbol{IC}_{y^*,x} - \boldsymbol{S}_{y^*,x}). \tag{4.3}$$

The investment costs ($\boldsymbol{IC}$), which are discussed in detail in Section 4.2.3, may be partly compensated by a subsidy $\boldsymbol{S}$ in the event that a subsidy program for the technology exists. Both the investment costs and subsidy amounts depend on the year in which the technology is installed (y^*). Using a financing rate j, the remaining investment costs are then annualized over a financing period w, which may vary according to technology x. As such, Equation (4.3) holds for $y \in [y_x^*, y_x^* + w_x]$; however, the fixed costs in Equation (4.2) may hold for $y \in [y_x^*, y_x^* + lt_x]$, where lt_x indicates the technical lifetime

[156] Analogous to Equation (4.1b), grid supply is separated into two variables depending on whether it is stored or converted by a technology x or if it is directly used to cover the exogenous demand d, the latter indicated by the subscript $EUT = EUT_{demand}$.

[157] The technical efficiency included in Equation (4.1e) depends not only on the technology x but also on the time slice t and the EUT. The temporal differentiation is important for heat pumps, whose efficiency may differ over time due to changes in the source temperature (e.g., outside air temperature), whereas the dependence on EUT is essential for technologies such as micro-CHP, whose efficiency depends strongly on the type of energy being produced.

[158] The subscript f_x denotes the matching between the input fuel f and technology x.

[159] This factor represents the carbon intensity of the fuel emitted in combustion, i.e., according to the chemical composition. Any emissions arising in the construction and decommissioning of energy systems are not taken into account.

[160] The parameter $factor_{CO_2,t,EUT}$ depends on the time slice t as the amount of CO_2 emitted during the energy conversion to the EUT may be variable depending on, e.g., the electricity generation mix.

of technology x and $lt_x \geq w_x$.[161] In other words, the fixed operation and maintenance costs may extend past the financing period, as long as the technology is still installed and the technical lifetime has not been reached.

In addition to the fixed costs, a significant share of the consumer's energy expenses result from the variable costs that arise from purchasing either an energy use type from an energy provider or a fuel to be consumed by a DER system. Currently, it is most common to see these costs defined according to energy units, i.e., kWh. Within the scope of this paper, these are referred to as energy-based costs ($\boldsymbol{EBC}$) and are defined in Equation (4.4),

$$\begin{aligned}\boldsymbol{EBC}_y = \sum_{t,EUT} &\Big[\boldsymbol{GS}_{y,t,EUT=EUT_{demand}} \cdot \sum_{epc} \big[ep_{y,t,EUT,epc}\big]\Big] \\ &+ \sum_{t,f_x,EUT} \Big[\sum_{x} \big[\frac{\boldsymbol{XS}_{y,t,x,EUT}}{\eta_{t,x,EUT}}\big] \cdot \sum_{epc} \big[ep_{y,t,f_x/EUT,epc}\big]\Big]. \end{aligned} \tag{4.4}$$

The energy price ep can be defined either for an energy use type, e.g., electricity, or for a fuel, e.g., gas (indicated by the subscript f_x/EUT). In both cases, the retail price for the consumer is made up of energy price components (epc) such as acquisition, taxes and grid fees, which may vary over time slice t and year y. The corresponding energy price is then used to determine the annual costs arising from consuming energy use types directly from the grid ($\boldsymbol{GS}_{y,t,EUT=EUT_{demand}}$) as well as the transformation or storage of an energy use type or fuel by a technology ($\frac{\boldsymbol{XS}_{y,t,x,EUT}}{\eta_{t,x,EUT}}$).

As the regulation of energy prices in future years remains uncertain, COMODO allows for prices as well as individual price components of energy use types to be defined according to capacity (kW) rather than energy units.[162] In this case, the consumer pays a capacity price (cp) for the grid capacity relative to the maximum[163] amount of energy use type needed to be supplied by the grid over time slices t in year y, referred to in Equation (4.5) as capacity-based costs ($\boldsymbol{CBC}$):

$$\boldsymbol{CBC}_y = \sum_{EUT} \Big[\frac{max_t\Big(\sum_x \big[\boldsymbol{GS}_{y,t,x,EUT}\big] + \boldsymbol{GS}_{y,t,EUT=EUT_{demand}}\Big)}{t} \cdot \sum_{cpc} \big[cp_{y,t,EUT,cpc}\big]\Big]. \tag{4.5}$$

[161] It should be noted that, by definition, the model may choose to remove a technology before the end of its technical lifetime or even before the end of the financing period if it leads to an overall decrease in the total costs.

[162] Technically speaking, although only energy use types are mentioned here, Equation (4.5) could also be applied to a grid-supplied fuel such as gas. This is, however, omitted to simplify the explanation.

[163] It should be noted that Equation (4.1d) still holds for Equation (4.5). In other words, $max_t\big(\sum_x \big[\boldsymbol{GS}_{y,t,x,EUT}\big] + \boldsymbol{GS}_{y,t,EUT=EUT_{demand}}\big)$ would be equal to $q_{grid,EUT}$ if the maximum amount demanded by the consumer over time slice t reached the size of the connection capacity. Furthermore, it is also possible to allow for time-variable capacity prices by calculating the maximum of a subset of time slices, e.g., in the case of peak pricing.

The variable costs $\boldsymbol{EBC}$ and $\boldsymbol{CBC}$ may be reduced if a consumer's DER system is eligible to benefit from incentive programs offering energy-based remuneration ($\boldsymbol{EBR}$). Classic examples include compensation for feeding-in energy to the grid via, e.g., feed-in-tariffs or market premiums; however, certain technologies may also be eligible for remuneration for self-consumption, i.e., if an energy use type is locally generated and then consumed on site. On the other hand, some technologies are restricted as to how much they are allowed to produce and self-consume, paying a fee for each kilowatt-hour over the limit. The yearly amount of variable remuneration[164] a consumer may receive is calculated according to Equation (4.6),

$$\boldsymbol{EBR}_y = \sum_{t,x,EUT} \Big[\boldsymbol{GFI}_{y,t,x,EUT} \cdot er_{y,t,x,EUT} + \Big(\boldsymbol{XFI}_{y,t,x,EUT} - \boldsymbol{GS}_{y,t,x,EUT} \Big) \cdot \Big(scr_{y,x,EUT} - scf_{y,x,EUT} \Big) \Big], \qquad (4.6)$$

such that the amount of energy fed into the grid $\boldsymbol{GFI}$ is compensated according to a energy remuneration er, and the amount of energy fed into technology x that does not come from the grid ($\boldsymbol{XFI}$-$\boldsymbol{GS}$) is rewarded or penalized according to a self-consumption remuneration scr or self-consumption fee scf, respectively.

4.2.3. Piecewise Linearization of Costs for Current and Future Years

Investment costs are equal to the capital costs that must be paid to install a certain decentralized energy technology, as introduced in Equation (4.3). These include not only the costs for the technology itself but also for additional hardware or labor costs that are needed for the technology to run. Investments in decentralized technologies are done linearly, meaning the consumer may install the exact capacity (kW) that is optimal for the individual or communal energy system.[165] As explained in Section 4.1.2, many existing studies using MILP methods assume linear, capacity-specific investment costs for each technology. Capacity-specific investment costs (€/kW), however, may vary drastically depending on the total size of the technology installed: For example, a larger system may benefit from lower costs per kW due to, e.g., economies of scale or a decrease in the specific installation costs. Especially for very small systems (e.g., less than 5 kW), the cost difference from one kW to the next may be substantial.

[164] As opposed to investment subsidies, which are accounted for in Equation (4.3).

[165] Restrictions limiting the minimum size of the investment object are taken into account, as many decentralized technologies are only available starting from, e.g., 2 kW.

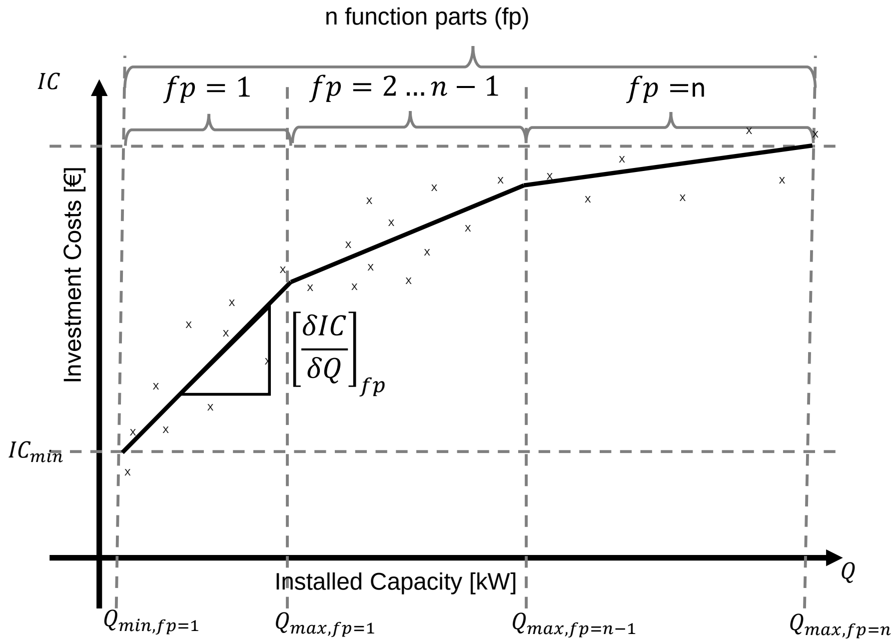

Figure 4.2.: Graphical example of the piecewise-linear function used to determine investment costs

In order to mimic this non-linear cost structure in a linear model, a piecewise-linear cost function is built for each technology's investment costs.[166] In doing so, individual linear costs functions (so-called 'function parts') for different system sizes are joined together to create a curve-like form similar to a logarithmic growth function for each DER technology.[167] Figure 4.2 presents an illustrative example for a technology with a minimum achievable capacity $Q_{min,fp=1}$ and maximum achievable capacity $Q_{max,fp=n}$. As shown in the figure, each function part has a minimum[168] and maximum capacity, which defines the range of system sizes that are assumed to exhibit the same capacity-specific investment costs. For example, all systems with installed capacities that fall between the minimum ($Q_{min,fp=1}$) and maximum ($Q_{max,fp=1}$) of the first function part are assumed to have the same marginal costs, which is determined by the linear slope of

[166] Although the description presented focuses on the investment costs, a piecewise-linear function is also used to determine the capacity-specific FOM costs as well as the capacity-specific subsidy values, as these may also greatly depend on the system size. See Appendix C.3 for a graphical overview of the piecewise-linear functions assumed for the investment and FOM costs in the application in 4.3, as well as a thorough presentation of the subsidies included in COMODO.

[167] The cost functions for some technologies, such as thermal storage and solar thermal, do not display a logarithmic curve. In fact, the capacity-specific costs may increase once the systems size exceeds a certain capacity. The additional costs result from technical requirements in scaling-up system size, e.g., construction, system control or design.

[168] The minimum capacity of a function part is equal to the maximum capacity of the previous function part, with the exception of the first function part where a starting value ($Q_{min,fp=1}$) is given (see Equation (4.9)).

the first function part, $\frac{\delta IC}{\delta Q}_{fp=1}$. A decrease in the slope from one function part to the next reveals how the capacity-specific investment costs may be reduced by an increase in total installed capacity.

The corresponding equation for determining the investment costs $\boldsymbol{IC}$ in year y for technology x using the piecewise-linear function shown in Figure 4.2 can be seen in Equation (4.7),

$$\begin{aligned}\boldsymbol{IC}_{y_x,x} = {} & IC_{Q_{min},x} \cdot \gamma_{y_x,x,fp_x=0} \\ & + \sum_{fp_x=1}^{\boldsymbol{N}} \left[(Q_{max,y_x,x,fp_x} - Q_{max,y_x,x,fp_x-1}) \cdot \left[\frac{\delta IC}{\delta Q}\right]_{x,fp_x} \cdot \gamma_{y_x,x,fp_x} \right] \\ & - \left[(Q_{max,y_x,x,fp_x=\boldsymbol{N}} - \boldsymbol{Q}_{y_x,x}) \cdot \left[\frac{\delta IC}{\delta Q}\right]_{x,fp_x=\boldsymbol{N}} \cdot \gamma_{y_x,x,fp_x=\boldsymbol{N}} \right], \end{aligned} \tag{4.7}$$

with $\boldsymbol{N} \leq n$, where n is the maximum number of function parts and $\boldsymbol{N}$ indicates the function part in which the total installed capacity $\boldsymbol{Q}_{y_x,x}$ falls on the x-axis, i.e.,

$$Q_{max,y_x,x,fp_x=\boldsymbol{N}-1} \leq \boldsymbol{Q}_{y_x,x} \leq Q_{max,y_x,x,fp_x=\boldsymbol{N}}. \tag{4.8}$$

and

$$Q_{max,y_x,x,fp_x=0} = Q_{min,y_x,x,fp_x=1}. \tag{4.9}$$

As illustrated in Equation (4.7), the investment costs for a system with installed capacity $\boldsymbol{Q}_{y_x,x}$ are determined by first taking the investment costs of the minimum achievable capacity Q_{min} ($IC_{Q_{min},x}$) and then adding the investment costs of each additional unit of capacity until the full system size has been reached. As shown in Figure 4.2, this is done piecewise for each function part according to the capacity increase from one function part to the next, namely the difference between the maximum capacity of the current function part and of the previous function part (Q_{max,y_x,x,fp_x} - Q_{max,y_x,x,fp_x-1}), multiplied by the slope of the linear cost function for the current function part ($\frac{\delta IC}{\delta Q}_{x,fp_x}$). This is done up until the $\boldsymbol{N}$th function part containing $\boldsymbol{Q}_{y_x,x}$, as shown in Equation (4.8). As the total installed capacity may not be equal to the maximum capacity of the $\boldsymbol{N}$th function part, the investment costs must be "corrected" for the difference in capacity, $Q_{max,y_x,x,fp_x=\boldsymbol{N}} - \boldsymbol{Q}_{y_x,x}$. The decision whether to install the technology as well as the navigation of the function parts are imposed using binary variables.[169]

A learning rate γ is included in Equation (4.7) to account for changes in the investment costs that may occur over future time periods. In addition to the investment year y and the technology x, the learning rate may also differ according to each function part as

[169] Binary variables are excluded from the equations to increase readability.

systems of varying sizes may be subject to different cost degressions over time.[170]

4.2.4. Technology Specifics

In addition to designing the objective function and building the piecewise cost function, another major contribution of the paper at hand is the modeling of complex decentralized energy technologies. As discussed in Section 4.2.1, COMODO can optimize both investment and dispatch decisions simultaneously. In doing so, additional constraints must be included for certain DER systems to ensure technical accuracy of the model.

Generation from solar technologies, which include PV for electricity and solar thermal for space and water heating, is subject to a modified version of the capacity constraint shown in Equation (4.1c), i.e.,

$$\boldsymbol{XS}_{y,t,x=PV/ST,EUT=elec/heat} \leq G_t \cdot \eta_{t,x=PV/ST,EUT=elec/heat} \cdot \boldsymbol{Q}_{y,x=PV/ST}, \tag{4.10}$$

where G_t represents the global solar irradiation on a tilted area measured in kW/m^2. The parameter G_t is determined not only relative to the orientation and tilt angle of the solar system itself but also according to the direct and indirect solar radiation at the location at a specific time, the latter depending on both the solar altitude and azimuth.[171] The global solar irradiation on a tilted area is then multiplied by the technology-specific efficiency $\eta_{t,x=PV/ST,EUT=elec/heat}$, which represents the ability of the system to transform the solar energy into the desired EUT. For PV systems, the factor $\eta_{t,x=PV,EUT=elec}$ is equal to $\frac{\alpha_0}{spacefactor_{PV}}$, where α_0 represents the optical efficiency[172] and $spacefactor_{PV}$ is equal to the maximum amount of PV capacity per square meter[173]. For the case of solar thermal, the efficiency is determined by a quadratic function

$$\eta_{t,x=ST,EUT=heat} = \alpha_1 - \alpha_2 \cdot \frac{T_{collector,t} - T_{ambient,t}}{G_t} - \alpha_3 \cdot \frac{(T_{collector,t} - T_{ambient,t})^2}{G_t}, \tag{4.11}$$

as recommended by the [European Solar Thermal Industry Federation, 2007]. In this case, α_1 describes the technical efficiency of the system, accounting for optical efficiency losses. The remaining part of Equation (4.11) accounts for any heat loss due to the radiation and convection of the heat transfer medium used in the collector. The quadratic

[170] In Equation (4.7), the learning rate corresponding to the investment costs for the minimum installed capacity ($IC_{Q_{min},x}$) is shown using the subscript $fp = 0$. As there is no function part equal to zero, this should be understood as the learning rate for the starting (i.e., minimum) capacity Q_{min}.

[171] The global solar irradiation on a tilted area may also be influenced by the building characteristics specific to the consumer, e.g., roof construction, surrounding topography, etc. The global solar irradiation on a tilted area is calculated according to [Eicker, 2012]. See Appendix C.3.8 for more information.

[172] The optical efficiency accounts for losses due to, e.g., reflection, shade, heat or residue on the PV panels. Although these conditions may vary from one time slice to the next, the optical efficiency within the model is assumed to be an average value held constant over time.

[173] This assumption is based on the current PV module types available.

function contains two heat-loss coefficients, α_2 and α_3, multiplied by the temperature difference between the mean collector temperature $T_{collector,t}$ and ambient temperature $T_{ambient,t}$.

Furthermore, as the roof size for a single consumer or consumer group is limited, rooftop installations of PV and ST systems must compete for the available roof space rs,

$$rs \geq \boldsymbol{Q}_{y,x=ST} + \frac{\boldsymbol{Q}_{y,x=PV}}{spacefactor_{PV}}, \tag{4.12}$$

where the optimal installed capacity of PV in kW ($\boldsymbol{Q}_{y,x=PV}$) is converted to area according to the parameter $spacefactor_{PV}$.[174]

Next, additional technology-specific equations must be included in COMODO to account for battery and thermal storage. In particular, storage technologies introduce a temporal shift into the model, allowing for energy to be consumed or transformed at a different point in time than it was generated or purchased. In other words, the amount of energy that can be injected into or discharged from the storage in time slice t depends on the storage level, $\boldsymbol{SL}$, which is relative to the storage level in the previous time slice $t-1$,

$$\begin{aligned}\boldsymbol{SL}_{y,t,x=storage,EUT} =& \boldsymbol{SL}_{y,t-1,x=storage,EUT} \cdot (1-\beta_{t,x=storage,EUT}) - \boldsymbol{XS}_{y,t,x=storage,EUT} \\ &+ \Bigg(\sum_{x_1 \neq storage} \Big[\boldsymbol{XFI}_{y,t,(x_1 \rightarrow x_2=storage),EUT} \Big] \\ &+ \boldsymbol{GS}_{y,t,x=storage,EUT} \Bigg) \cdot \eta_{t,x=storage,EUT}. \end{aligned} \tag{4.13}$$

The temporal shift between $t-1$ and t results in storage losses equal to β, while the injection of energy either from a technology other than storage ($\boldsymbol{XFI}_{y,t,(x_1 \rightarrow x_2=storage)}$), in this case x_1[175], or from the grid ($\boldsymbol{GS}_{y,t,x=storage,EUT}$) must be corrected for the storage's technical efficiency η. The amount of energy discharged from the storage ($\boldsymbol{XS}_{y,t,x=storage,EUT}$) can then be used either directly by the consumer in its current energy use type or fed into another technology to be transformed to another energy use type.

Similar to the investment costs discussed in Section 4.2.3, the available storage volume (in kWh) for technology x in year y is calculated using piecewise-linear functions according to an installed storage capacity (in kW). Therefore, storage level $\boldsymbol{SL}$ in time slice t must be less than or equal to the available storage volume $\boldsymbol{SV}$ for technology x, energy use type EUT and year y, i.e., $\boldsymbol{SL}_{y,t,x,EUT} \leq \boldsymbol{SV}_{y,x,EUT}$.

Furthermore, technologies that handle multiple energy use types, such as CHP or

[174] For solar thermal, the installed capacities, e.g., $\boldsymbol{Q}_{y,x=ST}$ in Equation (4.12), are given in square meters.

[175] The subset (x_1, x_2) is included in Equation (4.13) to specify that, in this case, the energy flows from one technology x_1 into a storage technology x_2.

power-to-heat (PtH) systems, require additional mathematical constraints. For example, CHP systems may consume gas, diesel or even hydrogen to produce both electricity and heat according to a power-to-heat ratio $\eta_{EUT=elec}/\eta_{EUT=heat}$,

$$\boldsymbol{XS}_{y,t,x=CHP,EUT=elec} = \frac{\eta_{t,x=CHP,EUT=elec}}{\eta_{t,x=CHP,EUT=heat}} \cdot \boldsymbol{XS}_{y,t,x=CHP,EUT=heat}, \tag{4.14}$$

where $\boldsymbol{XS}$ indicates the amount of energy production by the CHP system for the energy use type electricity ($EUT = elec$) and heat ($EUT = heat$) in time slice t. PtH technologies, which include electric heaters and heat pumps, consume electricity either produced by another technology ($\boldsymbol{XFI}$), in this case x_1[176], or purchased from the electricity grid ($\boldsymbol{GS}$) to generate heat supply ($\boldsymbol{XS}$), as shown in Equation (4.15):

$$\begin{aligned}\boldsymbol{XS}_{y,t,x=PtH,EUT=heat} = \eta_{t,x=PtH,EUT=heat} \cdot \Bigg(\sum_{x_1} \Big[\boldsymbol{XFI}_{y,t,x_1,x_2=PtH,EUT=elec} \Big] \\ + \boldsymbol{GS}_{y,t,x=PtH,EUT=elec} \Bigg). \end{aligned} \tag{4.15}$$

Whereas the efficiency η of an electric heater (e.g., a heating rod or electric boiler) tends to be less than one and remain constant for every time slice t, the efficiency of heat pumps not only reaches levels at least 3x higher but also fluctuates from one time slice to the next. The performance of electric heat pumps, i.e., the COP, is highly dependent on the temperature delta between the source temperature and the desired flow temperature of the heating system. In order to determine the temperature-dependent, variable COP of electric heat pumps, the following equation is developed[177],

$$COP_t = \eta_t = 0.0016(T_{flow} - T_{source,t})^2 - 0.2058(T_{supply} - T_{source,t}) + 8.7302, \tag{4.16}$$

where T_{flow} indicates the desired flow temperature, $T_{source,t}$ the outside source temperature in time slice t and COP_t the resulting COP in time slice t. A larger delta between the outside source temperature and the desired flow temperature leads to lower COPs, i.e., colder days lead to lower efficiency levels. The flow temperature for the heating system is assumed to depend on the technical construction of the heating system and, in turn, on the modernization standard of the building considered.[178]

[176] The subset (x_1, x_2) is included in Equation (4.15) to specify that in this case, the energy flows from one technology x_1 into a PtH technology x_2.

[177] The construction of the equation is based on data from [Ruhnau, 2019], [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2019] and industry data.

[178] For example, it is assumed that an existing building has a flow temperature of 50°C and newly-built buildings a flow temperature of 35°C.

4.3. Application

To demonstrate the capabilities of the model developed, three scenarios are defined and examined using COMODO. The Status Quo, Smart Tech and Smart Market scenarios as well as the corresponding assumptions pertaining to the consumer types, market conditions and DER systems are explained in Section 4.3.1. Section 4.3.2 presents and compares the scenario results with regards to investment behavior, energy generation and consumption as well as the costs for each household. The next subsection, Section 4.3.3, investigates the yearly and hourly marginal costs of energy provision. Finally, a sensitivity analysis is performed in Section 4.3.4 to explore the impact of higher carbon prices on the choices of the households considered.

4.3.1. Scenario Definition

Three scenarios are constructed that vary according to their technical and regulatory frameworks. More specifically, the scenarios aim to depict a progression in the amount of information available to consumers and their DER systems. Figure 4.3 shows an overview of the scenario definitions and corresponding attributes.

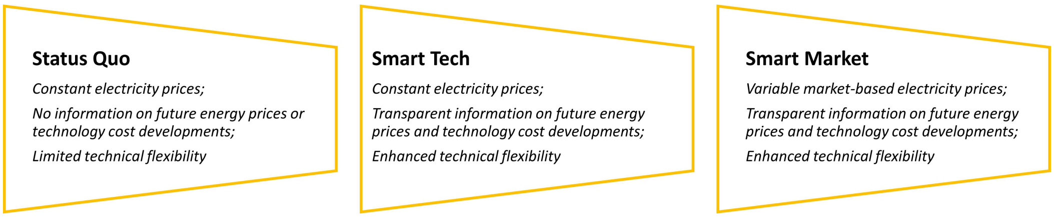

Figure 4.3.: Overview of the scenario definitions investigated in Chapter 4

The first scenario, a so-called Status Quo scenario, assumes that the technologies receive no information regarding electricity market conditions, i.e., consumers see only a constant retail price. Furthermore, the consumers' investment decisions are made based on the data for only one model year rather than the entire time horizon. As such, it is assumed that consumers have no knowledge of how investment costs, remunerations, heat and electricity demand as well as weather profiles and retail prices will develop and therefore assume that all future model years will be identical to the first model year, in this case 2025.[179] The operation of the DER systems, however, is optimized on a daily basis, meaning the technologies themselves are only capable of forecasting weather and demand patterns for a single day. As a result, the optimization strategy is limited in its ability to plan generation and storage flows, similar to the current status quo.

[179] Although the consumer can not see future price or costs developments at the time of the investment decision, the consumer will still pay the, e.g., retail price that is assumed for the model year according to Figure 4.4 later on in this section. This is done ex-post in order to normalize the results shown in Section 4.3.2.

The second scenario, referred to as the Smart Tech scenario, assumes that DER systems are capable of receiving information on the demand and weather conditions for all time steps in all model years. In terms of operation, this means that technologies can better manage their energy provision by, e.g., using storage to optimize generation and consumption over a single week rather than a single day.[180] Furthermore, households are exposed to forecasts on energy price developments as well as expected changes in investment costs and subsidy values for decentralized energy technologies. In other words, investment decisions can be made with knowledge on future economic and regulatory conditions.

The third scenario, i.e., the Smart Market scenario, builds upon the Smart Tech scenario and allows for additional information on the current and future electricity market to be available to consumers and their technologies. In this scenario, the constant retail electricity price is replaced with a variable tariff to reflect changes in electricity supply and demand occurring in the market.[181] As a result, the profitability of decentralized electricity generators, storages as well as electricity-based heaters may increase as these technologies seek to optimize operation according to the hourly variations in electricity prices.

Defining the Consumer

COMODO is particularly well designed for analyzing the energy provision of privately-owned single-family homes in which the owner is also the resident of the house. In this case, the investment decision lies solely with one party such that a cost minimization can be performed without a mismatch in the incentives between investor and technology user.[182] Therefore, within each of the three scenarios, four privately-owned, single-family household types are considered, two with four residents and two with two residents. Table 4.2 shows the assumptions on the key consumer characteristics of each household type.[183] All consumers considered are assumed to live in Cologne, Germany.

Each household type is defined by individual load profiles for electricity and heat consistent with the annual demand values shown in Table 4.2. For electricity, the hourly demand for lighting, information and communication technology as well as household

[180] At the time of this paper, the standard setting in COMODO is that the storage technologies are able to shift energy consumption within a time frame of one week. Other storage systems would have to be considered to expand this time frame.

[181] It should be noted that the electricity market price is assumed to be unaffected by the electricity consumption and generation behavior of the individual consumer. In other words, the variable tariff is not endogenously coupled with the single consumer's energy provision and is handled rather as an exogenously-defined input parameter.

[182] Especially for multi-family homes, the landlord/tenant dilemma distorts the incentives for investment: While the landlord bears the investment costs, the tenant may financially profit from using certain technologies.

[183] The key characteristics are defined in line with [Shamon et al., 2021], with the household types presented being closely linked to the household types $HH1b\_A\_t3$ (HH1), $HH2b\_A\_t3$ (HH2), $HH1b\_N\_t1$ (HH3) and $HH2b\_N\_t1$ (HH4).

	HH1	HH2	HH3	HH4
number of residents	4	2	4	2
share of residents employed	25%	100%	25%	100%
building age	existing	existing	new	new
living space $[m^2]$	122.4	96.0	122.4	96.0
roof size $[m^2]$	60	60	60	60
appliance type	standard	standard	efficient	efficient
annual electricity demand $[kWh_{el}]$	5674	3414	3723	2469
annual heat demand $[kWh_{th}]$	18051	14158	8849	6940
peak electricity demand $[kW_{el}]$	4.7	4.8	4.1	3.7
peak heat demand $[kW_{th}]$	15.4	12.1	15.6	12.2
financing rate [%]	5	5	5	5
financing period* $[a]$	15	15	15	15

*Financing period holds as long as the technical lifetime is exceeded

Table 4.2.: Consumer characteristics of each household type based on [Shamon et al., 2021]

appliances is determined using a tool[184] developed in [Pflugradt, 2016]. In doing so, an individual load profile is generated for each household type according to the consumer characteristics affecting electricity consumption behavior such as, e.g., location, number of residents, appliance efficiencies, working hours[185] and vacation periods[186]. The sum of the hourly load profiles results in the annual electricity demand shown in Table 4.2. For heat, on the other hand, first the annual heat demand is estimated before being broken down into an hourly consumption profile. The demand is assumed to be for both space and water heating, i.e., via a central heating system. As can be seen in Table 4.2, the annual heat demand varies with living space and building age, with the latter being indicative of the insulation status: While existing buildings are assumed to have a specific heat demand of 147.5 $\mathrm{kWh_{th}/(m^2a)}$, newly built homes are assumed to require 72.3 $\mathrm{kWh_{th}/(m^2a)}$. The annual heat demand is transformed into daily values following the concept of heating degree days[187] based on temperature profiles taken from 2015 weather data measured at the Cologne Airport location.[188] The daily values are then converted into hourly profiles using the structures of the typical days described in the

[184]Load profiles are derived using the *Loadprofilegenerator* (Version 7.2): `https://www.loadprofilegenerator.de/`.

[185]The share of residents employed indicated in Table 4.2 are assumed to work for eight hours per day, five days a week during daytime hours at a location other than the residence.

[186]It is assumed that each household type is on vacation for two weeks in July.

[187]The heating degree days are calculated according to [Alt, 2013]. In line with the assumptions in [Verein Deutscher Ingenieure, 2019], it is assumed that the heating is turned on once the daily average outside temperature goes below 15°C for existing buildings and below 12°C for newly-built buildings.

[188]The weather data published by Deutscher Wetterdienst can be found at `ftp://opendata.dwd.de/climate_environment/CDC/observations_germany/climate/10_minutes/air_temperature/historical/`, `ftp://opendata.dwd.de/climate_environment/CDC/observations_germany/climate/10_minutes/solar/historical/` and `ftp://opendata.dwd.de/climate_environment/CDC/observations_germany/climate/10_minutes/wind/historical/`

German engineering guidelines.[189]

All consumers are assumed to make an energy investment in the year 2025, installing either the first system in a new building or a replacement system in an existing building. In other words, for households with existing technologies, it can be assumed that any technology installed beforehand will no longer be able to operate in the year 2025, requiring a new investment. The time period considered in the optimization runs up to 2045, with 2040 being the last possible year for investment. Investments in solar systems are limited to the roof size, which is assumed to be equal for each household type regardless of the living space. Furthermore, it is assumed that each household type is equipped with the necessary infrastructure to allow for an investment in any of the DER systems considered. In other words, sufficient electric grid capacity[190] as well as a connection to the gas grid is implicitly assumed.

