Technische Universität München
TUM School of Management

Three Essays on Decarbonizing Energy Systems: Mobility Electrification and Hydrogen

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Vollständiger Abdruck der von der TUM School of Management der Technischen Universität München zur Erlangung einer

Doktorin der Wirtschafts- und Sozialwissenschaften (Dr. rer. pol.)

genehmigten Dissertation.

Vorsitz: Prof. Dr. Sebastian Schwenen

Prüfende der Dissertation:

1. Prof. Dr. Gunther Friedl
2. Prof. Dr. Svetlana Ikonnikova

Die Dissertation wurde am 12.04.2024 bei der Technischen Universität München eingereicht und durch die TUM School of Management am 15.07.2024 angenommen.

Acknowledgements

First and foremost, I want to express my gratitude to my supervisor, Prof. Dr. Gunther Friedl, for his support throughout my doctoral studies. Thank you for all your valuable feedback and trust, which motivated and enabled me to pursue multiple topics of interest in the scope of this dissertation. I have learned a lot and value the freedom you gave me to explore my ideas. I am very thankful that you encourage us to explore research topics focusing on ESG, which will hopefully also have a positive impact outside academia. I appreciate the supportive atmosphere you have established at your chair that allows your doctoral students to assist each other in their research and learn from each other's skills. I am very grateful for the opportunities you created for me to gain new perspectives and receive exceptional input from researchers outside of TUM through conferences and my research stay at NTU.

I thank my mentor, Prof. Dr. Svetlana Ikonnikova, for her excellent advice, feedback, and research ideas we have discussed over the last few years. I highly appreciate your guidance and encouragement to work on topics that excite me and that I can learn from. I also want to thank Prof. Dr. Xu Yan for hosting my research stay at NTU and providing helpful input on my research ideas. Further, I thank Prof. Dr. Sebastian Schwenen for heading my examination committee.

I want to thank Dr. Maximilian Blaschke for his amazing guidance throughout my PhD journey. Thank you so much for all the great discussions, feedback, and encouragement in the last years that have allowed me to learn how to navigate academia and trust my ideas. And, of course, I thank you for making working together so much fun and being a great friend that I can always count on.

The key component that made my PhD journey truly special is my amazing colleagues at the Chair of Management Accounting. I am incredibly grateful for our amazing times together and will miss the whole team very much. I will treasure all the beautiful memories we shared and am looking forward to making more memories in the future. I also want to thank Patricia Norum for always helping me with all my administrative tasks and taking good care of all of us. Furthermore, I want to thank my student assistants, Jan Natter, Daniela Arbelaez Gomez, Alina Gries, and Nikolas Bunk.

I especially thank my parents, Claudia and Erwin Steinbach, for always having my back and encouraging me to pursue my ambitions. Being the first person in my extended family to attend university, I have never taken your continued and unconditional support for granted. I admire the sacrifices you made that allowed me to work toward my goals. I would never be where I am today without you.

Lastly, I want to thank my husband, Philipp Merz, for supporting me in reaching any new goals I set for myself. You encourage me to trust myself and give me strength whenever I need it. Thank you for allowing me to be the best version of myself.

Abstract

This dissertation includes three essays that tackle challenges associated with the main decarbonization strategies of the transport and industrial sectors: mobility electrification and hydrogen usage. I analyze the potential grid instability, the requirement for increased renewable energy integration, and the risk to energy equity arising from mobility electrification. Additionally, I address the regulatory uncertainties holding up hydrogen market development. The first essay evaluates the potential of reducing EV-related grid investment needs through decentralized photovoltaic electricity generation and battery energy storage systems. Using power-flow analyses on representative grid models, I find significant societal cost savings that can be utilized in policy measures to increase renewable electricity consumption and energy security. The second essay investigates the asymmetry in EV-related grid costs between higher- and lower-income neighborhoods. I uncover tremendous grid cost asymmetries, which could lead to an inequitable grid cost allocation. Therefore, alternative dynamic electricity and grid tariffs or income-dependent subsidies should be explored. The third essay derives a future European hydrogen market design and recommendations for the attached regulation. Leveraging across-industry exploratory interviews, I aim to reduce market uncertainty by developing detailed recommendations on market development policy measures, infrastructure regulations, and hydrogen and certificate trading. Through this dissertation, I aim to provide policymakers, energy market players, and researchers with valuable insights into upcoming challenges in the clean energy transition and effective mitigation strategies. By facilitating informed decision-making and advancing research efforts, I aim to contribute to the progress of the clean energy transition and a more sustainable future.

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1 | Introduction

1.1 Motivation and background

> "*The world must come together to confront climate change. There is little scientific dispute that if we do nothing, we will face more drought, famine and mass displacement that will fuel more conflict for decades.*"
> **Barack Obama, Former President of the United States of America in his his Nobel Peace Prize acceptance speech on the 10th of December 2009 (Obama et al., 2009)**

> "*Climate change is the single greatest threat to a sustainable future but, at the same time, addressing the climate challenge presents a golden opportunity to promote prosperity, security and a brighter future for all. It can strengthen our efforts across the development agenda – from renewable energy to climate smart agriculture to sustainable transport. If we invest what is necessary, we will reap the benefits in terms of reduced poverty, more inclusive societies and greater opportunity and dignity for all.*"
> **Ban Ki-Moon, Former Secretary-General of UN during his Climate Leaders Summit speech on the 11th of April 2014 (Ki-Moon, 2014)**

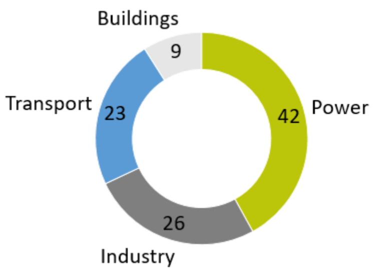
Climate change is one of the biggest global challenges our society faces today. While the threat of climate change has already been called out decades ago (see, for example, Wigley and Raper (1990) or Ball (1999)), a sense of urgency and need for action has only begun to emerge in recent years. In the meantime, the effects of climate change on society and ecosystems have become increasingly noticeable. Climate change has devastating effects on our environment, endangering ecosystems, species, and biodiversity (see, e.g., Thomas et al. (2004), Doney et al. (2012), Bellard et al. (2012) or Carlson et al. (2022)). Until today, significant changes in regional climates were already uncovered, increasing the risk for natural disasters and endangering lives (see, e.g., Brown et al. (2023) or Gottlieb and Mankin (2024)). The negative economic effects of climate change fundamentally threaten global welfare (see, e.g., Tol (2009). These negative social welfare effects tend to over-proportionally impact lower-income countries, as, for example, reported by Bastien-Olvera et al. (2024).

With climate change as a global challenge, global political cooperation is required to enable sufficient speed in transforming technologies, processes, and regulations towards reduced climate impact. In 2015, all members of the United Nations established the 17 Sustainable Development Goals (SDG) as part of their 2030 Agenda for Sustainable Development (United Nations, 2015a). These goals combine ambitions of economic development, reduced inequality, and mitigating climate change. In the same year, another fundamental step aiming for more international cooperation and accountability was the signing of the Paris Agreement. As the first legally binding international treaty on climate change, 196 countries agreed to work towards the goal of limiting the global average temperature to 1.5-2°C compared to pre-industrial levels (United Nations, 2015b). Following the agreement, multiple countries have established carbon neutrality targets.

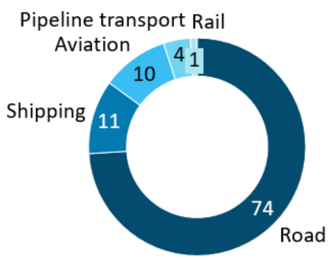
While significant progress has been made since the mentioned agreements in 2015, both the assessment of the Sustainable Development Goals as well as the United Nations Climate Conference (COP 28) last year find that the agreed-upon climate goals remain at risk (United Nations, Rat der Europäischen Union, 2023). Especially decarbonizing the energy system and reducing the use of fossil fuels were in focus during the COP 28 discussions in order to meet the net zero 2050 carbon emission goal (Rat der Europäischen Union, 2023). Building upon the net zero 2050 ambition of the Paris Agreement, the International Energy Association (IEA) developed the IEA's Net Zero Emissions by 2050 Scenario (NZE). Within this scenario, the IEA aims to combine the goals of energy sector net zero CO_2 emissions by 2050 and universal energy access by 2030 (IEA, 2023a). Every year, they track 50 components that are critical for a clean energy system against the NZE trajectory. In the last year, they found that only 3 of the 50 components are currently on track (IEA, 2023a).

In order to successfully work towards the net zero targets and mitigate further falling behind current ambitions, policymakers need to provide the guardrails to accelerate the clean energy transition. However, finding the appropriate measures can be challenging for governments and policymakers around the globe. Especially the energy system can be complex and is often confronted with conflicting goals, such as aiming for clean but affordable energy (see, e.g., United Nations (2015a) and (IEA, 2023a)). Planning, investment, and implementation cycles tend to span up to multiple decades, making it necessary to create an understanding of future scenarios in 2030 or up to 2050 already today. Hence, it is of integral importance and great urgency that researchers develop an understanding of upcoming challenges and mitigating policy measures in the clean energy transition. I dedicate this dissertation to supporting policymakers navigating pathways toward clean energy and reaching their climate targets.

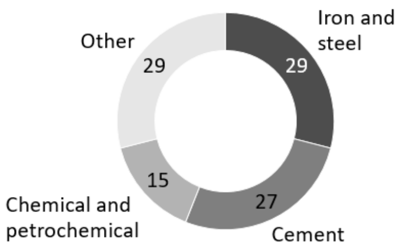
In order to understand which sectors and industries most endanger meeting the net zero targets, I derived the focus areas of this dissertation from large drivers in CO_2 emissions.



(A) All.



(B) Transport.



(C) Industry.

FIGURE 1.1: Breakdown of 2022 global CO_2 emissions by sector and subsector based on IEA (2023b,e,c), in %.

As can be seen in Figure 1.1, the transport and the industry sectors together represent about half of global CO_2 emissions. For the transport sector, road emissions are responsible for by far the largest share, emitting 74% of related CO_2 emissions. The most promising solution to significantly reducing these emissions is to electrify mobility. As they allow driving emissions to solely depend on the electricity mix, countries around the globe promote electric vehicle (EV) adoption as a pathway towards carbon-neutral mobility (see, e.g., International Energy Agency (2021)). Driven by regulations such as the Inflation Reduction Act in the US and the EU-wide ban of internal combustion engine car sales after 2035, global EV sales have skyrocketed in recent years (see, e.g., IEA (2023d)).

This growing number of EVs, however, is a challenge for the power grid. As EV users tend to charge their EVs during similar times in the day, substantial load peaks could occur, as highlighted for example by Clement-Nyns et al. (2010), Nogueira et al. (2021) or Powell et al. (2022).

To prevent these peaks from causing overloads, grid operators will have to invest significantly in their infrastructure. According to Bermejo et al. (2021) and Elmallah et al. (2022), this might require billions in investment costs. Globally, grid investments are expected to increase by 217% in 2030 compared to 2019, driven mainly by the increased electricity demand, e.g., through EVs and heat pumps, as well as renewable energy integration (IEA, 2021, Fraunhofer IEE, 2023).

In Essay I of this dissertation, I address the topics of grid stability and renewable energy integration for future EV adoption scenarios. My coauthor and I analyze the effectiveness of residential photovoltaic (PV) and battery energy storage systems (BESS) in reducing grid reinforcement costs caused by EV charging. We determine the societal value of decentralized residential electricity generation and storage systems in reducing public infrastructure costs and derive related policy recommendations. We leverage existing findings by, e.g., Denholm et al. (2013), Cohen et al. (2019) and Mancini et al. (2020), who uncover that residential PV and BESS systems are effective at reducing load peaks caused by EV charging. Further, we leverage the naturally higher motivation of EV users to install residential solar PV systems and self-consume electricity due to cost effects, as confirmed for example by Cohen et al. (2019) and Kost et al. (2021).

In Essay II, I connect the discussed topic of EV-related grid infrastructure investments to the challenge of energy equity. Researchers as, for example, Carley and Konisky (2020) and Brockway et al. (2021) find that the clean energy transition might further weaken the position of lower-income households. Hence, efforts to analyze energy equity and strive for energy justice through policy measures are intensifying (see, e.g., Diezmartínez and Short Gianotti (2022) and Scheier and Kittner (2022)). My coauthor and I suspect that an energy equity issue might also be arising in the case of EV-charging-related grid infrastructure cost. EV charging loads increase with EV adoption, depend on the EV model choice and are affected by the underlying user mobility behavior. Literature shows that all these aspects may be correlated with socio-economic attributes such as household income (Kelly et al., 2012, Sovacool et al., 2019, Gauglitz et al., 2020, Lee and Brown, 2021). Hence, higher-income neighborhoods might require over-proportional grid infrastructure investments, which would potentially be recovered via a surcharge on the electricity price for all households. We quantify the difference in the EV-charging-related grid reinforcement costs between lower and higher-income neighborhoods. From these calculations, we analyze potential inequities and develop mitigating policy measures.

For Essay III, I focus on large CO_2 emission drivers for which electrification is not an appropriate solution. Green hydrogen has the potential to complement the electrification of fossil-fuel-based processes and significantly decarbonize high-emission industries (European Commission, 2020a). For the industrial sector, 71% of global emissions are caused by the steel, cement, and chemical sectors (IEA, 2023a). Hence, all three of these sectors are currently in the focus of the net zero 2050 goal but significantly fall behind their decarbonization ambitions (IEA, 2023a). Therefore, employing green hydrogen is of the highest priority in decarbonizing steel and cement production, as well as replacing grey hydrogen in refineries and the chemical industry (Van der Spek et al., 2022, Braun et al., 2023, Egerer et al., 2024). In the transport sector, hydrogen could be used in heavier vehicles, such as trucks and busses, as well as in rail, shipping, and aviation (International Energy Agency, 2021, Van der Spek et al., 2022).

Due to these promising applications, the hydrogen strategy of the European Union aims to implement a liquid market with commodity-based hydrogen trading by 2030 (European Commission, 2020a). However, how this European hydrogen market should be designed remains unclear. This challenges players in the hydrogen market, who, according to Hydrogen Council (2022b), Dawin et al. (2023) and Lagioia et al. (2023) call for regulatory certainty, a clear target model, and robust international certification schemes. Although a large amount of literature has been published about hydrogen (see, for example, Blanco et al. (2022)), policy aspects for hydrogen have only been covered by a limited number of recent articles, such as Farrell (2023) and Van der Spek et al. (2022). Within this essay, my coauthor and I contribute to this upcoming research field by outlining the core design criteria and attached regulations of the future European hydrogen market. We build upon learnings from the natural gas market to evaluate appropriate infrastructure regulations, discuss market development policy measures, and analyze hydrogen and certificate trading systems.

Overall, the energy transition requires multifaceted research that enables the acceleration of carbon emission mitigation strategies for the most carbon-intensive sectors. I, therefore, dedicate my dissertation to supporting policymakers in finding appropriate measures to work towards the goal of affordable and clean energy (SDG 7) and understanding the complexities and challenges that may arise within its carbon mitigating strategies. The derivation of my research focus topics is depicted graphically in Figure 1.2. The following section provides an overview of how this dissertation contributes to existing research.