Defining the Market

A cornerstone of the scenario definition are the assumptions regarding future energy prices, as the minimization of variable costs is a key component of determining the least-cost energy provision. As described in Section 4.2.2, energy prices for private consumers consist not only of the day-ahead (i.e., spot) market bids but also include a wide range of taxes, surcharges and fees. The left-hand side of Figure 4.4 presents an overview of the retail price structures assumed for the year 2025, i.e., the first year of investment, for electricity, wood pellets and gas.[191] This is complemented by the line graph in the middle of Figure 4.4, which depicts the development of the retail prices between 2025 and 2040, i.e., the last year of investment considered in the scenarios. As shown in the bar graph, the retail prices in Germany are composed of a combination of four main cost components: grid fees, acquisition, renewable surcharge and concession and taxes. The future retail prices are determined by making assumptions on the developments of these individual energy price components, which are then summed up for each fuel type. The assumptions on the price components and their developments are made according to the regulatory state of affairs in Germany as of November 2021. Additional details on the fuel prices and individual price components can be found in Appendix C.2.

As per Figure 4.3 and explained in the scenario description, the Smart Market scenario

[189] The German engineering guidelines "Verein Deutscher Ingenieure" (VDI) provide profiles for 15 different so-called "typical regions" in Germany, with Cologne falling under Region 5. The daily profiles from the VDI are constructed based on measurements taken from the existing German building stock and therefore account for building-specific (e.g., absorption of heat from building materials) as well as inhabitant-specific (e.g., opening/closing of windows) characteristics. Ten "typical days" are given for each region, differentiated by criteria such as summer/winter/between seasons, workday/Sunday and cloudy/sunny. These typical days are matched to the heating degree days using the limit values given by [Verein Deutscher Ingenieure, 2019].

[190] An upper limit for the size of the electricity grid connection is included in the model.

[191] Only the energy carriers shown in Figure 4.4 are considered in the scenario analysis. Further energy carriers such as oil, hydrogen and steam (i.e., district heating) are omitted from the application.

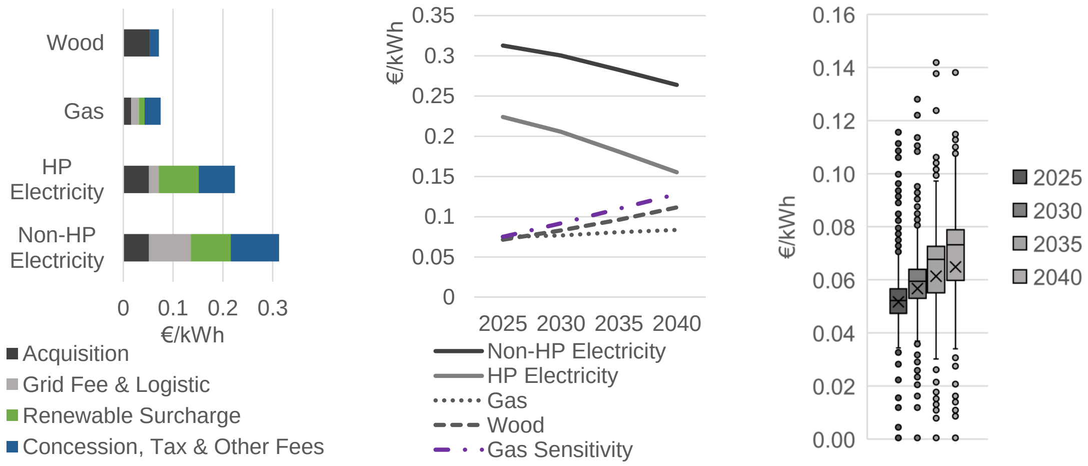

Figure 4.4.: Assumptions on fuel prices including the individual price structures in 2025 (left) and developments in the retail prices up to 2040 (middle) for all three scenarios as well as the variance of the hourly electricity acquisition prices assumed in the Smart Market scenario (right)

allows for end consumers and their technologies to receive transparent market signals in the form of variable electricity prices. The box plot on the right-hand side of Figure 4.4 summarizes the data set for the hourly acquisition prices assumed in the Smart Market scenario between 2025 and 2040.[192] The boxes specify the interquartile ranges, whose height grows significantly between 2025 and 2040. The lines in the boxes on the right-hand side of Figure 4.4 indicate the average of the acquisition price over each year. These are then used in the Status Quo and Smart Tech scenarios as the constant yearly acquisition price, consistent with the dark grey area in the graph on the left-hand side of Figure 4.4. The retail price is then calculated by taking the hourly acquisition prices and adding the other price components (i.e., grid fees, renewable surcharge and concession, taxes and other fees), which are assumed to remain constant for every hour within a single year.

Unlike the other fuels, electricity is separated into two categories in Figure 4.4, namely "Heat-Pump Electricity" and "Non-Heat-Pump Electricity". Whereas the latter indicates the price for "typical" electricity consumption for, e.g., lighting and appliances, the former refers to a lower electricity tariff that is solely available for heat pump operation as imposed by German energy regulation at the time of this analysis (see [Mailach and Oschatz, 2021]). On average, the retail electricity price decreases from 31.2 €-ct./kWh$_{el}$ in 2025 to 26.3 €-ct./kWh$_{el}$ in 2040 for non-heat-pump electricity use and from 22.4

[192] The hourly acquisition prices for future years are taken from the study [Gierkink et al., 2021], which was completed at the Institute of Energy Economics at the University of Cologne (EWI). The prices can be understood as the marginal costs of electricity generation in Germany, which are estimated using the energy system model DIMENSION. DIMENSION is a European investment and dispatch model that accounts for, e.g., national and European decarbonization targets. For more information about the DIMENSION model, see [Helgeson and Peter, 2020].

€-ct./kWh$_{el}$ in 2025 to 15.5 €-ct./kWh$_{el}$ for heat-pump electricity use.

Furthermore, as of the year 2021, the use of fossil fuels such as natural gas in Germany requires that consumers pay a price for the resulting carbon emissions. In Figure 4.4, this is indicated in the gas price by the renewable energy surcharge shown in green, equal to 1.1 €-ct./kWh$_{th}$ in 2025 and 1.8 €-ct./kWh$_{th}$ in 2040.[193] Since German policymakers have yet to define the mid- to long-term carbon pricing strategy for the residential and commercial building sector, an alternative gas price labelled "Gas Sensitivity" in Figure 4.4 is used in the sensitivity analysis in Section 4.3.4, which assumes a higher carbon price in 2030 (2.5 €-ct./kWh$_{th}$), 2035 (4.0 €-ct./kWh$_{th}$) and 2040 (5.5 €-ct./kWh$_{th}$).[194] In sum, the energy price components for gas add up to an overall price of 7.5 €-ct./kWh$_{th}$ in the main and sensitivity analyses in 2025 and rise to 8.4 €-ct./kWh$_{th}$ in the main analysis in 2040 and to 12.8 €-ct./kWh$_{th}$ in 2040 in the sensitivity analysis.

Techno-Economic and Regulatory Assumptions for DER Systems

As explained in Section 4.1.3, key contributions of this work include the high level of technical as well as regulatory detail for a wide range of technologies together with the piecewise linearization of investment costs, FOM costs and subsidies for multiple future years. Appendix C.3 provides an overview of the techno-economic and regulatory assumptions for each technology considered in the application. More specifically, technical descriptions including assumptions on, e.g., efficiencies and lifetimes are presented in individual subsections for condensing boilers, micro-CHP, electric heaters, electric heat pumps, pellet stoves, solar thermal systems, thermal storage, PV and battery storage. Moreover, graphical overviews of the piecewise-linear investment and FOM costs are shown for each technology, derived from an extensive data set collected from a wide range of industry and academic sources based on values for the year 2020. In order to determine the future investment costs for each investment year between 2025 and 2040, technology-specific learning rates are derived and used to scale the 2020 values (see Table C.4 in Appendix C.4). All investment costs are assumed to decrease over time, with some newer technologies reaching reductions of 50% by 2040.

The subsections in Appendix C.3 also provide details on the regulatory assumptions on investment subsidies as well as variable remunerations and fees specific to the respective technologies. Incentive programs that exist in Germany as of November 2021 are accounted for in this analysis. The households considered are therefore eligible to receive

[193] These values are calculated based on a carbon price of 55 €/t$_{CO_2}$ in 2025, as set by the German federal government (see `https://www.bundesregierung.de/breg-en/issues/nationaler-emissionshandel-1685054`). For the remaining years up to 2040, the carbon price is determined endogenously by the energy system model DIMENSION (see Footnote 192) based on the scenario examined in [Gierkink et al., 2021], equal to 61 €/t$_{CO_2}$ in 2030, 78 €/t$_{CO_2}$ in 2035 and 89 €/t$_{CO_2}$ in 2040. These are then converted to €/kWh based on the carbon emissions factor of natural gas.

[194] The carbon prices used in the sensitivity analysis are taken from [Repenning et al., 2021] and are calculated in the same manner as described in Footnote 193.

investment subsidies for heat pumps, solar thermal systems and pellet stoves.[195] With the revision of the subsidy program in 2021, compensation that was historically set as a fixed amount per technology was replaced with a percentage of the capital (i.e., investment plus installation[196]) costs that were to be refunded. As such, the piecewise-linear investment costs determine the magnitude of the subsidy, which then decrease according to the same learning rates. Furthermore, electricity feed-in from a PV system is assumed to be remunerated according to the hourly acquisition price, as summarized on the right-hand side of Figure 4.4, plus a market premium (see Appendix C.3.8). CHP systems, on the other hand, receive a fixed feed-in tariff for electricity supplied to the grid and are also subject to remuneration for any electricity generation that is self-consumed (see Appendix C.3.2).

4.3.2. Results of the Household Optimization

The results of the investment decisions as well as the subsequent total annual costs (TAC), CO_2 emissions levels, volumes of electricity and gas consumption, the self-consumption shares of PV systems and the yearly averages of the marginal costs for electricity and heat provision for each household type within each model year and scenario are shown in Table 4.3. The TAC are equal to the sum of the annualized investment costs (AIC), variable costs and FOM costs corrected by the remuneration for a single year, as shown in Table C.5 in Appendix C.5.[197] The total costs, i.e., the objective values of the optimization variable **TC** given in Equation (4.1a) in Section 4.2.2, are presented in Table C.6 in Appendix C.5 for each household type and scenario.[198]

The installed capacities in all three scenarios shown in Table 4.3 present a clear trend for gas-driven solutions. Households combine gas boilers for base generation together with electric heaters to cover any demand peaks. All households install a cumulative capacity equal to their heat peak as given in Table 4.2 in Section 4.3.1. As the information available in each of the scenarios becomes more complex, the size of the gas boilers decreases by 0.1 kW while the electric capacity rises by 0.1 kW. In the Smart Market scenario, in particular, the opportunity of low electricity prices in certain hours creates an incentive for some households to slightly increase their electricity-consuming capacities. However, as can be seen by cross-referencing Table 4.3 with Table C.5 in Appendix C.5, variable costs remain more or less unchanged between the Smart Tech and Smart Market scenarios despite the small shift from gas to electricity grid consumption found in the latter. As such, it may be concluded that the simultaneity of hours with higher heat demand and high retail electricity prices prevents the electric heater from taking full advantage of low retail electricity prices. Surprisingly, the variable electricity prices

[195] As outlined in [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a].
[196] See [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b]
[197] The values for TAC given in the tables are not discounted but rather the present value. As such, summing the TAC over the complete time horizon will not equal the total costs shown in Table C.6 in Appendix C.5.
[198] The total costs are calculated assuming an interest rate (i.e., i in Equation (4.1a)) equal to 3%.

HH		Status Quo 2025	2030	2035	2040	Smart Tech 2025	2030	2035	2040	Smart Market 2025	2030	2035	2040
1	GB [kW]	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.4	8.4	8.4	8.4
	PV [kW]	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	EH [kW]	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	7.0	7.0	7.0	7.0
	BS [kW]	-	-	-	-	-	3.6	3.6	3.6	-	3.6	3.6	3.6
	TAC [€/a]	4054	4035	4040	2251	4054	4052	4091	2024	4054	4045	4082	2013
	CO_2 [t/a]	4.0	3.9	3.7	3.6	4.0	3.7	3.6	3.6	4.0	3.7	3.6	3.6
	EG [$\frac{kWh}{a}$]	3091	3091	3091	3091	3088	1282	1282	1282	3104	1299	1311	1316
	GG [$\frac{kWh}{a}$]	16020	16510	16447	16443	16023	17275	17241	17207	16005	17256	17222	17188
	PVSC [%]	52.7	47.7	48.4	48.4	52.7	62.8	63.2	63.5	52.7	62.9	63.3	63.6
2	GB [kW]	7.1	7.1	7.1	7.1	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
	PV [kW]	-	-	-	-	-	-	-	10.0	-	-	-	10.0
	EH [kW]	5.0	5.0	5.0	5.0	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
	TAC [€/a]	2906	2885	2877	2413	2904	2882	2873	2386	2902	2880	2872	2397
	CO_2 [t/a]	3.7	3.5	3.3	3.2	3.7	3.5	3.3	2.7	3.7	3.5	3.3	2.7
	EG [$\frac{kWh}{a}$]	3605	3605	3605	3605	3658	3658	3658	2168	3668	3668	3668	2172
	GG [$\frac{kWh}{a}$]	14362	14362	14362	14362	14309	14309	14309	12378	14299	14299	14299	12372
	PVSC [%]	-	-	-	-	-	-	-	35.7	-	-	-	35.7
3	GB [kW]	4.7	4.7	4.7	4.7	4.6	4.6	4.6	4.6	4.5	4.5	4.5	4.5
	PV [kW]	5.3	5.3	5.3	5.3	-	-	-	10.0	-	-	-	10.0
	EH [kW]	10.8	10.8	10.8	10.8	10.9	10.9	10.9	10.9	11.0	11.0	11.0	11.0
	TAC [€/a]	2655	2636	2626	1466	2492	2456	2416	1967	2484	2446	2403	1975
	CO_2 [t/a]	2.2	2.1	2.0	1.9	2.7	2.4	2.2	1.8	2.7	2.4	2.2	1.8
	EG [$\frac{kWh}{a}$]	2309	2309	2309	2309	4067	4067	4067	2136	4082	4082	4082	2151
	GG [$\frac{kWh}{a}$]	8007	8238	8212	8181	8682	8682	8682	7863	8667	8667	8667	7848
	PVSC [%]	48.1	43.4	44.0	44.7	-	-	-	29.1	-	-	-	29.1
4	GB [kW]	3.7	3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	EH [kW]	8.5	8.5	8.5	8.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
	TAC [€/a]	1886	1864	1841	1549	1886	1863	1840	1552	1882	1860	1837	1548
	CO_2 [t/a]	2.0	1.8	1.7	1.6	2.0	1.8	1.7	1.6	2.0	1.8	1.7	1.6
	EG [$\frac{kWh}{a}$]	2737	2737	2737	2737	2755	2755	2755	2755	2771	2771	2771	2771
	GG [$\frac{kWh}{a}$]	6833	6833	6833	6833	6815	6815	6815	6815	6797	6797	6797	6797

GB: Gas Condensing Boiler Capacity, PV: Photovoltaic Capacity, EH: Electric Heater Capacity, BS: Battery Storage Capacity, TAC: Total Annual Costs, CO_2: Annual Carbon Dioxide Emissions from Gas and Electricity Consumption, EG: Annual Electricity Grid Consumption, GG: Annual Gas Grid Consumption, PVSC: PV Self-Consumption Share

Table 4.3.: Results of the main analysis in Chapter 4

in the Smart Market scenario do not create an incentive for the endogenous investment in a thermal storage, which would be a logical decision if households could financially benefit via arbitrage. The lack of thermal storage prevents the decoupling of generation and consumption such that heat must be used directly at the time of production, regardless of the electricity price.

Nevertheless, the model results reveal that installed capacities vary stronger across household types than across scenarios. While the heat demand peaks of HH1 and HH2 resemble those of HH3 and HH4, respectively, the annual heat demands differ for each household type (see Table 4.2 in Section 4.3.1). Existing buildings, i.e., HH1 and HH2, are assumed to have higher annual heat demands and are found to install larger gas boilers compared to the newly-built buildings, i.e., HH3 and HH4, who demand less heat over the year. The latter two household types choose to combine smaller gas boilers with larger electric heaters, using electricity to cover their absolute peak heat demand. As such, it may be lucrative for consumers to invest in larger gas capacities, despite higher specific investment costs compared to electric heaters, as long as a certain number of full-load hours can be reached.[199]

Furthermore, high energy demand is found to be a key driver for decentralized PV electricity generation and consumption. Household types HH1 and HH3 have comparatively high electricity and heat demands as these household types are assumed to have four, as opposed to two, residents (see Table 4.2 in Section 4.3.1). In fact, as can be seen in Table 4.3, the substantial energy demand of HH1 triggers an investment in a 10 kW PV system (i.e., the largest capacity possible given the assumed roof size) across all scenarios immediately in the first year 2025. In doing so, HH1 is able to consume more than 50% of the generated electricity directly via, e.g., the electric heater as well as for other appliances. In 2030 of the Smart Tech and Smart Market scenarios, HH1 decides to complement its PV system with a battery storage to further increase the self-consumption share to 63%. Following a similar logic, the relatively high energy demand of HH3 drives an investment in a 5.3 kW PV system in 2025 in the Status Quo scenario; however, in the other two scenarios, the transparency of future reductions in investment costs and electricity prices results in the installation of a 10 kW PV system being delayed until 2040.[200] The larger capacities in the Smart Tech and Smart Market scenarios, in turn, yield a lower self-consumption share of roughly 30% compared to 50% in the Status Quo scenario. For the other two-person households, the lower energy demand appears to hinder the investment in a PV system: HH2 only installs a PV system in 2040 in the Smart Tech and Smart Market scenarios for reasons analogous to those discussed above for HH3. For HH4, the energy needs of the household are too low to reach the self-consumption shares large enough to justify the capital costs.

As is to be expected, the installation of a PV system reduces the annual electricity consumption from the grid, as shown in Table 4.3. Moreover, the amount of gas that is consumed from the grid is also reduced, e.g., in HH2 and HH3, as a greater amount of heat is provided by the electric heater using PV electricity. In turn, these households are able to lower their CO_2 emissions more effectively than households without PV systems who only benefit from the predefined reduction in the carbon intensity of the German power mix.

For each household type, a drop in the TAC can be observed in Table 4.3 in 2040 as investments made in 2025 have reached the end of their financing period, thus strongly

[199] Full-load hours of the gas boilers lie between 1675 (HH3, Status Quo) and 2092 (HH2, Smart Market) per year.

[200] In the Status Quo scenario, the consumer believes that the relatively high electricity prices in 2025 will remain constant for the complete time horizon, making self-consumption from a PV system more attractive. On the other hand, in the scenarios with foreseeable price reductions, HH3 abstains from an investment in a PV system in 2025; however, by 2040, the capital costs of the PV system have decreased such that an investment is economical despite the lower retail electricity price.

decreasing the AIC (see Table 4.2 in Section 4.3.1 and Table C.5 in Appendix C.5).[201] As is to be expected, the similarities in the investment decisions lead to very little discrepancies in the TAC across scenarios.[202] In fact, just looking at the annual costs, it may appear that the Status Quo scenario is more economical than the other, more efficient scenarios. However, when considering the discounted total costs over the complete time horizon shown in Table C.6 in Appendix C.5, the increase in the amount of information available tends to have a positive effect on cost savings, especially for households with larger energy demands (i.e., HH1 and HH3).[203] It is also worth noting that neither gas boilers nor electric heaters benefit from governmental funding. In other words, under the assumptions outlined in Section 4.3.1, the incentive mechanisms offered for other heating technologies such as heat pumps and micro-CHP are not effective in instigating investment for the household types considered.

4.3.3. Investigating the Marginal Costs of Energy Provision

As explained in Sections 4.1.2 and 4.1.3, one key contribution of this work is the evaluation of the implicit shadow prices for each EUT, referred to in this paper as the marginal costs of energy (i.e., heat or electricity) provision. Generally speaking, an interpretation of the shadow prices in MILP models is not possible due to their non-linear nature. However, in this analysis, the technique outlined by [Williams, 1989] and [Williams, 2013] is used such that a second model run is performed for each household type and scenario in which all binary variables are set equal to the values found in the first unrestricted optimization. In doing so, the non-linear model is then linearized, allowing for the marginal values of the equilibrium constraint (i.e., the first-order condition of Equation (4.1b)) to be interpreted as the marginal costs of heat or electricity provision. Simply put, the marginal costs of energy provision reveal the price that the consumer pays for the energy used, which is estimated by the model as the change in the total costs (i.e., the objective value) if the consumer were to demand an additional kWh of energy. As such, the marginal costs depend strongly on the options available to the consumer to supply or generate energy at each point in time.

The results of the marginal costs of electricity provision as well as as the marginal costs of heat provision averaged over all hours of each model year are shown in Table 4.4 for each household type and scenario. To aid in the understanding of the marginal costs,

[201] As electric heaters have a technical lifetime of fifteen years, systems that are built in 2025 must be replaced in 2040. As such, households who only invest in 2025 (e.g., HH4) will have paid off all of their annualized investment costs by 2040, yet will begin a new financing period for the replacement electric heater in 2040. This is equal to roughly 24-27 €/a, depending on the thermal capacity (see Table C.5 in Appendix C.5).

[202] The one noteworthy exception is the difference between the Status Quo scenario and the Smart Tech and Smart Market scenarios for HH3 due to the difference in the investment decisions, as explained below.

[203] It should be noted that any additional costs associated with a technology's ability to handle increased amounts of information (e.g., software, digital infrastructure, hardware accessories) are not considered in this analysis.

HH		Status Quo 2025	2030	2035	2040	Smart Tech 2025	2030	2035	2040	Smart Market 2025	2030	2035	2040
1	HM [$\frac{€\text{-ct}}{kWh}$]	5.4	5.5	5.7	5.8	5.4	5.6	5.8	5.9	5.4	5.6	5.8	5.9
	EM [$\frac{€\text{-ct}}{kWh}$]	22.9	22.3	21.1	20.1	22.9	17.9	17.3	16.7	22.9	17.6	17.1	16.4
2	HM [$\frac{€\text{-ct}}{kWh}$]	5.5	5.5	5.8	5.9	5.6	5.6	5.9	5.6	5.6	5.6	5.8	5.6
	EM [$\frac{€\text{-ct}}{kWh}$]	31.3	30.1	28.2	26.4	31.3	30.1	28.2	19.3	31.2	29.9	28.1	19.4
3	HM [$\frac{€\text{-ct}}{kWh}$]	4.6	4.7	4.8	4.9	4.7	4.8	5.0	4.9	4.8	4.8	5.0	4.9
	EM [$\frac{€\text{-ct}}{kWh}$]	23.1	22.4	21.2	20.1	31.3	30.1	28.2	19.2	31.2	29.9	28.1	19.4
4	HM [$\frac{€\text{-ct}}{kWh}$]	4.7	4.7	4.9	5.0	4.7	4.8	5.0	5.1	4.7	4.8	5.0	5.1
	EM [$\frac{€\text{-ct}}{kWh}$]	31.3	30.1	28.2	26.4	31.3	30.1	28.2	26.4	31.2	29.9	28.1	26.2

HM: Average Marginal Cost for Heat Provision, EM: Average Marginal Cost for Electricity Provision

Table 4.4.: Marginal costs of energy provision for each household type, year and scenario in the main analysis

Figure 4.5 shows the electricity provision and demand, the heat provision and demand as well as the marginal costs of energy provision for HH1 (left) and HH3 (right) for the second and first weeks in February[204] 2040, respectively, in the Smart Tech scenario. Looking first at the marginal cost of electricity provision depicted by the yellow line in the bottom graph in Figure 4.5, the profile frequently flattens at a level equal to the retail electricity price (i.e., 26.4 €-ct./kWh$_{el}$ in 2040) for both household types. In these hours, an additional kWh of demand would be covered by electricity from the grid, hence the marginal cost equaling the retail price. For households without PV installations, this holds true in every hour, as depicted by similarities in the average marginal costs of electricity provision in Table 4.4 for HH2 (i.e., Status Quo scenario as well as 2025-2035 of the Smart Tech and Smart Market scenarios), HH3 (i.e., 2025-2035 of the Smart Tech and Smart Market scenarios) and HH4.[205]

However, in hours in which PV generation is consumed, the marginal costs of electricity provision sink. In fact, in hours in which solar irradiation coincides with low energy demand, the marginal costs of electricity provision approach zero as excess PV electricity is fed into the grid. In this case, PV electricity would hypothetically be available if demand were to increase, hence the marginal costs undercutting the retail electricity price.[206] This can be seen for example, on the right-hand side of Figure 4.5 via the dips in the yellow line in the bottom graph (i.e., the marginal costs of electricity provision) that coincide with the peaks of the yellow line in the top graph (i.e., PV electricity generation), with the yellow line in the bottom graph meeting the x-axis in the 757th hour when the black lines in the top and middle graphs (i.e., electricity and heat demand,

[204]These weeks were chosen because these include the hour in which the household's heat demand is at its absolute peak.

[205]The values in the Smart Market scenario listed here may deviate slightly (i.e., < 1%) from the constant retail electricity prices seen in the Smart Tech scenario results due to minor shifts in the operation of the electric heater in response to hours with lower electricity prices.

[206]The self-consumption of decentralized PV electricity presents consumers with an indirect financial incentive by facilitating the evasion of taxes, levies and surcharges that are charged when consuming electricity from the grid, as explained in [Jägemann et al., 2013b].

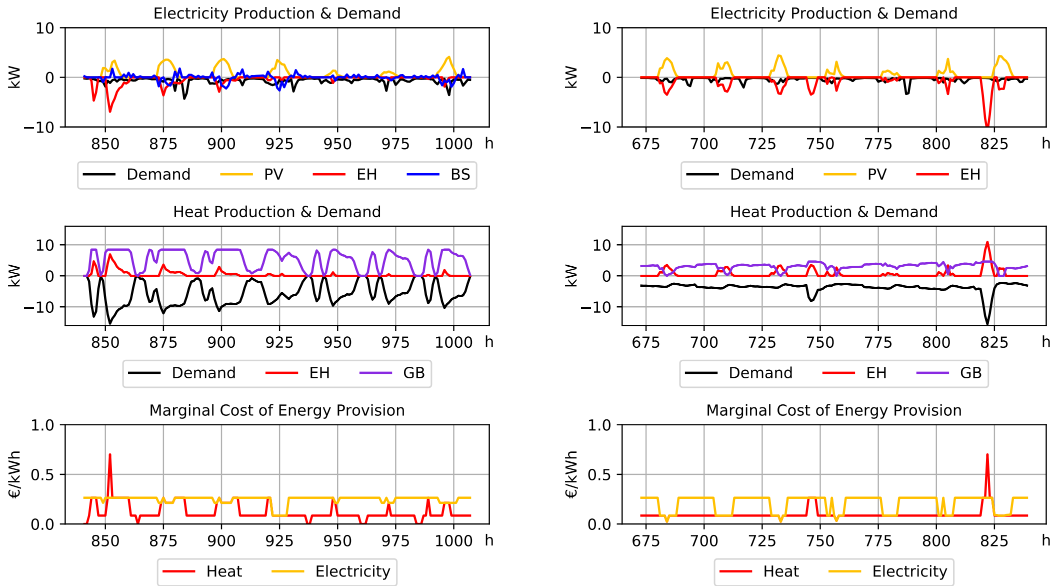

Figure 4.5.: Hourly supply, demand and marginal costs of electricity and heat provision in the second week of February 2040 for HH1 (left) and first week of February 2040 for HH3 (right) in the Smart Tech scenario in the main analysis

respectively) are at their weekly lows. As a result of the PV self-consumption, the average marginal costs of electricity provision for HH2 and HH3 in 2040 in the Smart Tech and Smart Market scenarios as well as HH3 in the Status Quo scenario drop significantly (i.e., > 24%) compared to the retail electricity price (see Table 4.4). For HH1, high energy demand drives an investment in battery storage in the Smart Tech and Smart Market scenarios to shift the consumption of PV generation to cover demand in, e.g., peak evening hours, which can be seen in the structure of the blue line in the top graph on the left-hand side of Figure 4.5. The battery storage coupled with a PV system, in turn, leads to HH1 being able to decrease its electricity supplied from the grid. In fact, as can be seen in Figure C.11 in Appendix C.5, HH1 is able to reduce it's electricity consumption from the grid to zero in many more hours in the Smart Tech and Smart Market scenarios compared to the Status Quo scenario.[207] These effects, in turn, drive down the average marginal costs of electricity provision even further, reaching a lowest average value of 16.4 €-ct./kWh$_{\mathrm{el}}$ in 2040 in the Smart Market scenario (see Table 4.4).

The marginal costs of heat provision follow a similar trend as electricity, with the majority of hours following the gas price corrected by the boiler efficiency (e.g., reaching 8.5 €-ct./kWh$_{\mathrm{th}}$ in 2040). However, unlike with electricity, heat demand may drop to zero in certain hours, causing the marginal costs of heat provision to also fall to zero — an effect that can clearly be seen for HH1 when examining the middle and lower

[207]This effect can be profitable for more than just the household. Smart technologies can strongly influence the consumers grid consumption pattern, therefore potentially reducing the expansions to the distribution grid.

graphs on the left-hand side of Figure 4.5.[208] On the other hand, contrary to what is seen with the marginal costs of electricity provision, the marginal costs of heat provision spike upwards in moments of higher heat demand. For the majority of these peaks, the household would be able to ramp up the production from the electric heater, which results in a marginal cost of heat provision equal to the marginal cost of electricity provision (see, e.g., the meeting of the red and yellow lines in the lower graphs of Figure 4.5 coinciding with times of electric heater production, indicated by spikes in the red line in the middle graphs of Figure 4.5). However, as heat can not be bought from a central supplier, it must be able to be generated by the household, which in turn requires sufficient generating capacity. Yet the investment decision in the peak technology of the households is based on the absolute peak heat demand, which in the case of HH1 occurs in the 852$^{\text{nd}}$ hour and for HH3 in the 822$^{\text{nd}}$ hour. Therefore, the marginal costs of heat provision in these peak hours not only reflect the increased variable costs but also the additional investment costs needed to provide the extra kW of heat.[209]

The average marginal costs of heat provision shown in Table 4.4 reflect the combination of the effects discussed above. All values are significantly under the gas price, indicating the frequency of hours with zero heat demand, i.e. 2996h/a for existing buildings and 3956h/a for newly-built buildings. The high share of hours in which zero demand occurs in the latter drastically reduces the average marginal costs of heat provision. Furthermore, the newly-built HH3 and HH4 cover a larger share of their heat demand with gas, which also helps to lower the average marginal costs compared to existing buildings HH1 and HH2, who use their electric heater more frequently.

4.3.4. Sensitivity Analysis

Motivation and Design of the Sensitivity Analysis

A common challenge associated with the modeling of future energy systems is the inability to predict the unpredictable. In fact, a large body of literature is dedicated to assessing uncertainty and its effect on MILP optimization results (e.g., [Mavromatidis et al., 2018]). Estimating future energy prices based on today's information is particularly precarious, as unforeseen shifts in, e.g., regulation, geopolitics or market dynamics may significantly effect price developments. Nevertheless, studies such as the IEA's World Energy Outlook ([International Energy Agency, 2020]) have emerged as

[208] It should be noted that the two household types shown in Figure 4.5 have very different hourly demand structures due to the difference in building age. HH3 is a newly-built building that is equipped with, e.g., floor heating, which is rarely turned on or off and thus creates a small amount of base demand. HH1, on the other hand, is an existing building with radiatiors and a central heating system, which can be adjusted as need be. This creates a more volatile demand structure that may reach a higher level but also drop to zero during, e.g., nighttime hours. A strong peak is given in both profiles, which are constructed based on [Verein Deutscher Ingenieure, 2019] (see Section 4.3.1).