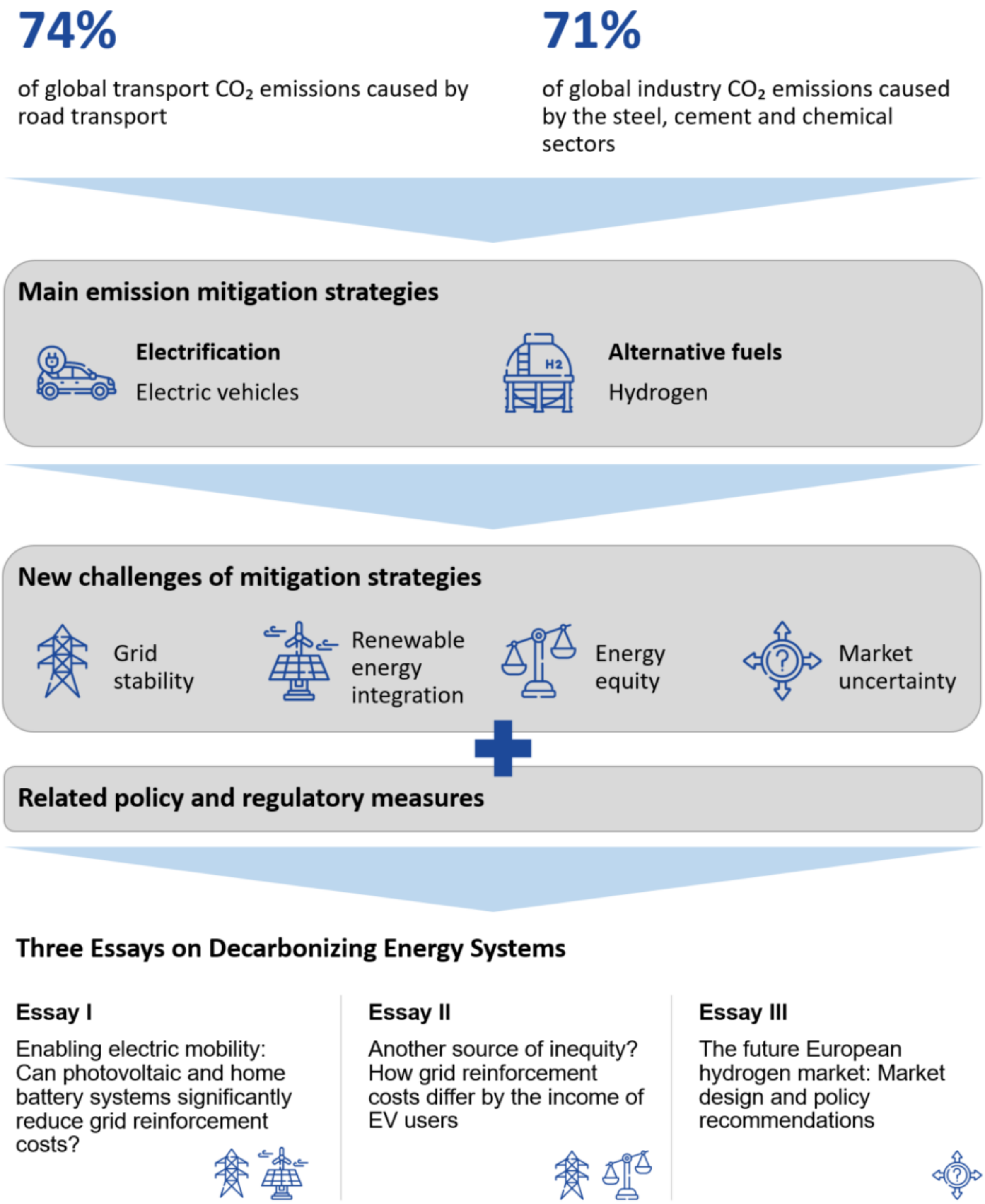


FIGURE 1.2: Illustrative derivation of the three essay topics included in this dissertation from key CO_2 emission drivers in the transport and industry sectors.

1.2 Objectives and literature

I take different perspectives in all three essays and connect them to varying research streams. While the first two essays focus on EV-related grid reinforcement costs, they still connect to partly distinct literature streams. Essay I has a more technical focus and links to the literature on the load effects of residential PVs and BESS systems. Essay II, however, leverages insights from social sciences to uncover potential energy equity challenges arising through EV-related infrastructure costs. In Essay III, I build upon the research on green hydrogen, market design, and the natural gas commodity market to derive a future green hydrogen market design.

Firstly, we include the literature on EV-related electric load and grid effects relevant to the first two essays. To accommodate higher adoption levels of EVs, distribution grid need to be strengthened, leading to substantial infrastructure costs. Early studies such as those by Clement-Nyns et al. (2010), Lopes et al. (2011), Green et al. (2011) and Fernandez et al. (2011) are among the first to analyze the impact of EVs on distribution grids. Clement-Nyns et al. (2010) find that plug-in hybrid electric vehicle adoption levels of 10% to 30% already result in significant voltage imbalances and power losses. Subsequent research by various authors uncovers similar results with grids being unable to cope with the EV charging loads in different countries and grid settings (Lopes et al., 2011, Fernandez et al., 2011, Salah et al., 2015, Muratori, 2018a, Kapustin and Grushevenko, 2020, Nogueira et al., 2021, Powell et al., 2022). Green et al. (2011), Richardson (2013) and Das et al. (2020) contribute to the discourse by offering overviews and outlooks of the challenges associated with integrating EVs into existing grid infrastructures. As grid operators need to expand capacity to accommodate increasing EV charging demands, Wangsness and Halse (2021) find that increases in EV penetration result in significant grid reinforcement costs. The recent trend towards exclusive battery-powered electric vehicles (BEVs) and higher charging capacities could further increase the strain on the grid, requiring enhancements of the existing infrastructure (Mowry and Mallapragada, 2021, German Government, 2021, International Energy Agency, 2021, Steadman and Higgins, 2022).

Numerous studies (e.g., Clement-Nyns et al. (2010), Lopes et al. (2011), Wang et al. (2011), Qian et al. (2011), Mwasilu et al. (2014), Loisel et al. (2014), Szinai et al. (2020), Strobel et al. (2022), Blumberg et al. (2022)) deduce that coordinated (smart) charging or vehicle-to-grid settings could alleviate the challenges posed by EVs on distribution grids. However, these authors frequently assume that coordinated charging could be imposed on all EV users. Such coordinated charging, which is optimized for grid stability, might not be realistic as regulations enforcing such measures would first have to be implemented. When smart charging is not imposed from an outside entity but driven by consumer cost optimization through smart meters adjusting for dynamic tariffs, multiple authors find the risk of even higher induced load peaks if tariffs are not carefully calibrated (see, e.g., Unterluggauer et al. (2023), Daneshzand et al. (2023) or Stute and Kühnbach (2023)). Further, smart charging must balance grid stability with other, sometimes conflicting objectives, such as increasing renewable energy integration (Strobel et al., 2022).

In Essay I, we investigate an alternative load peak mitigation measure. The extended use of residential electricity generation has the potential to support EV charging without the the requirement to pass the electricity through the grid (Denholm et al., 2013, ElNozahy and Salama, 2014, Cohen et al., 2019). Decentralized electricity generation could reduce the power-flow from the grid to the households (see, for example, Yazdanie et al. (2016), Candelise and Westacott (2017)) and limit the necessary grid investments. Various researchers advocate for charging strategies incorporating decentralized generation, particularly leveraging residential PVs for EV charging, which has positive impacts on the grid capacity for both PVs and EVs (e.g., Denholm et al. (2013), ElNozahy and Salama (2014), Bhatti et al. (2016), Hoarau and Perez (2018)).

However, the biggest challenge in leveraging PV-generated electricity for EV charging is the limited temporal alignment between generation and charging cycles. To address this challenge, the literature suggests the integration of BESS to optimize load matching (see, e.g., ElNozahy and Salama (2014), Yazdanie et al. (2016), Candelise and Westacott (2017), Hoarau and Perez (2019), Mancini et al. (2020) and Freitas Gomes et al. (2020)). Improving load matching through combined PV and BESS systems could offer significant financial benefits for EV users. Analyses like that of Hoarau and Perez (2019) evaluate different tariff structures and explore the complex effects of these tariffs on the adoption of decentralized generation and EVs. However, since many households in Europe or the US pay based on kWh consumption, these households can reduce their electricity bill by self-consuming the generated electricity. The levelized costs of self-producing electricity with small residential PV and battery systems are frequently below residential electricity tariffs (compare, for example, Kost et al. (2021) with Eurostat (2020)). Given the higher electricity consumption of EV users, it is even more attractive for these consumers to install their generation systems, as, for example, observed by Wen et al. (2023). These households could leverage the cost difference between purchasing and self-producing electricity (as discussed in Cohen et al. (2019) or Kaufmann et al. (2021)), thereby reducing load impacts on distribution grids. While the direct consumer cost savings through self-consumption are relatively straightforward to determine, the societal value of reduced infrastructure demand remains to be uncovered and is likely not accounted for in current subsidy schemes and policy measures.

To address this research gap, Essay I investigates the potential value of decentralized electricity generation and storage in mitigating grid costs and discusses associated policy measures. We consider rural, suburban, and urban contexts to account for the significant variations in available rooftop PV installation space and grid specifications. Through these analyses, we aim to support policymakers and grid operators in facilitating greater uptake of EVs within their grids while improving renewable energy integration.

In Essay II, we put our emphasis on how socio-economic factors such as income influence EV-related grid impacts. When assessing the impact of EVs on distribution grids, most studies typically depict all households within the simulated distribution grid as having uniform EV adoption and usage patterns. However, socio-economic variables such as income, age, gender, occupation, education level, ethnicity, home ownership status, residence type, and political beliefs influence mobility patterns (see, for example, Ewing and Cervero (2010) and Abulibdeh et al. (2014)), the adoption of new technologies (as shown in Rai and Robinson (2015)), and specifically EV adoption (Westin et al., 2018, de Rubens, 2019, Sovacool et al., 2019, Muehlegger and Rapson, 2019, Chen et al., 2020, Römer and Steinbrecher, 2021, Lee and Brown, 2021, Berneiser et al., 2021, Romero-Lankao et al., 2022). Homogeneously modeling grid impacts may, therefore, lead to significant inaccuracies (Gauglitz et al., 2020). Among all socio-economic factors, income remains the primary determinant of EV adoption (Lee and Brown, 2021). Römer and Steinbrecher (2021) observed that households with above-average income are up to 200% more likely to own an EV. Muehlegger and Rapson (2019) and Berneiser et al. (2021) support these findings and uncover that medium to high-income groups tend to show increased EV adoption. Lee and Brown (2021) observe the same effect in the UK. Analysis of survey data from over 5000 respondents in the Nordics by Sovacool et al. (2019) reveals a correlation between higher income and increased likelihood of EV ownership and more expensive car models. Consistent findings are reported by Higgins et al. (2017), Hardman et al. (2016), and Chen et al. (2020). These more expensive and often larger car models tend to exhibit higher electricity consumption, increasing charging loads (Weiss et al., 2020).

In addition to EV adoption and car model choice, driving behavior significantly influences EV charging patterns and the potential for load peaks. These driving behaviors are influenced by socio-economic variables such as age, gender, level of education, and occupation. Depending on these factors, the number of trips per day as well as the departure and arrival times vary significantly, which impacts charging schedules (see, e.g., Kelly et al. (2012), Langbroek et al. (2017), Fischer et al. (2019) and Zhang et al. (2020)). As socio-economic factors may contribute to higher worst-case power flows, researchers like Gauglitz et al. (2020) and Powell et al. (2022) challenge current charging modeling approaches and push for including these factors in load assessments. Fischer et al. (2019) simulate EV charging demand, accounting for socio-economic factors such as household income and occupation, and analyze the resulting load curves in a German context. Similarly, a recent forecast for 2035 in the US by Powell et al. (2022) criticizes current charging modeling approaches. Employing a data-driven model that distinguishes by driver income, housing, and miles traveled, they discover that EV charging loads can increase peak net electricity demand by up to 25%. They further deduct implications regarding the dissemination of charging points. Lee and Brown (2021) simulate EV charging loads across UK households with varying economic statuses. Their findings indicate that higher-income households tend to cause larger load peaks, potentially leading to disproportionately high grid reinforcement costs. Consequently, they bring up the issue of a fair grid cost allocation. Although only a handful of studies incorporate socio-economic factors into load assessments, none give estimations on the related distribution grid reinforcement needs or associated grid reinforcement costs.

Fairness in the allocation of these grid reinforcement costs depends on the perspective. Tornblom and Foa (1983) defines three principles for cost allocation: need-based, contribution-based, or equal sharing. In the context of reducing CO_2 emissions, Hammar and Jagers (2007) observe a preference among most individuals for the principle of contribution (equity), meaning that those generating more emissions should strive for higher emission reductions. The issue of fairness in bearing the mentioned grid infrastructure costs is more nuanced. Higher-income households with more electric vehicles may cause disproportionately high infrastructure expenses but also reduce CO_2 emissions. However, as EVs should become more affordable with economies of scale in the coming years, we may assume an equal share of vehicle electrification in lower- and higher-income households. But even at this point, differences in required grid reinforcements may persist due to variations in driving behavior and vehicle ownership. Applying the principle of contribution-based fairness would require higher-income households to fully carry the caused asymmetry in grid reinforcement costs.

However, in many countries, residential grid reinforcement costs are included in electricity prices through fixed charges and per kWh fees (as seen in Keane and Vladareanu or Batlle et al. (2020) and, for example, Bundesnetzagentur (2020a) and Bundesministerium für Wirtschaft und Klimaschutz (2021) in Germany). Without political interventions, increased grid reinforcement costs could increase electricity prices for all consumers. Such an increase might be considered unfair under the principle of fairness according to the contribution, as higher-income neighborhoods over-proportionally drive these grid reinforcement costs.

Previous literature does not include socio-economic considerations in analyzing grid cost scenarios and could thus not quantify potential inequities. Addressing this research gap, we focus our analysis on household income as a critical socio-economic factor and raise a discussion on energy equity. We aim to measure the over-proportional impact of higher-income EV users on grid reinforcement costs. Our paper aims to quantify the over-proportional grid reinforcement cost impact of higher-income EV users. We leverage real-life trip data and grid power-flow analyses to compare the grid reinforcement costs of above-average and below-average income neighborhoods. Our paper connects previous literature on electric vehicle charging and grid stability to the increasingly relevant field of energy equity. Our findings are of significant relevance for policymakers, who are increasingly recognizing social factors in electricity pricing, regulatory frameworks, and overall policy instruments (see, e.g., Baskin (2021), Cappers and Satchwell (2022), International Monetary Fund (2022) and National Conference of State Legislatures (2022)). Furthermore, our analysis highlights the need for grid planners to incorporate socio-economic factors such as income into their grid planning models, which some providers are already adopting (see, for example DigiKoo (2022)).

In Essay III, I focus my analysis on the field of future hydrogen market design and regulation, following the call of a multitude of researchers and organizations for further exploration of this under-researched field (see, e.g., Mulder et al. (2019), International Energy Agency (2019), Deutsches Zentrum für Luft- und Raumfahrt (2020), Hydrogen Council (2022b), Blanco et al. (2022), Dawin et al. (2023) and Lagioia et al. (2023)). Numerous studies have been published on the topic of hydrogen, spanning various research fields (see, e.g., reviews in Blanco et al. (2018) and Blanco et al. (2022)). However, the research focus lies predominantly on technical feasibility and production costs. More recent analyses further address developing estimations for the future global hydrogen market sizes and resource flows as well as modeling hydrogen trading (see, e.g., Nuñez-Jimenez and de Blasio (2022), Ikonnikova et al. (2023), Zhu et al. (2023), Liu et al. (2023), Zhang et al. (2023) and Li et al. (2024)). However, even with efficient production of hydrogen, establishing a well-functioning hydrogen market requires an appropriate design and trading system (see, e.g., Hydrogen Council (2022b), Dawin et al. (2023) and Lagioia et al. (2023)). Current regulatory uncertainties hold back investments in the hydrogen market, potentially jeopardizing the ambitious decarbonization goals set by the EU for 2030 (Lagioia et al., 2023). Only a few recent articles cover hydrogen market design and policy aspects. Farrell (2023) conducted a multidisciplinary literature review focusing on policy design for green hydrogen. However, they center their analysis around the cost competitiveness of hydrogen applications and associated policy financial support. Meanwhile, Van der Spek et al. (2022) analyze the state of hydrogen infrastructure regulation proposals and draw parallels to the natural gas market. They advocate for more precise infrastructure regulation, particularly concerning higher hydrogen shares within the grid.

The literature argues that more mature European energy markets should be investigated to develop a suitable hydrogen market design. The natural gas market is often proposed as a suitable analogy, primarily due to the physical similarities of both gases and the potential of using retrofitted natural gas pipelines for hydrogen transport (see, e.g., Mulder et al. (2019), Adam et al. (2020), Cerniauskas et al. (2020), Neuhauser et al. (2020), PWC (2021), Deutsche Energie-Agentur (2021), Hydrogen Europe (2021b) and Van der Spek et al. (2022)). Therefore, we look into key market design aspects within the energy sector and the European natural gas market to derive critical hydrogen market design dimensions. In many energy markets, policymakers take the role of market designers, reshaping transaction rules and infrastructure to address various market failures (see, e.g., Roth (2007) and Vazquez and Hallack (2015)). These failures include information asymmetry, hold-up of investment due to high uncertainty, and economies of scale when a dominant player controls a high fixed cost market (Roth, 2018, Mulder et al., 2019). The objective in energy market design is to establish a regulatory framework where market participants' actions work towards energy policy targets (Ringler et al., 2017). However, as described by Vazquez and Hallack (2015), there is often no one-size-fits-all solution, and policymakers must weigh the costs and benefits of various options.