[209] Supplementary model runs with increased peak demand indicate that the marginal costs of energy provision in the peak hours shown in Figure 4.5 reflect the investment in one additional kW of electric heater capacity.

standard sources for commodity price predictions. Yet for the end consumer, it remains unclear how the different price components will evolve over time.

This is especially true when considering the fee for CO_2 emissions that was just recently introduced by the German government. Currently, CO_2 emissions in Europe are priced according to a European certificate trading system known as the EU-ETS. At the time of this paper, emissions arising from end energy use in residential and commercial buildings are not included in the EU-ETS. Therefore, German policymakers have introduced an independent pricing system for the buildings sector, setting a price of 55 €/t_{CO_2} in 2025; however it is unclear how this price will develop in the longer term.

In the main analysis, the CO_2 price post-2025 is set equal to the EU-ETS price, which is determined endogenously by the energy system model DIMENSION. However, studies such as [Repenning et al., 2021] have suggested that the carbon price in the building sector will far exceed the certificate price, reaching levels equal to 125 €/t_{CO_2} (i.e., 2.5 €-ct./kWh_{th}) in 2030, 200 €/t_{CO_2} (i.e., 4 €-ct./kWh_{th}) in 2035 and 275 €/t_{CO_2} (i.e., 5.5 €-ct./kWh_{th}) by 2040. In order to examine the consequences of alternative carbon price pathways, a sensitivity analysis is performed for the Smart Tech and Smart Market scenarios in which the values from [Repenning et al., 2021] are assumed for the CO_2 prices in the German buildings sector.[210] In doing so, the long-term retail gas price is increased significantly compared to the main analysis, reaching 9.2 €-ct./kWh_{th} in 2030 and 12.8 €-ct./kWh_{th} in 2040 (see Figure 4.4 in Section 4.3.1).[211]

Key Findings of the Sensitivity Analysis

Analogous to the results of the main analysis, the results of the sensitivity analysis are presented in Table 4.5, with a detailed overview of the annual cost results shown in Table C.7 and the total costs shown in Table C.6 in Appendix C.5. As expected, the increase in the long-term retail gas price leads to significant changes in the investment decisions in all four household types in the Smart Tech and Smart Market scenarios. Below, the key findings of the sensitivity analysis are outlined and compared to the results of the main analysis.

[210] The Status Quo scenario is not included in the sensitivity analysis as, by definition, the investment decision is unaffected by future price developments, i.e., the consumer sees only the retail gas price in 2025. Although the AIC remain unchanged between the two scenarios, the variable costs increase in the sensitivity analysis due to the higher carbon prices. Therefore, for completeness, the total costs of the Status Quo scenario in the sensitivity analysis are included in Table C.6 in Appendix C.5.

[211] Although the sensitivity analysis is centered around a scenario with higher CO_2 prices, it should be noted that a more expensive retail gas price may in reality be due to increases in any of the price components including, e.g., the costs of gas acquisition. In other words, the results presented in Section 4.3.4 may be more generally interpreted as a consequence of rising retail gas prices in the German building sector.

		Smart Tech				Smart Market			
HH		2025	2030	2035	2040	2025	2030	2035	2040
1	HP $[kW]$	6.0	6.0	6.0	6.0	5.9	5.9	5.9	5.9
	TS $[kW]$	49.1	49.1	49.1	49.1	51.6	51.6	51.6	51.6
	PV $[kW]$	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
	EH $[kW]$	4.6	4.6	4.6	4.6	4.5	4.5	4.5	4.5
	TAC [€/a]	4479	4358	4189	1847	4467	4350	4178	1817
	CO_2 [t/a]	1.8	1.3	1.0	0.8	1.8	1.3	1.0	0.8
	EG $[\frac{kWh}{a}]$	7558	7578	7599	7607	7571	7602	7625	7642
	PVSC [%]	53.4	52.9	52.6	52.5	53.7	53.1	52.9	52.6
	HM $[\frac{\text{€-ct}}{kWh}]$	5.2	4.9	4.4	4.0	5.2	4.9	4.4	3.8
	EM $[\frac{\text{€-ct}}{kWh}]$	24.3	23.3	21.9	20.6	24.2	23.3	22.0	20.6
2	GB $[kW]$	6.7	6.7	6.7	-	6.6	6.6	6.6	-
	HP $[kW]$	-	-	-	4.4	-	-	-	4.4
	TS $[kW]$	-	-	-	34.2	-	-	-	34.1
	PV $[kW]$	-	-	-	10.0	-	-	-	10.0
	EH $[kW]$	5.4	5.4	5.4	4.1	5.4	5.4	5.4	4.2
	TAC [€/a]	2906	3101	3289	2762	2903	3098	3286	2748
	CO_2 [t/a]	3.7	3.5	3.3	0.6	3.7	3.5	3.3	0.6
	EG $[\frac{kWh}{a}]$	3685	3685	3685	5377	3701	3701	3701	5416
	GG $[\frac{kWh}{a}]$	14281	14281	14281	-	14266	14266	14266	-
	PVSC [%]	-	-	-	39.2	-	-	-	39.3
	HM $[\frac{\text{€-ct}}{kWh}]$	5.7	6.7	7.8	4.1	5.7	6.7	7.7	4.0
	EM $[\frac{\text{€-ct}}{kWh}]$	31.3	30.1	28.2	19.9	31.2	29.9	28.1	20.0
3	HP $[kW]$	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.1
	TS $[kW]$	31.9	31.9	31.9	31.9	28.0	28.0	28.0	28.0
	PV $[kW]$	6.8	6.8	6.8	6.8	-	-	-	10.0
	EH $[kW]$	7.8	7.8	7.8	7.8	8.1	8.1	8.1	8.1
	TAC [€/a]	2868	2808	2726	972	2749	2652	2511	1574
	CO_2 [t/a]	1.0	0.7	0.5	0.4	1.4	1.0	0.7	0.4
	EG $[\frac{kWh}{a}]$	3891	3888	3888	3884	6390	6393	6398	3694
	PVSC [%]	39.1	39.3	39.4	39.6	-	-	-	29.0
	HM $[\frac{\text{€-ct}}{kWh}]$	4.0	3.8	3.4	3.1	4.5	4.2	3.8	2.9
	EM $[\frac{\text{€-ct}}{kWh}]$	23.2	22.5	21.2	20.0	31.2	29.9	28.1	19.5
4	HP $[kW]$	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
	EH $[kW]$	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
	TAC [€/a]	2098	2030	1931	1305	2085	2018	1918	1286
	CO_2 [t/a]	1.1	0.8	0.6	0.5	1.1	0.8	0.6	0.5
	EG $[\frac{kWh}{a}]$	4715	4715	4715	4715	4726	4726	4726	4726
	HM $[\frac{\text{€-ct}}{kWh}]$	4.5	4.3	3.8	3.4	4.5	4.2	3.8	3.4
	EM $[\frac{\text{€-ct}}{kWh}]$	31.3	30.1	28.2	26.4	31.2	29.9	28.1	26.2

GB: Gas Condensing Boiler Capacity, HP: Heat Pump Capacity, TS: Thermal Storage Capacity, PV: Photovoltaic Capacity, EH: Electric Heater Capacity, TAC: Total Annual Costs, CO_2: Annual Carbon Dioxide Emissions from Gas and Electricity Consumption, EG: Annual Electricity Grid Consumption, GG: Annual Gas Grid Consumption, PVSC: PV Self-Consumption Share, HM: Average Marginal Cost for Heat, EM: Average Marginal Cost for Electricity

Table 4.5.: Results of the sensitivity analysis

Sensitivity Finding #1: Electric heat pumps replace gas boilers as the base heating technologies, which drastically reduces the emissions of the households considered

The increase in the retail gas price leads to higher variable costs for gas boilers, making the investment unattractive for three out of four household types. Instead, electric heat pumps emerge as the base technology, once again combined with an electric heater to cover hours of peak heat demand. Just as in the main analysis, the model chooses to cover a large share of the heat demand with the more capital-intensive technology, while the more inexpensive technology is built to be turned on in select hours when consumption spikes.[212] Whereas, HH1, HH3 and HH4 cover their heat demand completely with electricity, HH2 installs a gas boiler to be used in the first fifteen years before switching over to an electric heat pump in 2040. The delay in investment can be attributed to the assumptions regarding the building characteristics: HH2, just like HH1, is assumed to be an existing building, which means that a radiator heating system is assumed. In this case, heat pumps require higher flow temperatures to reach the same target room temperature, which in turn decreases the COP (see Section 4.2.4).[213] Since HH2 only has two residents, the lower annual heat demand compared to HH1 causes the investment in a heat pump to be uneconomical as the full-load hours can not be reached that would justify the lower efficiency gains. By 2040, significant reductions in the investment costs of heat pumps combined with the increased retail gas price drive HH2 to modify their heating system.

The change in the main source of energy from gas in the main analysis to electricity in the sensitivity analysis leads to a drastic change in carbon emissions, as can be seen by comparing Table 4.3 with Table 4.5. High efficiencies of electric heat pumps combined with the avoided fossil fuel consumption lead to a reduction of emissions by at least 45% in 2025 for the case in which the household does not install a PV system (i.e., HH4, Smart Market). This emission reduction is then increased as soon as households begin covering shares of their electricity consumption using a PV system, and even more so when introducing a thermal storage. By maximizing the self-consumption share of PV electricity in both heat generation as well as direct electricity use, consumers are able to reduce their consumption of carbon-intensive electricity from the grid. In doing so, emissions can be reduced in 2025 by up to 64% (HH3, Smart Tech) compared to the main analysis, reaching up to 80% in 2040 depending on the household type. As such, it can be concluded that the increase in the carbon price in the German building sector assumed in the sensitivity analysis would be effective in incentivizing investments in renewable generators and lowering the emissions of the household types considered.[214]

[212] Similar to the main analysis, information gains tend to decrease the capacity of the base technology while the capacity of the peak technology slightly increases.

[213] New buildings, on the other hand, are often heated with floor heating systems, which can process lower flow temperatures.

[214] It should be noted that this analysis only accounts for the carbon emissions resulting from the final energy consumption of the households. There is no crediting for emissions reduction that may arise in the German power sector due to the household's feed-in of renewable electricity.

Aggregated over the entire time horizon, up to an additional 50 tonnes of CO_2 can be avoided in the sensitivity analysis compared to the main analysis, as shown in Table C.8 in Appendix C.5. The decrease in carbon emissions increases the households' total costs, which vary according to the timing and the type of new investments. Additional abatement costs arising from the deeper decarbonization in the sensitivity analysis compared to the main analysis are found to be highest for HH2 at 293 €/tCO_2 in the Smart Tech Scenario, as shown in Table C.8 in Appendix C.5. All other households exhibit lower carbon abatement costs, ranging between 36 €/tCO_2 (HH3, Smart Tech Scenario) and 56 €/tCO_2 (HH1, Smart Tech Scenario). These households experience earlier investments in lower-carbon technologies, which result in a greater amount of emissions savings over time combined with lower gas consumption and, in turn, CO_2 levies.

Sensitivity Finding #2: Increase in electricity demand via heat pumps makes investments in PV systems even more attractive

As explained in Section 4.3.2, PV systems are only lucrative if a certain self-consumption share can be reached. In the sensitivity analysis, HH2 and HH3 achieve even higher self-consumption shares by using PV electricity to run their heat pumps. Furthermore, contrary to the Smart Tech results of the main analysis, the increased electricity demand drives HH3 to invest in a PV system in 2025 rather than waiting until 2040. This is not seen in the Smart Market scenario, as dips in the electricity price during daytime hours tend to negate the benefits of distributed PV generation. Lastly, even with complete electrification, the low electricity and heat demands assumed for HH4 do not exceed the threshold to make an investment in a PV system economical.

Sensitivity Finding #3: Investments in thermal storage emerge to help manage heat demand peaks as well as increase self-consumption of PV generation and maximize heat pump efficiency

As can be seen in Table 4.5, both four-person households, i.e., HH1 and HH3, choose to install thermal storage in the first year of investment (i.e., 2025) in the sensitivity analysis with higher retail gas prices. In fact, the results show a clear preference to couple thermal storage with investments in heat pumps and PV systems. In doing so, the heat pump is able to maximize the use of PV electricity generation by supplying heat into the thermal storage during sunny periods and discharging the storage, e.g., during heat demand peaks in evening hours. In other words, thermal storage is able to alleviate the mismatch in hours with strong solar irradiance and high heat consumption. HH2, for example, switches from a gas boiler/electric heater system to a heat pump/thermal storage/PV/electric heater system in 2040. As a result, HH2 reaches a self-consumption share of 39.2% in the sensitivity analysis compared to 35.7% in the main analysis despite significantly larger electricity demand. Furthermore, thermal storage create an opportunity for heat pumps to adjust their operation to make the most of their COP profile, i.e., by ramping-up production in hours with high efficiencies and ramping-down in hours with low efficiencies, independent of demand. This is particularly clear when looking at the hourly production and consumption profiles, as discussed below. Finally, thermal storage systems allow the household to install heat pumps and electric heaters with lower capacities, with the cumulative capacity sized to cover roughly 70% of the heat demand peak. Households without a thermal storage system install heating capacity up to their heat peak, similar to the main analysis.

Sensitivity Finding #4: Stricter emission pricing increases total costs of households' energy provision

The increased carbon price for the German building sector in the sensitivity analysis drives the households to spend more on their energy provision than in the main analysis. This comparison holds true for all household types and for each scenario. As explained above, the higher retail gas price leads to three out of four households avoiding gas investments completely, choosing a more capital-intensive investment in 2025 compared to the main analysis, as can be seen by comparing the AIC in Table C.7 with Table C.5 in Appendix C.5.[215] For example, HH4 faces in both the Smart Tech and Smart Market scenarios of the sensitivity analysis AIC that are twice as high compared to the main analysis. An even more extreme example is HH3, whose early investment in PV in the Smart Tech scenario of the sensitivity analysis leads to nearly five times higher yearly capital costs than in the Smart Tech scenario of the main analysis. For HH1, the difference in the AIC between analyses is not as pronounced due to the investment in a capital-intensive battery storage seen in the main analysis. However, in electrifying their heating systems in the sensitivity analysis, household types HH1, HH3 and HH4 are able to benefit from lower heat pump tariffs together with higher efficiency levels of the heat pump and increased self-consumption shares of the PV system. This results in an immediate reduction in the variable costs in the first year of investment, i.e., 2025, for the households with fully electric heating systems by 3% (HH4, Smart Tech) up to 44% (HH3, Smart Tech). By 2040, decreasing electricity prices continue to lower variable costs, achieving a 14% (HH1, Smart Tech, 2040) up to a 34% (HH2, Smart Market, 2040) reduction compared to the main analysis.

These counteracting effects result in HH1, HH3 und HH4 in the sensitivity analysis increasing their TAC anywhere from 10% (HH1, both scenarios) to 15% (HH3, Smart Tech) in 2025 and decreasing their TAC by 9% (HH1, Smart Tech) to 51% (HH3, Smart Tech) in 2040 compared to the main analysis.[216] All in all, these household types see a rise in total costs in the sensitivity analysis ranging from 3.5% (HH3, Smart Market) to 5.4% (HH1, Smart Tech) over the complete time horizon (see Table C.6 in Appendix

[215]It should be noted that the AIC shown in Table C.7 in Appendix C.5 have already been corrected for the heat pump subsidy, consistent with Equation (4.3) in Section 4.2.2.

[216]By 2040, decreases in variable costs outweigh increases in AIC as the financing period for investments from 2025 has ended.

C.5). For HH2, as explained above, an early investment in a gas boiler remains the least-cost option in the sensitivity analysis despite higher retail gas prices. As a result, total costs increase by 8.2% in the Smart Tech scenario compared to the main analysis, which is the greatest discrepancy seen across all household types. Consistent with the results of the main analysis, the total costs across the scenarios of the sensitivity analysis also decrease as more information becomes available to the households and their DER systems.

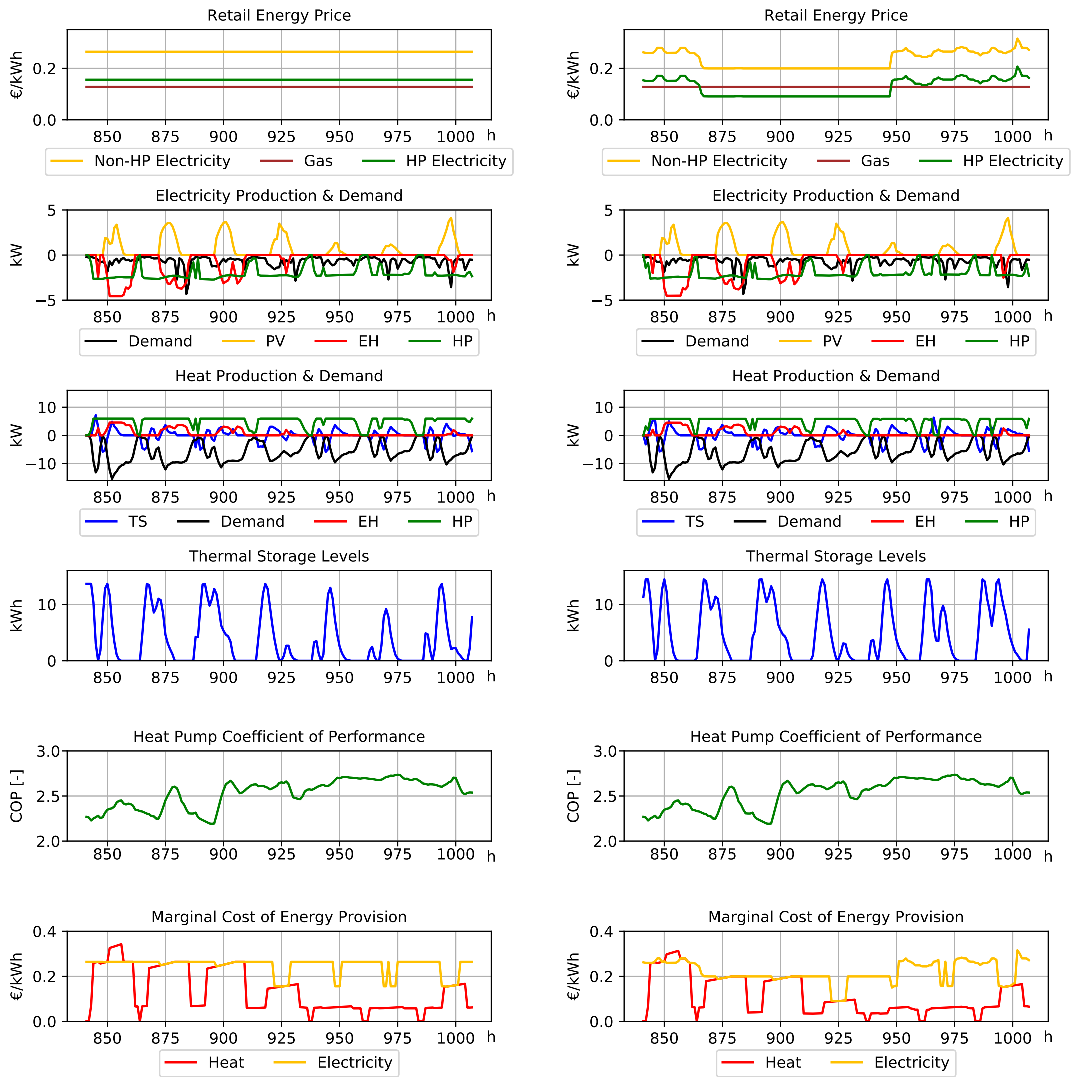

Figure 4.6.: Hourly results of the sensitivity analysis for HH1 in the second week of February 2040 for the Smart Tech scenario (left) and the Smart Market scenario (right)

Sensitivity Finding #5: Electrification of heat production increases marginal costs of electricity provision and decreases marginal costs of heat provision

Contrary to the presentation of the main results, the average marginal costs of electricity and heat provision for the sensitivity analysis are included with the other results in Table 4.5. In addition, Figure 4.6 shows the retail energy prices, the electricity provision and demand, the heat provision and demand, the thermal storage levels, the COP of the heat pump as well as the marginal costs of energy provision for HH1 for the second week in February 2040 in the Smart Tech (left) and Smart Market (right) scenarios.

The trends described in Section 4.3.3 hold true for the marginal costs of electricity provision found in the sensitivity analysis. As such, the average values for households without PV systems are found to be equal to the retail electricity prices and are thus identical to the results of the main analysis (i.e., the values for HH2 in years 2025-2035 of the Smart Tech and Smart Market scenarios, HH3 in years 2025-2035 of the Smart Market scenario and HH4). Furthermore, similarities can also be seen in the results for HH2 and HH3 in 2040, with decentralized generation of PV systems once again driving down the marginal costs of electricity provision in certain hours. In the sensitivity analysis, however, slightly higher average values arise as the increase in electricity demand via the heat pumps drives a higher amount of grid consumption (see Tables 4.3, 4.4 and 4.5). Nevertheless, two distinct anomalies stand out when comparing the average marginal costs of electricity provision in the two analyses: First, an earlier investment in a PV system in the Smart Tech scenario of the sensitivity analysis leads to HH3 reducing their marginal costs of electricity provision in all model years rather than just in 2040. Second, the lack of battery storage together with the increased electricity demand result in HH1 facing higher average marginal costs for electricity provision in the sensitivity than in the main analysis. As a result, the average marginal costs of electricity provision increase by up to 30% in the years 2030-2040 in both scenarios of the sensitivity analysis.

For the marginal costs of heat provision, the shift in the investment decision away from gas and towards a fully electric energy provision has some interesting consequences. Contrary to the main analysis, marginal costs of heat provision shown in Table 4.5 decrease over time as the fuel prices, in this case the retail non-heat-pump and heat-pump electricity prices, also decline. As explained in Section 4.3.3, the marginal costs of heat provision may equal the marginal costs of electricity provision in times when electricity could be consumed to ramp up heat production. In this case, two electricity-consuming technologies are available yet are subject to different tariffs. Looking at Figure 4.6, the marginal costs of heat provision and the marginal costs of electricity provision (i.e., the red and yellow lines, respectively, in the bottom graphs) meet at a level equal to the retail non-heat-pump electricity price (i.e., the yellow line in the top graphs) in several instances during the first three days of the week (i.e., hours 841-912). Here, it can be concluded that the electric heater fueled with electricity from the grid would be the next least-cost option.[217]

The heat pump, on the other hand, is designed as a base generator and is therefore limited in its ability to increase production due to capacity constraints. Nevertheless, the combination with thermal storage allows heat pumps to play a crucial role in driving down the marginal costs of heat provision by (i) ramping down production despite higher demand levels to evade lower COPs, no PV generation and/or high retail electricity prices, and (ii) continuing to run in times of low or no demand to benefit from strong COPs, PV generation and/or low retail electricity prices. Examples of the second effect can be seen by looking at Figure 4.6: Marginal costs of heat provision remain below the marginal costs of electricity provision for most of the second half of the week, e.g., hours 933 to 994. During this time, heat demand drops below the levels of the previous days, which in turn allows HH1 to avoid using the electric heater (see the black and red lines in third graphs from the top). As such, heat demand is covered by the heat pump together with thermal storage, who optimize the charging and discharging of the storage to minimize the costs of heat provision. In doing so, the heat pump uses the correlation between PV generation and high COPs to continue generating heat in times of zero heat demand in order to feed heat into the thermal storage, e.g., in hours 937-938, 960-962 and 984-986 in the Smart Tech scenario. Heat produced from the heat pump is then supplied by the thermal storage in hours with higher heat demands, resulting in the marginal costs of heat provision staying between 3.5 and 6.6 €-ct./kWh$_{\mathrm{th}}$ over this time frame.

In the 852$^{\mathrm{nd}}$ hour, i.e., the hour of peak heat demand for HH1, the marginal costs of heat provision also reach their maximum value, as can be seen in Figure 4.6. Whereas the marginal costs of heat provision in the peak demand hour in the main analysis include the investment costs for 1 kW of additional heating capacity, the availability of thermal storage offers a less capital-intensive option.[218] In this case, the storage could, e.g., shift one unit of heat discharge from the previous hour to the peak hour, using an electric heater in the previous hour to supply the missing kW. Comparing Figures 4.5 and 4.6, this effect leads to the maximum value for HH1 decreasing from 0.70 €-ct./kWh$_{\mathrm{th}}$ in the main analysis to about 0.33 €-ct./kWh$_{\mathrm{th}}$ in the sensitivity analysis. All in all, the flexibility introduced via thermal storage leads to significant reductions in the yearly averages of the marginal costs, as can be seen in Table 4.5. In fact, the absolute values of the average marginal costs of heat provision are found to be up to 38% lower than those seen in the main analysis.

[217] It is interesting to note that the curves of the marginal costs of heat provision discussed here do not plateau at the level equal to the retail price, as seen with the marginal costs of electricity provision, but rather have a slightly increasing slope. This is due to the hourly losses of the thermal storage that occur over time, referred to as β in Equation (4.13) in Section 4.2.4.

[218] In fact, additional model runs of the sensitivity analysis show that an increase in the peak demand by 1 kW leads to only a 0.1 kW increase in the capacity of the electric heater, with the capacities of all other technologies remaining unchanged.

Sensitivity Finding #6: Variable electricity prices have little effect on the costs of energy provision for the households considered

The main analysis and the sensitivity analysis present different investment strategies for the household types to cover their energy demands. Nevertheless, in both cases, the investment decisions appear to be unaffected by the differences in the definitions of the Smart Tech and Smart Market scenarios. In other words, the introduction of hourly, market-based variable electricity prices does not drive a major change in the cost-minimizing technology mix for the households considered. Yet the presence of a thermal storage coupled with electricity-consuming heating technologies in the sensitivity analysis creates an opportunity for households to take advantage of the variable electricity price structure. For example, comparing the Smart Tech (left) and the Smart Market (right) scenarios in Figure 4.6, the heat pump in the Smart Market scenario ramps up in times of lower electricity prices (e.g., in hours 961-963 and 985-987) to deliver larger heat volumes to the thermal storage. The thermal storage can then be discharged to relieve the heat pump in hours with unfavorable electricity prices (i.e., in hours 967/968 and 983). Moreover, dips in the electricity price also incentivize the electric heater to increase production compared to the Smart Market scenario, as seen in hour 996 in Figure 4.6. In this case, the peak heating technology is activated in addition to the baseload electric heat pump, increasing electricity consumption. This effect leads to a slight increase in the maximum amount of electricity consumed from the grid in a single hour in the Smart Market scenario, which occurs in times of low electricity prices and high thermal storage feed-in (see Tables C.9 and C.10 in Appendix C.5).[219]

Surprisingly, however, neither the variable costs nor the marginal costs of energy provision presented in Table C.7 in Appendix C.5 and Table 4.5, respectively, differ significantly across scenarios.[220] This insinuates that (i) the thermal storage is limited in its ability to benefit from arbitrage and (ii) households in the Smart Tech and Smart Market scenarios optimize operation, for the most part, according to the same criteria: maximizing of the use of PV electricity in the heat production of heat pumps and using thermal storage to shift the consumption of this heat to hours with demand peaks. Because both the solar irradiation and demand profiles are identical across scenarios, the possibilities for discrepancies in the operation of the technologies are limited, leading to similar costs despite different price structures.

[219] Though the model results reveal a minimal effect between scenarios, alternative "smart" price signals that account for, e.g., grid conditions or grid availability could support the technologies in exploiting their flexibility potential. Furthermore, it should be noted that households do not pay or redeem compensation for changes in grid connection size as the costs of electric networks are not considered within this analysis.

[220] This comparison holds true as long as the installed capacities are the same across scenarios. For HH3, for example, differences in the investment decision between 2025-2035 lead to cost deviations, as explained above.

4.4. Conclusion

Within this paper, the mixed-integer linear programming model COMODO is developed to determine the cost-minimal energy provision for an end consumer or consumer group accounting for electricity, water heating and space heating. The model uses its extensive technology catalog to perform an investment and dispatch optimization for multiple years, minimizing total costs over a long-term time horizon in a dynamic anticipative optimization. Developments in techno-economic data, regulatory frameworks and energy market conditions are taken into account to help understand the key drivers affecting the end consumer's energy investment choices. Furthermore, piecewise-linear cost functions are developed to more accurately represent the technology investment costs, FOM costs and subsidies for different systems sizes and for future years. In order to demonstrate the capabilities of the model developed, an exemplary application is presented to investigate the investment and energy use decisions of four single-family homes in Germany for the years 2025 to 2045. Three scenarios are designed that build upon each other regarding amount of information available to consumers and their decentralized energy technologies. Finally, a sensitivity analysis then examines the effects of higher carbon pricing in the German building sector on the consumer's energy provision.

The results reveal the investment and operational strategies as well as the energy costs of the households under changing technical, market and regulatory conditions. The Status Quo scenario, which is meant to resemble the technical and regulatory standard of today, shows a clear preference for gas boilers as a base technology coupled with electric heaters to cover demand peaks. The inability of households to receive forecasts on future developments in technology costs, energy prices or demand structure leads to households deviating from the long-term, cost-minimal investment and therefore spending more on their energy provision compared to the other two scenarios. The introduction of transparent information on future costs, prices and demand in the Smart Tech scenario affects each household type differently, with the energy demand levels playing a central role. Households with higher demand levels invest in PV systems immediately in 2025, while other households with lower demands either wait until 2040 (i.e., the last year of investment) or do not invest at all. The household with the highest energy demand invests in a battery storage in 2030 to maximize the self-consumption of PV electricity. The choice of heating technologies, however, remains unchanged compared to the Status Quo scenario. These results also hold for the Smart Market scenario, which extends the Smart Tech scenario such that households are exposed to variable retail electricity prices. While the opportunity of hourly retail electricity prices does not have a strong effect on the investment decision or household expenditures, increases in carbon pricing is found to play a significant role. When subject to higher carbon prices, the retail gas price increases to the point where most of the households choose to fully electrify their heat provision, i.e., installing a heat pump combined with thermal storage, PV and an electric heater. With this alternative technology mix, households on average experience an increase in total costs ranging from 3.5% to 5.4% over the complete time horizon and realize a long-term decrease in annual carbon emissions of up to 80% compared to the analysis with lower carbon pricing.

The paper at hand also presents a novel method of analyzing the marginal costs of electricity and heat provision, i.e., the shadow prices of the model's equilibrium constraints. The results reveal a strong correlation between the implicit marginal costs of electricity provision and the retail electricity price in all scenarios and both analyses (i.e., with lower and higher carbon pricing). As such, the decrease in the retail electricity price that is assumed for future years drives the yearly average of the marginal costs of electricity provision downwards over time. Deviations are found to occur in hours with PV electricity generation or during peak demand. The self-consumption of PV electricity, in particular, is identified to have significant potential in reducing marginal costs. Similarly, the marginal costs of heat provision are also found to be linked to the fuel price: If gas-fired technologies are used, as is the case in the analysis with lower carbon pricing, the average marginal costs increase over the years following the upwards trend in the gas price development. However, if electricity-consuming technologies are used, the average as well as hourly marginal costs of heat provision tend to equal the marginal costs of electricity provision. The use of electricity generated by decentralized PV systems via electric heat pumps coupled with thermal storage yields drastic reductions in the marginal costs of heat provision.

As is the case in any model-based analysis, this research is subject to several limitations. First, the proposed model assumes perfectly rational behavior and perfect foresight over the full model horizon. Although this assumption is typical for MILP energy models, the information on future developments may result in more capital-intensive technologies being selected than would be chosen under real-world conditions. Second, consumers may make decisions on their energy provision based on additional non-monetary preferences or risk assessments, which are difficult to include in a cost-minimizing model.[221]

The model COMODO presented in this paper offers a wide range of opportunities for future research. For example, in this analysis, only single-family homes are considered. However, COMODO is designed to be able to optimize any consumer type or group. As such, additional analyses examining, e.g., larger living complexes, industry consumers or other non-residential buildings could be an interesting extension of this work. Increasing the heterogeneity of the consumer types could allow for a larger pool of consumers to be considered, e.g., on a neighborhood, national or even multi-country level.[222] Furthermore, although the technology catalog developed is already relatively extensive, investment objects could be added to allow for a more realistic depiction of the current scope of installed and available decentralized technologies (e.g., air conditioning, gas heat pumps, electric vehicles, electrolyzers, etc.) as well as building retrofits (e.g., insulation improvements). Additional options for energy supply such as district heating or hydrogen could also be implemented; however, uncertainty regarding aspects such as

[221] The concept of including preferences in MILP models is addressed in [Shamon et al., 2021].