Several critical factors need to be covered when defining market design aspects and associated regulations for widely used energy carriers like natural gas and hydrogen. Firstly, as laid out by Vazquez and Hallack (2015) and Roth (2018), transmission infrastructure regulation and access rights are of high importance. Typically, transmission infrastructure is eventually opened to third parties, known as third-party access (TPA), to foster competition, as exemplified in the First Gas Directive (Cronshaw et al. (2008)). This infrastructure can either be owned by integrated energy producers or unbundled as for the natural gas market, ensuring transparent access for all potential suppliers within the market (Cronshaw et al. (2008), Vazquez and Hallack (2015)). The current regulatory proposal by the Council of the European Union suggests introducing unbundling as the default model but allowing independent transmission system operators under certain conditions yet to be clearly defined (Council of the European Union, 2023a).

A second critical aspect of market design involves the trading setup. The natural gas market is an example of commodity trading in Europe, with commodities representing tradable units of energy within a physical network during specific periods (Büsch, 2013, Priolon, 2019). A competitive commodity market features high trading volumes, numerous suppliers and buyers, and full transparency (Peck and Shell, 1990, Mulder et al., 2019), which requires accessible infrastructure for communication and exchange (Neuhauser et al., 2020). While natural gas is commonly traded over-the-counter (OTC) or on energy exchanges like the EEX, OTC markets dominate in Europe (Burger, 2014, ACER, 2019, Trinomics and LBST, 2020). Exchanges, conversely, provide standardized contracts, eliminate credit risk, and are favored for derivative products (Burger, 2014).

Furthermore, Vazquez and Hallack (2015) stress that aligning commodity trading with infrastructure limitations in gas or power markets is crucial. Various models like point-to-point, zone, or postage stamp models can be utilized (Schwintowski, 2014, Robinius et al., 2014, Robinius, 2015)). In the point-to-point model, each trading transaction corresponds to a specific source-drain connection (Schwintowski, 2014). However, this model leads to significant transaction costs due to complex contracts and limited competition (Robinius et al., 2014). The other extreme, the postage stamp model offers high trading flexibility but poses technical implementation challenges as outlined by Robinius et al. (2014) and Robinius (2015). Market participants can freely inject or withdraw energy carriers regardless of distance. Nonetheless, the limitations of infrastructure and puffer reserves create hurdles to its adoption on a cross-border scale. As a compromise, the zone model accounts for capacity restrictions (Robinius et al., 2014). The market is divided into zones, in which the postage stamp model is applied, overseen by balancing group managers and market zone coordinators ensuring supply-demand balance (Haucap et al., 2011, Robinius et al., 2014). The Virtual Trading Point (VTP) facilitates separate booking of injection and withdrawal contracts, promoting trading flexibility even across zones (Robinius et al., 2014). In the European natural gas market, policymakers transitioned from the point-to-point model to the exit-entry model, which is an example of the zone model where the market zones correspond roughly to national markets of EU member states (Robinius et al., 2014, Chyong, 2019). For the case of hydrogen, the choice of market model is not yet clear. While the European Hydrogen Strategy as described in European Commission (2020a) advocates for a point-to-point access model to be adopted initially, other institutes, for example, Bundesverband der Energie- und Wasserwirtschaft (2021), argue for introducing a small exit-entry system early on.

Similarly to electricity generation, Hydrogen Europe (2021b), Bundesverband der Energie- und Wasserwirtschaft (2021) and International Renewable Energy Agency and RMI (2023) emphasize the integral importance of certification of greenhouse gas (GHG) emissions in hydrogen production. For the case of hydrogen, the specific decision regarding whether to implement a mass balance system, as outlined in Article 30 of the second Renewable Energy Directive (RED II), or to use a book and claim system similar to the electricity sector, remains subject of ongoing discussion Council of the European Union and European Parliament (2018), Deutsche Energie-Agentur (2022), Hydrogen Europe (2021b), White et al. (2021). Also, the geographic scope of the certificates still needs to be defined. Additionally, given the uncertainties surrounding the future hydrogen market, Dawin et al. (2023), Lagioia et al. (2023) or Farrell (2023) advocate for political support measures, including direct financial support.

In order to contribute to the sparse literature on hydrogen market design and regulation, we investigate how the European hydrogen market should be designed based on insights from the established natural gas market discussed above. Specifically, we investigate the feasibility of translating infrastructure regulations from the natural gas market to the emerging hydrogen market. Furthermore, we explore the suitability of various market development policy measures as well as hydrogen and certificate trading setups. In making decisions regarding the hydrogen market design, it is integral to remember that the hydrogen market is just emerging, and EU regulations and sustainability objectives heavily influence its expected rapid development. In contrast, the natural gas market has matured gradually over several decades, with regulatory frameworks introduced in hindsight. Consequently, applying learnings from the natural gas market design to the hydrogen sector can be complex and may present multiple challenges. With this essay, we support policymakers in the ongoing detailing of their regulatory hydrogen and green energy packages. Further, we aim to advance hydrogen market development by assisting current and future industry players in finding a joint understanding of the future hydrogen market design.

1.3 Methods

For each essay, I apply varying methods that I consider most suitable to the respective research question. The first two essays use quantitative approaches, performing simulations that leverage real-life data and account for the inherent uncertainty in the systems analyzed. While the second essay builds on the mobility simulation and grid model of Essay I, modeling was significantly adjusted to account for the effects of the EV user income separation we investigated. In Essay III, we employ a qualitative method that relies on a literature review and interviews to create insights into the emerging field of hydrogen market research. In the following, I outline the methodologies used in each essay.

In Essay I, our model builds on the EV and PV grid load effect and grid interaction models as explored by Denholm et al. (2013), Yazdanie et al. (2016), Candelise and Westacott (2017), Wang and Infield (2018), Fischer et al. (2019) and Powell et al. (2022). We need to model PV generation profiles, BESS operation, household electricity loads, EV mobility, and charging profiles as input for our power-flow simulation, which then detects overloads within the grids. We reinforce the respective overloading grid element in case of overloads and determine the associated costs. As all the mentioned input parameters have inherent uncertainty, we use a Monte Carlo approach leveraging empirical distributions and a Markov chain for the simulated EV charging loads. To account for seasonal changes, we simulate the months of March, June, September, and December. We utilize representative distribution grids in rural, suburban, and urban settings to account for differences in the grid structure, household characteristics, and mobility behavior. Within each setting, we examine three scenarios: case 1 without any decentralized generation or storage, case 2 incorporating residential PV rooftop installations, and case 3 integrating both PV rooftop installations and battery systems within households. We compare the determined grid reinforcement costs between these three cases to derive the societal value of the PV or BESS systems. Essay I showcases our approach in a European distribution grid situated in the Munich region of Southern Germany. This approach is adaptable to various other grids or geographical regions. We analyze six EV and PV penetration levels ranging from 20% to 60%.

To derive the EV charging loads, we randomly assign EVs to households by reflecting the distribution of car ownership and car model types owned for each area type. We use real-life mobility data to sample synthetic trips using a time-inhomogeneous first-order Markov chain, similar to Wang and Infield (2018) and Fischer et al. (2019). From this mobility behavior, we deduce each EV's charge state over time and determine the related charging loads. These EV charging loads are then combined with the electricity load profiles of each household, which are derived via empirical sampling.

To deduce the power generation of the PVs, we sample from publicly available historical monthly PV generation profiles. To deduct a suitable PV installation potential, we leverage the average available rooftop area for different housing types and their distribution in each area. When assigning PVs (and BESS) to households, we account for the observation that PV and EV usage are often correlated. As BESS system, we use a customary BESS product with a sizing of 10 kW that closely aligns with the expected future home battery sizing for households given in current studies. Households always aim to prioritize self-consuming and then saving generated electricity before feeding it to the grid.

In Essay II, we connect the grid model and mobility simulation developed in Essay I to literature on the effects of income on EV adoption, car model choice and mobility behavior, as explored, for example, by Kelly et al. (2012), Sovacool et al. (2019), Gauglitz et al. (2020), Berneiser et al. (2021) and Lee and Brown (2021). As for Essay I, we again use a Monte Carlo approach to account for uncertainty in the model and adjust the empirical distributions and Markov chain model to reflect the impacts of household income. We thereby extend the models of Fischer et al. (2019), Lee and Brown (2021) and Powell et al. (2022), who analyze the impact of socio-economic factors on EV charging loads by deriving the associated grid stability impacts and reinforcement costs, as well as their energy equity implications. We analyze scenarios that reflect the current German government target of 15 million EVs on German roads by 2030 (German Government, 2021).

We simulate electricity loads for two neighborhood types: below-average (lower) and above-average (higher) income, meaning a 50:50 split of households. For each neighborhood type, we assign income-based EV adoption and model choices and simulate the respective mobility behavior based on representative real-life driving data. Again, we perform our analysis of representative distribution grids in urban, suburban, and rural settings. Our power-flow simulations then assess each setting for potential overloads. We calculate grid reinforcement costs to mitigate these overloads for each grid and neighborhood type. Based on these reinforcements, we derive the grid cost asymmetry between the two neighborhood types. While we use distribution grids in Bavaria (Germany) as an illustrating example, the approach may be applied to any grid or geographical region.

An important additional element we need to include compared to our approach in Essay I is that we need to create two neighborhood types, higher- and lower-income. We hence populate the grids with the related income group by sampling from the household distributions of each neighborhood and grid type. We then randomly allocate EVs based on the income group's EV adoption and model choice distribution. For this purpose, we adjust the EV adoption level as well as car ownership distribution by neighborhood type. Currently, a household's probability of owning an EV is up to three times as high for higher-income compared to lower-income households. As this effect might lessen in the future, we also test the impact of equal EV adoption. To derive income-dependent car model distributions, we leverage current real-life income-dependent car model distributions and project them on new car sales to reflect the German car park in 2030. To sample EV driving patterns and charging loads for both income groups, we use separate time-inhomogeneous Markov chain simulations fitted upon the real-life mobility behavior of each income class from a representative German mobility study.

In Essay III, our objective is to contribute to an upcoming literature field with so far sparse findings available, namely the core design criteria and regulation of the future European hydrogen market. We use the Grounded Theory Method (GTM), a qualitative approach based on Glaser and Strauss (1967), Corbin and Strauss (1990) and Corbin and Strauss (2015), that is particularly suitable for under-researched fields. With our interview-based approach, we extend the literature reviews of Van der Spek et al. (2022) and Farrell (2023), thereby supporting policymakers and hydrogen market players in developing a hydrogen market target design.

We use the four-step analysis approach for inductive concept development developed by Gioia et al. (2013) based on the GTM. We select adequate interview partners via theoretical sampling and define five expert groups: utility companies, industrial companies of high-priority hydrogen applications, commodity energy exchanges, government and research institutes, and the energy sector focus of consulting companies. The selected expert groups were recently confirmed as the most relevant stakeholders in a hydrogen market analysis published after our interviews. We identified 46 potential interviewees in these highly specialized fields, many representing leading players in European or global markets. After prioritizing 33 particularly relevant candidates, we conducted 16 expert interviews. We performed data collection and analysis simultaneously using an iterative approach typical of GTM. In total, we identified 17 categories, with four core categories emerging from the data. In our analysis, the number of new concepts decreased significantly after the sixth interview, with only limited additional concepts arising in the following interviews.

1.4 Results and policy implications

In all three essays, I use differing modeling and analysis approaches that advance our understanding of the grid impacts of electric mobility as well as the market dynamics of the future European hydrogen economy. In this section, I give an overview of each essay's main findings and policy implications.

Essay I analyzes the mitigation potential of decentral residential PV energy generation and battery storage regarding EV-related grid instability and reinforcement cost. In all investigated scenarios and grid types, residential PV systems can significantly reduce grid overloads. This effect is even more substantial when also battery storage systems are employed. Overall, rural grids are most prone to overloads, and suburban grids are of the highest stability. Hence, PV and BESS systems are the most promising in mitigating overloads in rural settings. For areas where grid reinforcements are not feasible, e.g., due to residents' resistance, PV and especially PV and BESS installations might be promising mitigation measures.

Grid reinforcement cost savings vary significantly with EV and PV penetration across different grid types. PV and BESS systems consistently outperform standalone PV systems. In rural areas, the highest cost savings are seen with lower EV and PV (and BESS) penetration, but increasing EV penetration levels will require inevitable infrastructure upgrades. Due to their stability, suburban grids show high savings potential at high EV penetration levels. In contrast, urban grids benefit most from PV (and BESS) installations at medium to high EV penetration. In Germany, potential cost savings from PV alone could reach €1.2 billion, and combined PV and BESS systems could save up to €3.2 billion. These savings could increase further if other electricity-saving and load-shifting measures supporting the weaknesses of decentralized PV generation are employed during winter months.

To reward the grid stabilization benefits of PV and BESS systems as EV penetration rises, policymakers may adjust subsidies for PV and BESS systems, particularly for west-oriented systems that mitigate EV charging peaks. Policymakers could also target subsidies to households in bottleneck areas of the grid. Additionally, reinvesting identified grid reinforcement cost savings into low-interest financing or low-cost rental options could support lower-income households historically struggling to benefit from PV subsidies.

In Essay II, we uncover the EV charging-related imbalance in grid costs between higher- and lower-income neighborhoods. Higher-income areas cause a significantly higher number of grid overloads, necessitating more extensive reinforcements. In rural, suburban, and urban grids, the additional costs for higher-income neighborhoods soar by 50%, 3,266%, and 478%, respectively, compared to lower-income counterparts. Extrapolating to EU distribution grids, this asymmetry could amount to €14 billion. Analyzing the underlying factors of these cost imbalances, we find that differences in EV adoption and driving patterns largely cause these disparities.

If grid costs increase, the electricity price for all consumers rises. Higher-income neighborhoods bear a larger burden due to their higher electricity consumption. Yet, this contribution fails to offset the substantial additional reinforcement costs they cause. Equitable cost allocation would require higher-income households to bear this burden fully, not impacting other consumers' electricity prices. Policymakers could reduce these inequities by promoting dynamic tariffs, e.g., time-of-use tariffs, to mitigate the grid impact of EV charging in higher-income neighborhoods. Alternatively, they could implement smaller grid tariff zones to isolate high-cost areas. However, such an approach can be highly complex. Further, policymakers may address the asymmetry in EV adoption and model choice between income groups. For any policy measure, EV ownership and usage over combustion engine cars should never be discouraged.

In Essay III, we leverage across-industry expert interviews and analogies to the natural gas market to derive a suitable European hydrogen market design and attached regulation. Our findings span the topics of market development policy measures, infrastructure regulation as well as hydrogen and certificate trading.

Our experts emphasize the urgency for policymakers to create planning certainty from the political side to accelerate investments and overcome challenges such as the chicken-and-egg problem during market ramp-up. They recommend direct industry support on capital expenditure (CAPEX) rather than operational expenditure (OPEX). Very strict regulations, such as the correlation and additionality requirements regarding green electricity use in Article 27 of the delegated act (RED II), should be avoided or delayed to ensure the hydrogen market's growth is maintained. Policymakers should explore avenues to enhance the profitability of hydrogen business models, such as through CO_2 price increases, contracts for difference, tax breaks, or quotas.

Echoing regulations in the natural gas market, our experts advocate for introducing fundamental regulations like third-party access, unbundling, and the entry-exit system early to ensure planning certainty or after a grace period to foster market development. Exploring cross-subsidization of infrastructure between natural gas and hydrogen and implementing EU-wide feed-in regulations in natural gas infrastructure are also proposed.

In designing the hydrogen commodity trading system, our experts agree to mirror the natural gas trading system, incorporating OTC trading, energy exchanges, spot markets, and futures markets. They highlight the potential of energy exchanges in supporting market development by introducing hydrogen price indices and offering hedging opportunities, liquidity, and price transparency. Additionally, they recommend adopting a book and claim system on at least an EU scale to represent hydrogen's sustainability.

1.5 Structure of the dissertation

This dissertation includes three distinct research projects outlined in Table 1.1, each with its own objectives, methodologies, and primary contributions. Since each essay is intended for separate publication in academic journals, key concepts or definitions are explained within each essay and might be repeated. Chapter 2 includes Essay I, which uncovers the effect of residential PV and battery systems on EV-related grid costs. Chapter 3 consists of Essay II, which analyzes the impact of household income on grid infrastructure cost induced by EV charging. Essay III, covered in Chapter 4, explores an appropriate European hydrogen market design and attached regulation. Lastly, I conclude my findings and propose fields of future research in Chapter 5.

Table 1.1: Dissertation overview.