[222] For example, the German residential building stock is examined using COMODO in [Arnold et al., 2023].

prices and pipeline accessibility may pose challenges. Investigating the marginal costs of heat provision, as done in this work, offers a promising research avenue for understanding the costs of decentralized heat supply and the competitiveness to centralized heat providers. Moreover, the input data used in the application could be increased in complexity to account for, e.g., weather phenomena or smaller (<1h) time steps to improve the accuracy on generation, grid consumption and storage cycles. Lastly, research questions surrounding shifts in the regulatory landscape could be complementary extensions to the sensitivity analysis performed in this work. Topics such as the consequences of capacity pricing, carbon reduction targets or restrictions on fossil fuel use could provide valuable insights for, e.g., policymakers.

A. Supplementary Material for Chapter 2

A.1. Nomenclature

Throughout Chapter 2, notation as listed in Table A.1 is applied. Unless otherwise noted, bold capital letters indicate sets, lowercase letters parameters and bold lowercase letters optimization variables.

Sets		
$f \in \mathbf{F}$		Fuel type ($f1$: Subfuels)
$i \in \mathbf{I}$		Technologies (electricity generators, ptx plants, cars)
$m, n \in \mathbf{M}$		Markets
$s \in \mathbf{S}$		Sector (rt: road transport, el: electricity, et: energy transf.)
$t \in \mathbf{T}$		Time ($\mathbf{T}$: time slices)
Parameters		
$l_{m,t}$	MWh	Exogenous electricity demand
l_{peak}	MWh	Peak electricity demand
$dr_{m,t}$	bn. km	Exogenous demand road transport
x	-	Availability of electricity generator
v	-	Capacity value of electricity generators
$\bar{k}$	MW	Transmission capacity
η	-	Efficiency
δ	EUR/MW	Fixed costs
γ	EUR/MW	Variable costs electricity generation
κ_{f1}	tCO_2eq/MWh	Fuel-specific emission factor
$\kappa_{f1,upstream}$	tCO_2eq/MWh	Fuel-specific upstream emission factor
$GHG_{cap,s,t}$	tCO_2eq	Sector-specific greenhouse gas emissions cap
TC	bn. EUR	Total costs
Optimization variables		
$\bar{\mathbf{x}}$	MW	Electricity generation capacity
$\mathbf{g}$	MWh	Electricity generation
$\mathbf{k}$	MWh	Electricity transmission between markets
$\mathbf{ec}$	MWh	Energy consumption
$\mathbf{sr}$	bn. km	Supply road transport
$\mathbf{fp}$	MWh	Fuel production
$\mathbf{ft}$	MWh	Fuel trade
$\mathbf{ffi}$	MWh	Fuel feed-in
$\mathbf{em}$	tCO_2eq	GHG emissions
$\mathbf{cpt}$	tCO_2	CO_2 capture

Table A.1.: Model sets, parameters and variables used in Chapter 2

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.2.: Country codes used in Chapter 2

A.2. Supplementary information on the electricity market module

The model covers all 28 countries of the European Union, except for Cyprus and Malta, but includes Norway and Switzerland. Existing electricity generation capacities in 2015 are based on a detailed power plant database developed at the Institute of Energy Economics at the University of Cologne, which is mainly based on the Platts WEPP Database ([Platts, 2016]) and regularly updated. The investment decisions and generation profiles for a wide range of power plants are optimized endogenously. These include conventional, combined heat and power (CHP), nuclear, onshore and offshore wind turbines, roof and ground photovoltaic (PV) systems, biomass (CHP-) power plants (solid and gas), hydro power plants, geothermal power plants, concentrating solar power (CSP) plants and storage technologies (battery, pump, hydro and compressed air energy (CAES)).[223] Only countries without existing nuclear phase-out policies are allowed to invest in nuclear power plants. Investments in carbon capture and storage (CCS) technologies are not allowed due to a general lack of social acceptance in European countries. Technological improvements in, e.g., efficiency are taken into account using vintage classes. These are then included in the model as an additional technology option that is only available from a certain point in time onwards.

The objective function of the model seeks to minimize the accumulated discounted total system costs.[224] All cost assumptions for technologies listed above are taken from the power plant database at the Institute of Energy Economics at the University of Cologne. Key cost factors are investment, fixed operation and maintenance and variable production costs as well as costs due to ramping thermal power plants. Investment costs occur for new investments in generation and storage units and are annualized with a 7 % interest rate for the depreciation time. The fixed operation and maintenance costs represent staff costs, insurance charges, interest rates and maintenance costs. Variable

[223] The use of lignite and biomass sources (solid and gaseous) is restricted by a yearly primary energy potential in MWh per country.

[224] The total system costs do not include investment costs for electricity grid extensions nor operational costs for grid management.

costs are determined by the fuel price, net efficiency and total generation of each technology. Depending on the ramping profile additional costs for attrition occur. CHP plants can generate income from the heating market, thus reducing the objective value ([Jägemann et al., 2013a]). The model applies a discount rate of 2.75 % for discounting of future cashflows to the present (net present value).

Short-term deployment of renewable technologies is taken into account via minimal deployment targets (based on [ENTSO-E, 2015a]) for 2020 and remain constant up to 2050.[225]

The model also considers several subregions within the countries, which differ with regard to the hourly electricity feed-in profiles and the achievable full load hours of wind turbines (onshore and offshore) and solar power plants (PV and CSP) per year. Overall, the model distinguishes between 47 onshore wind, 42 offshore wind and 38 solar subregions across Europe. The hourly electricity feed-in of wind and solar power plants per subregion are based on historical hourly wind speed and solar radiation data by EuroWind (2011).[226] The deployment of wind and solar power technologies is restricted by a space potential in km^2 per subregion.

Yearly national electricity consumption is assumed to follow the Ten-Year Network Development Plan (TYNDP) from [ENTSO-E, 2015b] and the European Commission's e-Highway 2050 Project ([European Commission, 2015]). It is important that the countries' future electricity consumption, i.e., their exogenous electricity demand, does not assume any additional electricity demand from, e.g., electric vehicles or power-to-x systems. This additional electricity demand is determined endogenously from the energy transformation and road transport modules. Therefore, specific scenarios fitting this criteria were chosen from [ENTSO-E, 2015b] and [European Commission, 2015], namely the Small & Local scenario for 2040 and 2050. Hourly electricity demand is based on historical hourly load data from ENTSO-E ([ENTSO-E, 2012]). Interconnector capacities are taken into account via one node per country. Hence, the model covers 28 countries connected by 65 transmission corridors. Existing and future extensions of net-transfer capacities are exogenously defined and may in some cases limit the power exchange across country borders. This data has been taken from [ENTSO-E, 2015b], [Bundesnetzagentur, 2016] and [European Commission, 2015].

[225] This statement holds true for all technologies with the exception of offshore wind. Expected deployment projections were taken from [WindEurope, 2017] for 2020 and [EWEA, 2015] for 2030 and 2050

[226] While the securely available capacity of dispatchable power plants within the peak-demand hour is assumed to correspond to the seasonal availability, the securely available capacity of wind power plants (onshore and offshore) within the peak-demand hour (capacity value or capacity credit) is assumed to amount to 5 %. In contrast, PV systems are assumed to have a capacity value of 0 % due to the assumption that peak demand occurs during evening hours in the winter. A peak-demand constraint ensures enough back-up capacity to meet security of supply requirements given a high share of fluctuating renewables ([Jägemann et al., 2013a]).

A.3. Supplementary material for the methodology

A.3.1. Key links between the modules

Figure A.1 provides an illustration of the links between the electricity market, the energy transformation and the road transport modules, represented by endogenous demands for electricity and ptx fuels as well as the respective endogenous prices resulting from the integrated optimization.

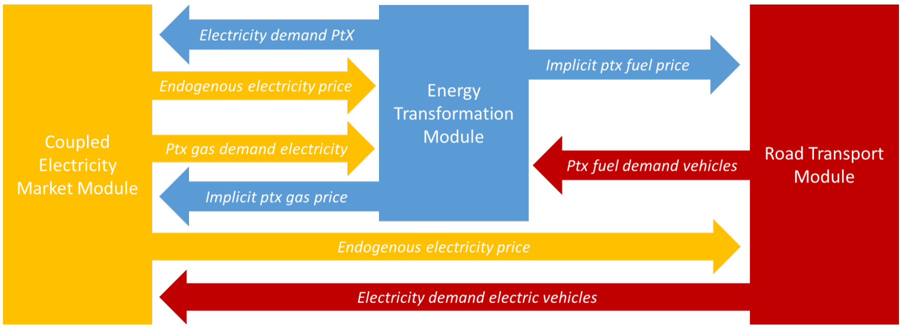

Figure A.1.: Exchange of endogenous information between the modules in the integrated model

A.4. Additional data and assumptions

A.4.1. Direct and upstream emission factors

Substitute Fuel	**Direct Emissions (TTW)**	**Upstream Emissions (WTT)**	**Description Production Cycle**
Diesel	0.268	0.052	Crude oil production, crude refining. distribution
Biodiesel	0.268	0.192	Rape cultivation, rapeseed drying, oil production, biodiesel production, distribution
PtX Diesel	0.268	0.005	Distribution
Gasoline	0.253	0.046	Crude oil production, crude refining, distribution
Biogasoline	0.253	0.191	Wheat cultivation, grain drying, storage and handling, ethanol production, distribution
PtX Gasoline	0.253	0.005	Distribution
CNG	0.204	0.028	NG production, distribution, compression
Biogas (hc)	0.204	0.053	Fermentation, upgrading, compression, distribution
Biogas (lc)	0.204	0.053	Fermentation, upgrading, compression, distribution
PtX CH4	0.204	0.012	Distribution
LNG	0.204	0.053	NG production, liquefaction, loading and unloading terminal, road transport
Bio LNG	0.204	0.077	Fermentation, upgrading, liquefaction, distribution
PtX LCH4	0.204	0.016	Distribution
H2	0.000	0.334	NG production, stream reforming, pipeline, compression
PtX H2	0.000	0.047	Distribution
LH2	0.000	0.423	NG production, stream reforming, liquefaction, road transport
PtX LH2	0.000	0.015	Distribution
Biosolid	0.327	0.028	Wood plantation & chipping
Coal	0.339	0.059	Hard coal provision
Lignite	0.403	0.020	Lignite provision
Nuclear	0.000	<0.001	Uranium ore extraction, fuel production

Table A.3.: Direct and upstream emission factors [tCO_2eq/MWh][227]

[227] The upstream emission factors are taken from [Edwards et al., 2014] and include CO_2 emissions resulting from production and conditioning. Any CO_2 emissions emitted during transportation of the fuel to market is not accounted for in the upstream emission factor. The direct emissions factors are taken from [Department for Business, Energy and Industrial Strategy, 2016] and [UBA, 2017]. The production cycle includes dispensing at retail site.

A.4.2. Selected data and assumptions used in the energy transformation module

In the following, additional explanations and technical details about the technologies used in the energy transformation module are presented. An electrolysis system uses electricity in an endothermic process to split water into hydrogen and oxygen. Alkaline and PEM electrolysis vary according to their electrolyte solution and electrode composition; however, both operate at temperatures ranging from 50 to 80 degrees Celsius. The hydrogen produced can either be sold directly or be stored to successively produce methane via catalytic methanation, hydrocarbons via Fischer-Tropsch synthesis, or a low-carbon natural gas mixture via feeding into the natural gas grid. During catalytic methanation, carbon dioxide and hydrogen undergo an exothermic reaction at temperatures between 200 and 400 degrees Celsius to yield methane, steam and heat.[228] Fischer-Tropsch synthesis is a more complex process in which carbon monoxide and hydrogen build carbon chains via a series of exothermic reactions followed by an endothermic hydrocracking isometrisation distillation to separate the crude product into usable fuels (e.g., ptx gasoline, ptx diesel). A simplified production ratio of ptx gasoline to ptx diesel of 9.8 : 20.1 is applied in the model ([Becker et al., 2012]). CO_2 is used to create the carbon monoxide via reverse CO shift ([Schmidt et al., 2016]).

The feed-in of hydrogen into the natural gas grid is modeled with an upper limit of 10 vol-% of natural gas. Note that hereby it is assumed that the changes in the energy density of the gas mix (natural gas / ptx hydrogen gas mix) are negligible, i.e., one MWh of injected ptx hydrogen adds one MWh to the natural gas supply, or, stated differently, it substitutes one MWh of natural gas and thereby reduces the amount of CO_2 emissions from combustion accordingly. Thereby, the model implicitly assumes a certificate market for units of decarbonized gas (i.e., hydrogen feed-in). As such, the energy transformation module can feed-in hydrogen gas up the upper 10 vol-% limit, being based on the natural gas demand of all sectors in each respective country as a proxy. The certificate market for decarbonized gas allows the road transport module to buy decarbonized gas. Note that thereby the total amount of decarbonized gas consumed in the road transport sector may exceed 10 vol-% of the total gas consumption of the road transport, as the feed-in limit is defined on total gas demand of all sectors and not of the road transport sector alone. In a model covering multiple sectors, the single sectors thereby compete for low-cost decarbonized gas via hydrogen feed-in on the certificate market.

For every mole of hydrogen produced, an electrolysis system produces a half-mole of oxygen that can be sold to, e.g. the industry or services sectors. The amount of oxygen produced is determined stoichiometrically based on the amount of ptx hydrogen produced by electrolysis, which is driven not only by the endogenous hydrogen demand but from the need for ptx hydrogen in the methanation or Fischer-Tropsch processes as

[228] As the heating sector is not accounted for in this analysis, efficiency gains due to the recycling of the heat generated by methanation is not considered.

well. To determine the amount of oxygen produced, octane was assumed for gasoline and hexadecane for diesel.

Table A.4 gives an overview of the key assumptions made for each ptx investment object considered in the energy transformation module with regard to investment costs, FOM costs, efficiency and technical lifetime. It should be noted that only integrated systems are considered for methanation and Fischer-Tropsch systems, meaning that all investments in methanation and Fischer-Tropsch technologies include the simultaneous investment in a PEM electrolysis to produce the ptx hydrogen required in the subsequent methanation or Fischer-Tropsch processes. Therefore, the techno-economical parameters, e.g., investment costs, for methanation and Fischer-Tropsch systems in Table A.4 are for integrated, as opposed to stand-alone, systems. This is especially important when considering the efficiencies, which are always defined with respect to the electricity input of the integrated system, i.e., the amount of fuel output relative to the amount of electricity input.[229] The FOM costs also include the stack replacement costs of the electrolysis system, calculated based on the assumptions in [Grahn, 2017].

Conversion systems to liquefy gaseous hydrogen or natural gas are also taken into account in the energy transformation module. Because liquefaction plants also consume electricity, they are modeled analogous to ptx systems as investment objects. Unlike the integrated ptx systems, liquefaction plants are assumed to be stand-alone systems. The techno-economic assumptions for the liquefaction plants are in Table A.5.

[229] PEM electrolysis in integrated systems is also allowed to produce ptx hydrogen in stand-alone mode.

Table A.4.: PtX Cost

		2020	2030	2050	Main sources
Investment costs [EUR/(kW$_{el}$)]	Alkaline Electrolysis	833	500	383	[Henning and Palzer, 2015], [FfE, 2016], [Elsner and Sauer, 2015], [Schiebahn et al., 2015]
	PEM Electrolysis	980	545	484	[Elsner and Sauer, 2015], [Schmidt et al., 2016]
	Methanation coupled w/ PEM	1317	845	717	[Grahn, 2017], [Brynolf et al., 2018], [Tremel et al., 2015]
	Fischer-Tropsch coupled w/ PEM	1887	1152	917	[Grahn, 2017], [Brynolf et al., 2018], [Tremel et al., 2015], [Smejkal et al., 2014]
FOM costs (incl. stack replacement for electrolysis) [EUR/(kW*a)]	Alkaline Electrolysis	40	21	16	[Schmidt et al., 2016], [Grahn, 2017]
	PEM Electrolysis	50	23	18	[Schmidt et al., 2016], [Grahn, 2017]
	Methanation coupled w/ PEM	63	35	28	[Schmidt et al., 2016], [Grahn, 2017]
	Fischer-Tropsch coupled w/ PEM	83	46	37	[Schmidt et al., 2016], [Grahn, 2017]
Efficiency [MWh$_{th}$/MWh$_{el}$]	Alkaline Electrolysis	0.67	0.70	0.70	[FfE, 2016], [Elsner and Sauer, 2015], [Schiebahn et al., 2015]
	PEM Electrolysis	0.65	0.67	0.71	[Schmidt et al., 2016]
	Methanation coupled w/ PEM	0.48	0.50	0.54	[Schmidt et al., 2016], [Grahn, 2017], [Brynolf et al., 2018], [Tremel et al., 2015]
	Fischer-Tropsch coupled w/ PEM	0.45	0.47	0.51	[Schmidt et al., 2016], [Grahn, 2017], [Brynolf et al., 2018], [Tremel et al., 2015]
Technical Lifetime [a]	Alkaline Electrolysis	15	20	25	[Henning and Palzer, 2015], [FfE, 2016], [Elsner and Sauer, 2015], [Schiebahn et al., 2015]
	PEM Electrolysis	15	20	25	[FfE, 2016], [Elsner and Sauer, 2015], [Schiebahn et al., 2015]
	Methanation coupled w/ PEM	15	20	25	[Elsner and Sauer, 2015], [Brynolf et al., 2018], [Parra and Patel, 2016]
	Fischer-Tropsch coupled w/ PEM	15	20	25	[Brynolf et al., 2018], [Becker et al., 2012]
Interest rate [%]	All	7	7	7	[Kost et al., 2018]

Table A.5.: Liquefaction assumptions

Hydrogen Liquefaction	**Efficiency (MWh_{fuel}/MWh_{el})**	3.53	[Amos, 1998], [Krewitt and Schmid, 2005], [U.S. Department of Energy, 2009]
	Technical Lifetime (a)	25	[Krewitt and Schmid, 2005]
	Investment Costs 2020/2030/2050 (EUR/kW_{el})	1588 / 761 / 622	[Pfennig et al., 2017]
	FOM Costs (EUR/kW_{el}*a)	91	[Krewitt and Schmid, 2005]
	Interest Rate (%)	7	[Kost et al., 2018]
Methane/ Natural Gas Liquefaction	**Efficiency (MWh_{fuel}/MWh_{el})**	17.37	[Franco and Casarosa, 2014]
	Technical Lifetime (a)	20	[Schmidt et al., 2016]
	Invest Costs 2020/2030/2050 (EUR/kW_{el})	5466 / 5286 /4927	[Schmidt et al., 2016], [Songhurst, 2014]
	FOM Costs (EUR/kW_{el}*a)	211	[Schmidt et al., 2016]
	Interest Rate (%)	7	[Kost et al., 2018]

Fuel transport costs between markets [EUR/MWh_{th}/km]	
PtX Gasoline/PtX Diesel	0.010
Gas Mix/PtX CH4	0.002
Liq. Gas Mix/PtX LCH4	0.015
PtX H2	0.090
PtX LH2	0.020

Table A.6.: Ptx fuel transport costs between markets[230]

A.4.3. Selected data and assumptions used in the road transport module

In the following, additional details about the technologies used in the road transport module are presented.

	2015	2020	2030	2040	2050
Gasoline	22'475	22'573	22'769	22'769	22'769
Diesel	24'275	24'373	24'569	24'569	24'569
Gasoline HEV	23'890	23'752	23'476	23'123	22'769
Diesel HEV	25'803	25'646	25'332	24'951	24'569
Gasoline PHEV	31'774	30'125	26'829	26'110	25'371
Diesel PHEV	34'318	32'529	28'950	28'174	27'377
CNG	24'729	24'631	24'436	24'363	24'289
CNG HEV	26'286	25'922	25'195	24'742	24'289
CNG PHEV	34'960	32'905	28'793	27'979	27'146
H2 FCV	66'746	54'892	31'184	27'990	24'796
BEV	34'900	31'042	27'581	26'114	24'646

Table A.7.: PPV vehicle cost [EUR/vehicle][231]

[230] Based on [Balat, 2008], [Dodds and McDowall, 2014], [IEA, 2013], [Yang and Ogden, 2007].
[231] Own calculations based on [Wietschel et al., 2010], [Fraunhofer IWES et al., 2015], [Henning and Palzer, 2015], [ADAC, 2015], [Arndt et al., 2016], [IEA, 2017] and [Özdemir, 2011].
[232] Own calculations based on [Wietschel et al., 2010], [Fraunhofer IWES et al., 2015], [Henning and Palzer, 2015], [ADAC, 2015], [Arndt et al., 2016], [IEA, 2017] and [Özdemir, 2011].

	2015	2020	2030	2040	2050
Diesel	26’003	26’585	27’748	27’748	27’748
Diesel HEV	31’156	30’966	30’498	29’123	27’748
Diesel PHEV	41’437	38’523	32’696	31’820	30’920
CNG	28’955	28’841	28’612	28’526	28’440
CNG HEV	34’692	33’594	31’448	29’940	28’440
CNG PHEV	46’141	41’999	33’714	32’761	31’785
BEV	41’021	36’967	32’100	30’392	28’684
H2 FCV	78’452	64’519	36’653	32’899	29’145

Table A.8.: LDV vehicle cost [EUR/vehicle][232]

	2015	2020	2030	2040	2050
Diesel	108’157	109’959	113’565	113’565	113’565
Diesel HEV	144’209	143’332	140’757	138’181	135’196
LNG	130’689	130’046	128’758	127’471	126’183
LNG HEV	174’253	170’819	163’952	157’085	150’218
BEV	441’640	397’219	250’000	180’000	130’689
LH2 FCV	441’640	397’219	308’376	219’533	130’689

Table A.9.: HDV vehicle cost [EUR/vehicle][233]

[233] Own calculations based on [Wietschel et al., 2010], [Fraunhofer IWES et al., 2015], [Henning and Palzer, 2015], [ADAC, 2015], [Arndt et al., 2016], [IEA, 2017] and [Özdemir, 2011].

	2015	2020	2030	2040	2050
AT	65	67	71	76	80
BE	76	82	89	95	101
BG	34	35	37	39	40
HR	19	21	23	24	26
CZ	48	52	60	68	75
DK (East)	16	17	18	18	19
DK (West)	18	20	21	22	22
EE	8	8	9	9	10
FI	48	48	50	51	52
FR	453	480	507	533	550
DE	621	626	651	663	671
GB	417	444	483	513	540
GR	58	59	60	62	63
HU	29	32	36	41	45
IE	31	34	41	45	48
IT	342	358	379	387	407
LV	9	10	10	11	11
LT	17	18	19	19	20
NL	104	108	114	120	125
NO	33	34	36	37	39
PL	112	128	149	167	179
PT	56	57	64	68	72
RO	42	46	57	67	74
SK	14	17	22	24	26
SI	16	17	19	20	21
ES	192	201	231	257	278
SE	77	79	86	91	95
CH	59	61	65	69	74

Table A.10.: PPV road transport demand [Billion km][234]

[234]Own calculations based on [European Commission, 2016a] and [EWI et al., 2014].

	2015	**2020**	**2030**	**2040**	**2050**
AT	11	12	14	16	18
BE	13	14	16	17	19
BG	3	3	3	3	3
HR	4	5	5	6	6
CZ	9	9	11	12	13
DK (East)	5	5	6	7	8
DK (West)	6	6	6	7	8
EE	1	1	1	1	1
FI	5	6	6	6	7
FR	118	125	140	156	174
DE	44	46	51	57	62
GB	73	75	81	87	94
GR	14	15	17	18	20
HU	9	9	10	11	12
IE	16	16	18	20	21
IT	85	87	92	96	101
LV	1	1	2	2	2
LT	2	2	3	3	3
NL	21	22	23	25	28
NO	9	10	11	12	13
PL	21	23	30	38	48
PT	21	21	22	23	24
RO	7	7	8	9	10
SK	4	4	5	5	6
SI	3	3	4	4	5
ES	22	23	24	26	28
SE	12	12	13	14	15
CH	4	5	5	5	6

Table A.11.: LDV road transport demand [Billion km][235]

[235] Own calculations based on [European Commission, 2016a] and [EWI et al., 2014].

	2015	2020	2030	2040	2050
AT	4	4	5	6	6
BE	11	12	15	17	18
BG	1	1	1	2	2
HR	1	1	2	2	2
CZ	5	6	6	7	8
DK (East)	1	2	2	2	2
DK (West)	2	2	2	3	3
EE	0	0	0	0	0
FI	2	3	3	3	3
FR	30	34	42	47	50
DE	53	59	67	70	72
GB	33	34	38	41	44
GR	4	5	5	5	6
HU	3	3	4	4	4
IE	1	2	2	3	3
IT	20	22	24	26	28
LV	1	1	1	1	1
LT	1	1	1	1	1
NL	7	8	8	9	9
NO	2	3	3	3	3
PL	25	28	35	40	43
PT	1	2	2	2	2
RO	3	4	5	6	6
SK	2	2	3	3	3
SI	1	1	2	2	2
ES	51	55	63	70	75
SE	3	3	3	4	4
CH	4	5	5	5	6

Table A.12.: HDV road transport demand [Billion km][236]

[236]Own calculations based on [European Commission, 2016a] and [EWI et al., 2014].

	2015	2020	2030	2040	2050
Gasoline	0.71	0.60	0.55	0.53	0.53
Diesel	0.66	0.54	0.46	0.42	0.42
Gasoline HEV	0.46	0.43	0.40	0.36	0.34
Diesel HEV	0.43	0.40	0.37	0.36	0.34
Gasoline PHEV	0.37	0.33	0.29	0.28	0.28
Diesel PHEV	0.35	0.31	0.26	0.24	0.24
CNG	0.70	0.61	0.58	0.55	0.53
CNG HEV	0.53	0.44	0.39	0.37	0.37
CNG PHEV	0.36	0.33	0.30	0.28	0.28
H2 FCV	0.34	0.32	0.28	0.26	0.24
H2 Hybrid FCV	0.34	0.32	0.28	0.26	0.24
H2 PHEV FCV	0.25	0.24	0.21	0.20	0.19
H2 ICE	0.45	0.44	0.41	0.40	0.38
BEV	0.20	0.19	0.16	0.15	0.15

Table A.13.: PPV fuel consumption [kWh/km][237]

	2015	2020	2030	2040	2050
Diesel	1.01	0.86	0.77	0.75	0.71
Diesel HEV	0.81	0.69	0.61	0.60	0.57
Diesel PHEV	0.54	0.49	0.42	0.40	0.38
CNG	1.25	1.22	1.17	1.08	1.03
CNG HEV	1.00	0.98	0.94	0.86	0.82
CNG PHEV	0.62	0.60	0.56	0.51	0.49
LNG	1.25	1.22	1.17	1.08	1.03
LNG HEV	1.00	0.98	0.94	0.86	0.82
BEV	0.31	0.30	0.25	0.23	0.22
H2 FCV	0.61	0.52	0.46	0.45	0.43
LH2 FCV	0.61	0.52	0.46	0.45	0.43

Table A.14.: LDV fuel consumption [kWh/km][238]

[237] Own calculations based on [EWI et al., 2014], [Dodds and McDowall, 2014], [Dodds and Ekins, 2014], [DLR et al., 2012], [dena and LBST, 2017], [PLANCO Consulting, 2007] and [Papadimitriou et al., 2013].

[238] Own calculations based on [EWI et al., 2014], [Dodds and McDowall, 2014], [Dodds and Ekins, 2014], [DLR et al., 2012], [dena and LBST, 2017], [PLANCO Consulting, 2007] and [Papadimitriou et al., 2013].

	2015	2020	2030	2040	2050
Diesel	2.45	2.30	2.10	1.90	1.77
Diesel HEV	1.72	1.61	1.47	1.33	1.24
CNG	2.54	2.36	1.97	1.88	1.79
CNG HEV	1.78	1.65	1.38	1.31	1.25
LNG	2.54	2.36	1.97	1.88	1.79
LNG HEV	1.78	1.65	1.38	1.31	1.25
BEV	0.80	0.80	0.80	0.80	0.80
H2 FCV	1.47	1.38	1.26	1.14	1.06
LH2 FCV	1.47	1.38	1.26	1.14	1.06

Table A.15.: HDV fuel consumption [kWh/km][239]

[239] Own calculations based on [EWI et al., 2014], [Dodds and McDowall, 2014], [Dodds and Ekins, 2014], [DLR et al., 2012], [dena and LBST, 2017], [PLANCO Consulting, 2007] and [Papadimitriou et al., 2013].

	Fuel Type	2015	2050	Sources
Investment Cost [EUR/kW]	Gasoline/Diesel	10	10	[Krewitt and Schmid, 2005], [Mariani, 2016], [Schmidt et al., 2016]
	Gas	65	30	
	Liquefied Gas	40	20	
	H2	350	100	
	LH2	280	100	
	Electricity	550	350	
Interest Rate [%]	All	10	10	[Platts, 2016]
Lifetime [a]	All	25	25	[IEA, 2013]
FOM Cost [% of investment cost]	Gasoline/Diesel	3.2	3.2	[Schmidt et al., 2016]
	Gas	0.4	0.4	
	Liquefied Gas	3.2	3.2	
	H2	2.9	2.9	
	LH2	2.9	2.9	
	Electricity	1.0	1.0	
Variable Cost [EUR/MWh]	Gasoline/Diesel	0.05	0.05	[IEA, 2013]
	Gas	11	7	
	Liquefied Gas	5	5	
	H2	15	15	
	LH2	5	5	
	Electricity	0.1	0.1	
Full Load Hours	All	2000	2000	[IEA, 2013]
Fuel Distribution Costs to Refueling/Charging Station [EUR/MWh]	Gasoline/Diesel	1.0	1.0	[Balat, 2008], [Dodds and McDowall, 2014], [IEA, 2013], [Yang and Ogden, 2007]
	Gas	1.0	1.0	
	Liquefied Gas	2.3	2.3	
	H2	13.2	13.2	
	LH2	3.0	3.0	
	Electricity	6.7	6.7	

Table A.16.: Techno-economic assumptions for refueling/charging stations as well as fuel distribution costs to refueling/charging stations as used in the road transport module

A.5. Supplementary information on the scenario framework

	2020		2030	
	$MtCO_2$ Target	**cp. 2015**	**$MtCO_2$ Target**	**cp. 2005**
AT	19.1	-5%	13.9	-36%
BE	25.4	-10%	18.0	-35%
BG	9.0	4%	7.4	0%
HR	6.5	4%	5.5	-7%
CZ	17.6	5%	13.8	-14%
DK (East)	5.1	-13%	3.8	-39%
DK (West)	6.0	-13%	4.4	-39%
EE	2.2	2%	1.7	-13%
FI	12.1	-8%	9.0	-39%
FR	143.8	-7%	100.8	-37%
DE	170.4	-7%	113.2	-38%
GB	126.0	-6%	89.5	-37%
GR	20.4	2%	20.4	-16%
HU	12.1	10%	9.9	-7%
IE	10.9	-13%	9.4	-30%
IT	108.0	-3%	86.8	-33%
LV	2.8	5%	2.5	-6%
LT	2.6	-44%	3.5	-9%
NL	29.9	-10%	23.4	-36%
NO	10.7	-7%	6.8	-38%
PL	48.4	3%	34.7	-7%
PT	19.7	3%	18.4	-17%
RO	14.5	10%	10.7	-2%
SK	6.1	6%	5.5	-12%
SI	5.1	1%	3.6	-15%
ES	82.2	-4%	75.0	-26%
SE	19.7	-8%	14.4	-40%
CH	15.6	-7%	10.7	-38%

Table A.17.: Decarbonization targets for the road transport sector, based on the EU Effort Sharing CO_2 Targets

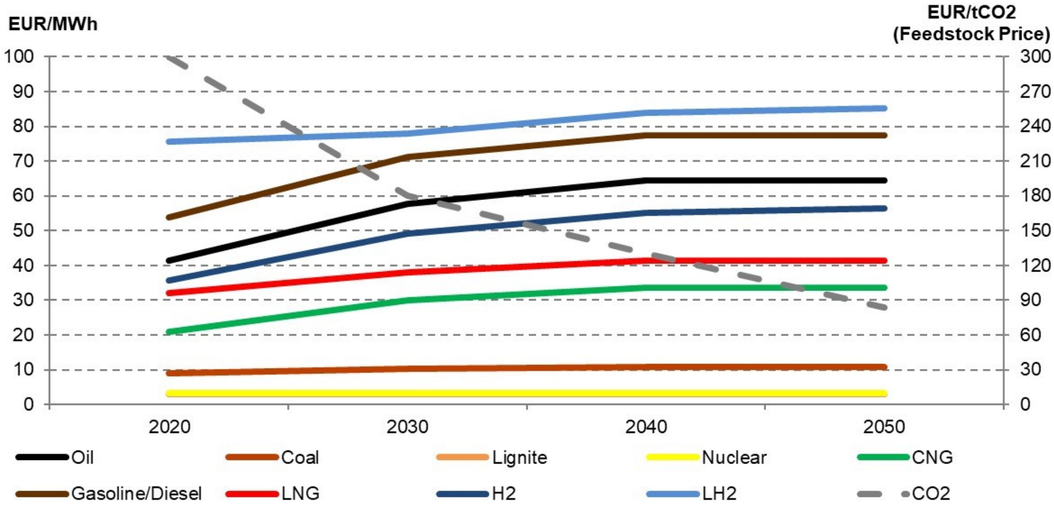

Figure A.2.: Assumptions on fossil fuel and CO_2 feedstock (from direct air capture) price developments based on [IEA, 2016b], [DLR et al., 2014], [Krewitt and Schmid, 2005], [EIA, 2015], [Henderson, 2016] and [Schmidt et al., 2016]. Fossil fuel prices include any production costs (e.g., oil refining or methane reformation) and exclude taxes and fees.