	Essay I (Chapter 2)	**Essay II (Chapter 3)**	**Essay III (Chapter 4)**
Title	Enabling electric mobility: Can photovoltaic and home battery systems significantly reduce grid reinforcement costs?	Another source of inequity? How grid reinforcement costs differ by the income of EV users	The future European hydrogen market: Market design and policy recommendations
Problem addressed	EV charging leads to grid reinforcement requirements that require mitigation measures.	EV-related grid reinforcement cost might vary by socio-economic factors such as income and lead to energy inequity.	The regulation attached to the European hydrogen market design remains unclear, holding up investments.
Research question	What is the EV-charging related grid cost saving potential of residential PV and battery systems?	What is the EV-charging related grid reinforcement cost difference between above-average and below-average neighborhoods?	How should the European hydrogen market and attached regulation be designed based on learnings from the natural gas market?
Main contribution	Residential PV and especially combined battery systems can significantly reduce grid instability and grid reinforcement costs in all area types.	Induced grid instability and reinforcement costs differ strongly in all area types, which requires mitigating policy measures to prevent energy equity issues.	Detailed recommendations for market development policy measures, infrastructure regulation, and hydrogen and certificate trading are derived.

2 | Enabling electric mobility: Can photovoltaic and home battery systems significantly reduce grid reinforcement costs?

Sarah A. Steinbach and Maximilian J. Blaschke

The increasing adoption of electric vehicles driven by government plans to strongly electrify mobility will challenge the current distribution grid infrastructure. The related electricity demand increases the risk of overloads in transformers and lines and will require significant grid enhancements and infrastructural investments. Our paper evaluates the potential of reducing investment needs through decentralized photovoltaic electricity generation and battery energy storage systems. We use power-flow analyses on representative grid models to test rural, urban, and suburban grids' resilience to higher electric vehicle penetration. We find significant societal benefits with a simultaneous uptake of decentralized generation and estimate savings of up to €3.2 billion solely within the German grid. In rural areas, photovoltaic and battery systems are especially effective for electric vehicle penetrations up to 20%. Suburban and urban grids could achieve significant savings for electric vehicle penetrations up to 60%. We recommend that policymakers facilitate decentralized electricity generation to unlock additional benefits from a societal cost perspective, increase the share of sustainable electricity consumption, and improve energy security.

Keywords: Electric vehicles; Electric grid; Photovoltaic systems; Energy storage system; Infrastructure cost

2.1 Introduction

Countries all over the globe invest in the uptake of electric vehicles (EVs) to reduce carbon emissions and pave the way toward carbon neutrality in the transportation sector. The United Kingdom, Canada, and the European Union even banned the sales of internal combustion engine cars after 2035 (International Energy Agency, 2021). The increasing number of EVs, however, poses challenges to the power grid. Driving profiles show that most consumers charge their EVs at similar times during the day, especially in the early evening. Unfortunately, this simultaneous charging of many EVs could lead to significant load peaks within the grids (e.g., Clement-Nyns et al. (2010), Nogueira et al. (2021) and Powell et al. (2022)). A recent 2035 forecast by Powell et al. (2022) for the US uncovers peak net electricity demand increases by up to 25%, confirming the challenges imposed on electric grids. Nogueira et al. (2021) expect the current electric grid capacity in Northern Portugal to fail due to EV-related load peaks as early as 2026. To prevent these peaks from causing overloads, grid operators around the globe will have to upgrade and further expand the grid infrastructure. Following Bermejo et al. (2021) and Elmallah et al. (2022), this might require billions in investment costs. Decentralized electricity generation, e.g. via residential photovoltaic systems, has the potential to reduce the grid enhancements necessary for EV integration (e.g., Denholm et al. (2013) and Cohen et al. (2019)). This potential can be increased further if load matching is improved via battery energy storage systems (e.g., Mancini et al. (2020) and Freitas Gomes et al. (2020)). Cohen et al. (2019) show that EV users have a higher willingness to install such systems while simultaneously reducing peak load effects. However, the societal value of these peak load reduction effects and related infrastructure savings are not yet analyzed. More market design and policy-focused literature streams like Bravo et al. (2021), Grimm et al. (2021) and García-Cerezo et al. (2021) investigate the expansion of power grids in various settings but also do not provide detailed insights on the societal value of decentralized generation and storage for the overall system infrastructure. Our research investigates the effectiveness of residential photovoltaic (PV) and battery energy storage systems (BESS) in reducing grid reinforcement costs caused by EV charging. We calculate the necessary reinforcement costs in three scenario settings: (1) without any distributed generation or storage, (2) with PV systems, and (3) with combined PV and BESS systems. By comparing these three scenarios, we uncover the societal value of decentralized residential electricity generation and storage systems in reducing public costs for necessary grid infrastructure. We determine the weaknesses of the grid, discuss measures to solve them and derive policy recommendations accordingly.

Clement-Nyns et al. (2010), Lopes et al. (2011), Green et al. (2011) and Fernandez et al. (2011) were among the first to point out the challenges to the distribution grids caused by EVs. Clement-Nyns et al. (2010) expect significant voltage imbalances and power losses beginning at 10% plugin-hybrid electric vehicle penetration levels. Following Clement-Nyns et al. (2010), several other authors find similar results in different countries and grid scenarios (see Lopes et al. (2011), Fernandez et al. (2011), Salah et al. (2015), Muratori (2018b), Kapustin and Grushevenko (2020), Nogueira et al. (2021) and Powell et al. (2022)). Green et al. (2011), Richardson (2013) and Das et al. (2020) provide literature reviews and general overviews and outlooks on the problem of integrating electric vehicles into the grid. As grid operators need to expand grid capacity to cope with the challenge of EV charging loads, Wangsness and Halse (2021) find that increases in EV penetration lead to significant grid reinforcement costs. Recent trends for a shift in technology towards sole battery-powered electric vehicles (BEVs) and increasing charging powers could further aggravate the challenges to the grid, requiring new solutions and improvements within the infrastructure (e.g., Mowry and Mallapragada (2021) and Steadman and Higgins (2022)).

Coordinated ("smart") charging or "vehicle to grid" settings could reduce the challenges of EVs on the distribution grids as shown by many papers (e.g., Clement-Nyns et al. (2010), Lopes et al. (2011), Wang et al. (2011), Qian et al. (2011), Mwasilu et al. (2014), Loisel et al. (2014), Szinai et al. (2020), Strobel et al. (2022) and Blumberg et al. (2022)). However, these authors frequently assume that coordinated charging could be imposed on all EV users. Such coordinated charging might not be realistic as regulation enforcing such measures must be implemented first. When smart charging is not mandated by an external entity, but rather motivated by consumers seeking to optimize costs via smart meters that adapt to dynamic tariffs, multiple authors find the risk of even higher induced load peaks if tariffs are not carefully calibrated (see, e.g., Unterluggauer et al. (2023), Daneshzand et al. (2023) or Stute and Kühnbach (2023)). Furthermore, smart charging must balance grid stability with other, sometimes competing objectives, such as integrating more renewables (Strobel et al., 2022).

Another alternative measure could be the extended use of residential electricity generation to support EV charging from decentralized sources without the need to pass the electricity through the grid (Denholm et al., 2013, ElNozahy and Salama, 2014, Cohen et al., 2019). Decentralized electricity generation may reduce the power-flow from the grid to the households (see, for example, Yazdanie et al. (2016) and Candelise and Westacott (2017)) and reduce the necessary grid enhancements. Charging strategies with decentralized generation are well supported by existing literature, where the utilization of PV for EV charging has shown to have a positive impact on the grid's capacity for both PVs and EVs (e.g., Denholm et al. (2013), ElNozahy and Salama (2014), Bhatti et al. (2016) and Hoarau and Perez (2018)).

The biggest challenge to the effectiveness of using PV-generated electricity for EV charging, however, is their limited timely overlap. Related literature recommends and considers battery energy storage systems in their evaluations to improve load matching (e.g., ElNozahy and Salama (2014), ElNozahy et al. (2015a), Hoarau and Perez (2019), Mancini et al. (2020), Freitas Gomes et al. (2020), Yazdanie et al. (2016) and Candelise and Westacott (2017)). Improving load matching with combined PV and BESS systems may provide significant financial benefits for EV users. Hoarau and Perez (2019) evaluate different tariff structures and investigate the complex effects of these tariffs on the adoption of decentralized generation and electric vehicles. However, as many households across Europe only pay according to the amount of kWh consumed, these households will simply aim to reduce the electricity bill with their own electricity generation: The levelized costs of self-producing electricity with a small residential PV and battery system frequently undercut residential electricity tariffs (e.g., compare Kost et al. (2021) with Eurostat (2020)). As EV users have a higher electricity consumption, they could have an increased willingness to install their own generation systems (see, for example, Wen et al. (2023)). These households may leverage the cost difference between buying and self-producing electricity (e.g., see Cohen et al. (2019) and Kaufmann et al. (2021)) and reduce the load effects on the distribution grids simultaneously. While the directly related cost savings via self-consumption on the consumer side are comparably easy to determine, the societal value of reduced infrastructure demand remains to be discovered and likely not reflected in current subsidy schemes and policy measures.

We tackle this research gap by investigating the potential value of decentralized electricity generation and storage in reducing the costs for the power grid and discussing policy measures accordingly. We consider rural, suburban, and urban settings to account for the significant differences in area types regarding available rooftop PV installation space and grid specifications. With this analysis, we support policymakers and grid operators to enable a higher share of EVs within the respective grids.

The paper is organized as follows: Section 2.2 describes the methodology. Section 2.3 then presents and discusses the results, while section 2.4 concludes.

2.2 Methods

We perform power-flow analyses to reveal potential overloads within the grid with the Newton-Raphson method using the matpower package in MATLAB (Zimmerman et al., 2011). After sampling electric vehicles amongst the grid nodes, the simulation diagnoses grid overloads in five-minute intervals for the months of March, June, September, and December to achieve high accuracy and account for seasonal changes. We analyze representative distribution grids in rural, suburban, and urban settings at different levels of EV adoption to account for differences in the grid structure, household characteristics, and mobility behavior. This paper showcases the approach with inputs for a European distribution grid in the Munich region in the South of Germany. The approach, however, may also be applied to any other grid or geographical region. For every setting, we simulate three cases: case 1 without any decentralized generation or storage, case 2 with residential PV rooftop installations, and case 3 with PV rooftop installations plus battery installations within the houses. Figure 2.1 illustrates the building blocks within the simulation.

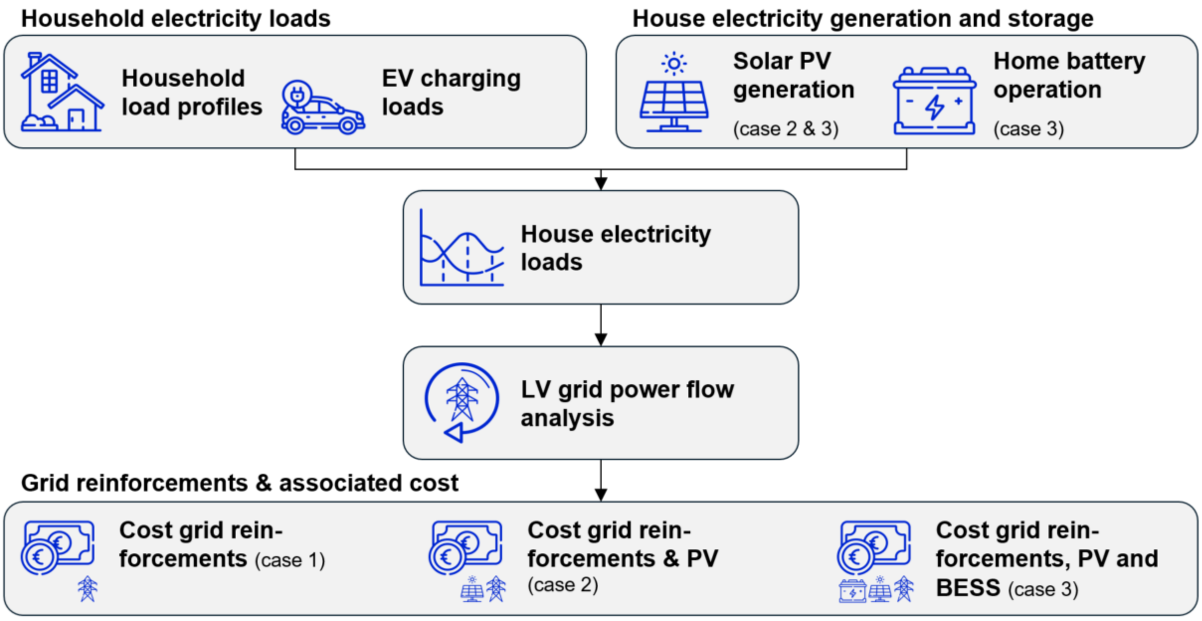


FIGURE 2.1: Simulation approach to determine the costs to solve overloads within distribution grids.

The simulation reflects the inherent uncertainty in the system through a Monte Carlo approach and is structured as follows:

1. We sample household and EV charging loads on a household level.
2. We sample PV generation (case 2 and case 3) and home battery operation (case 3) on top of the household loads.
3. For each node of the grid, we aggregate the associated household loads, PV generation (case 2 and case 3) and home battery operation (case 3) to derive house-specific electricity loads.
4. We perform a power-flow analysis on the grid nodes and their connections. In case of overloads, we reinforce the respective overloading grid element.
5. We calculate the costs for grid reinforcements to solve the overloads and compare the costs between the three cases to derive the societal value of the PV or BESS systems.

We analyze the following six EV and PV penetration levels: (EV 20%, PV 20%), (EV 40%, PV 20%), (EV 40%, PV 40%), (EV 60%, PV 40%) and (EV 60%, PV 40%). We consider EV penetration relative to all cars on the road and PV penetration relative to all residential houses accounting for average available roof area.

2.2.1 Household and EV loads

Using empirical sampling and the Load Profile Generator of Pflugradt (2017), we generate 1,000 representative German household electricity load profiles for each season. The Load Profile Generator has been widely used and validated in literature (e.g., Lopez et al. (2019), Haider and Schegner (2020) and Huang et al. (2021)) and allows the creation of representative synthetic household electricity load profiles based on a full behavior simulation of the respective household (Pflugradt (2017)). We then categorize these load profiles by household size. To create representative electricity loads for houses in rural, suburban and urban areas in the Munich region, we sample household load profiles aligned with the distribution of household sizes per area type in Bavaria according to Bayrisches Landesamt für Statistik (2021). We further create area-specific distributions of households per building, as those vary by area type according to Statistisches

Bundesamt (2021). The respective household size and household per building distributions can be found in A.4.1.

We then assign EV loads to households by determining the number of private cars owned per household based on the area type using the German Mobility Panel data set (Karlsruher Institut für Technologie, 2020). To reflect the markets' increasing focus on BEVs as the future technology, we choose to use BEVs only (German Government, 2021, International Energy Agency, 2021). We use various EV segments to account for different charging needs and power consumption: Mini (Volkswagen e-UP), Small (Renault Zoe Z.E. 40 R110), Compact (Volkswagen ID.3 Pro), Medium (Tesla Model 3 Long Range Dual Motor), and SUV (Audi e-tron 55 quattro). The respective car segments are based on the newly registered cars in 2021 as provided by the German federal transport agency (Kraftfahrt Bundesamt, 2021). The usable battery capacity was assigned based on EV Database (2022), where technical specifications for EVs currently on the market are collected. The electricity consumption is taken from real-life driving tests by ADAC (2022). Specifications for the car segments used are outlined in Table 2.1 below.

Table 2.1: Car segment distribution, battery capacity and consumption (Kraftfahrt Bundesamt, 2021, EV Database, 2022, ADAC, 2022).

Segment	**Mini**	**Small**	**Compact**	**Medium**	**SUV**
Share (%)	7	16	20	15	43
Usable battery (kWh)	32	41	58	76	87
Electricity consumption (kW/100km)	17.7	20.3	19.3	20.9	25.8

To account for differing seasons in our simulation, we adjusted the electricity consumption for ambient temperature using Al-Wreikat et al. (2022), Climate-Data (2022). This adjustment is required, as the energy efficiency of an EV is significantly influenced by ambient temperature, with temperatures between 0°C and 15°C decreasing vehicle ranges by up to 28% compared to driving at moderate temperatures from 15°C to 25°C (Liu et al., 2018, Al-Wreikat et al., 2022).