A.6. Supplementary results of the integrated multi-sectoral model (coupled)

A.6.1. Additional European road transport results

The marginal CO_2 abatement costs for single countries are shown in Table A.18.

	2015	2020	2030	2040	2050
AT	0	147	0	114	496
BE	0	175	112	121	497
BG	0	0	0	0	496
HR	0	0	0	42	496
CZ	0	0	0	130	501
DK (East)	0	175	100	116	496
DK (West)	0	175	96	116	496
EE	0	0	0	0	469
FI	0	175	0	0	470
FR	0	175	73	59	496
DE	0	168	70	92	499
GB	0	168	80	88	496
GR	0	0	0	0	496
HU	0	0	0	35	496
IE	0	175	0	63	499
IT	0	0	0	0	496
LV	0	0	0	0	495
LT	0	903	0	0	481
NL	0	175	0	46	496
NO	0	114	25	6	496
PL	0	129	110	137	501
PT	0	0	0	0	496
RO	0	0	0	111	496
SK	0	0	0	57	497
SI	0	0	40	130	498
ES	0	168	0	124	501
SE	0	175	0	0	488
CH	0	175	75	105	496

Table A.18.: Marginal CO_2 abatement costs, road transport sector [EUR/tCO2]

A.6.2. Developments in the European electricity sector

One of the main objectives of the research at hand is to develop a consistent, integrated multi-sectoral energy system model that can be used to understand the cross-sectoral effects under the increased electrification of fuel production and road transport. The scenario results for the European road transport sector shown in Section 2.3.2 reveal that both electric vehicles and ptx fuels will play an important role in reaching the sector-specific decarbonization targets. Because of the endogenous nature of the model presented, the consequences of these changes in fuel consumption patterns in the electricity sector can be quantified.

Figure A.3 shows the results of the electricity capacities and generation in Europe in 2020, 2030 and 2050. The overall installed capacity in Europe more than doubles, from 1160 GW in 2020 to 2660 GW in 2050. Declining costs as well as the sector-specific European CO_2 target drives the investments in renewable energy, which ultimately dominate the electricity mix. For the European conventional power plant fleet, decarbonization drives a switch from coal- to gas-fired power plants. In 2050 there is a large share of open-cycle gas turbines (OCGT) which serve as backup capacities, offering security of supply under high penetration of VRE. The net electricity generation in Europe rises from 3600 TWh in 2020 to 4950 TWh in 2050. Renewable energy resources comprise 54 % in 2030 and 88 % in 2050 of all European electricity produced. Wind power yields the largest share with 40 % in 2050, followed by PV with a share of 30 % of total electricity generation in 2050.

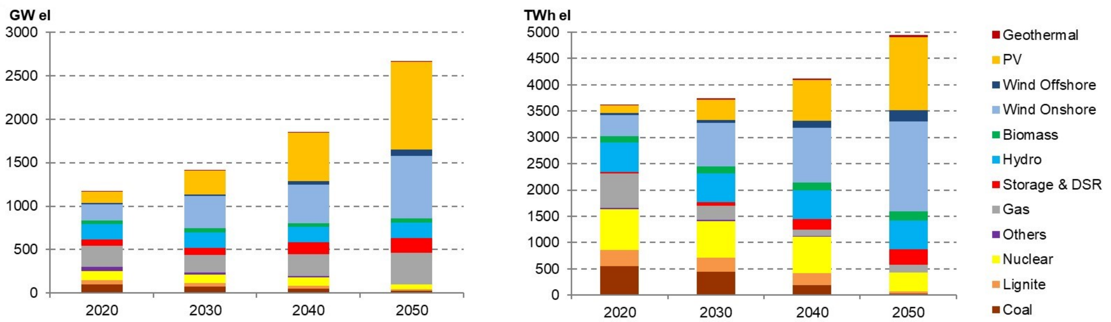

Figure A.3.: Installed electricity capacity (left) and generation (right) in Europe in 2020, 2030 and 2050 in the coupled model

The developments in the European road transport sector described in Section 2.3.2 drive a significant increase in electricity demand over time. As such, the investments in electricity capacities between 2030 and 2050 shown in Figure A.3 are made, in part, to generate electricity to serve the additional electricity demand from road transport and ptx processes. As shown in Figure A.4, the exogenous demand before ptx and electric mobility decreases over time due to, among others, efficiency improvements. Nevertheless, electrolysis, integrated Fischer-Tropsch and liquefaction systems, accounting for nearly 130 GW_{el} in 2050, demand an additional 630 TWh of electricity to serve fuel-cell and natural gas PPVs, LDVs and HDVs. An additional 570 TWh of electricity is consumed directly by BEVs. As a result, the European electricity demand is increased by nearly 33 % in 2050, from 3675 TWh to 4870 TWh.

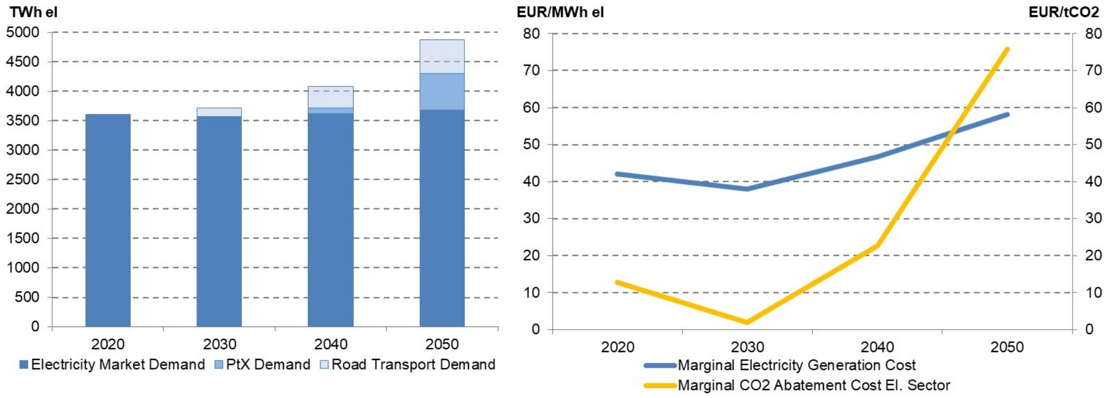

Figure A.4.: Electricity consumed by the exogenous electricity demand as well as the endogenous ptx and road transport demand in Europe in 2020, 2030 and 2050 in the coupled model (left); Results of the marginal electricity generation costs (weighted-average across all EU countries) and marginal CO_2 abatement costs for the electricity sector in the coupled model (right)

The average short-term marginal costs of electricity generation across all European countries are shown in Figure A.4. The average European marginal costs of electricity generation increases from 38 EUR/MWh_{el} in 2030 to 58 EUR/MWh_{el} by 2050. Increasing investments in VRE, which are needed to achieve the sector-specific decarbonization target, require investments in flexible backup capacities to ensure security of supply. Also, changes in variable costs of price-setting power plants due increasing fuel price projections or fuel switches may increase average marginal electricity generation costs. Countries with lower marginal costs tend to build VRE capacity for export into other EU countries. In 2050, large NTC capacities allow the electricity prices across Europe to converge, as electricity imports and exports are often unrestricted until equilibrium is reached. Finland, for example, exhibits the lowest marginal costs of electricity generation at 50 EUR/MWh_{el} and Italy the highest at 67 EUR/MWh_{el} in 2050 (Table A.19).

The marginal CO_2 abatement costs in the European electricity sector, driven by the sector-specific European-wide decarbonization target of -90 % compared to 1990, are also shown in Figure A.4. Between 2020 and 2030, Europe relies on low-cost decarbonization options such as a gradual switch from coal to gas and renewable expansion at cost-efficient locations. In particular, because the model is designed as a social planner problem with perfect foresight, it anticipates the 2050 emissions target. Restrictions on yearly capacity additions increase investments in low-emission generation capacities ahead of time, causing a gradual decrease in the marginal CO_2 abatement costs. By

2030, the marginal CO_2 abatement costs sink to 2 EUR/tCO_2, as investments in VRE have relaxed the CO_2 constraint. After 2030, the decarbonization target becomes more restrictive, pushing the CO_2 price to reach just over 75 EUR/tCO_2 by 2050. Because of the consistent, integrated nature of the model, the marginal costs of electricity generation as well as the marginal CO_2 abatement costs of the electricity sector properly account for the endogenous demand from electric vehicles and ptx systems. As such, the electricity sector enables not only the decarbonization of itself but also of major parts of the road transport sector, both via the increased electrification and ptx fuel production.

A.6.3. Developments in energy transformation technologies

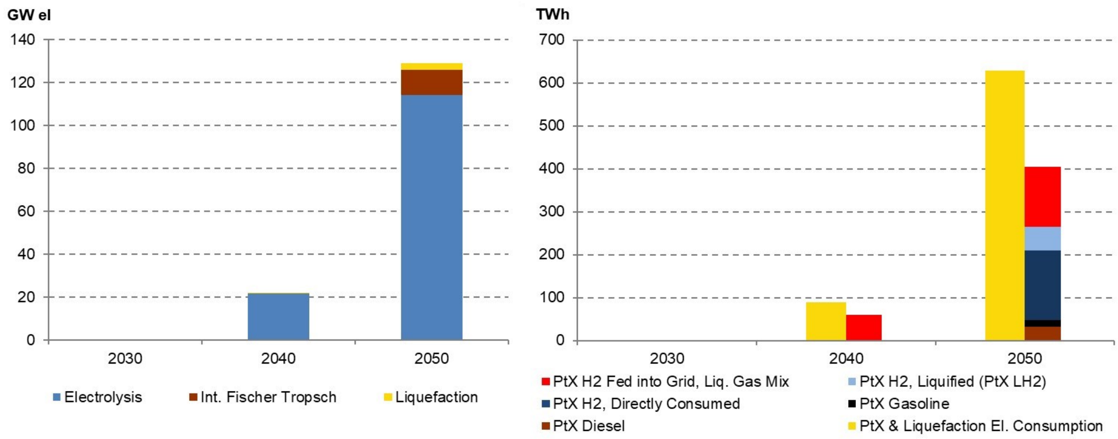

Figure A.5.: Installed capacities (left) as well as electricity consumption and fuel production (right) of ptx and liquefaction technologies in Europe between 2030 and 2050

Table A.19.: Results of the yearly average marginal electricity generation costs and endogenous PtX input electricity prices in 2040 and 2050 in EUR/MWh_{el}

	2040		2050		
	Marginal Costs Electricity Generation	**Input Price Electricity, Electrolysis**	**Marginal Costs Electricity Generation**	**Input Price Electricity, Electrolysis**	**Input Price Electricity, Fischer-Tropsch**
AT	53	-	62	42	-
BE	56	40	60	38	-
BG	44	36	54	29	55
HR	51	-	64	50	-
CZ	49	41	65	53	-
DK (East)	52	37	57	43	-
DK (West)	51	34	57	42	-
EE	45	34	56	26	-
FI	39	22	50	14	47
FR	45	33	59	46	-
DE	53	39	59	44	-
GB	47	27	59	41	-
GR	49	-	62	47	-
HU	49	40	61	45	-
IE	42	20	57	37	-
IT	55	-	67	50	-
LV	45	36	57	28	-
LT	44	36	57	30	-
NL	55	39	60	41	-
NO	33	7	54	26	-
PL	46	40	59	41	-
PT	36	15	51	20	50
RO	41	31	52	33	54
SK	48	41	62	46	-
SI	51	41	64	50	-
ES	40	24	54	30	51
SE	36	13	51	21	47
CH	53	-	62	46	-
EU	**47**	**31**	**58**	**38**	**51**

A.7. Supplementary assumptions and results of the decoupled model

A.7.1. Exogenous parameters

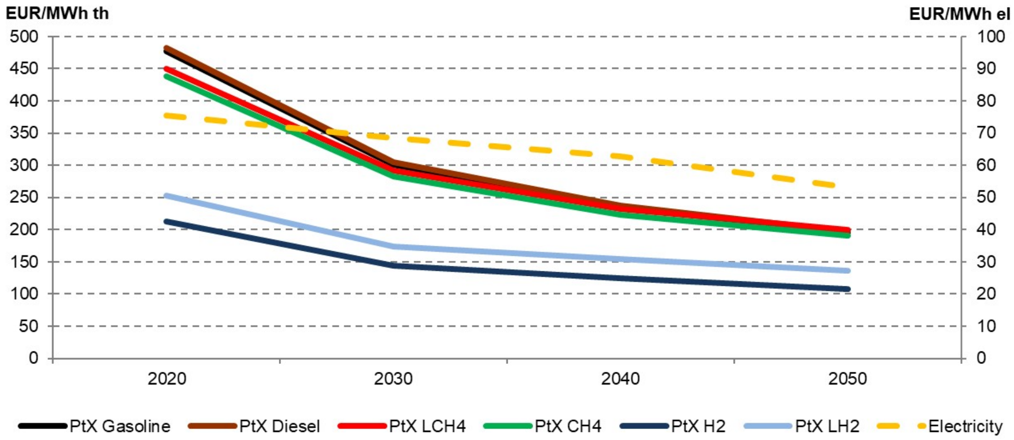

Figure A.6.: Exogenous ptx fuel and electricity prices assumed in the decoupled model

A.7.2. Selected delta comparisons

	2015	2020	2030	2040	2050
AT	0	17	0	-40	27
BE	0	-6	0	65	27
BG	0	0	0	0	27
HR	0	0	0	-42	27
CZ	0	0	0	-8	23
DK (East)	0	-6	7	-27	27
DK (West)	0	-6	12	-26	27
EE	0	0	0	0	55
FI	0	-6	11	70	54
FR	0	-6	19	10	27
DE	0	-4	36	-22	25
GB	0	2	13	-10	27
GR	0	0	0	0	27
HU	0	0	0	-35	27
IE	0	-6	0	11	25
IT	0	0	0	0	27
LV	0	0	0	0	29
LT	0	5	0	0	42
NL	0	-6	0	24	27
NO	0	56	83	84	27
PL	0	12	2	49	32
PT	0	0	0	0	27
RO	0	0	0	10	27
SK	0	0	0	-41	27
SI	0	0	13	-9	25
ES	0	-4	0	19	27
SE	0	-6	11	70	36
CH	0	-6	18	-15	27

Table A.20.: Delta marginal CO_2 abatement costs, road transport sector (decoupled minus coupled) [EUR/tCO2]

B. Supplementary Material for Chapter 3

B.1. Nomenclature

Throughout Chapter 3, notation as listed in Tables B.1 and B.2 is applied. Unless otherwise noted, bold capital letters indicate sets, lowercase letters parameters and bold lowercase letters optimization variables.

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 B.1.: Model sets and parameters used in Chapter 3

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 B.2.: Model variables used in Chapter 3

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 B.3.: Country codes used in Chapter 3

B.2. 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.

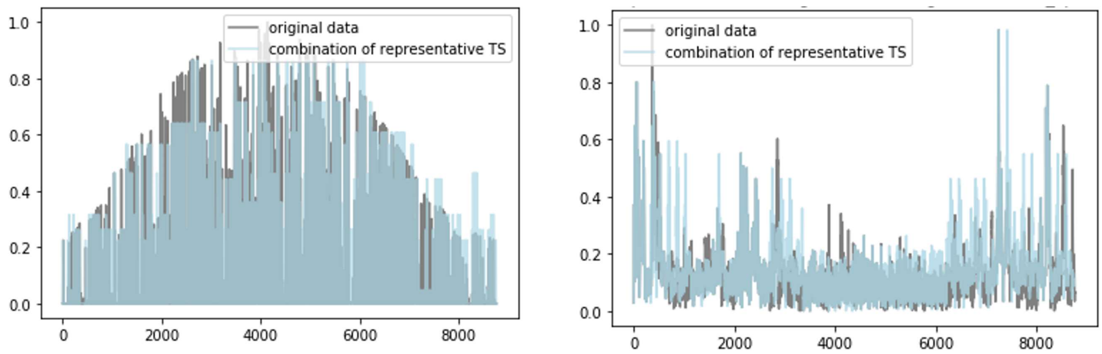

Figure B.1.: Illustrative depiction of how data sets with full temporal resolution may be recreated using typical days using the example of solar irradiation (left) and wind speed (right)

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.

B.3. Supplementary data and assumptions

B.3.1. 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 B.4.: 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 B.5.: 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])

B.3.2. Techno-economic assumptions within the modules

	Investment Costs [€/kW$_{el}$] 2019	2030	2040	2050	FOM Costs [€/kW$_{el}$*a]	Technical Efficiency [-]	Technical 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 B.6.: 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 Costs [€/kW$_{el}$]	FOM Costs [€/kW$_{el}$*a]	Variable Costs [€/MWh$_{el}$]	Feasibility Factor [-] 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 B.7.: 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 B.8.: 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 B.9.: 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 B.10.: 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 B.11.: 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] 2019	2030	2040	2050	FOM Costs [€/kW*a]	Thermal Efficiency [-]	Electric Efficiency [-]	Technical 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 B.12.: 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] 2019	2030	2040	2050	FOM Costs [€/kW*a]	Technical Efficiency [-]	Technical 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 B.13.: 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] 2019	2030	2040	2050	FOM Costs [€/kW*a]	Technical Efficiency [-]	Technical 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 B.14.: 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 B.15.: 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 B.16.: 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 B.17.: 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 B.18.: 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])

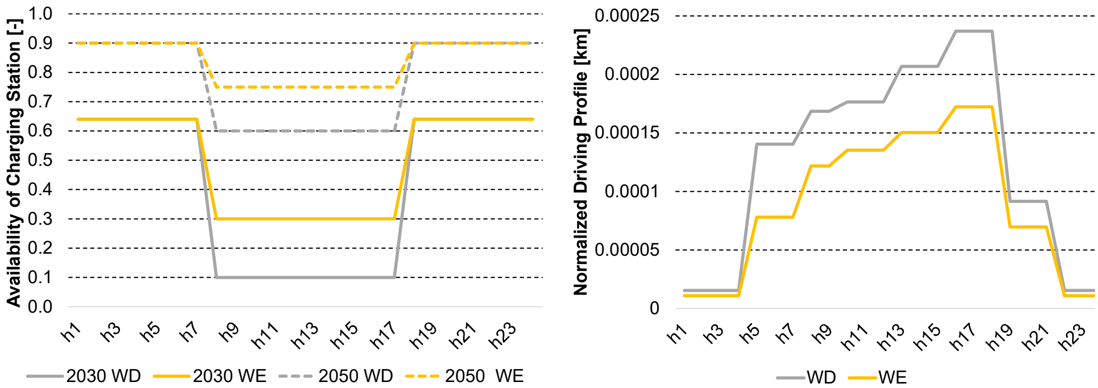

Figure B.2.: Hourly availability of charging stations in 2030 and 2050 (left) and hourly driving profiles (right) of private passenger vehicles for a typical weekday (WD) and weekend day (WE) assumed for each country (based on German data sources including [Bamberg et al., 2020], [Statistisches Bundesamt,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

B.3.3. Assumptions on exogenous demand and fuel consumption pathways

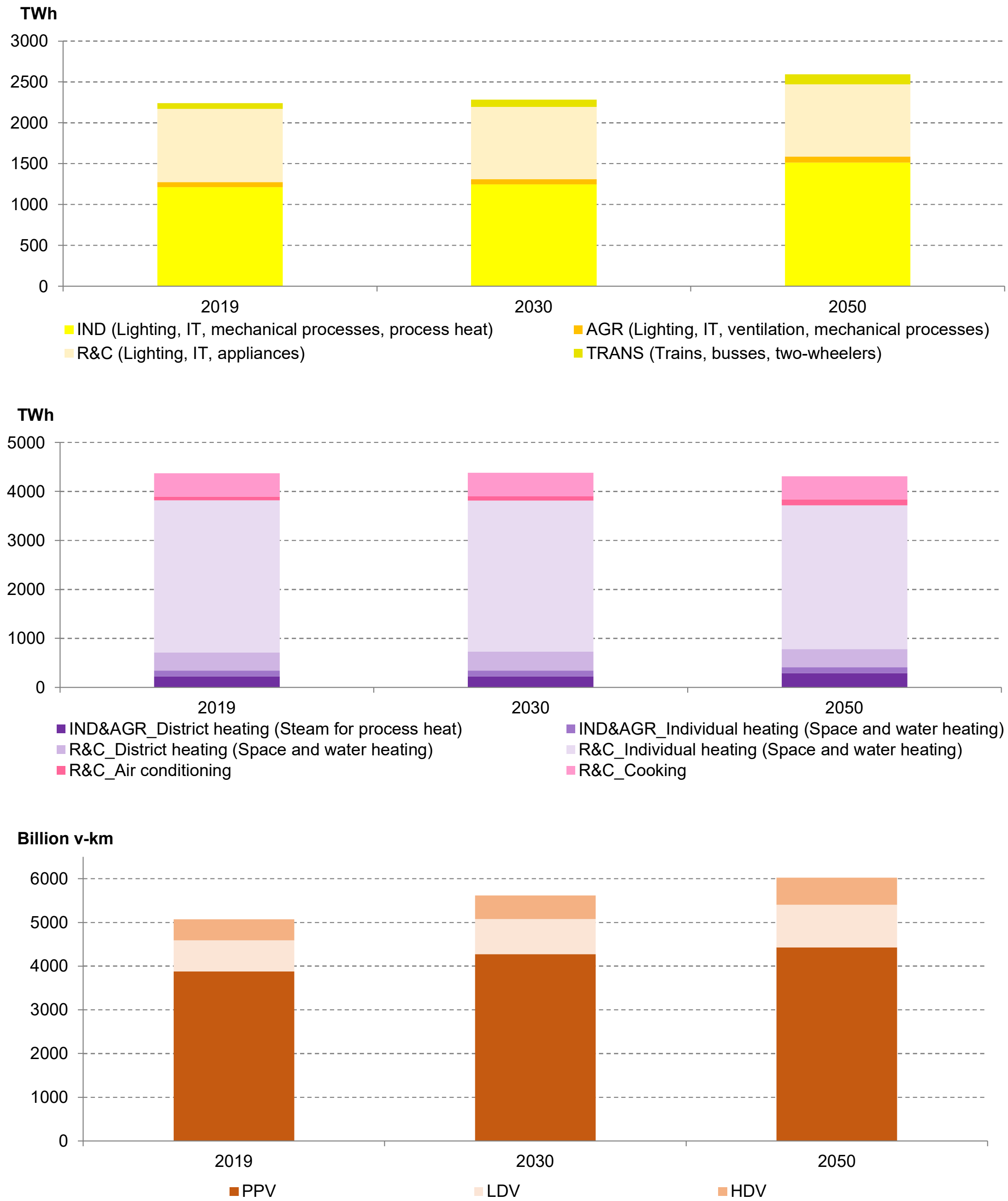

Figure B.3.: Assumptions on the development of useful and secondary electricity demand (top), useful heat demand (middle) and useful demand for vehicle kilometers (bottom) in the end-use sectors in Europe up to 2050
(own assumptions based on [Mantzos et al., 2019], [dena et al., 2021] and [Helgeson and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

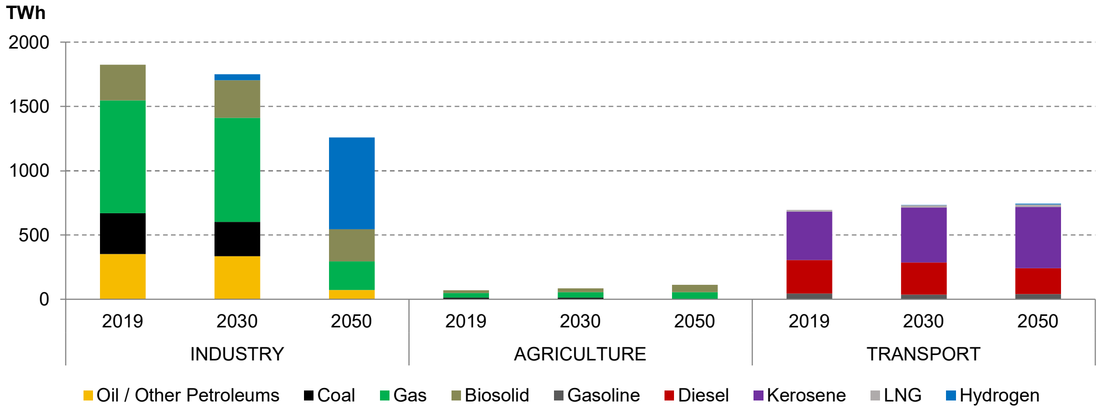

Figure B.4.: Assumptions on the development of fuel consumption in the end-use sectors in Europe up to 2050
(own assumptions based on [Mantzos et al., 2019], [dena et al., 2021])

B.3.4. 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 B.19.: 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 B.20.: Import prices of green hydrogen and synthetic (ptx) fuels from the North African region, calculations based on [Brändle et al., 2020]

B.4. Supplementary results on the investment decisions and generation amounts of the endogenous modules in the Green Island Europe scenario

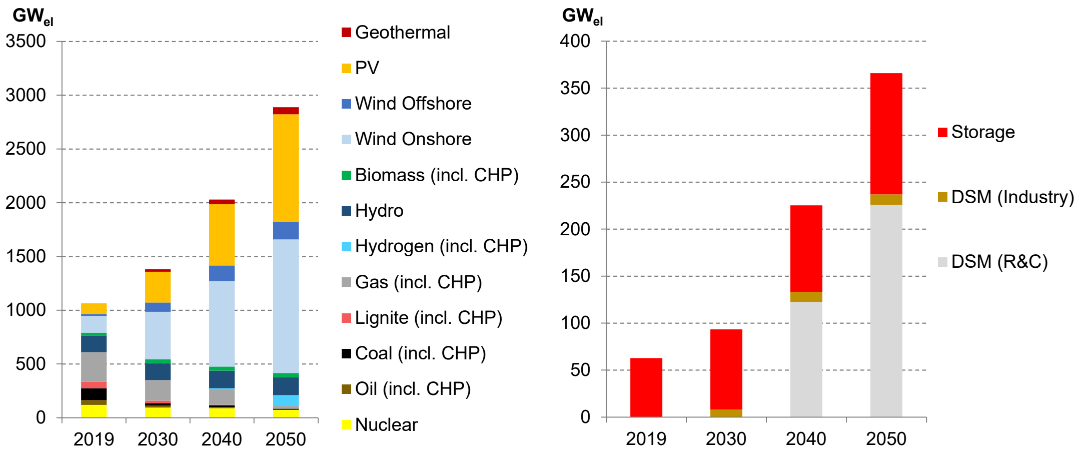

Figure B.5.: Results on installed capacities of electricity generators (left) as well as electricity storage and DSM processes (right) in Europe up to 2050 in the Green Island Europe scenario

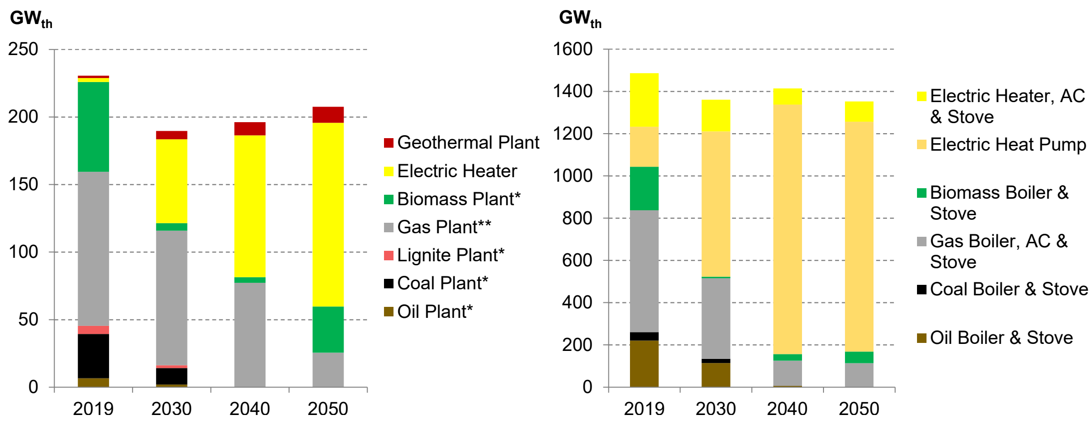

Figure B.6.: Results on installed heat capacities of district heat generators (left) and individual heating, cooking and cooling technologies (right) in Europe up to 2050 in the Green Island Europe scenario

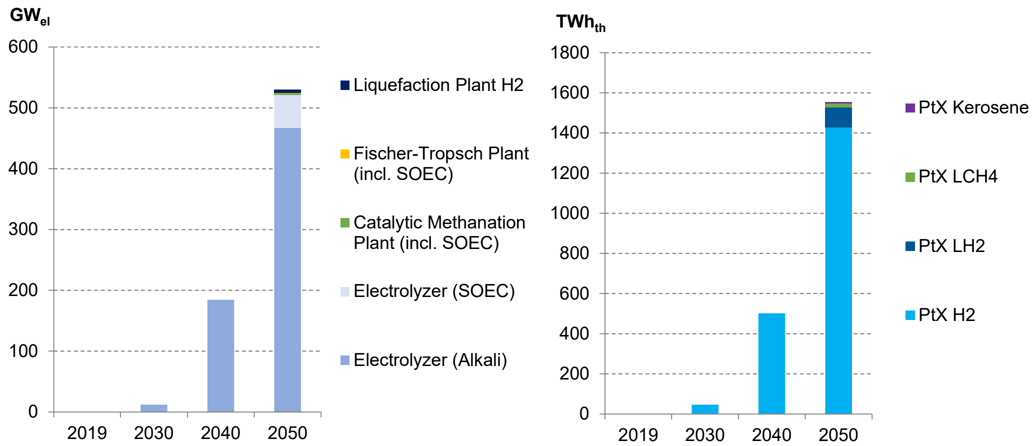

Figure B.7.: Results on the installed capacities of ptx technologies (left) and production volumes of green hydrogen and synthetic fuels (right) in Europe up to 2050 in the Green Island Europe scenario

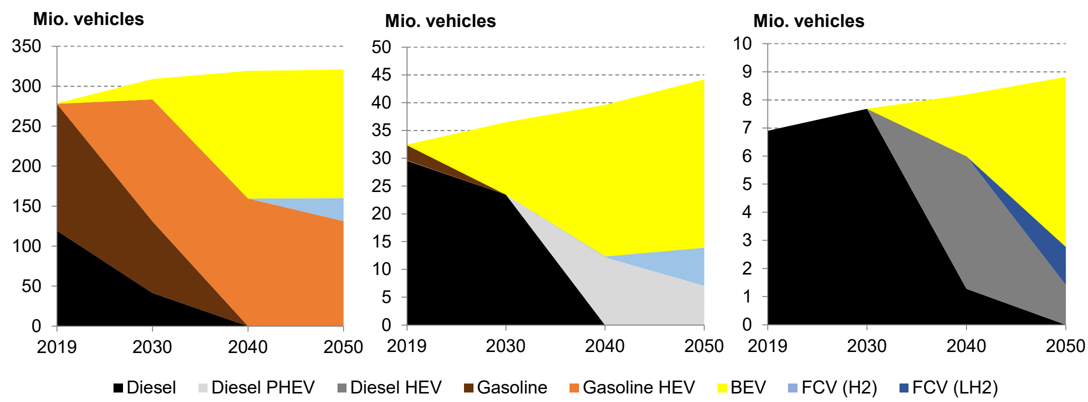

Figure B.8.: Results on road transport investments for private passenger vehicles (left), light-duty vehicles (middle) and heavy-duty vehicles (right) in Europe up to 2050 in the Green Island Europe scenario

B.5. Detailed comparison of Green Island Europe and Green Importer Europe scenarios

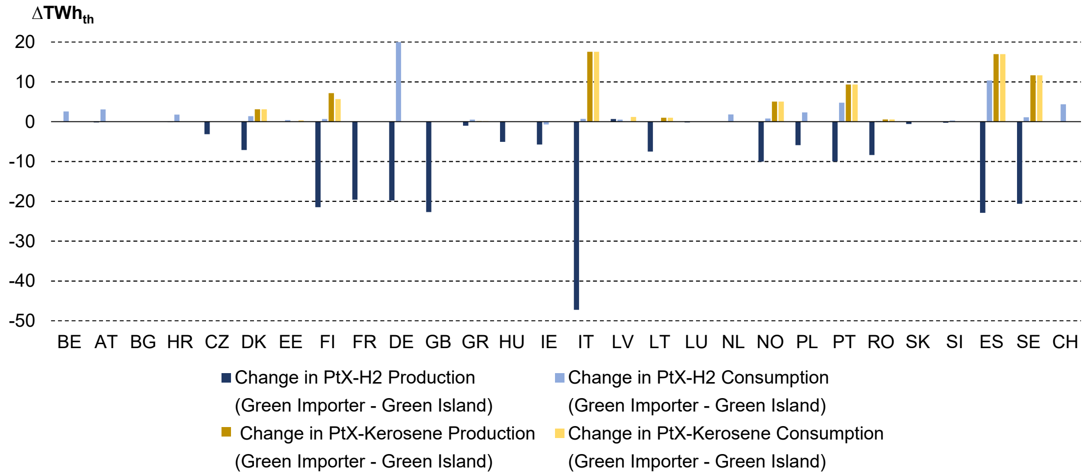

Figure B.9.: Change in the resulting green hydrogen (PtX-H2) and synthetic kerosene (PtX-Kerosene) production and consumption in between the Green Importer Europe scenario and Green Island Europe scenario in 2050

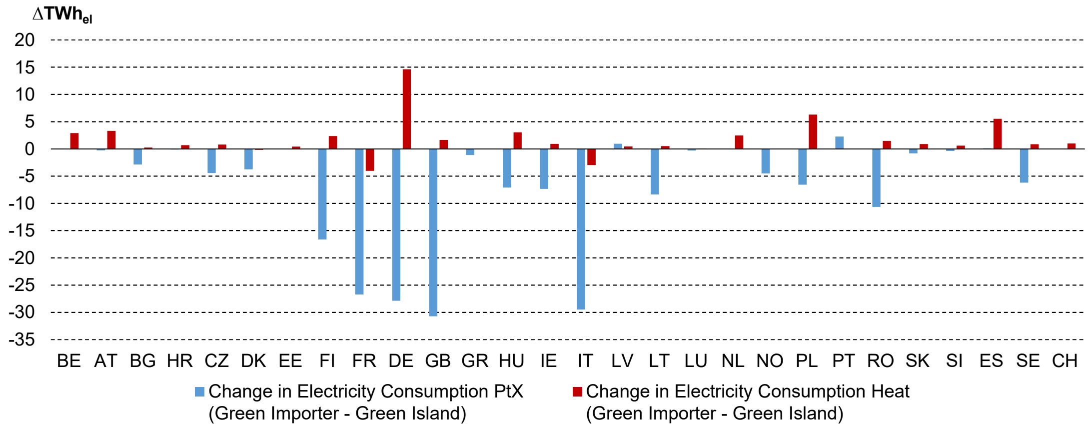

Figure B.10.: Change in the resulting electricity consumption from ptx technologies and heaters between the Green Importer Europe scenario and Green Island Europe scenario in 2050

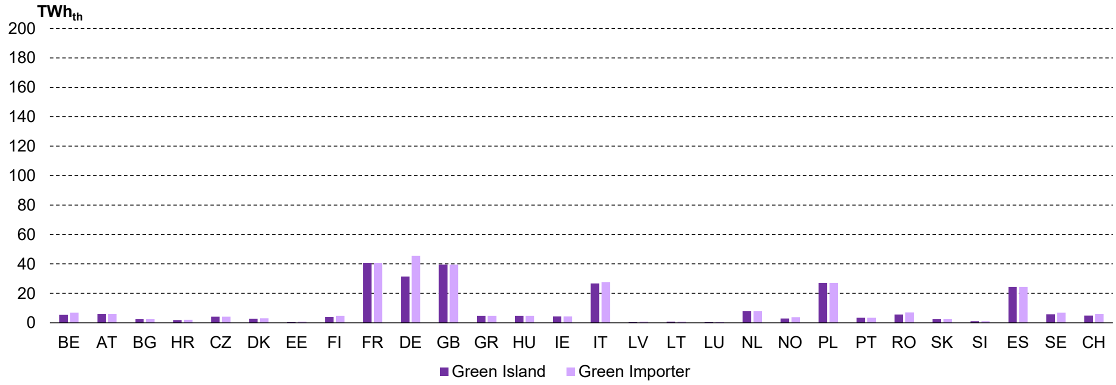

Figure B.11.: Results of the consumption of green hydrogen (in $\mathrm{TWh_{th}}$) in the transport sector in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

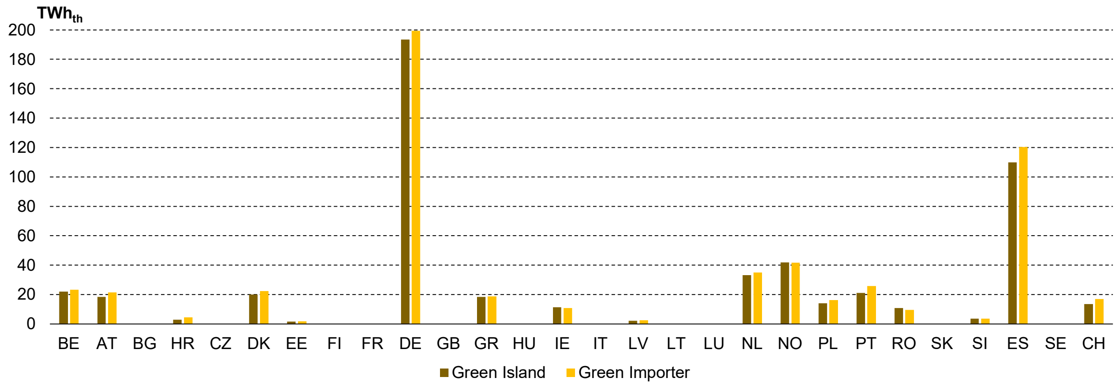

Figure B.12.: Results of the consumption of green hydrogen (in $\mathrm{TWh_{th}}$) for electricity generation in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

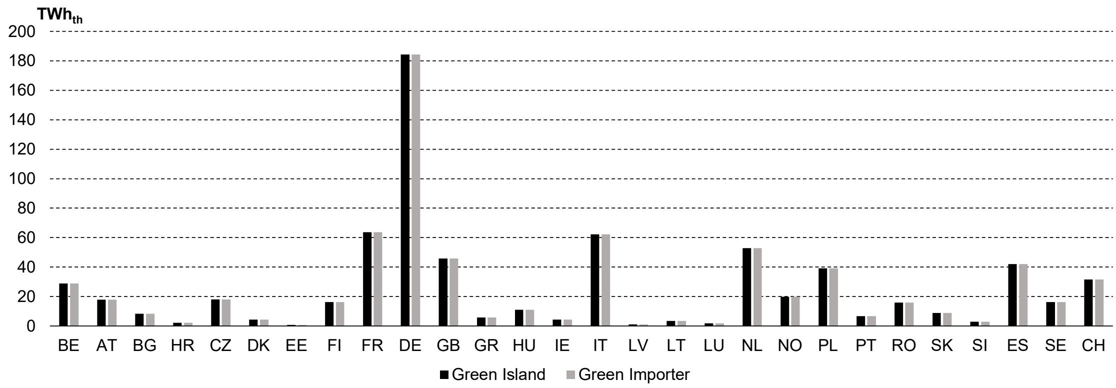

Figure B.13.: Results of the consumption of green hydrogen (in $\mathrm{TWh_{th}}$) in the industry sector in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

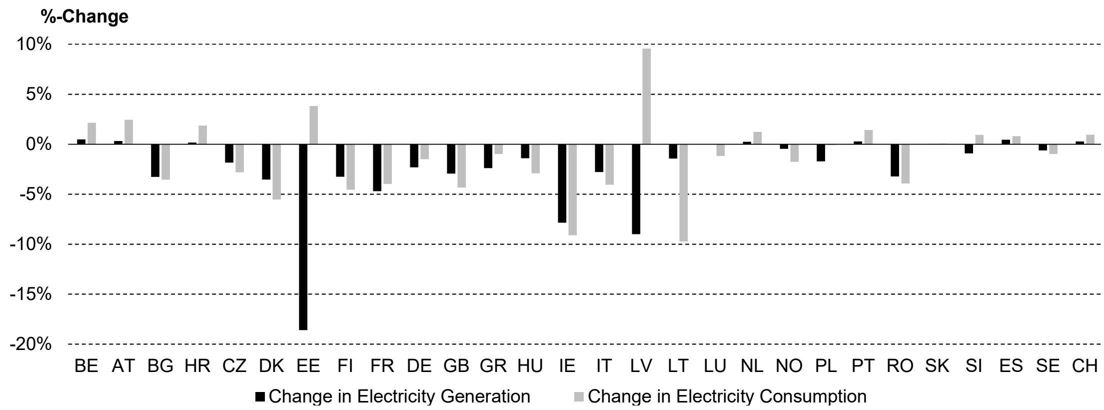

Figure B.14.: Change in the resulting total electricity generation and consumption in % between the Green Importer Europe scenario and Green Island Europe scenario in 2050

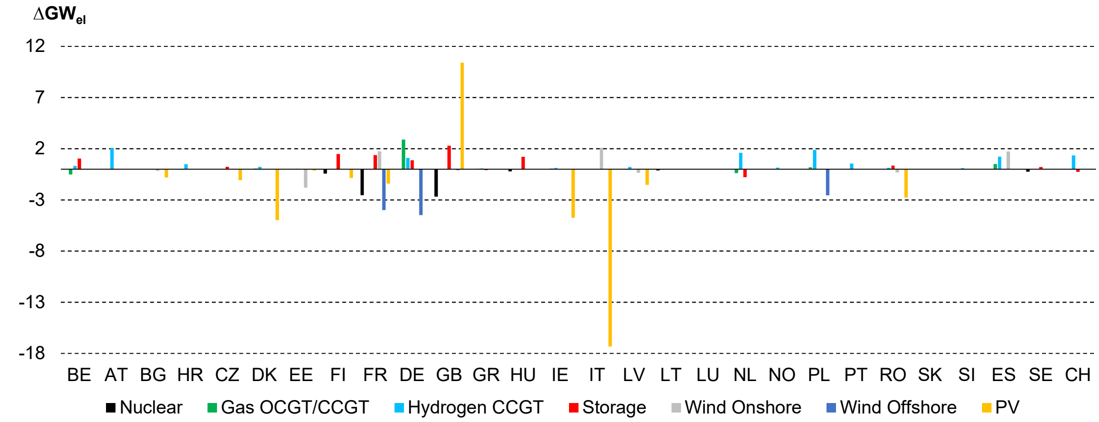

Figure B.15.: Change in the resulting installed capacity of electricity generators between the Green Importer Europe scenario and Green Island Europe scenario in 2050

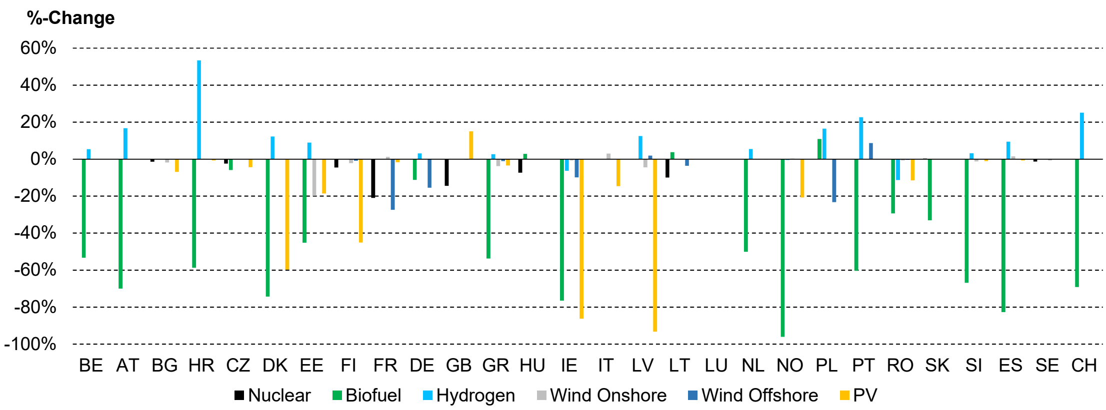

Figure B.16.: Change in the resulting electricity generation mix in % between the Green Importer Europe scenario and Green Island Europe scenario in 2050

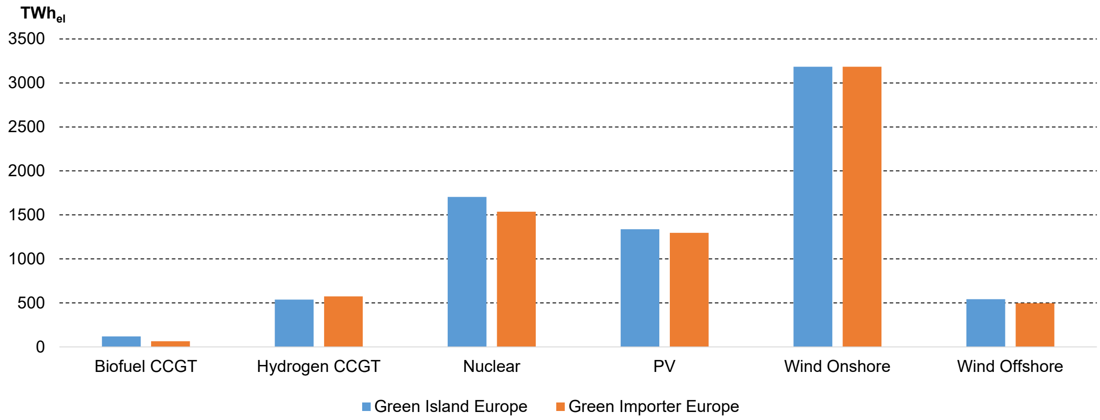

Figure B.17.: Electricity generation volumes in the Green Island Europe and Green Importer Europe scenarios in 2050 (hydro and geothermal power not pictured)

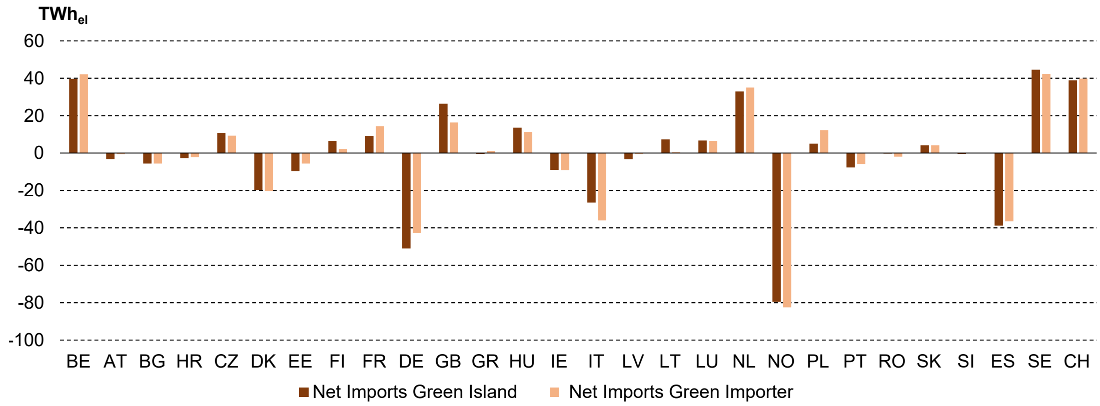

Figure B.18.: Net imports of electricity in the Green Island Europe and Green Importer Europe scenarios in 2050

B.6. Country-specific results of welfare analysis

B.6.1. 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 3.3.4). 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.[240] As can be seen in Figure B.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$_{\text{th}}$. 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$_{\text{th}}$ and 59 €/MWh$_{\text{th}}$ in the Green Island Europe and Green Importer Europe scenarios, respectively (see Figure B.20 in B.5). 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 decreases its capacities in electrolyzers as well as in integrated

[240] 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.

SOEC-methanation systems, and, in doing so, decrease the electricity consumption for ptx fuel production (see B.10 in B.5). 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 €/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 TWh_{th} of its domestic product and instead ramps down its green hydrogen production (-1 TWh_{th}) while also increasing domestic green hydrogen consumption (+1 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 €/MWh_{th}. Portugal, on the other hand, also reduces its green hydrogen exports by 15 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 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 B.9 and B.10 in B.5). 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.

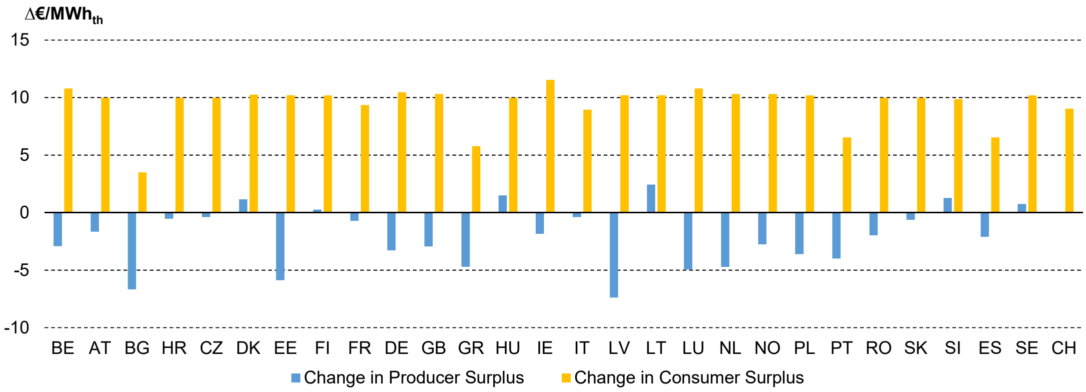

Figure B.19.: Differences in producer and consumer surplus for green hydrogen producers and consumers (in €/MWh_{th}) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

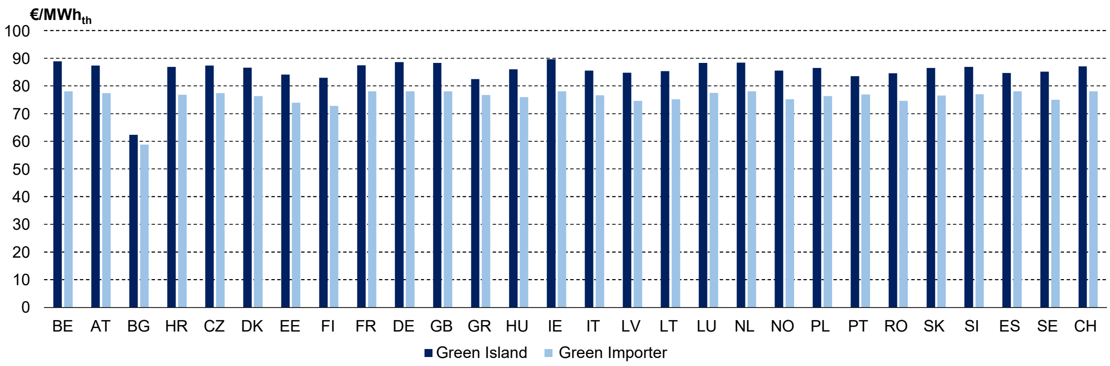

Figure B.20.: Results of the endogenous prices for green hydrogen (in €/MWh_{th}) produced in each country for the Green Island Europe and Green Importer Europe scenarios in 2050

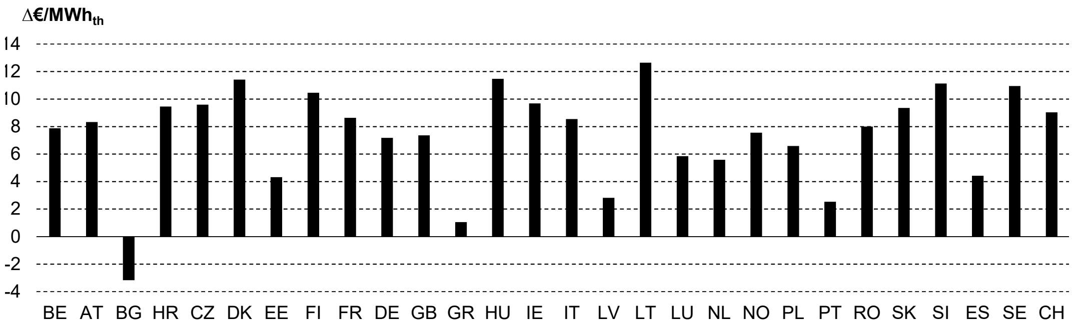

Figure B.21.: Differences in total welfare for green hydrogen producers and consumers (in €/MWh_{th}) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

B.6.2. 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 B.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 3.3.4, 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 B.10 and B.14 in B.5). 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 B.16 in B.5), 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 $\mathrm{MW_{el}}$) 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 B.9-B.18 in B.5).

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 B.14-B.18 in B.5). 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 $\mathrm{GW_{el}}$ of PV capacity compared to 1.7 $\mathrm{GW_{el}}$ 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 B.10 and B.14 in B.5. 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.

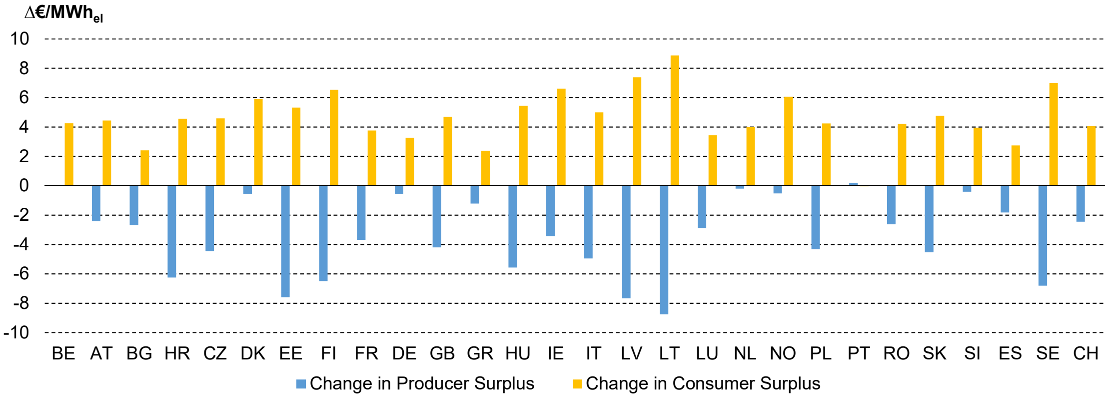

Figure B.22.: Differences in producer and consumer surplus for electricity generators and consumers (in €/MWh$_{el}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

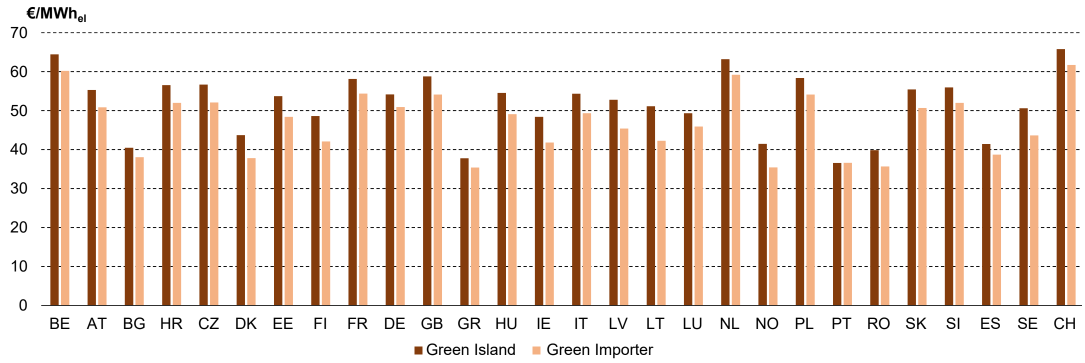

Figure B.23.: Results of the endogenous electricity prices (in €/MWh$_{el}$) in the year 2050, equal to the demand-weighted average over all time slices, for each country modeled in the Green Island Europe and Green Importer Europe scenarios

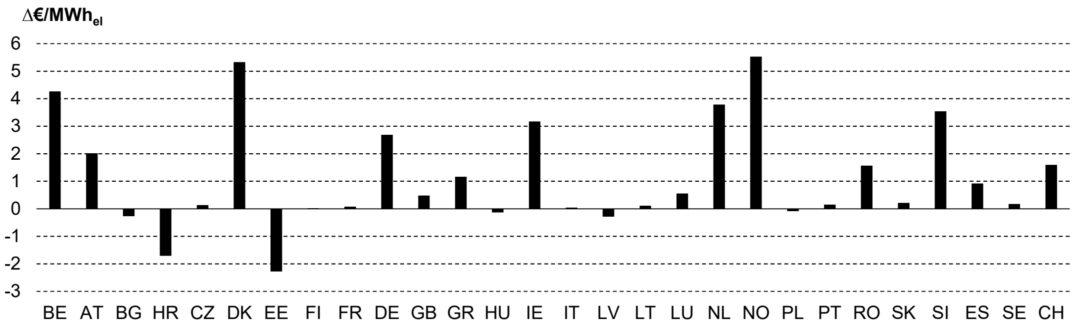

Figure B.24.: Differences in total welfare for electricity producers and consumers (in €/MWh$_{el}$) in European countries in 2050 when allowing imports of green hydrogen from outside Europe (Green Importer Europe minus Green Island Europe)

C. Supplementary Material for Chapter 4

C.1. Nomenclature

Throughout Chapter 4, notation as listed in Tables C.1 and C.2 is applied. Unless otherwise noted, optimization variables are indicated using bold, uppercase letters.

Sets		
y	-	year
x	-	technology
f	-	fuel
EUT	-	energy use type
fp	-	function part
t	-	time resolution
cpc	-	capacity price components
epc	-	energy price components
Parameters		
i	-	interest rate
j_x	-	financing rate of technology x
w_x	a	financing period of technology x
y	a	year
y_0	a	start year
y_x^*	a	installation year of technology x
lt_x	a	technical lifetime of technology x
γ_x	-	learning rate of technology x
$IC_{x,min}$	€	minimal investment costs of technology x
$\delta IC/\delta Q$	$€/kW$, $€/kWh$, $€/m^2$	capacity-specific investment costs
n	-	maximum number of function parts
$d_{y,t,EUT}$	kW	exogenously-defined energy demand for energy use type EUT in time slice t and year y
$cap_{CO_2,y}$	t_{CO_2}	consumer emissions cap in year y
$factor_{CO_2,f_x}$	g/kWh	CO_2 factor of fuel f used in technology x
$factor_{CO_2,t,EUT}$	g/kWh	average CO_2 factor of an energy use type EUT supplied by the grid in time slice t
$\eta_{t,x,EUT}$	-	efficiency of technology x producing energy use type EUT in time slice t
rs	m^2	roof size
$q_{grid,EUT}$	kW	size of the connection capacity for the corresponding energy use type EUT
$ep_{y,t,EUT,epc}$	$€/kWh$	energy price
$cp_{y,t,EUT,cpc}$	$€/kW$	capacity price
$er_{y,t,EUT}$	$€/kWh$	energy remuneration
$scr_{y,x,EUT}$	$€/kWh$	self-consumption remuneration
$scf_{y,x,EUT}$	$€/kWh$	self-consumption fee
G_t	kW/m^2	global solar irradiation on a tilted area
α_0	-	optical efficiency
$T_{collector,t}$	K	mean collector temperature
$T_{ambient,t}$	K	ambient temperature
T_{flow}	K	flow temperature
$T_{source,t}$	K	source temperature of heat pumps
rs	m^2	available roof space

Table C.1.: Model sets and parameters used in Chapter 4

$\boldsymbol{TC}$	€	total costs
$\boldsymbol{FC_y}$	€$/a$	fixed costs in year y
$\boldsymbol{AIC_{y,x}}$	€$/a$	annualized investment costs in year y
$\boldsymbol{IC_{y_x^*,x}}$	€	investment costs for technology x in the installation year y_x^*
$\boldsymbol{S_{y_x^*,x}}$	€	subsidy allocation for technology x in the installation year y_x^*
$\boldsymbol{FOMC_{y,x}}$	€$/a$	fixed operation and maintenance costs for technology x in year y
$\boldsymbol{EBC_y}$	€$/a$	energy-based costs in year y
$\boldsymbol{CBC_y}$	€$/a$	capacity-based costs in year y
$\boldsymbol{EBR_y}$	€$/a$	energy-based remuneration in year y
$\boldsymbol{HR_{y,x,EUT}}$	€$/a$	remuneration received via a time-variable (hourly) compensation for eligible technology x and energy use type EUT in year y
$\boldsymbol{Q_{y,x}}$	kW, kWh, m^2	capacity, storage volume or panel area for technology x in year y
$\boldsymbol{GFI_{y,t,x,EUT}}$	kW	feed-in of energy into grid
$\boldsymbol{XFI_{y,t,x,EUT}}$	kW	feed-in of energy into technology x
$\boldsymbol{GS}_{y,t,EUT=EUT_{demand}}$	kW	energy supply from the grid to cover exogenously-defined energy demand $d_{y,t,EUT}$
$\boldsymbol{GS}_{y,t,x,EUT}$	kW	energy supply from the grid
$\boldsymbol{XS}_{y,t,x,EUT}$	kW	energy supply from a decentralized energy technology
$\boldsymbol{N}$	-	number of the function part comprising the optimal installed capacity of a certain technology
$\boldsymbol{Qmin}$	kW, kWh, m^2	minimum achievable capacity
$\boldsymbol{SL_{y,t,x,EUT}}$	kWh	storage level in time slice t
$\boldsymbol{SV_{y,t,x,EUT}}$	kWh	available storage volume for a certain technology x

Table C.2.: Model variables used in Chapter 4

C.2. Additional Information on the Assumptions on Fuel Price Developments

Within the analysis in Chapter 4, three energy carriers are available to households: wood pellets, gas and electricity. In the following, the assumptions on the price components and price developments shown in Figure 4.4 in Section 4.3.1 are explained for each fuel type.