We use real-life driving patterns from the German Mobility Panel (Karlsruher Institut für Technologie, 2020), collected between September 2019 and the beginning of March 2020. This data set provides weekly trip data for 32,223 car trips, including driving times, trip purposes, and timings for rural, suburban and urban regions. We remove outliers from the data set by excluding drivers performing holiday trips or very long journeys (above 200km, longer than 132 min) to represent common driving behaviors likely to be charged at home, resulting in a data set of 22,803 trips. We assume the first trip of each day always starts and the last trip of each day always ends at the home node. From this trip data, we sample synthetic trips using a time-inhomogeneous first-order Markov chain. Markov chain models, also related to EV charging loads, are frequently used in uncertainty modeling, balancing high accuracy with moderate computational cost (Wang and Infield, 2018). We create trip samples between "Home", "Work" and "Other" locations and deduct synthetic EV driving and charging profiles, differentiating between weekdays and weekends. We choose the Markov chain to be time-inhomogeneous, as the probability of moving from one location to another is time-dependent. All trip recordings from the German Mobility Panel are self-reported and show a rounding bias resulting in approximately 75% of arrival and departure times with a right-hand digit of 0 or 5. We, therefore, conduct our simulation in five-minute intervals, also reducing computation time. Testing our model at one minute accuracy did not affect our results.

We focus on charging while at home, as it is the most frequently used charging option (virta, 2021). Once the EV arrives home and is parked for more than 10 minutes, the probability of starting to charge the EV is determined based on the state of charge (SOC) using Franke and Krems (2013) as

$$p_{charge} = \min\left(\left(1 - \frac{1}{1 + e^{-0.15(SOC-60\%)}}\right) c_l, 1\right)$$

which was calibrated using Schäuble et al. (2017). This inverse s-shaped relationship between the state of charge and the probability of starting the charging process was developed by Franke and Krems (2013) through a six-month field study of 79 EV drivers. The analysis of the charging behavior of EV fleets in Germany performed by Schäuble et al. (2017) then allowed us to calibrate the parameters for our simulation setting. The factor c_l can be chosen location-dependent and is, in our case, adjusted for whether a private charger is available or the charger is public and assumed in front of the house.

We base the EV charging simulation on Fischer et al. (2019) and adapt for uniform driving behavior across households to reduce complexity in line with other literature on EV-PV interaction. To start our simulation, we first sample the number of trips performed by each car on that day. In the second step, we use the first-order Markov property to define trip destinations, distances, speeds, and associated parking times depending on the start location of the current trip and its time of day (as time-inhomogeneous). After each trip, we update the state of charge of the EV to reflect the distance driven and add the related charging loads to the household loads. The model fits well with the empirical data, resulting in an average total driving time of 40.1 min (40.2 min in the data as a reference) and an average trip frequency of 2.07 (2.09 in the data) daily trips.

2.2.2 PV generation and home battery operation

To simulate power generation through PVs, we leverage frequently used PV generation profiles for the exemplary location of Munich (Germany) from Staffell and Pfenninger (2016), Pfenninger and Staffell (2016) and Pfenninger and Staffel (2019) for 1980-2019 and use these profiles for an empirical sampling of the respective seasons. To determine the PV installation potential for a rooftop, we distinguish between single-, double- and multi-household buildings for which we deduct the average available roof area from Mainzer et al. (2014), which can be found in A.4.2. Using a standard system power density of 200W/m^2 (as, e.g., used by Trinasolar (2020)), we derive an average PV installation potential of 7.1kW, 7.6kW, and 10kW, respectively. When assigning PVs (and BESS) to households, we consider that PV and EV usage are often correlated, increasing the probability for PV (and BESS) installation by 31% in cases where a resident within the building owns an EV (Cohen et al., 2019). We use the Tesla Powerwall 10kW battery with an energy capacity of 13.5 kWh and charging efficiency of 90% for the home battery system (Tesla, 2022). We use this BESS to reflect a customary BESS product with a sizing that closely aligns with the expected future home battery sizing for households as predicted by Kost et al. (2021) and Fraunhofer-Institut für System- und Innovationsforschung ISI et al. (2022). We do not differentiate between EV and non-EV owning households in BESS sizing, as the effect of owning an EV on BESS sizing is unclear. If the EV is in use during most days, the household would prefer a larger battery, while for households with EVs often parked at home during the day, a smaller BESS would be preferable.

As for the case of Germany, the levelized cost of electricity for a small residential PV and battery system has been between 8.33 ct/kWh and 19.72 ct/kWh in 2020 (Kost et al., 2021). This number was already far below average household electricity prices of 30.43 ct/kWh in the same year (Eurostat, 2020). In light of the current surging electricity prices during the European energy crisis, households aim to maximize the self-consumption of PV-generated electricity and use it directly within the household. In case of overproduction of electricity, the home battery

(BESS) charges until it reaches its capacity limit. Only when overproduction remains after the BESS finishes charging PV-generated electricity is fed into the grid. Feed-ins are curtailed at 70% of the PVs maximum capacity in line with current regulation (Bundesamt für Justiz, 2021). If the electricity consumption is higher than the PV electricity generation, the household first leverages the BESS until the battery is fully discharged and consumes electricity from the grid afterward.

2.2.3 LV distribution grids

We analyze the different area and grid specifications using the SimBench low-voltage (LV) distribution grids, which represent German benchmark distribution networks (Dzanan Sarajlic and Christian Rehtanz, 2019, Meinecke et al., 2020). We choose to use the SimBench LV grids distinguished by area types: The SimBench LV 02 as the rural, the SimBench LV 05 as the semi-urban, and SimBench LV 06 as the urban LV grid. The grids include 95, 109, and 108 consumers (houses), respectively. Following Cossent et al. (2011), we estimate investment costs for line reinforcements of 85–125€/m in Germany. Transformer update costs are taken from Cossi et al. (2012), who assigns investment costs of €26,970 to a 250kVA transformer as used in the rural grid and €61,730 to a 630kVA transformer within the suburban and urban grid.

2.3 Results and discussion

2.3.1 Load profiles

First, we investigate the load peak reduction enabled by the PV and BESS installations. As an illustrating example, we show the rural grid loads for an EV and PV penetration of 40% on a Friday in March. Figure 2.2 visualizes the total household loads, their aggregation with the EV load profiles, the net loads when including PV generation, and the net loads when also including BESS operation.

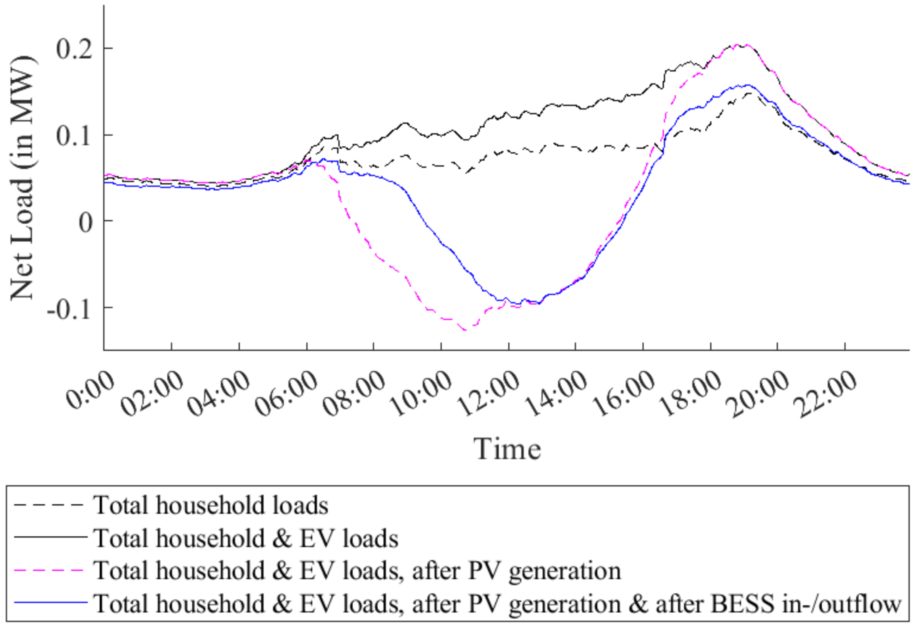


FIGURE 2.2: Net load profiles of the rural grid including 95 houses: aggregation of households loads, EV loads, PV generation and BESS in-/ outflow for a Friday in March, 40% EV, 40% PV penetration.

As visible in the aggregated household and EV loads of Figure 2.2, the additional EV charging loads intensify existing household load peaks, confirming related literature. The PV generation partially covers these load peaks. However, there is a time lag between the maximum PV generation capacity around mid-day, while load peaks occur later in the day. We can see active BESS operation, charging the battery throughout the morning and mid-day and discharging in the afternoon/evening to flatten the load peaks. This first load analysis indicates that the combined use of PV and BESS can help reduce load peaks and strain on the grid.

When we investigate the load profiles of an entire week, weekday load peaks occur in the late afternoon to evening, while weekend peaks occur earlier (around mid-day). The differing load peaks between varying days of the week emphasize that investigation of only one average daily profile is insufficient for adequate load assessment. As the load profiles also show significant differences between the seasons, we will further investigate the seasonal effects in our later analysis.

2.3.2 Overload analysis

This subsection analyzes the occurring grid overloads for each area type. We differentiate between line and transformer overloads and investigate the impact of PV and BESS for all seasons. We again illustrate our findings using an EV and PV penetration of 40%. A.5.1 provides an overview of average weekly overloads during each month. The winter season is the most adverse setting for our PV and BESS approach, as household and EV loads are the highest, and PV generation is the lowest. Hence, our further analysis focuses on the month of December. Each overload in Figure 2.3 represents a 5-minute interval in which an overload occurs.

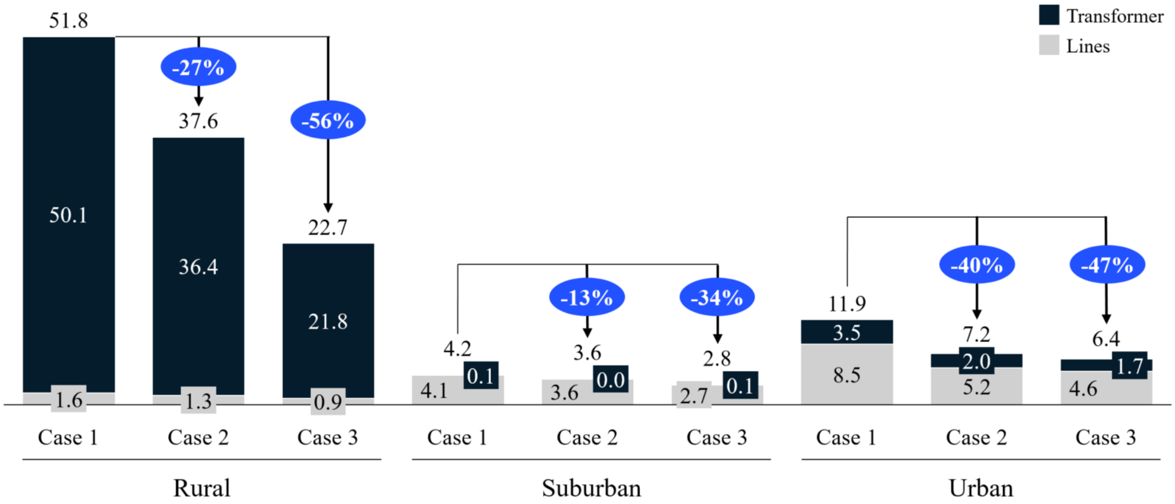


FIGURE 2.3: Average number of weekly overloads in December, 40% EV, 40% PV penetration.

We find that rural grids tend to be most prone to overloads, while suburban grids are the most stable. The rural grid also shows the most significant reduction in overloads through PV and BESS, reducing average weekly overloads by 56% with BESS and 27% without. When 40% of all houses have a PV (and BESS), the higher number of single-family houses in the rural setting makes a difference. The single-family houses lead to a higher ratio of PV generation in relation to household and EV loads compared to suburban and urban settings. Boosting PV and BESS installation in rural areas is, therefore, more effective. Nevertheless, PV and BESS can also significantly reduce overloads in suburban and urban settings. Regarding the type of overload, the small capacity of the rural transformer (250kVA) is the source of most overloads in the rural grid. In contrast, the suburban and urban grids mostly exhibit overloads within their lines.

In settings where grid reinforcements are no option, e.g., due to residents' resistance, PV, especially PV and BESS installations, can significantly reduce overloads, especially in the months with higher solar radiation (see A.5.1).

2.3.3 Reinforcement cost

Next, we investigate the average reinforcement costs required to stabilize the grids with and without PV (and BESS). We focus on the results for December as our worst-case season to ensure grid stability throughout the year. We show the results for all seasons in A.5.2.

As visible in Figure 2.4, PV and BESS installations reduce the number of overloads in the grid and reduce the required reinforcement costs for grid stabilization for all grid types and scenarios analyzed. However, the magnitude of the reduction dramatically varies between the grid types and the PV and EV penetration levels.

FIGURE 2.4: Average simulated grid reinforcement costs (in €) in December.

For the rural grid, PV (and BESS) installation could achieve an 18% (39%) reduction in reinforcements costs in a 20% EV penetration scenario. For higher EV penetration levels, PV and BESS installations can no longer significantly reduce grid reinforcement costs. This is caused by the inevitable transformer upgrade for these higher EV penetration levels, as apparent by the occurring overloads in Section 2.3.2. We do not see a significant reinforcement cost increase for EV penetrations of 60%, as only few additional line reinforcements are required and the majority of costs is driven by the transformer upgrade. These results are in line with Wangsness and Halse (2021), who also find that rural grids experience significant grid costs even at lower EV penetration levels as investments in higher grid capacity have historically been comparatively low.

Suburban grids have greater resilience than other grid types. PV (and BESS) installations become especially relevant at higher EV penetration levels: At an EV penetration of 60%, we see a sudden jump in reinforcement costs as lines and transformers begin to overload regularly. These costs can be reduced significantly by up to 12% (49%) through PV (and BESS) installations but remain high.

As we saw in Section 2.3.2, the urban grid is far more stable than the rural and slightly less stable than the suburban grid. This stability influences the grid reinforcement costs: Similar to the suburban grid, the reinforcement costs increase at an EV penetration of 40% and exhibit a sudden jump in cost at EV penetration levels of 60%. Again, PV (and BESS) installations are most effective at medium to high EV penetration levels, reducing grid reinforcement costs by up to 22% (46%).

Policymakers and grid operators must prepare for a sudden jump in grid reinforcement costs with scenarios above 40% EV penetration in rural settings. For suburban and urban areas, costs will spike as soon as we face 60% EV penetration levels. We should utilize additional electricity saving or load-shifting measures such as smart charging or electricity tariff adaptations in the winter to circumvent large grid reinforcements.

2.3.4 Cost savings and policy implications

Lastly, we investigate the reinforcement costs that can be saved with each PV (and BESS) installation. We focus again on the December grid reinforcement costs. As Table 2.2 shows, grid reinforcement cost savings differ significantly between the grid types and EV and PV penetration levels. In all cases, the PV and BESS systems dominate the PV systems concerning reinforcement cost savings.

Table 2.2: Grid reinforcement cost savings per PV (& BESS).

Penetration		**Rural savings**		**Suburban savings**		**Urban savings**	
EV	***PV***	***PV***	***&BESS***	***PV***	***&BESS***	***PV***	***&BESS***
20%	20%	€200	€449	€9	€12	€32	€36
40%	20%	€13	€40	€81	€132	€107	€157
40%	40%	€21	€103	€54	€120	€81	€170
60%	40%	€11	€49	€39	€254	€178	€376
60%	60%	€21	€82	€93	€377	€167	€358

For rural grids, the most significant savings can be generated at an EV and PV (and BESS) penetration level of 20%, saving €200 (€449) in grid reinforcement costs per PV (and BESS). Hence, policymakers may free up these cost savings to further support the necessary generation system installations and increase the share of renewable electricity generation simultaneously. However, rising EV penetration will inevitably force grid operators to upgrade rural infrastructure in the long run.

Due to the high stability of the suburban grid in scenarios with low EV penetration, PV (and BESS) installations unfold their highest saving potential at a later stage. Supporting PV (and BESS) installations in an EV and PV penetration scenario of 60% could be beneficial if the supporting actions to incentivize an additional system installation cost less than the respective €93 (€377) in cost savings for the grid.

As the urban grid is more robust than the rural but more vulnerable than the suburban grid, PV (and BESS) installations are especially attractive at medium to high EV penetration levels. PV and BESS combined systems could save an average of €157-€376 in these scenarios. Sole PV systems would save, on average, €81-€178.

When performing cost estimations for the total amount of 19.4 million residential buildings and considering the share of the rural, suburban, and urban distribution of these houses in Germany, the potential cost savings could amount to €0.3-€1.2 billion for PV installations and €0.4-€3.2 billion for PV and BESS combined systems (Bundesinstitut für Bau-, Stadt- und Raumforschung et al., 2017, Statista, 2021, Statistisches Bundesamt, 2022a). Accounting for the 119 million residential buildings in the EU with their respective distribution into rural, suburban and urban regions, these cost savings could even reach €1.6-€7.1 billion for PV installations and €2.6-€19.2 billion for PV and BESS (RICS Data Services, 2020). As mentioned in Section 2.3.3, the savings potential is even higher in case other electricity saving and load shifting measures can support the grid and reduce the weaknesses of the decentralized photovoltaic generation during the winter months.

As EV penetration increases, policymakers could, for example, adjust current PV (and BESS) subsidies to reward their future grid stabilization effects and related public cost savings. However, current residential PV and BESS systems frequently already yield returns of more than 5% (Wirth, Harry, Fraunhofer ISE, 2021). Furthermore, PV- and BESS-adoption promoting measures such as tax benefits are continuously being expanded to reward the increased renewable electricity generation (Bundesministerium für Finanzen, 2023). Hence, these systems do usually not require further subsidization to be profitable. However, storage systems or photovoltaic units that are oriented to the west providing electricity during EV charging peaks could benefit from additional compensation for their grid stabilizing effects. As we find that failures within the grid are often caused by certain bottleneck elements, such as specific lines or transformers, policymakers could also explore offering additional subsidies to households in these bottleneck areas on top of their across-the-board PV- and BESS-promoting measures. As PV and BESS systems are already yielding positive returns today, the more inhibiting factor in PV and BESS installations appears to be the installment costs financing. The identified grid reinforcement cost savings could therefore also be invested into offering low-interest financing schemes or low-cost rental options. This measure could especially support lower-income households, who struggled to benefit from PV-subsidies in the past (Borenstein and Davis, 2016). Rental PV- and BESS-options are already offered today and could be leveraged to create such support schemes (Enpal, 2023).

2.4 Conclusion

This paper analyzes the effectiveness of decentralized electricity generation with PV and BESS for reducing grid reinforcement costs caused by EV charging. Results show that overloads and grid reinforcement costs can be reduced through PV (and BESS) in all tested settings. We thereby expand existing literature an PV-EV synergies within the grid, by quantifying their grid cost impact. We use a German setting as an illustrating example but want to emphasize that the approach can be reused and applied to almost any other region. In rural grids, a single combined PV and BESS system could save almost €450 in grid reinforcement cost within a 20% EV penetration setting. Hence, fostering small PV and BESS systems could be an alternative way to reduce grid infrastructure needs. However, grid reinforcements in rural grids become inevitable with higher EV penetration levels. Suburban and urban grids start failing with 60% EV penetration and could save up to €380 per PV and BESS system. Considering the size of the German grid, these savings could reach up to €3.2 billion. Hence, we encourage policymakers to further investigate these grid reinforcement cost-saving effects and consider the societal effects of decentralized energy generation and storage systems in their policy measures. This may allow for adjustments in subsidies for battery storage systems or photovoltaic systems that are oriented to the west to produce during evening EV charging peaks. Policymakers could further opt to target households in bottleneck areas with additional financial support. The grid reinforcement cost savings could also be utilized for low-interest PV-financing schemes or low-cost rental options, especially for lower-income households. From a societal perspective, supporting more decentralized generation may provide additional benefits like improved energy security and increased grid stability. However, PV and BESS systems are not solutions that would fit all problems at once. Especially in the winter months, additional electricity saving and load peak reduction measures, such as smart charging or higher electricity prices during peak hours, need to be introduced to support the cost-saving effectiveness of PV and BESS installations.

3 | Another source of inequity? How grid reinforcement costs differ by the income of EV users

Sarah A. Steinbach and Maximilian J. Blaschke

The simultaneous charging of many electric vehicles in future mobility scenarios may lead to peaks and overloads threatening grid stability. The necessary infrastructure investments vary by the number and model type of vehicles driven and the residents' charging preferences. These attributes significantly depend on socio-economic factors such as income. Our power flow simulations based on real-life driving profiles predict massive cost asymmetries with an investment demand up to 33-fold in higher-income compared to lower-income neighborhoods. Many grid operators may redistribute these costs through an across-the-board electricity price increase for all households. In times of rising electricity prices, these unwanted inequitable costing allocations could lead to serious challenges and energy poverty. Policymakers should consider countermeasures like dynamic electricity pricing schemes, income-based electric vehicle subsidies or improved charging network access to ensure energy equity in future mobility scenarios. Our discussion of socio-economic factors on EV grid infrastructure and their quantification provide new contributions to the energy equity discussion.

Keywords: Electric vehicles; Electric grid; Grid planning; Socio-economic factors; Energy equity

3.1 Introduction

With tightening carbon emission regulations in the transportation sector, more and more consumers are switching to electric vehicles (EVs). However, charging a high number of EVs poses challenges to the distribution grids: Most consumers prefer charging their EVs at similar times during the day, especially in the early evening hours. However, simultaneous charging of multiple EVs could lead to significant load peaks, causing overloads within the grids (Clement-Nyns et al., 2010, Lopes et al., 2011, Muratori, 2018a). These overloads increase with EV adoption and depend on the EV model choice as well as the applied charging patterns. All these factors may be correlated with socio-economic attributes like household income (Kelly et al., 2012, Sovacool et al., 2019, Gauglitz et al., 2020, Lee and Brown, 2021). Therefore, grid operators may have to over-proportionally enhance the grid infrastructure in areas with many high-income households. These costs must be borne, most likely via a surcharge on the electricity price for all households. Hence, the high infrastructure investments mainly caused by high-income neighborhoods would also place a particular burden on lower-income households. This cost cause imbalance in combination with current cost allocations within the electricity tariffs could, therefore, lead to an unfair distribution of costs. Households within the lowest income classes may have to reduce or even stop basic activities like cooking or washing, or have to compensate on other expenses. In times of rapidly increasing energy prices, energy equity, therefore, becomes a topic of increasing social and public interest, as energy poverty begins to affect even middle-class households (Henger and Stockhausen, 2022). Recent research, like Carley and Konisky (2020), finds that the clean energy transition might disadvantage lower-income households. Brockway et al. (2021) reveals that lower-income neighborhoods experience stronger grid limitations, reducing their access to residential photovoltaics and potentially hindering EV adoption. This could potentially disadvantage entire population groups. Hence, efforts to accurately measure energy inequity and strive for energy justice through policy measures are increasing (see, for example, Diezmartínez and Short Gianotti (2022) and Scheier and Kittner (2022)). With a rapid transition towards electric vehicles ahead of us, it is now most relevant to be aware of the social consequences of the corresponding infrastructure investments. Up to now, it is still unclear to what extent these investments may lead to inequities and how these cost imbalances should be dealt with from a political perspective. Our paper investigates and quantifies the difference in the necessary grid reinforcement costs between lower and higher-income neighborhoods. From these calculations, we determine the over-proportional grid reinforcement costs of higher-income EV users as well as the potential for energy inequities. Based on our findings, we derive policy recommendations to help prevent financial pressure and energy inequity on lower-income households.

The high infrastructure costs are rooted in the problem that electric vehicles require reinforcements in grid infrastructure. Clement-Nyns et al. (2010), Lopes et al. (2011), Green et al. (2011) and Fernandez et al. (2011) are among the first to investigate the impact of EVs on the distribution grids. Clement-Nyns et al. (2010) uncover that plug-in hybrid electric vehicle penetrations levels between 10% and 30% lead to significant voltage imbalances and power losses. Building on these findings, numerous authors find similar results with grids being unable to handle EV charging loads in different countries and grid scenarios (Lopes et al., 2011, Fernandez et al., 2011, Salah et al., 2015, Muratori, 2018a). Green et al. (2011), Richardson (2013) and Das et al. (2020) contribute to the discussion by providing general overviews and outlooks of the challenges coming when integrating electric vehicles into the grid. The recent technological shift towards sole battery-powered electric vehicles (BEVs) and higher charging powers could further increase the pressure on the grid, requiring new solutions and improvements within the infrastructure (Mowry and Mallapragada, 2021, German Government, 2021, International Energy Agency, 2021).

When analyzing EVs' impact on the distribution grids, most studies model all households within the simulated distribution grid with homogeneous EV adoption and usage behavior. However, socio-economic factors such as income, age, gender, occupation, level of education, ethnicity, home ownership and residence type as well as political orientation play a role in mobility per se (e.g., Ewing and Cervero (2010) and Abulibdeh et al. (2014)), in the adoption of new technologies (e.g. Rai and Robinson (2015)) and specifically EV adoption (Westin et al., 2018, de Rubens, 2019, Sovacool et al., 2019, Muehlegger and Rapson, 2019, Chen et al., 2020, Römer and Steinbrecher, 2021, Berneiser et al., 2021, Lee and Brown, 2021, Romero-Lankao et al., 2022). The homogeneous modeling of grid impact could hence be prone to significant errors (Gauglitz et al., 2020). Of all possible socio-economic factors, income is still the primary driver of EV adoption (e.g., Lee and Brown (2021)). Römer and Steinbrecher (2021) find that above-average household income increases the likelihood of owning an EV by as much as 200%. Muehlegger and Rapson (2019) and Berneiser et al. (2021) support these claims, finding that medium to high-income groups tend to show higher EV adoption. Lee and Brown (2021) find the same phenomenon in the UK. Analyzing survey data from more than 5000 respondents in the Nordics, Sovacool et al. (2019) uncover that higher income is associated with an increased likelihood of owning an EV and more expensive car models. Hardman et al. (2016), Higgins et al. (2017) and Chen et al.

(2020) find similar results. These more expensive and frequently larger car models tend to have higher electricity consumption, increasing charging loads (Weiss et al., 2020).

Besides EV adoption and car model choice, driving patterns greatly affect EV charging patterns and potential load peaks. The driving patterns depend on socio-economic factors, including age, gender, and level of education or occupation. Depending on these factors, the number of trips per day as well as the departure and arrival times impacting charging times vary significantly (Kelly et al., 2012, Langbroek et al., 2017, Fischer et al., 2019, Zhang et al., 2020). Since socio-economic factors may lead to higher worst-case power flows, papers like Gauglitz et al. (2020) or Powell et al. (2022) criticize current charging modeling approaches and call to include these factors in load assessments: Fischer et al. (2019) simulate EV charging demand accounting for socio-economic factors such as household income or occupation and analyze the related load curves in a German setting. The recent 2035 forecast for the US, as developed by Powell et al. (2022), also criticizes current charging modeling approaches. Using a data-driven model distinguishing driver income, housing, and miles traveled, they find that EV charging loads increase peak net electricity demand by up to 25% and deduct related implications as for example the charging point dissemination. Lee and Brown (2021) simulate EV charging loads of UK households with differing economic statuses. They find that higher-income households cause larger load peaks, potentially leading to over-proportionally high grid reinforcement costs. Their paper hence raises the issue of a fair grid cost allocation. While only a few studies include socio-economic factors in their load assessment, none of these studies provide estimations on the related distribution grid reinforcement needs or related grid reinforcement costs.

Fairness in the allocation of these grid reinforcement costs is a matter of perspective. Tornblom and Foa (1983) distinguishes the allocation of costs between three principles: The allocation of costs along the need, along the contribution to a problem, or to a simple equal share. In the context of reducing CO_2 emissions, Hammar and Jagers (2007) find that most individuals prefer the principle of contribution (equity), where people who contribute more emissions should have to achieve higher emission reductions. The issue of fairness in bearing the here-mentioned grid infrastructure costs is slightly more complicated, as higher-income households with more electric vehicles might cause over-proportionally high infrastructure costs but also reduce CO_2 emissions. However, in the coming years, EVs are expected to become cheaper with economies of scale. In the long run, we may assume an equally high share of vehicle electrification in lower- and higher-income households. At that point, we may still face differing costs in required grid reinforcements due to driving behavior and vehicle ownership. Applying the principle of fairness according to contribution would require higher-income households to carry the caused asymmetry in grid reinforcement costs to the full extent.

However, residential grid reinforcement costs in many countries are compensated for as part of the electricity price via a fixed component as well as a fee per kWh (see Keane and Vladareanu, Batlle et al. (2020) and, for example, Bundesnetzagentur (2020a), Bundesministerium für Wirtschaft und Klimaschutz (2021) in Germany). Without any political corrections, increased grid reinforcement costs would lead to an overall electricity price increase for all consumers. This price increase could be considered inequitable to the principle of fairness according to the contribution, as higher-income neighborhoods over-proportionally cause these grid reinforcement costs.

Previous literature does not consider socio-economic factors for the related grid cost scenarios and, hence, could not quantify the potential inequities. Tackling this research gap, we focus our analysis on household income as a critical socio-economic factor and raise a discussion on energy equity. Our paper aims to quantify the over-proportional grid reinforcement cost impact of higher-income EV users. We, therefore, use real trip data from Karlsruher Institut für Technologie (2020) in a grid power flow analysis to compare the grid reinforcement costs of above-average with below-average income neighborhoods. Our paper builds on previous literature in electric vehicle charging and grid resilience to provide a contribution to the increasingly relevant field of energy equity. To the best of our knowledge, grid infrastructure investments for electric vehicles have not been brought into context with socio-economic factors before. This context, however, should be highly relevant for policymakers, who increasingly incorporate social aspects as critical factors in electricity pricing and regulatory measures and policy instruments overall (Baskin, 2021, Cappers and Satchwell, 2022, International Monetary Fund, 2022, National Conference of State Legislatures, 2022). Furthermore, our paper illustrates the need for grid planners to include socio-economic factors such as income in their grid planning models, as some providers already started to do so (see DigiKoo (2022)). The paper is organized as follows: We present our modelling approach, EV adoption scenario and resulting load patterns in Section 3.2. Within Section 3.3, we derive the resulting grid overloads, the associated infrastructure costs, their implications for the electricity prices and discuss mitigating political levers. Finally, Section 3.4 provides a concluding discussion with policy recommendations.

3.2 Methods

We simulate electricity usage for two neighborhood types: below-average (lower) and above-average (higher) income, meaning a 50:50 split of households by income. For these two neighborhood types, we assign respective EVs considering adoption and model choices and fit the corresponding mobility behavior based on representative real-life driving data. We use representative distribution grids in urban, suburban, and rural settings to account for the differing structure and load capacity (Dzanan Sarajlic and Christian Rehtanz, 2019, Meinecke et al., 2020). After allocating empirically sampled electric vehicles amongst the grid nodes, our power flow simulations check each setting for overloads. While we showcase the approach with inputs for distribution grids in Bavaria in the South of Germany, the approach may be applied to any grid or geographical region. The differences observed between above- and below-average neighborhoods with a 50:50 split already showed such significant cost imbalances that a further split of the population in smaller groups would most likely only lead to even more extreme results. Due to smaller samples and less data availability, we, however, would not receive stronger or more robust findings. The simulation builds upon Steinbach and Blaschke (2023) and is structured as displayed in Figure 3.1.

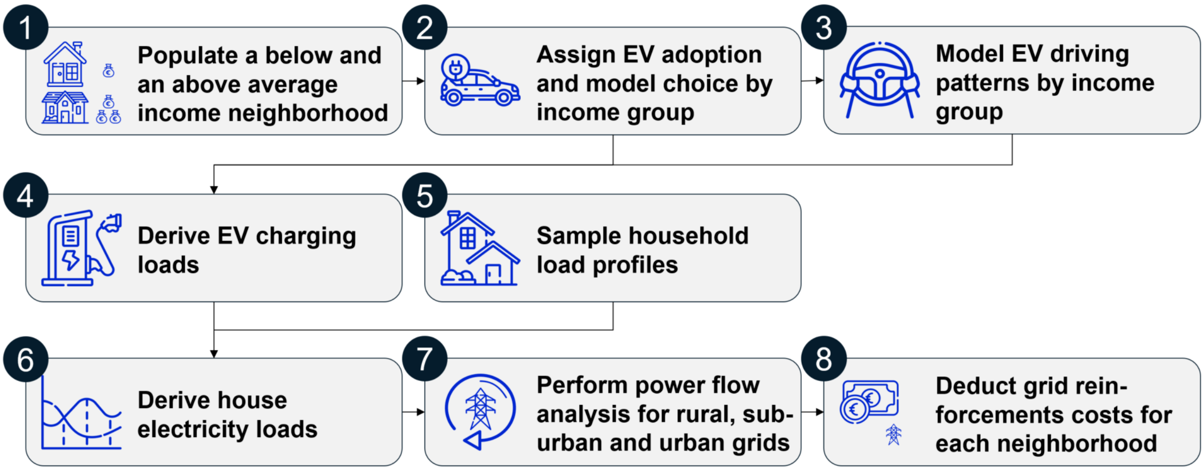


FIGURE 3.1: Simulation approach to quantify the costs of reinforcing distribution grids.