For wood, the price composition is relatively straightforward. Unlike the other energy carriers, the price for wood pellets consists only of acquisition together with concession, taxes and fees. Wood acquisition and processing make up 74% of the overall price of wood pellets.[241] The remaining share of the retail price includes, e.g., the value added tax as well as costs for logistics and storage. Wood pellet prices are assumed to increase drastically by more than 55% from 7.2 €-ct./kWh$_{th}$ in 2025 to 11.1 €-ct./kWh$_{th}$ in 2040 as a result of increasing material costs ([Shamon et al., 2021]).[242]

Gas, on the other hand, is made up of all four price components. Generally speaking, grid fees, which are paid by the end consumer to the energy provider, are passed on to grid operators in order to manage, maintain and expand the grid infrastructure. For gas, the grid fee makes up a 21% share of the overall gas price in 2025 and is assumed to stay constant at 1.6 €-ct./kWh$_{th}$ up to 2040. The price for gas acquisition follows the assumptions of the Sustainable Development Scenario in the IEA's World Energy Outlook 2020 ([International Energy Agency, 2020]) and equals 1.54 €-ct./kWh$_{th}$ in 2025 and increases by a mere 2% by 2040.[243] Furthermore, as explained in Section 4.3.1, end consumers in Germany are now required to pay a price for their resulting carbon emissions from energy provision, assumed to equal 1.1 €-ct./kWh$_{th}$ in 2025 and reach 1.8 €-ct./kWh$_{th}$ by 2040. The higher carbon prices assumed in the sensitivity analysis in Section 4.3.4 are assumed to equal 2.5 €-ct./kWh$_{th}$ in 2030, 4.0 €-ct./kWh$_{th}$ in 2035 and 5.5 €-ct./kWh$_{th}$ in 2040. Lastly, more than 40% of the retail price in 2025 is composed of payments for concession fees, taxes and other surcharges, which for the most part remain constant over the time period considered. All in all, the energy price components for gas add up to an overall price of 7.5 €-ct./kWh$_{th}$ in 2025 and rise to 8.4 €-ct./kWh$_{th}$ in 2040 in the main analysis and to 12.8 €-ct./kWh$_{th}$ in 2040 in the sensitivity analysis.

Unlike the other fuels, electricity is subject to two separate tariffs, as illustrated in Figure 4.4 in Section 4.3.1, namely "Heat-Pump Electricity" and "Non-Heat-Pump Electricity". The discrepancy between the two tariffs is primarily due to differences in grid fees: As electricity demand from heat pumps is more predictable due to strong correlations with weather conditions, they tend to provide less strain on the electricity grid. As such, heat pumps are subject to lower grid fees, making up 9% of the overall electricity

[241] See `https://gas.info/energie-gas/energie-preisvergleich/preisentwicklung-holzpellets`
[242] See `https://www.depi.de/pelletpreis-wirtschaftlichkeit#dau2v`
[243] It should be noted that the analysis at hand was performed prior to the Russian invasion of Ukraine in February 2022. Any consequential economic developments concerning the gas acquisition costs or supply restrictions are not considered in this work.

price as opposed to 27% for non-heat-pump electricity use in 2025. The grid fee for both heat-pump and non-heat-pump electricity use is assumed to increase linearly after 2025, reaching 2.4 €-ct./kWh$_{el}$ and 10.5 €-ct./kWh$_{el}$ by 2040, respectively. Furthermore, around 30% of the retail price for both non-heat-pump and heat-pump electricity use is composed of payments for concession, taxes and further fees. These remain mostly constant up to 2040. The third component is the renewable surcharge, as specified in the German Renewable Energies Act from the year 2000. This levy serves to refinance the renewable energy subsidies to support renewable expansion in Germany. In 2025, the renewable surcharge is assumed to reach its peak at 8 €-ct./kWh$_{el}$ for all electricity use before steadily decreasing to zero by 2040.[244] The final price component, i.e., the costs of electricity acquisition, is the only market parameter that differs across scenarios: For the Smart Market scenario, hourly electricity prices are assumed, as shown in the box plot on the right-hand side of Figure 4.4 in Section 4.3.1. For the Status Quo and Smart Tech scenarios, yearly averages of the hourly variable prices are set as constant electricity prices. At an average of 5.2 €-ct./kWh$_{el}$ in 2025, this cost component makes up the lowest share of the electricity retail price for both heat-pump and non-heat-pump use. By 2040, however, changes in electricity generation and demand in Germany yield an annual average acquisition cost of 6.5 €-ct./kWh$_{el}$. On average, the retail electricity price decreases from 31.2 €-ct./kWh$_{el}$ in 2025 to 26.3 €-ct./kWh$_{el}$ in 2040 for non-heat-pump electricity used and from 22.4 €-ct./kWh$_{el}$ in 2025 to 15.5 €-ct./kWh$_{el}$ for heat-pump electricity use. For the Smart Market scenario, a minimum retail price of 26.2 €-ct./kWh$_{el}$ and a maximum retail price of 37.7 €-ct./kWh$_{el}$ in 2025 and a minimum retail price of 20.0 €-ct./kWh$_{el}$ and a maximum retail price of 33.7 €-ct./kWh$_{el}$ in 2040 are assumed.

[244] Analogous to the carbon prices, the renewable energy surcharge is an endogenous result of the energy system model DIMENSION (see Footnote 192).

C.3. Detailed Description of the Economic and Technical Assumptions according to Technology Type

A significant contribution of the paper at hand is the inclusion of a wide range of technologies in the model. Each technology is subject to different technical, economic and regulatory characteristics, all of which must be accounted for in order to determine the cost-minimal energy provision. The following subsections present the technologies that are available to consumers, including a thorough explanation of the techno-economic assumptions. More specifically, the piecewise-linear investment costs, including installation and material costs, as well as the fixed annual operation and maintenance costs are shown in a series of figures.[245] For certain technologies, investment costs may be subsidized via incentive programs offered by the German government (c.f. [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a] and [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b]), as long as these fulfill certain technical requirements (see, e.g., [für Wirtschaft und Ausfuhrkontrolle, 2020]). Furthermore, technologies may also be eligible to receive financial remuneration for, e.g., decentralized electricity generation. Such regulatory aspects are also discussed below as they pertain to the specific technology.

C.3.1. Condensing Boilers

Conventional fuels such as natural gas or heating oil can be burned in a condensing boiler, achieving higher efficiencies compared to older non-condensing systems by taking advantage of upper, rather than the lower, heating values.[246] Oil condensing boilers are assumed to have an efficiency of 96% while gas condensing boilers are assumed to have an efficiency of 99%.[247] After installation, the household can use a gas condensing boiler for up to 25 years, while oil condensing boilers can be used for up to 20 years.[248]

[245] It should be noted that the investment costs illustrated in the following subsections do not include fuel storage systems (e.g., pellet or oil tank) or the installation of heating circuits such as radiators.

[246] Condensing boilers withdraw heat from the exhaust gas, causing the water in the exhaust to condense. This is not the case in conventional non-condensing boilers. Non-condensing boilers are not considered in this paper as new investments are assumed to be fully focused on the state-of-the art technology.

[247] Both assumptions are based on [Fleiter et al., 2016] and [Energinet.dk and Energi Styrelsen, 2012].

[248] The lifetime of gas condensing boilers is based on a life span of 17 to 30 years (see [Fleiter et al., 2016], [Energinet.dk and Energi Styrelsen, 2012], [Bettgenhäuser and Boermans, 2011], [Palzer, 2016], [Hedegaard and Münster, 2013], [Heinen et al., 2016], [Brown et al., 2018], [Omu et al., 2013], [Gerhardt et al., 2015] and [Kemna et al., 2007]). The lifetime of oil condensing boilers is taken from [Fleiter et al., 2016], [Energinet.dk and Energi Styrelsen, 2012], [Bettgenhäuser and Boermans, 2011], [Kemna et al., 2007] and [Palzer, 2016].

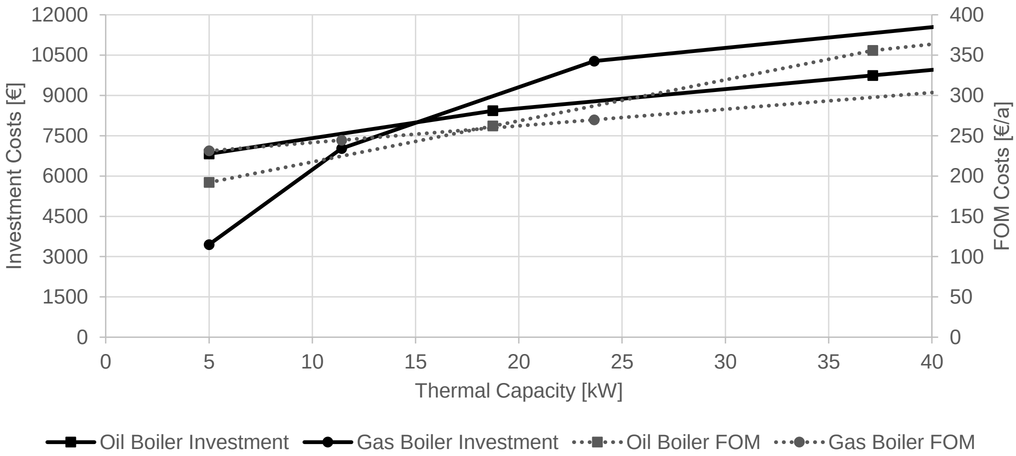

Figure C.1.: Investment and FOM costs of condensing boiler systems in 2020

Condensing boilers have the lowest specific investment costs compared to the other base heating technologies considered in this analysis. An exception are electric heaters, which are typically used as peak technologies. Investment costs for oil and gas condensing boilers are shown in Figure C.1 and are calculated based on [Mailach and Oschatz, 2016], [Mailach and Oschatz, 2017] and [Energinet.dk and Energi Styrelsen, 2012]. Further data from [Adolf et al., 2013] and [Fleiter et al., 2016] as well as additional industry sources were used for the investment cost analysis for gas boilers. The FOM costs are based on [Bettgenhäuser and Boermans, 2011], [Fleiter et al., 2016] and [Energinet.dk and Energi Styrelsen, 2012] and are depicted in Figure C.1 by the dotted lines.

The costs of storage systems for fuels, e.g., the construction of an oil or gas tank, are not included in these costs. As such, it is assumed that adequate storing options either already exist or are not needed, i.e., a grid connection is readily available. Furthermore, it is assumed that condensing boilers are already at an advanced development state and are therefore subject to only minimal reductions in investments costs in the coming years (see Table C.4 in Appendix C.4).

Moreover, it is assumed that no government-funded subsidies or other variable remunerations are available for condensing boilers at the time of this paper.[249]

[249] In reality, gas-condensing boilers could potentially qualify for subsides: According to [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a], 20% of the full investment costs (including installation (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b])) would be refunded if the system is "renewable ready" within two years after installation. In other words, a renewable energy heating system would have to be integrated into the the system and be able to supply a specific share of the energy demand ([für Wirtschaft und Ausfuhrkontrolle, 2020]). Technically speaking, the condensing boilers considered in this analysis could easily be combined with a renewable system, e.g., a solar heating system. Nevertheless, subsidies are modeled in COMODO according to the individual, as opposed to coupled, technology investment.

C.3.2. Combined-Heat-and-Power Systems

Combined-heat-and-power (CHP) systems allow for the simultaneous generation of both thermal and electrical energy, with natural gas or oil being converted into electricity and heat according to a so-called 'power-to-heat' ratio.[250] As such, the systems can achieve a high total efficiency by making use of the energy which may have been lost as heat. The consumer can choose between three CHP systems, namely an oil- or gas-fired motor or a gas-fueled fuel cell. The three systems do not only vary with respect to the fuel used but also according to their technical build, which leads to differences in the power-to-heat ratios and, in turn, the electric and thermal efficiencies, which are shown in Table C.3 for the CHP systems modeled.

CHP System Type	**Electric Efficiency** $\eta_{t,x=CHP,EUT=elec}$	**Thermal Efficiency** $\eta_{t,x=CHP,EUT=heat}$	**Selected Sources**
Gas CHP	30%	61%	[Klotz et al., 2014], [Verbraucherzentrale Nordrhein-Westfalen Energieberatung, 2013], [Wünsch et al., 2011], [Bürger et al., 2016], [Energinet.dk and Energi Styrelsen, 2012], [Diefenbach et al., 2017], [Björnebo et al., 2018], [Hamzehkolaei and Amjady, 2018], [Karmellos and Mavrotas, 2019], [Klein et al., 2014], [Fleiter et al., 2016]
Oil CHP	32%	57%	[Verbraucherzentrale Nordrhein-Westfalen Energieberatung, 2013], [Wünsch et al., 2011]
Fuel Cell	40%	52%	[Klotz et al., 2014], [Verheyen, 2011], [Wünsch et al., 2011]

Table C.3.: Efficiencies of CHP systems

Figure C.2 shows the assumed gas, oil and fuel cell CHP investment costs.[251] The graph clearly shows that fuel cells have higher costs than the other technologies, which

[250] The CHP systems in the model are assumed to have a constant power-to-heat ratio. Larger CHP plants may run flexibly and, as such, have varying power-to-heat ratios.

[251] The investment costs for gas-fired CHP are based on [Bürger et al., 2016], [Energinet.dk and Energi Styrelsen, 2012], [Mailach and Oschatz, 2016], [Adolf et al., 2013] and [Klein et al., 2014]; for oil-fired CHP based on [Verbraucherzentrale Nordrhein-Westfalen Energieberatung, 2013], [Wünsch et al., 2011]; and for fuel cells based on [Verbraucherzentrale Nordrhein-Westfalen Energieberatung, 2013], [Klotz et al., 2014], [Pehnt et al., 2012], [Ammermann et al., 2015], [Verheyen, 2011] and industry data.

is due to the difference in technical complexity as well as maturity of fuel cells compared to motor CHP systems. Motor CHP systems are typically modular such that higher capacities may be achieved by installing multiple motors. Therefore, the scaling effect is rather limited. Moreover, the assumed learning rates show that costs for fuel cells are expected to be reduced by 50% while costs for gas- and oil-fired motor CHPs see cost reductions of 23% by 2040 (see Table C.4). Furthermore, the assumptions for the FOM costs are depicted in Figure C.2.[252]

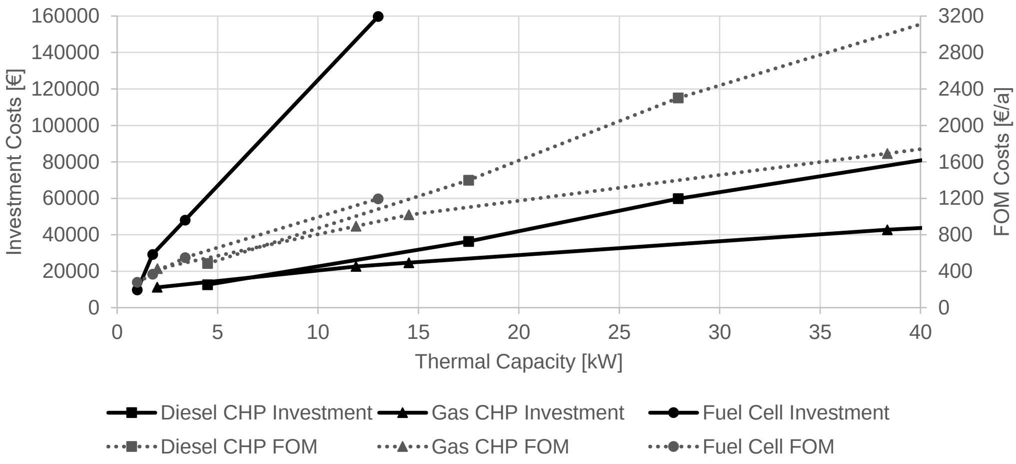

Figure C.2.: Investment and FOM costs of CHP systems in 2020

Electricity generation via CHP systems up to a capacity of 50 kW_{el}[253] is promoted with a feed-in tariff of 16 €-ct./kWh_{el} for electricity fed into the grid and a remuneration of 8 €-ct./kWh_{el} for all electricity which is not (see [Bundesamt für Justiz, 2020b]). Both are granted for up to 30,000 full-load hours (see [Bundesamt für Justiz, 2020a]).[254] Once installed, technical lifetimes of 15 years for motor CHP systems and 10 years for fuel cell systems are assumed [255]

[252] The FOM costs for gas-fired CHP are based on [Klotz et al., 2014]. Because of the technical similarities, it is assumed that the FOM costs of oil-fired CHP make up the same percentage share of investment costs as the FOM costs of gas-fired CHP. The FOM costs for fuel cells are based on [Klotz et al., 2014], [Pehnt et al., 2012], [Ammermann et al., 2015] and [Battelle Memorial Institute, 2017].

[253] The restriction on electric capacity of 50 kW_{el} is equal to about 101 kW_{th} for gas-fired CHP, 89 kW_{th} for oil-fired CHP and 65 kW_{th} for fuel cells.

[254] For simplicity, it is assumed in the model that the remuneration of 8 €-ct./kWh_{el} for 30,000 full-load hours of electricity generation is directly redeemed at the time of investment. Because of this one-time compensation, the feed-in tariff is then corrected to 8 €-ct./kWh_{el}.

[255] The assumption for motor CHP is based on [Ren and Gao, 2010], [Mailach and Oschatz, 2016], [Diefenbach et al., 2017], [Björnebo et al., 2018], [Hamzehkolaei and Amjady, 2018], [Energinet.dk and Energi Styrelsen, 2012] and [Fleiter et al., 2016]. For fuel cells, see [Ren and Gao, 2010], [Fleiter et al., 2016], [Verheyen, 2011] and [Brandoni and Renzi, 2015].

C.3.3. Electric Heater

The simplest form of power-to-heat technologies is the electric heater. This heating system is able to convert electricity into heat with near-zero energy losses.[256] Figure C.3 shows the assumed power to heat system investment costs based on [Beck et al., 2017] and [Bechem et al., 2015]. Electric heaters are usually used in combination with other heating technologies such as condensing boilers, CHP or electric heat pumps. In multi-technology systems, electric heaters typically supply heat in times of peak demand, i.e., serve as a peak technology. It is assumed that electric heaters are not subject to FOM costs. According to [Beck et al., 2017], investments must be renewed every 15 years due to limited technical lifetimes.

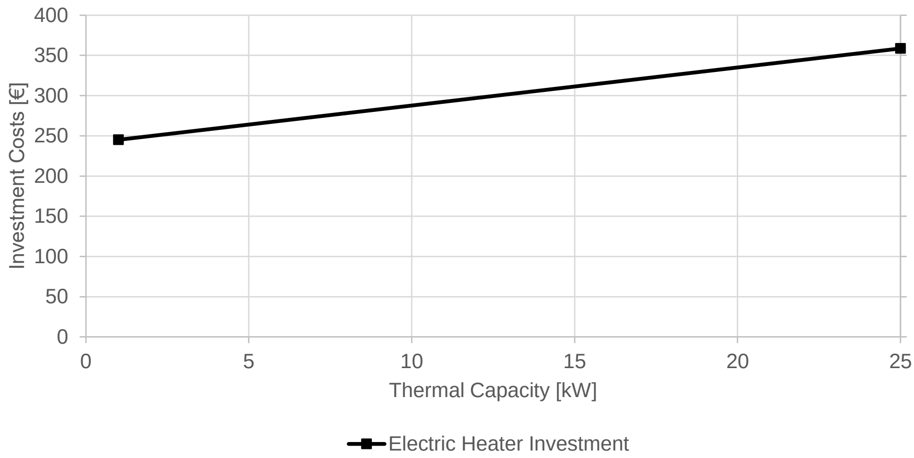

Figure C.3.: Investment costs of electric heaters in 2020

C.3.4. Electric Heat Pumps

Electric heat pumps use the enthalpy of an electricity input to extract energy from low-temperature energy sources in order to generate high-temperature space and warm water heating. Possible energy sources for this technology are ambient air (air-to-water), ground (water-to-water) or geothermal energy.

Figure C.4 shows the investment costs for the three different electric heat pumps included in COMODO: air-to-water, water-to-water (also known as collector) and geother-

[256] An efficiency of 100% is assumed.

mal.[257] The costs presented include the construction of the system to retrieve the source energy (e.g., collector or drilling). For water-to-water and geothermal systems, high investment costs are strongly driven by construction costs in order to access the energy source. Geothermal systems, in particular, have high installation costs due to the need for vertical drilling. Furthermore, FOM costs are also depicted in Figure C.4 for each heat pump type.[258] Once installed, electric heat pumps are assumed to have a technical lifetime of 20 years. [259]

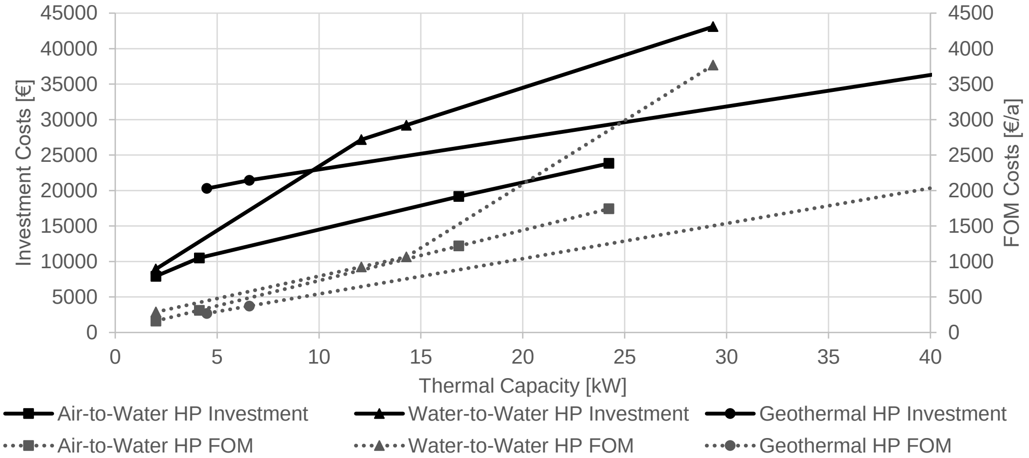

Figure C.4.: Investment and FOM costs of electric heat pump (HP) systems in 2020

As explained in Section 4.2.4, the performance of electric heat pumps is determined according to the COP, a variable efficiency factor that is highly dependent on the temperature delta between the source temperature and the desired flow temperature of the

[257]The investment costs for air-to-water electric heat pumps are based on [Beck et al., 2017], [Bettgenhäuser and Boermans, 2011], [Bürger et al., 2016], [Henning and Palzer, 2013], [Petrovic and Karlsson, 2016], [Pfnür et al., 2016], [Brown et al., 2018], [Mailach and Oschatz, 2016], [Mailach and Oschatz, 2017], [Omu et al., 2013], [Herkel et al., 2018], [Palzer, 2016], [Adolf et al., 2013], [Heinen et al., 2016], [Hedegaard and Münster, 2013], [Karmellos and Mavrotas, 2019] and industry data; for water-to-water electric heat pumps based on [Bettgenhäuser and Boermans, 2011], [Bürger et al., 2016], [Henning and Palzer, 2013] and [Petrovic and Karlsson, 2016]; and for geothermal electric heat pumps based on [Hardy et al., 2016] and industry data.

[258]The FOM costs assumed for air-to-water electric heat pumps are based on [Beck et al., 2017], [Bettgenhäuser and Boermans, 2011], [Henning and Palzer, 2013], [Petrovic and Karlsson, 2016], [Pfnür et al., 2016], [Heinen et al., 2016], [Brown et al., 2018], [Hedegaard and Münster, 2013], [Mailach and Oschatz, 2016], [Mailach and Oschatz, 2017], [Palzer, 2016] and [Heinen et al., 2016]; for water-to-water electric heat pumps based on [Bettgenhäuser and Boermans, 2011], [Henning and Palzer, 2013] and [Petrovic and Karlsson, 2016]; and for geothermal electric heat pumps based on [Brown et al., 2018] and [Palzer, 2016].

[259] [Henning and Palzer, 2013], [Omu et al., 2013], [Palzer, 2016], [Petrovic and Karlsson, 2016], [Gerhardt et al., 2015], [Heinen et al., 2016], [Beck et al., 2017], [Brown et al., 2018], [Herkel et al., 2018], [Karmellos and Mavrotas, 2019] and [Hedegaard and Münster, 2013] assume lifetimes in the range of 15 to 30 years.

heating system. Whereas the desired flow temperature depends on the consumer preference and building age, the heat source temperature is different for each type of heat pump. For air-sourced heat pumps, the heat-source temperature is the outside temperature. Thus, the temperature delta fluctuates strongly over time, with the COP decreasing when the outside temperature drops and the delta becomes larger. This variance in performance explains the relatively low investments costs shown in Figure C.4 compared to the other heat pump types. For the ground-sourced water-to-water heat pumps, the heat-source temperature at a depth of one meter below surface is calculated according to [Benker and Heidt, 2000].[260] In a depth of one meter, the temperature still varies with the outside temperature; however, the variance is reduced due to the insulation effect of the ground. This leads to a more stable COP compared to that of the air-to-water electric heat pump. For geothermal heat pumps, a heat-source temperature of 10°C is assumed. As a result, the temperature delta of geothermal heat pumps and the subsequent COP are constant over all time slices. All in all, heat pumps are capable of achieving COPs ranging from 2 and 6.

Electric heat pumps are eligible for subsidies equal to up to 35% of the full investment costs (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a]) including installation costs (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b]), as long as they reach an annual performance factor[261] of 3.5 for air-sourced or 3.8 for ground-sourced heat pumps in existing buildings and 4.5 for all heat pumps (i.e., regardless of source) in newly-constructed buildings (see [für Wirtschaft und Ausfuhrkontrolle, 2020]).

C.3.5. Pellet Stove

Renewable heat can be provided by burning wood pellets in a stove. Figure C.5 shows the investment costs assumed for pellet stoves based on [Raab et al., 2013]. These do not include the costs of storage and transportation of wood pellets. Up to 35% of the costs illustrated in Figure C.5 may be subsidized by the German government (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a] and [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b]). Furthermore, the FOM costs are also depicted in the figure, calculated as a share of 4.8% of the investment costs.[262] Once installed, wood pellet stoves can provide energy with an efficiency of 92% [263] for a technical lifetime of 20 years (see [Raab et al., 2013]).

[260]Data on the specific heat capacity (1175.75 J/(kg*K), density (1742.25 kg/m^3) and thermal conductivity (1.5025 W/(m*K)) is taken as a mean from [Bundesindustrieverband Deutschland Haus-, Energie- und Umwelttechnik e.V. and Bundesverband Wärmepumpe e.V., 2011]

[261]The annual performance factor is equal to the demand weighted average of the COP over the year.

[262]The literature states that the annual FOM costs range from 3.2% up to 6% of the investment costs. Sources for the FOM costs are [Breitschopf et al., 2010], [Bürger et al., 2016], [Stuible et al., 2016] and [Härdtlein et al., 2016].

[263]This efficiency is a mean between the different manufacturers, models and load levels.

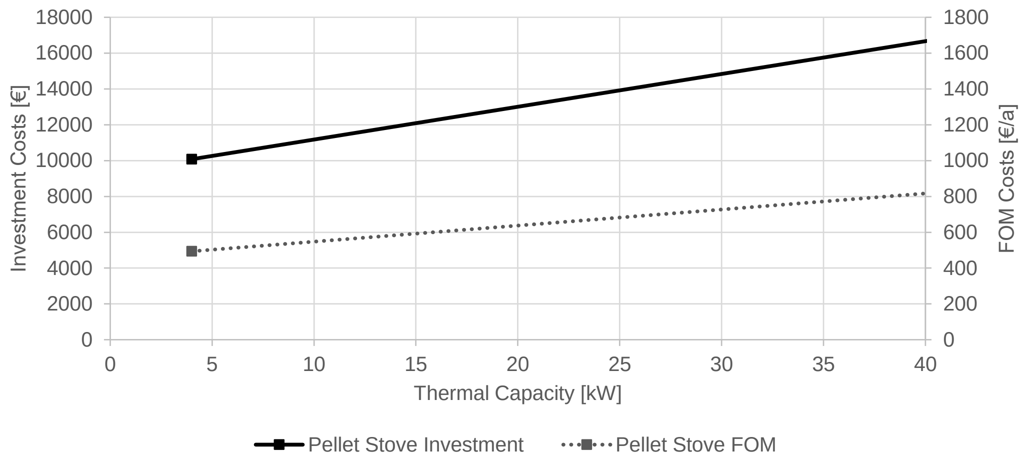

Figure C.5.: Investment and FOM costs of pellet stoves in 2020

C.3.6. Solar Thermal Plant

Solar thermal plants convert direct and indirect solar irradiation into heat for both space and water heating. Solar thermal systems are typically rooftop installations and thus depend on the solar irradiation on a tilted surface analogous to PV, as described below in Appendix C.3.8. In order to determine the heat production of such a system, the solar irradiation on the tilted surface is adjusted according to the energy losses. Based on [European Solar Thermal Industry Federation, 2007], these losses can be estimated using optical losses, which are included as a percentage, as well as first- and second-order heat losses.[264] The total heat losses then depend on the difference between the mean collector temperature[265] and the outside air temperature. Solar thermal systems are the only systems considered in the model whose size is measured in square meters (i.e., m^2) and not in kilowatts.

Figure C.6 shows the investment costs assumed for solar thermal systems for space and water heating.[266] Furthermore, the FOM costs are also depicted, calculated as a 1.6% share of investment costs.[267] Investments in solar thermal plants may receive subsidies up to 30% (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021a]) of the overall investment costs (see [Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2021b]). Once

[264] Within this paper, an optical efficiency of 80%, a first-order heat loss coefficient of approximately 3 $W/(m^2K)$ and a second-order heat-loss coefficient of 0.008 $W/(m^2K^2)$ based on [Trier, 2012] are assumed.

[265] Mean collector temperatures of 50°C for warm water systems and 60°C for space heating systems are assumed.

[266] The investment costs are based on [Thiel and Ehrlich, 2012], [Gerhardt et al., 2015], [Wiemken et al., 2008], [Bettgenhäuser and Boermans, 2011], [Ebert et al., 2011] and industry data.