For both neighborhood types,

1. we populate the grids with the related income group (above- or below-average-income households) by sampling from the household distributions of each neighborhood and grid

type.

2. we assign the related EV adoption level and model choice by randomly allocating EVs depending on the income group's EV adoption and model choice distribution.

3. we model the driving patterns for each EV depending on the income group by a time-inhomogeneous Markov chain simulation.

4. we derive the EV charging loads resulting from the EV driving patterns based on the charging probability as well as future car trips planned.

5. we empirically sample representative household electricity load profiles on a household level.

6. we consolidate the EV charging loads and household electricity load profiles by adding up all loads on a house-level.

7. we perform a power flow analysis, and if overloads occur, we reinforce the respective overloading grid element.

8. we calculate grid reinforcement costs to resolve these overloads for each grid and neighborhood type.

To account for inherent uncertainties, we use a Monte Carlo approach and derive the grid reinforcement cost asymmetry between the two neighborhood types within the simulation. The power flow analysis is performed using the Newton-Raphson method of the matpower package in MATLAB, which is frequently used in load analysis (Zimmerman et al., 2011). To consider the most challenging season for electricity usage, we perform the simulation using five-minute intervals for the month of December and sharing the results for an average week.

3.2.1 EV portfolio and driving patterns by income class

To assign our EV portfolio and driving patterns based on real-life data, we leverage the German Mobility Panel, a renowned 30 year project collecting representative mobility behavior of households (Karlsruher Institut für Technologie, 2020). First, we create a set of below- and above-average-income households for a German neighborhood. Using current German household net income data, we find that the average net income lies around 3,600€ per month (Statistisches Bundesamt, 2018, 2020). We leverage the household data from the German Mobility Panel to separate this data set by household income (Karlsruher Institut für Technologie, 2020). The data set states monthly income with steps of 500€ granularity. We separate into below- (lower) and above-average (higher) income households at 3,500€ net household income per month.

We again use household data from the German Mobility Panel to assign EVs to households by determining the number of private cars owned per household based on the area type (Karlsruher Institut für Technologie, 2020). When analyzing the average number of cars per household by income group, we can see significant differences, with lower-income households owning, on average, 0.94 and higher-income households 1.77 cars. When including EVs in our model, we choose to use BEVs only as this reflects the markets' direction to reduce all conventional vehicle powertrain technologies (German Government, 2021, International Energy Agency, 2021). We separate the EV into different segments: Mini (Volkswagen e-UP), Small (Renault Zoe Z.E. 40 R110), Compact (Volkswagen ID.3 Pro), Medium-sized (Tesla Model 3 Long Range Dual Motor), SUV (Audi e-tron 55 quattro) and Luxury (Porsche Taycan Turbo S). The different vehicle classes allow considering the varying power consumption and the corresponding charging needs. We derive the usable battery capacity from EV Database (2022), which compiles technical specifications for EVs currently on the market. The electricity consumption data is based on real-life driving tests by ADAC (2022) and Auto Motor und Sport (2020). Table 3.1 lists the car segments' specifications. Since our simulation investigates the demanding December conditions, we utilize climate data by Al-Wreikat et al. (2022) and Climate-Data (2022) to fine-tune the electricity consumption considering the ambient temperature. This adjustment is needed as ambient temperature significantly affects the energy efficiency of an EV. Specifically, temperatures between 0°C and 15°C decrease vehicle ranges by up to 28% in comparison with driving at moderate temperatures from 15°C to 25°C (Liu et al., 2018, Al-Wreikat et al., 2022).

Table 3.1: Car segment battery capacity and consumption (Auto Motor und Sport, 2020, EV Database, 2022, ADAC, 2022).

Segment	**Mini**	**Small**	**Compact**	**Medium-sized**	**SUV**	**Luxury**
Usable battery (kWh)	32	41	58	76	87	84
Electricity consumption (kW/100km)	17.7	20.3	19.3	20.9	25.8	33.0

To find the appropriate segment sizes for the German car market, we aggregate the newly registered cars per segment of 2021 as provided by the German federal transport agency (Kraftfahrt Bundesamt, 2021). To separate between lower and higher-income households, we leverage the car segmentation included in the German Mobility Panel to reflect model choice differences between income classes (Karlsruher Institut für Technologie, 2020). We choose to re-scale the newly registered car segment distribution from Kraftfahrt Bundesamt (2021) instead of simply using the 2019 German Mobility Panel's car segment distribution to reflect future car model choice instead of the existing German car park. The resulting impact of income on the car model choice can be seen in Table 3.2.

Table 3.2: Car segment distribution by income class.

Household group	Mini	Small	Compact	Medium-sized	SUV	Luxury
Lower-income	8%	19%	21%	12%	31%	8%
Higher-income	6%	13%	19%	17%	25%	19%
All	7%	16%	20%	15%	28%	14%

To simulate car driving patterns by income class, we use real-life representative driving data from the German Mobility Panel collected between September 2019 and the beginning of March 2020 (Karlsruher Institut für Technologie, 2020). This data set includes weekly trip data for 70,796 trips covering various modes of transportation, provided with travel times, trip purposes, and timings. These trips are recorded with one minute accuracy. After selecting only trips performed by car and outlier removal by excluding drivers performing holiday trips or very long journeys (above 200km, longer than 132 min), we arrive at a data set of 22,803 trips representing common driving patterns. We assume that the first trip of each day always starts at home and the last trip of each day ends at home. We generate synthetic trips for both income groups using this trip data set through a time-inhomogeneous first-order Markov chain. Markov chain models are a commonly used method for uncertainty modeling, particularly in the context of EV charging loads, due to their ability to achieve high accuracy at moderate computational costs (Wang and Infield, 2018). In this work, the Markov chain is employed to create trip samples between "Home", "Work" and "Other" locations, resulting in synthetic EV driving and charging profiles. Differentiating between weekdays, weekends, and times of day, we fit a time-inhomogeneous Markov chain for our mobility simulation. We choose the Markov chain to be time-inhomogeneous, as the probability of transitioning between locations is time-dependent.

When investigating the car trip dataset from the German Mobility Panel, we find that the self-reported recordings of arrival and departure times exhibit a rounding bias with approximately 75% of timing data points ending in a right-hand digit of either 0 or 5. These rounding biases might limit accuracy in a one minute interval level simulation. We hence opt to conduct our simulation in five-minute intervals, also reducing computation time. Testing the simulation at one minute accuracy did not affect our results.

The EV driving and charging simulation is based on Fischer et al. (2019) adapted by separating households only according to income to reduce complexity. To start our mobility simulation, we first sample the number of trips performed by each car of the lower (higher) income household on that day. In the second step, we use the first-order Markov property to define trip destinations, distances, speeds, and associated parking times depending on the start location of the current trip and its time of day (as time-inhomogeneous). Our model fits the empirical data well, with average daily driving time differing by 1.1% and an average daily trip frequency differing by 1.2% from the empirical data, respectively.

3.2.2 EV and household loads

The charging logic applied does not vary by income group. However, the differing mobility behavior of lower and higher-income households impacts charging patterns. After each EV trip, the EV updates its state of charge (SOC) to reflect the distance driven. Once the EV arrives home and parks for more than 10 minutes, the probability of starting the charging process is determined based on the state of charge as an inverse s-shaped relationship found in a six-month German field study of 79 EV drivers Franke and Krems (2013). The charging probability model from Franke and Krems (2013) defines the probability of starting the charging process as

$$p_{charge} = \min\left(\left(1 - \frac{1}{1 + e^{-0.15(SOC-60\%)}}\right) c_l, 1\right)$$

with the parameters calibrated using an analysis of the charging behavior of EV fleets in Germany performed by Schäuble et al. (2017). The factor c_l can be chosen location-dependent. We focus on charging at home, representing most charging instances (virta, 2021). We adjust c_l for whether a private charger is available or the charger is public and assumed to be located in front of the house. The charging process ends once the next trip is started or the EV battery is fully charged.

Applying charging patterns to stop at a charge level of 80% to improve battery health would lead to similar results.

We generate the household loads via empirical sampling in two steps: First, we generate 1,000 representative German household electricity load profiles for December using the Load Profile Generator of Pflugradt (2017) frequently used and validated by previous literature like Lopez et al. (2019), Haider and Schegner (2020) and Huang et al. (2021). It creates representative synthetic household electricity load profiles based on a full behavior simulation of the related households Pflugradt (2017). We categorize these load profiles by household size. In the second step, we construct the electricity load a typical neighborhood in rural, suburban, and urban areas for our exemplary setting of Bavaria, Germany. Therefore, we sample household load profiles via empirical sampling according to the distribution of household sizes per area type according to Bayrisches Landesamt für Statistik (2021). We also use area-specific distributions of households per building, as those vary by area type according to Statistisches Bundesamt (2021). The respective household size and household per building distributions can be found in Section A.6.

The loads $L_{h,t}$ occurring for each house h in the neighborhood at a five minute interval time point $t \in \{1, 2, ..., 2016\}$ in a week are hence defined as follows

$$L_{h,t} = \sum_{hh=1}^{k} \left(e_{hh,t} + \sum_{n=1}^{n_k} c_{n,t} \right)$$

where k is the number of households in the house h, $e_{hh,t}$ the household electricity load profile associated with the respective household hh at time t and $c_{n,t}$ the charging load of an EV n of the n_k EVs of owned by household k at time t.

3.2.3 LV distribution grids and synthetic neighborhoods

As in Steinbach and Blaschke (2023), we use the SimBench low-voltage (LV) distribution grids (Dzanan Sarajlic and Christian Rehtanz, 2019, Meinecke et al., 2020), which are designed to represent benchmark distribution grids for Germany. We opt for the SimBench grids as they allow us to analyze differing area types and the related differences in distribution grids. We perform our analysis on the SimBench LV 02 as the rural, the SimBench LV 05 as the semi-urban, and SimBench LV 06 as the urban LV grid. These encompass 95, 109, and 108 houses, respectively. To perform our analysis, we create synthetic lower (higher) income neighborhoods by allocating households sampled from the lower (higher) income data set to the SimBench grid nodes. We run a power flow analysis, and if overloads occur, we reinforce the respective overloading line or transformer.

Overloads occur, if for any grid element $g \in \{1, ..., G\}$ within a grid consisting of G elements the related capacity Cap_g is exceeded at any time point $t \in \{1, 2, ..., 2016\}$, meaning

$$\sum_{h \in H_g} L_{h,t} \leq Cap_g$$

is violated at any time t where H_g is the set of all houses supplied through the grid element g.

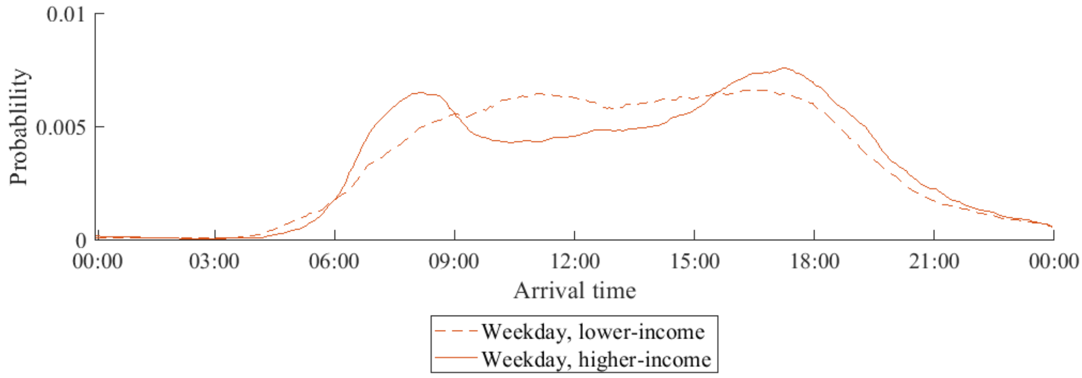
Investment costs for line reinforcements in Germany are estimated as 85–125€/m according to Cossent et al. (2011). We assign investment costs of 26,970€ to a 250kVA transformer upgrade used in the rural grid and 61,730€ to a 630kVA transformer upgrade for the suburban and urban grid in line with Cossi et al. (2012).

3.2.4 EV adoption scenario analyzed

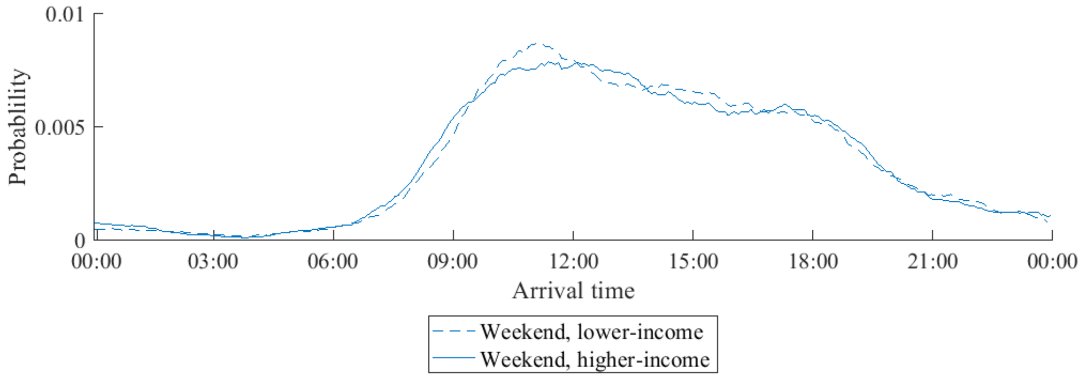
In order to simulate realistic future EV penetration levels, we use the current German government target of 15 million EVs on German roads by 2030 as the basis for our scenarios (German Government, 2021). Relative to the 2021 German car park of 48.24 million cars, this would equate to an EV adoption rate of 31.1% (Kraftfahrt-Bundesamt, 2021). Analysis of current EV sales reveals that a household's probability of owning an EV is up to three times as high for higher-income than for lower-income households (Römer and Steinbrecher, 2021). Using the 15 million EV target as a base (equating to an overall EV adoption rate of 31.1%) and accounting for higher-income households owning more cars, EV adoption rates would lie at 22.4% for lower-income and 35.7% for higher-income households. As we could expect this effect to become smaller as more EVs enter the market and prices decrease, we will include an analysis of equal EV adoption rates for both income groups in Section 3.3.2.

3.2.5 Driving patterns and load profile implications

First, we investigate the differences in driving patterns, EV charging behavior, and resulting load curves. In line with existing literature, we find that higher and lower-income households differ in their driving patterns. Our car trip dataset reveals that higher-income households perform more daily trips, with an average of 2.2 daily trips instead of 2.0 daily trips for lower-income households (Karlsruher Institut für Technologie, 2020). They also exhibit longer trip durations of, on average, 42 minutes instead of 38 minutes. Furthermore, higher-income households show more concentrated weekday home arrival times, leading to stronger load peaks, as visible in Figure 3.2.



(A) Weekdays.



(B) Weekends.

FIGURE 3.2: Probability of car arrival at home for an average weekday and weekend.

These effects are most likely also linked to differences in occupation and level of education between the two income groups, which have been shown to affect mobility behavior (Langbroek et al., 2017, Fischer et al., 2019, Zhang et al., 2020). While 46% of drivers in higher-income households are working full-time, this only applies to 25% of drivers in lower-income households within the data of Karlsruher Institut für Technologie (2020). The proportion of drivers with a university degree, which is often linked to a "nine-to-five" work schedule, is 43% for higher-income and only 26% for lower-income households. This may be the reason why we observe more concentrated weekday arrival times and increased car usage for high-income households. Due to the longer driving times, the hence higher electricity consumption, and the more pronounced weekday arrival time peaks, we expect the high-income households to induce stronger load peeks, especially on weekdays. This effect is also enhanced by the difference in EV adoption as well as model choice. Figure 3.3 shows the exemplary case of the induced load curves for an average week in December in the rural grid.