[267] [Brown et al., 2018], [Henning and Palzer, 2013] and [Gerhardt et al., 2015] provide data on the FOM costs as a share of the investment costs ranging between 1% and 2%.

installed, solar thermal plants can be operated for 20 years.[268]

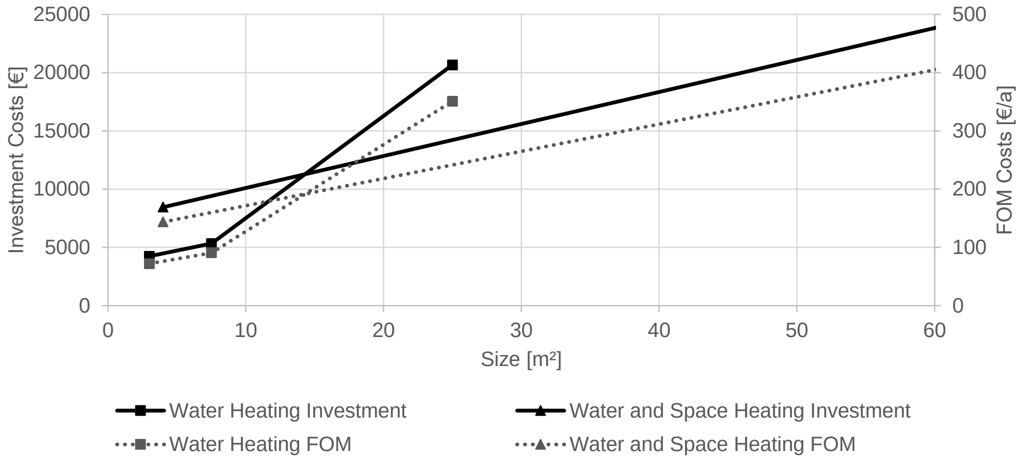

Figure C.6.: Investment and FOM costs of solar thermal systems for water and space heating in 2020

C.3.7. Thermal Storage

Thermal storage systems can be used in combination with any of the heat generation technologies described in order to decouple the time of heat generation and consumption. The thermal storage assumed in this paper is a sensible heat storage based on the storage medium water. Storage systems are designed according to a storage volume measured in kWh, which in turn defines the maximal amount of storable energy. Moreover, the maximum energy flow that can be fed into or be discharged from the storage system needs to be taken into consideration when designing the system. The maximal flow level is measured in kW. Figure C.7 illustrates the relationship between the maximum flow level and the storage volume.[269] As can be seen in the figure, the maximum flow level rises when the storage volume is increased.

[268] According to the technical lifetimes given in [Brown et al., 2018] and [Henning and Palzer, 2013].

[269] The relationship between the maximum flow level and storage volume shown in Figure C.7 was constructed by evaluating the specifications of storage systems from many different manufacturers.

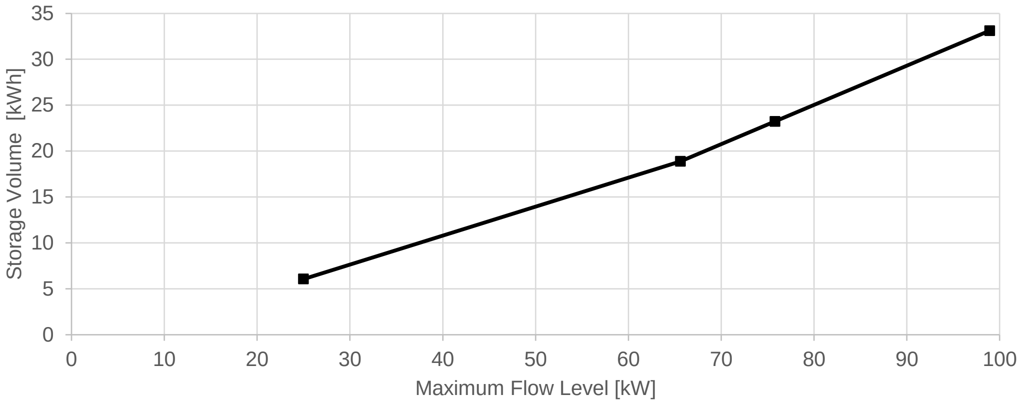

Figure C.7.: Relationship between the maximum flow level (kW) and storage volume (kWh) of thermal storage

Although thermal storage systems are not energy generators, they may also experience energy losses. When storing heat in a thermal storage, heat radiates from the storage tank and therefore lost from one point in time to the next.[270]

Figure C.8 shows the investment costs assumed for thermal storage based on industry data. For any storage volume above 76 kWh, specific installation costs increase drastically as a pre-assembling of parts is no longer possible due to the height and width of the larger storage tank. Furthermore, it is assumed that a thermal storage system itself is not subject to any FOM costs; however, it is assumed that the maintenance of the storage is carried out together with the inspection of the heat generating technology and is thus included in the FOM costs of the generating technology. Within this paper, a technical lifetime of 30 years is assumed for a simple thermal sensible heat storage.

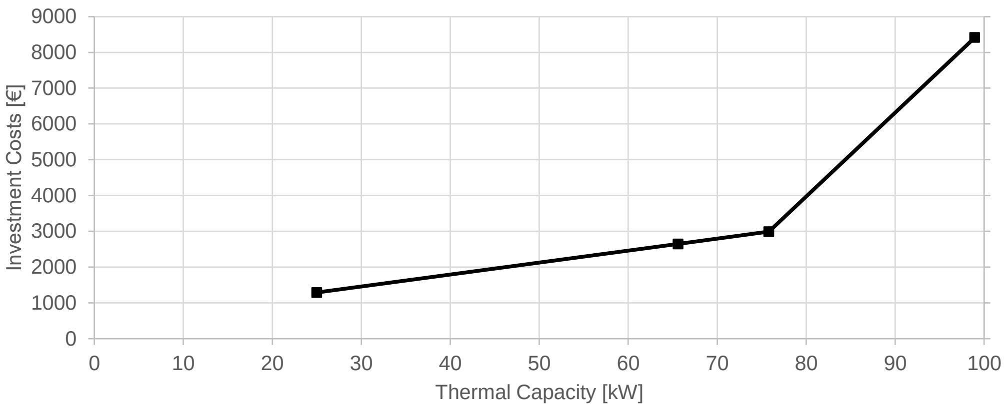

Figure C.8.: Investment costs of thermal storage systems in 2020

[270]Within this paper, a loss equal to 1% of the stored energy is assumed for each hour in which the energy is stored.

C.3.8. Photovoltaics

Photovoltaic (PV) panels are a renewable energy system used to convert irradiation from the sun into electricity, often installed on rooftops. To determine the amount of electricity produced, the calculation of the global irradiation on the inclined surface follows the functional estimations of the isotropic diffuse irradiation model stated in [Eicker, 2012]. Put simply, the radiation depends on the position of the sun relative to the PV panel and the losses in the atmosphere. The sun's position, in turn, depends on the location of the PV panel as well as the time of day.[271] For the research at hand, all PV systems are assumed to be south-facing[272] with an inclination of 35.5° [273]. Furthermore, a reflection coefficient of 0.2 is assumed in order to calculate the diffused reflection from the ground. Shade as well as other non-optimal conditions for the PV system that may vary according to the individual location of the installation of a specific consumer are ignored, assuming a full conversion of the direct incident sunlight.

Figure C.9 shows the investment costs of the PV system assumed.[274] As PV panels are modular installations, the cost function is almost linear and thus have near-constant specific investment costs. Furthermore, the figure also presents the FOM costs based on [Bergner and Quaschning, 2019] and industry data.

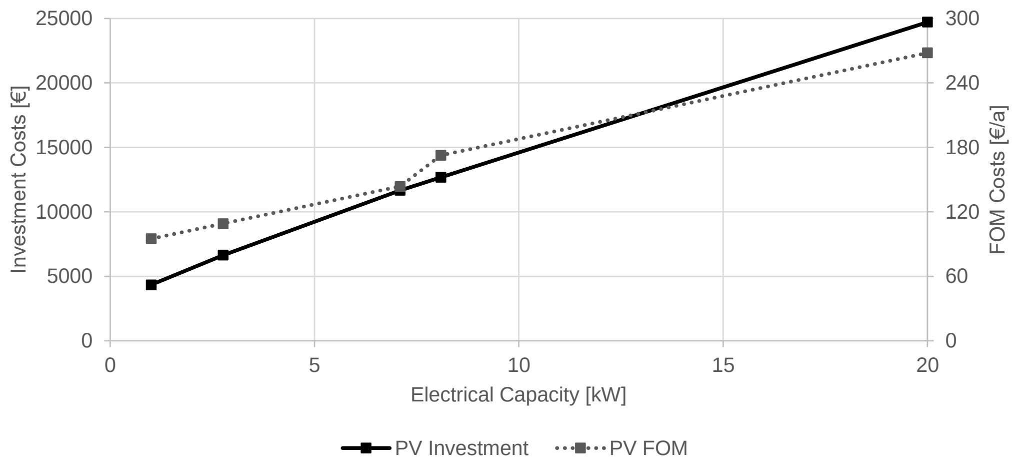

Figure C.9.: Investment and FOM costs of photovoltaic systems in 2020

[271] In order to calculate the solar position, a standard time-meridian (zonal) of 15 and a local meridian of 6.667 are assumed. Germany can be found on latitude 51.

[272] South-facing corresponds to a surface azimuth of 180°.

[273] For the assumptions in this paper, this inclination gives the highest observed generation.

[274] These are based on [Balcombe et al., 2015], [Beck et al., 2017], [Karmellos and Mavrotas, 2019], [Omu et al., 2013] and industry data.

Once installed, it is assumed that the PV system can operate for 25 years [275]. The electricity produced by the PV system can either be used directly to cover the consumer's individual electricity demand or fed into a heat generating technology, battery storage or the electricity grid. If the electricity is fed into the grid, consumers receive a market premium of 2.3 €-ct./kWh_{el} plus the compensation for selling the PV electricity to the market, i.e., the hourly spot-market electricity price at the time of feed in.[276]

C.3.9. Battery Storage

In order to allow for the flexible use of electricity, the consumer can choose to invest in an electricity storage system, i.e., a lithium-ion battery storage. With an efficiency of 81%[277], electric energy can be stored and supplied at a later point in time.[278] The installed capacity (kW) of a battery storage defines the installed storage volume (kWh) according to a so-called energy-to-power ratio.[279] Once installed, the battery storage can be used for up to 15 years.[280]

[275] [Beck et al., 2017], [Brown et al., 2018], [Palzer, 2016], [Omu et al., 2013], [Ren and Gao, 2010], [Henning and Palzer, 2013], and [Gerhardt et al., 2015] provide operational time frames between 20 and 30 years.

[276] According to German regulation, consumers with rooftop PV systems qualify for so-called "reference values", which are made up of the market premium plus the spot-market electricity price. The German government sets the reference value, which decreases by about 1.4% every month and is guaranteed for 20 years from the time of installation. In order to estimate the market premium in COMODO, the yearly average of the reference values are corrected for the yearly average of the spot-market price assumed in the scenario definition (see Figure 4.4 in Section 4.3.1) for the future years. For more information, see https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/RenewableEnergy/RegisterDataTariffs/start.html.

[277] The efficiency is calculated based on [Beck et al., 2017], [Lazard, 2017], [Diefenbach et al., 2017], [Fisher et al., 2019], [Bakhshi Yamchi et al., 2019], [Henning and Palzer, 2013], [May et al., 2018] and [Brown et al., 2018]. This value represents an efficiency for the storage cycle independent of the duration of storage, i.e., it accounts solely for energy losses resulting from the feeding in and discharging of electricity.

[278] At the time of this paper, the standard setting in COMODO is that a battery storage can be used to shift electricity consumption within a time frame of one week. Longer storing periods are not taken into account.

[279] In line with [Tsiropoulos et al., 2018] (see page 21), it is assumed that the storage volume in kWh is twice the amount of the storage capacity in kW.

[280] A technical lifetime of 15 years is assumed based on analyses from [Fisher et al., 2019], [Karmellos and Mavrotas, 2019], [May et al., 2018], [Brown et al., 2018], [Diefenbach et al., 2017] and [Balcombe et al., 2015].

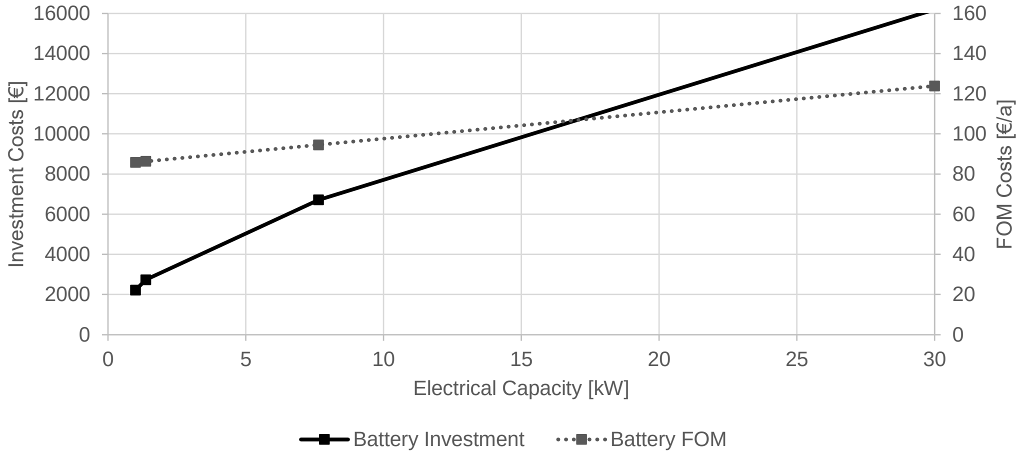

Figure C.10.: Investment and FOM costs of lithium-ion battery storage systems in 2020

Figure C.10 shows the investment costs of assumed lithium-ion battery storage systems.[281] The investment costs are assumed to decrease significantly (-50%) by 2040 (see Table C.4 in Appendix C.4). The FOM costs, based on [Lazard, 2017] and [Diefenbach et al., 2017], are also depicted by the dotted line.

At the time of this research, the purchase of a battery storage is not directly subsidized. Nevertheless, storage can help to reduce variable costs if they are used to optimize the use of decentralized electricity generation from, e.g., PV.

[281] These are based on [Beck et al., 2017], [Lazard, 2017], [Karmellos and Mavrotas, 2019], [Diefenbach et al., 2017], [Fisher et al., 2019], [Henning and Palzer, 2015] and industry data.

C.4. Assumptions on Learning Rates to Approximate Future Investment Costs

Costs for technology investments are assumed to decrease over time. This effect is included in the model via learning rates, consistent with manufacturer data. Technologies that are currently undergoing research are expected to face stronger decreases in costs than more mature technologies. The assumed learning rates are given in Table C.4, which illustrates the percentages of the costs in the specific year compared to the costs in 2020.

Technology	**2025**	**2030**	**2035**	**2040**	**based on**
CHP (Gas and Diesel)	94	89	83	77	[Bürger et al., 2016]
Fuel Cell	88	75	63	50	[Bürger et al., 2016]
Oil Condensing Boiler	99	98	97	96	own assumption
Gas Condensing Boiler	99	98	97	96	own assumption
Electric Heater	99	98	97	96	own assumption
Air-to-Water Heat Hump	97	93	91	89	[Bürger et al., 2016], [Palzer, 2016], [Energinet.dk and Energi Styrelsen, 2012], [Petrovic and Karlsson, 2016]
Water-to-Water Heat Pump	97	94	91	88	[Bürger et al., 2016], [Palzer, 2016], [Energinet.dk and Energi Styrelsen, 2012], [Petrovic and Karlsson, 2016]
Geothermal Heat Pump	98	95	93	91	[Bürger et al., 2016], [Henning and Palzer, 2015]
Photovoltaic	90	79	69	58	[Gerbert et al., 2018], [Palzer, 2016], [Bürger et al., 2016]
Lithium-Ion Battery Storage	100	58	54	50	[Henning and Palzer, 2015], [World Energy Council, 2016]
Solar Thermal	96	93	89	86	[Energinet.dk and Energi Styrelsen, 2012], [Gerhardt et al., 2015]
Thermal Storage	99	98	97	96	own assumption
Pellet Stove	98	96	94	91	[Bürger et al., 2016], [Nitsch et al., 2010], [Henning and Palzer, 2015], [Gröger, 2016]

Table C.4.: Learning rates for technology cost developments in % compared to 2020

C.5. Additional Results

		Status Quo				Smart Tech				Smart Market			
HH	[a]	2025	2030	2035	2040	2025	2030	2035	2040	2025	2030	2035	2040
1	AIC [€/a]	1799	1799	1799	25	1800	2111	2111	25	1795	2109	2109	25
	FOM [€/a]	426	426	426	426	426	515	515	515	426	515	515	515
	VC_{tot}[€/a]	2170	2195	2201	2190	2169	1709	1754	1776	2174	1704	1747	1765
	VC_{el}[€/a]	968	931	872	817	967	386	362	339	974	382	356	330
	VC_{gas}[€/a]	1201	1265	1328	1373	1202	1323	1392	1437	1200	1322	1391	1436
	RC[€/a]	231	265	266	272	231	197	205	208	231	197	204	208
	MP[€/a]	110	121	119	119	110	86	85	85	110	86	85	84
	TAC [€/a]	4054	4035	4040	2251	4054	4052	4091	2024	4054	4045	4082	2013
2	AIC [€/a]	464	464	464	24	450	450	450	845	448	448	448	846
	FOM [€/a]	235	235	235	235	235	235	235	423	235	235	235	423
	VC_{tot}[€/a]	2207	2186	2178	2153	2219	2197	2188	1607	2220	2198	2189	1618
	VC_{el}[€/a]	1130	1086	1018	953	1146	1101	1033	573	1148	1102	1034	585
	VC_{gas}[€/a]	1077	1100	1160	1200	1073	1096	1156	1034	1072	1095	1155	1033
	RC[€/a]	0	0	0	0	0	0	0	341	0	0	0	341
	MP[€/a]	0	0	0	0	0	0	0	148	0	0	0	148
	TAC [€/a]	2906	2885	2877	2413	2904	2882	2873	2386	2902	2880	2872	2397
3	AIC [€/a]	1165	1165	1165	27	336	336	336	848	332	332	332	848
	FOM [€/a]	360	360	360	360	230	230	230	418	230	230	230	418
	VC_{tot}[€/a]	1324	1326	1315	1294	1925	1890	1849	1222	1922	1883	1841	1229
	VC_{el}[€/a]	723	695	652	611	1274	1225	1148	565	1272	1219	1141	574
	VC_{gas}[€/a]	723	695	652	611	651	665	701	657	650	664	700	655
	RC[€/a]	131	147	147	147	0	0	0	357	0	0	0	357
	MP[€/a]	63	68	68	67	0	0	0	163	0	0	0	163
	TAC [€/a]	2655	2636	2626	1466	2492	2456	2416	1967	2484	2446	2403	1975
4	AIC [€/a]	288	288	288	26	283	283	283	26	279	279	279	26
	FOM [€/a]	229	229	229	229	228	228	228	228	228	228	228	228
	VC_{tot}[€/a]	1370	1347	1324	1294	1374	1351	1328	1297	1375	1353	1330	1294
	VC_{el}[€/a]	857	824	773	724	863	829	778	728	865	832	781	726
	VC_{gas}[€/a]	512	523	552	571	511	522	550	569	510	521	549	568
	TAC [€/a]	1886	1864	1841	1549	1886	1863	1840	1552	1882	1860	1837	1548

[a] The cost values given are not discounted but the actual payment in the described year. The costs are AIC: Annualized Investment Cost, FOM: Fixed Operation and Maintenance Cost, VC_{tot}: Total Variable Costs, $VC_{el/gas}$: Variable Cost for Electricity/Gas (included in VC_{tot}), RC: Remuneration for Direct Electricity Sales of PV Electricity Feed-In, MP: Market Premium for PV Electricity Feed-In, TAC: Total Annual Costs

Table C.5.: Annual costs of energy provision in the main analysis

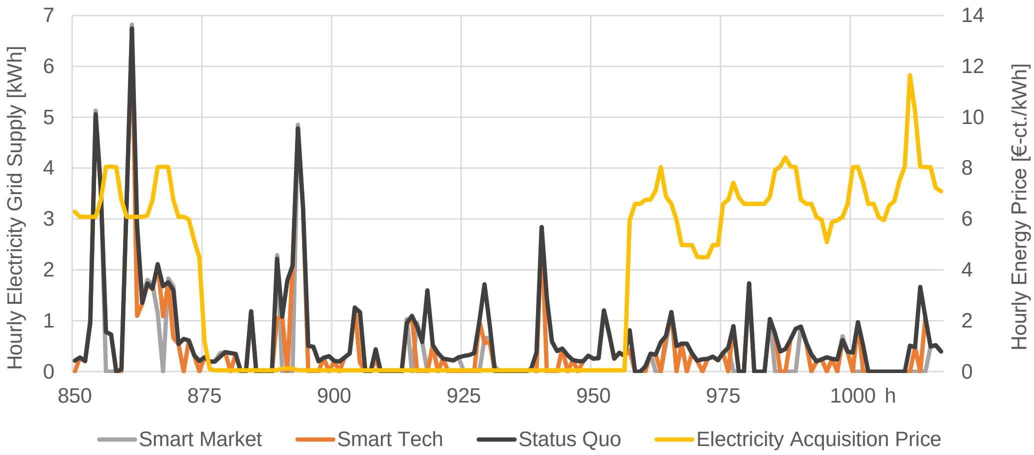

Figure C.11.: Electricity supplied from the grid in each of the three scenarios as well as the corresponding electricity acquisition prices of the main analysis for HH1 in the second week of February 2040

	HH	Status Quo	Smart Tech	Smart Market
Main Analysis	1	51690	51295	51210
	2	39176	39077	39087
	3	33745	33082	32993
	4	25268	25265	25220
Sensitivity Analysis	1	56011	54087	53888
	2	43112	42271	42202
	3	35922	34258	34140
	4	27140	26412	26216

Table C.6.: Total costs of energy provision in the main and sensitivity analyses

HH	[a]	Smart Tech 2025	Smart Tech 2030	Smart Tech 2035	Smart Tech 2040	Smart Market 2025	Smart Market 2030	Smart Market 2035	Smart Market 2040
1	AIC [€/a]	2196	2196	2196	24	2201	2201	2201	24
	FOM [€/a]	630	630	630	630	624	624	624	624
	VC_{tot}[€/a]	1982	1867	1699	1533	1968	1858	1687	1509
	VC_{el}[€/a]	1004	965	905	848	1008	973	917	856
	VC_{HP}[€/a]	977	901	794	685	960	885	770	653
	RC[€/a]	221	226	226	231	220	225	225	231
	MP[€/a]	108	109	110	110	107	109	109	110
	TAC [€/a]	4479	4358	4189	1847	4467	4350	4178	1817
2	AIC [€/a]	444	444	444	1587	441	441	441	1586
	FOM [€/a]	235	235	235	521	235	235	235	518
	VC_{tot}[€/a]	2227	2422	2610	1093	2227	2422	2611	1084
	VC_{el}[€/a]	1155	1110	1040	621	1158	1112	1043	632
	VC_{HP}[€/a]	0	0	0	472	0	0	0	451
	VC_{gas}[€/a]	1073	1312	1569	0	1070	1310	1568	0
	RC[€/a]	0	0	0	299	0	0	0	299
	MP[€/a]	0	0	0	141	0	0	0	141
	TAC [€/a]	2906	3101	3289	2762	2903	3098	3286	2748
3	AIC [€/a]	1698	1698	1698	26	717	717	717	847
	FOM [€/a]	373	373	373	373	237	237	237	425
	VC_{tot}[€/a]	1087	1030	946	866	1795	1699	1558	811
	VC_{el}[€/a]	752	723	678	635	1337	1281	1197	602
	VC_{HP}[€/a]	335	307	269	231	458	418	361	209
	RC[€/a]	195	197	196	198	0	0	0	345
	MP[€/a]	95	95	95	94	0	0	0	163
	TAC [€/a]	2868	2808	2726	972	2749	2652	2511	1574
4	AIC [€/a]	556	556	556	26	554	554	554	26
	FOM [€/a]	209	209	209	209	207	207	207	207
	VC_{tot}[€/a]	1333	1265	1166	1070	1324	1257	1157	1053
	VC_{el}[€/a]	968	930	872	817	968	930	873	813
	VC_{HP}[€/a]	365	335	294	253	357	327	284	240
	TAC [€/a]	2098	2030	1931	1305	2085	2018	1918	1286

[a] The cost values given are not discounted but the actual payment in the described year. The costs are AIC: Annualized Investment Cost, FOM: Fixed Operation and Maintenance Cost, VC_{tot}: Total Variable Costs, $VC_{\mathrm{el/gas/hp}}$: Variable Cost for Electricity/Heat Pump/Gas (included in VC_{tot}), RC: Remuneration for Direct Electricity Sales of PV Electricity Feed-In, MP: Market Premium for PV Electricity Feed-In, TAC: Total Annual Costs

Table C.7.: Annual costs of energy provision in the sensitivity analysis

HH		Smart Tech	Smart Market
1	ATC [€]	2792	2678
	ACA [t_{CO_2}]	50.01	49.88
	ACAC [€/t_{CO_2}]	55.83	53.70
2	ATC [€]	3194	3115
	ACA [t_{CO_2}]	10.89	10.89
	ACAC [€/t_{CO_2}]	293.44	286.06
3	ATC [€]	1176	1147
	ACA [t_{CO_2}]	32.59	27.55
	ACAC [€/t_{CO_2}]	36.09	41.64
4	ATC [€]	1147	997
	ACA [t_{CO_2}]	21.24	21.2
	ACAC [€/t_{CO_2}]	53.98	47.02

[a] ATC: Additional Total Costs, ACA: Additional Carbon Abatement, ACAC: Additional Carbon Abatement Costs

Table C.8.: Carbon abatement in the sensitivity analysis compared to the main analysis aggregated over the model years 2025-2045

	Status Quo				Smart Tech				Smart Market			
HH	2025	2030	2035	2040	2025	2030	2035	2040	2025	2030	2035	2040
1	6.75	6.75	6.75	6.75	6.73	6.73	6.73	6.73	6.82	6.82	6.82	6.82
2	5.23	5.23	5.23	5.23	5.49	5.49	5.49	4.10	5.53	5.53	5.53	4.14
3	10.98	10.98	10.98	10.98	11.11	11.11	11.11	11.11	11.18	11.18	11.18	11.18
4	9.26	9.26	9.26	9.26	9.35	9.35	9.35	9.35	9.44	9.44	9.44	9.44

Table C.9.: Maximum amount of electricity consumed from the grid in a single hour for each model year and scenario in the main analysis

	Smart Tech				Smart Market			
HH	2025	2030	2035	2040	2025	2030	2035	2040
1	9.81	9.81	9.81	9.81	9.85	9.85	9.85	9.85
2	5.60	5.60	5.60	8.31	5.66	5.66	5.66	8.34
3	9.60	9.60	9.60	9.60	9.81	9.81	9.81	9.81
4	11.18	11.18	11.18	11.18	11.19	11.19	11.19	11.19

Table C.10.: Maximum amount of electricity consumed from the grid in a single hour for each model year and scenario in the sensitivity analysis

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RESEARCH INTERESTS

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LANGUAGES

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PUBLICATIONS

Articles in Peer-Reviewed Journals:

- B. Helgeson, J. Peter (2020). The Role of Electricity in Decarbonizing European Road Transport – Development and Assessment of an Integrated Multi-Sectoral Model. *Applied Energy*, Vol. 262, Article 114365. ISSN 0306-2619.

Working Papers:

- B. Helgeson (2024). Europe, the Green Island? Developing an Integrated Energy System Model to Assess an Energy-Independent, CO_2-Neutral Europe. *EWI Working Paper* 02/24.
- C. Frings & B. Helgeson (2022). Developing a Model for Consumer Management of Decentralized Options. *EWI Working Paper* 22/05.
- B. Helgeson & J. Peter (2019). The Role of Electricity in Decarbonizing European Road Transport – Development and Assessment of an Integrated Multi-Sectoral Model. *EWI Working Paper* 19/01.
- J. Bertsch, C. Elberg, B. Helgeson, A. Knaut, C. Tode (2017). Disruptive Potential in the German Electricity System – An Economic Perspective on Blockchain. *EWI Working Paper*.

Further Publications:

- B.Helgeson, D. Schlund, M. Schönfisch, A. Polisadov, T. Pesch, F. Merten, C. Schneider, A. Scholz, A. Taubitz (2022). System modeling for the identification of innovative and sustainable applications (German title: Systemmodellierung zur Identifikation von innovativen und zukunftsfähigen Anwendungen). *Final report for the research project Competence Center Virtual Institute "Power to Gas and Heat"*, Vol. 1.
- B.Helgeson, R. Peters, B. Emonts, J. Breuer, N. Beltermann, J. Koj, D. Klemp, R. Wegener, V. Polinowski, J. Scholten, O. Feltges, L. Scholten, M. Bäuerle (2022). Evaluation of the use and impact of alternative fuels for the development of future regional infrastructure (German title: Bewertung des Einsatzes und der Auswirkungen alternativer Kraftstoffe für die Entwicklung der zukünftigen regionalen Infrastruktur). *Final report for the research project Competence Center Virtual Institute "Power to Gas and Heat"*, Vol. 3.
- H.Shamon, T. Rehm, B. Helgeson, F. Große-Kreul, M. Gleue, U. Paukstadt, G. Aniello, T. Schneiders, C. Frings, A. Reichmann, A. Löschel, T. Gollhardt, W. Kuckshinrichs, K. Gruber, P. Overath, C. Baedeker, F. Chasin, K. Witte, J. Becker (2021). Smart Energy in Households: Technologies, Business Models, Acceptance and Profitability (German Title: Smart Energy in Haushalten: Technologien, Geschäftsmodelle, Akzeptanz und Wirtschaftlichkeit). *Schriften des Forschungszentrums Jülich Reihe Energie & Umwelt / Energy & Environment* , Vol. 541. ISSN 1866-1793.
- D. Lindenberger, B. Helgeson, S. Paulus, J. Peter, A. Polisadov, L. Welder, P. Stenzel, M. Hehemann, M. Müller, N. Ebersbach, F. Knicker, P. Markewitz, M. Robinius, B. Emonts, D. Stolten, T. Pesch, J. Koj, O. Jochum, T. Marzi, C. Unger, J. Schaffert, J. Senner, N. Brücken, H. Praefke, C. Tsiklios, B. Zejnullahu, M. Fiebrandt, K. Görner, M. Muhler, J. Gödde, C. Berger, H. Ruland, F. Merten, C. Schneider, D. Schüwer, M. Buddeke, A. Nebel, A. Scholz, T. Hanke, M. Fischedick, D. Lemken, B. Oberschachtsiek, T. Meijer, L. Theves, U. Gardemann, M. Steffen, A. Heinzel (2018). System and Site Analyses - Flexibility Options in Power-Gas-Heat Systems (German title: System- und Standortanalysen - Flexibilitätsoptionen im Strom-Gas-Wärme System). *Final report for the research project Virtual Institute "Power to Gas and Heat"*, Vol. 1.

SELECTED SPEAKER APPEARANCES

2018 - 2023	**Guest lecturer on "The Role of Power-to-X in Decarbonizing Europe's Energy and Mobility System"** *EMBA Seminar on the Future of Mobility* (graduate level) University of Cologne in cooperation with the World Economic Forum
2020	**Virtual Energy Research – Virtual Energy Supply** *Presenter and representative of the project Virtual Institute "Power to Gas and Heat"* Workshop organized by EnergieAgentur.NRW

2018	**Sector-coupling – Focus electromobility** *Presenter and panelist* Stadtwerke Tagung 2018
2017	**Technology Roadmaps for Accelerating the Transition to Zero Carbon** *Presenter and panelist* Erasmus Energy Forum
2017	**21st Congress on Future Energy, Cross-Sectoral Transformation of the Energy System** *Presenter and panelist* e-world energy & water in cooperation with EnergieAgentur.NRW
2016	**Oil, Gas or Electricity: Trends in the Mobility Sector up to 2025** *Presenter and panelist* ewi Energy Conference

ACADEMIC AWARDS

- Recipient of the Theodor-Wessels Prize 2023 (third place) for the paper with Cordelia Frings, Developing a Model for Consumer Management of Decentralized Options.

August 24, 2024

Eidesstattliche Erklärung nach §8 Abs. 3 der Promotionsordnung vom 17.02.2015

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Köln, 30.06.2024