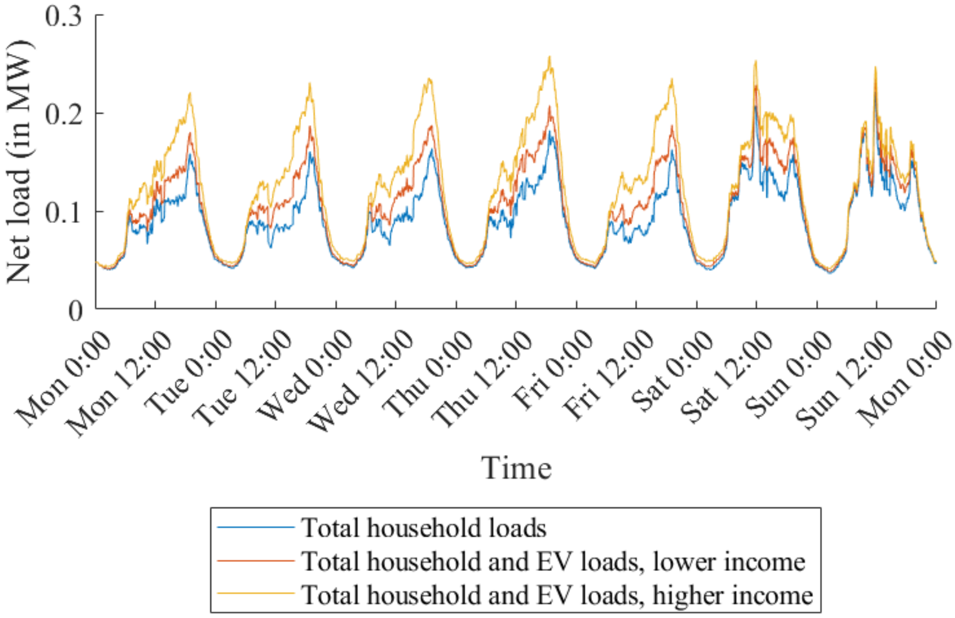


Figure 3.3: Net load profiles of households with and without EVs in the rural grid.

As expected, the load peak difference between higher- and lower-income households is especially pronounced on weekdays. Due to the stronger load peaks, we expect the higher-income neighborhood grids to be more at risk for overloads caused by EV charging.

3.3 Results

3.3.1 Impact on grid overloads

Based on these simulated load profiles, we investigate the overloads occurring for higher and lower-income rural, suburban, and urban neighborhoods. This overload analysis is relevant for grid planning, as it displays which neighborhoods require prioritization. Figure 3.4 illustrates the number of 5-minute intervals in which an overload occurs. For example, on average, the rural grid experiences 5 overloads during a week in the lower-income neighborhood, while 70 overloads occur in the higher-income neighborhood.

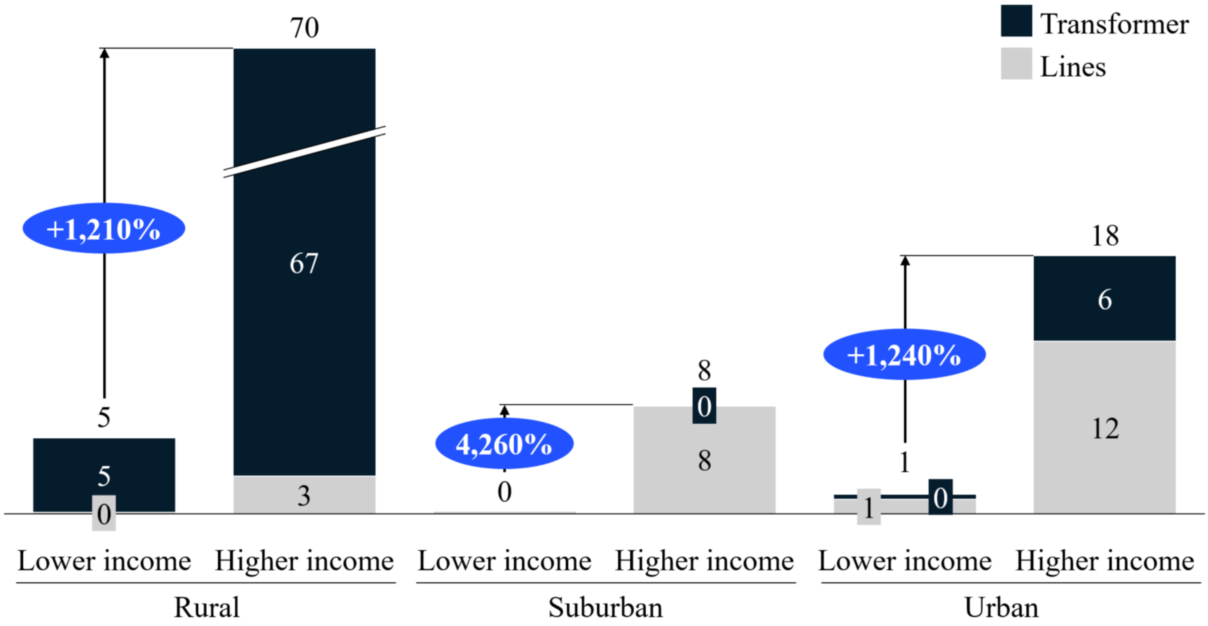


FIGURE 3.4: Average number of weekly overloads.

In all area types, higher-income neighborhoods would experience significantly more grid overloads, putting these neighborhoods higher on the grid operators' agenda for grid reinforcements. As the number of overloads and hence the probability for a blackout differ significantly between lower and higher-income neighborhoods, the importance of including socio-economic factors such as income in grid planning models becomes apparent. The rural grid is the weakest and exhibits the most overloads. However, a transformer replacement in this grid would solve the vast majority of overloads occurring, while mostly grid lines are the bottleneck in the other grid types.

3.3.2 Asymmetry in grid reinforcement costs and underlying effects

In this section, we derive the related grid reinforcement costs to mitigate the overloads previously outlined and stabilize the grid. The average reinforcement costs to be expected are illustrated in Figure 3.5. While the analysis does not prove a causal relationship between household income and grid reinforcement costs caused, it provides illustrating scenarios for future grid reinforcement costs to be expected for a representative higher-income compared to a lower-income neighborhood.

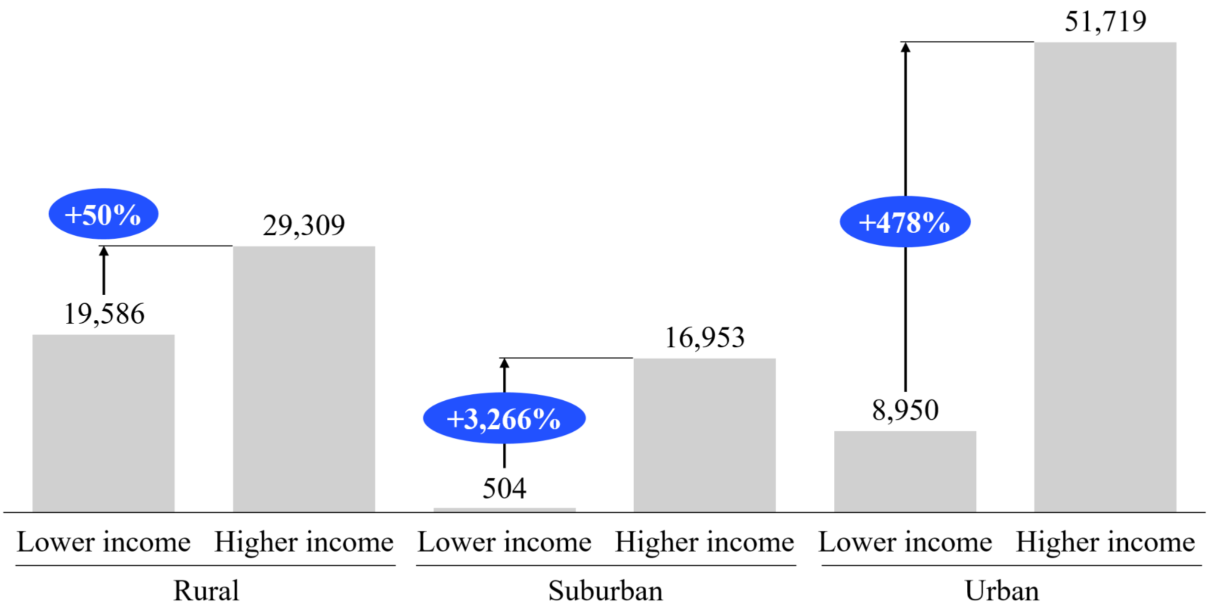


Figure 3.5: Average simulated grid reinforcement costs (in €).

We see 50% additional grid reinforcement costs for higher-income neighborhoods in the rural, 3,266% in the suburban, and 478% in the urban grid compared to lower-income neighborhoods. The additional reinforcement costs are the lowest for the rural grid as this grid is the least resilient overall. An upgrade of its bottleneck, the transformer, becomes inevitable even for lower EV charging loads. These significant asymmetries in grid reinforcement cost further illustrate the necessity for grid operators to include socio-economic factors such as income in their grid planning models to represent future grid costs adequately. These significant asymmetries also prevail when testing for the inclusion of residential electricity generation and storage. When extrapolating our findings to the around 119 million residential buildings in the EU and accounting for their distribution to rural, suburban, and urban areas, the potential grid cost asymmetry between higher- and lower-income neighborhoods could reach around €14 billion (Bundesinstitut für Bau-, Stadt- und Raumforschung et al., 2017, RICS Data Services, 2020, Statista, 2021, Statistisches Bundesamt, 2022a).

As decentral household electricity generation via a solar photovoltaic (PV) energy system, including a home battery, was not included in our model, these effects could be partially offset by higher-income households being more likely to invest in such systems. In our paper on the effect of solar PV and home battery systems on grid reinforcement costs, we observe some grid cost reduction effects through solar PV and home battery installations, however, of far lower magnitude than the asymmetry observed between higher- and lower-income neighborhoods (Steinbach and Blaschke, 2023). Hence, we decided not to include decentral electricity generation in our model for simplicity reasons. We can expect the significant asymmetry in grid reinforcement costs between higher- and lower-income neighborhoods to prevail.

In order to derive appropriate mitigating policy measures, we further analyze the impact of the underlying drivers for the additional grid reinforcement cost of higher-income neighborhoods. We quantify the standalone impact of differences in EV adoption, model choice, and driving patterns by neighborhood type. For that purpose, we keep all other parameters equal (ceteris paribus) and adjust one driver as follows.

- EV adoption: We derive the effect of EV adoption by assigning both income groups the same EV adoption rate of 31.1%.
- Model choice: We quantify the impact of model choice by assigning the car segment distribution of lower-income households to higher-income households.
- Driving patterns: We analyze the impact of driving patterns by assigning the driving patterns of lower-income groups to higher-income groups.

It is important to note that these three drivers are not additive. However, this analysis provides an understanding of the most effective levers for diminishing grid cost asymmetry and related inequities. In Figure 3.6, we first analyze the effect of EV adoption.

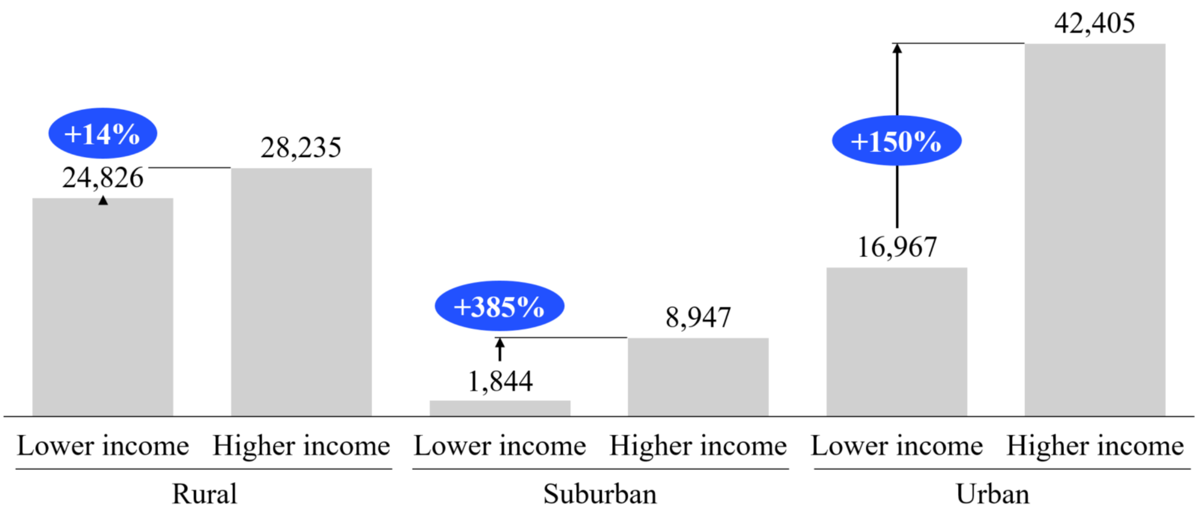


FIGURE 3.6: Average simulated grid reinforcement costs (in €) assuming equal EV adoption levels.

If EV adoption were equally distributed over all neighborhoods, the grid reinforcement cost asymmetries would shrink significantly. This effect, however, is partly caused by a related grid cost increase for lower-income neighborhoods. Nonetheless, our results show that even if equal EV adoption levels across income levels could be achieved, significant additional grid reinforcement costs for higher-income neighborhoods prevail, especially for the suburban and urban grids.

Figure 3.7 illustrates the impact of model choice and driving patterns of higher-income households. We discuss only the urban grid, as the effects for the other two grid types are similar.

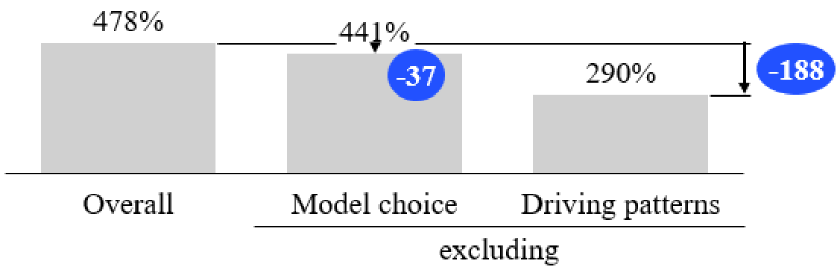


FIGURE 3.7: Breakdown of grid reinforcement costs asymmetries by the underlying drivers of model choice and driving patterns, urban grid.

Driving patterns strongly impact grid cost asymmetry, while the effect of model choice is relatively small. This can also be observed for the rural and suburban grids, with additional costs shrinking in the suburban and slightly also in the rural grid. For more details on this matter, please refer to Section A.7. These findings indicate that policymakers may foster EV adoption with all model sizes but focus more on reducing peak-hour charging to mitigate some behavioral effects of higher-income households.

3.3.3 Electricity pricing implications and related potential inequity

Residential grid reinforcement costs are currently paid for via the consumer electricity price, which is determined per kWh (Bundesnetzagentur, 2020a, Bundesministerium für Wirtschaft und Klimaschutz, 2021). These prices do not vary with the load or maximum power demand but are reimbursed with a flat-rate cost allocation (Bundesnetzagentur, 2020a). As can be seen in Figure 3.8, the proportion of the electricity price allocated to grid costs for an average household in 2021 was around 23% (Bundesministerium für Wirtschaft und Klimaschutz, 2021).

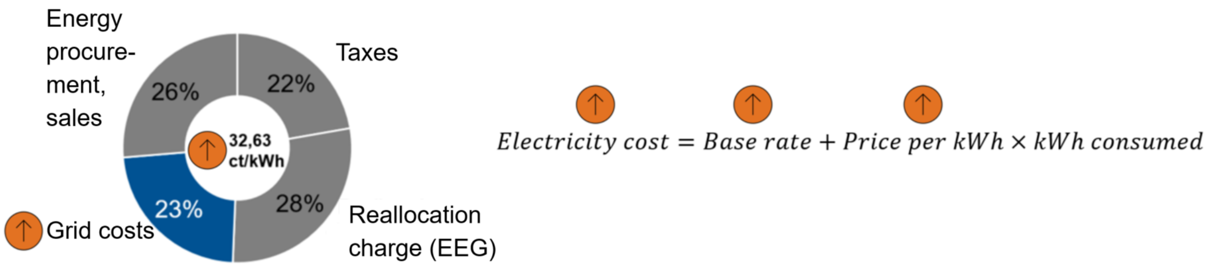


FIGURE 3.8: Electricity price split and cost calculation, Germany 2021 (Bundesministerium für Wirtschaft und Klimaschutz, 2021).

If grid costs increase, the electricity price for all consumers is inflated, and electricity costs increase for all households. Due to their higher total electricity consumption and related higher electricity costs, higher-income neighborhoods carry more of the grid reinforcement costs in total. However, as they only consume 16%-18% (based on the area type) more electricity than lower-income households, this contribution fails to offset the massive additional grid reinforcement costs caused. Furthermore, grid operators often split grid costs into a base rate in addition to a volumetric (per kWh) component. This base rate is not scaled with regards to consumption and hence further limits the grid cost contribution of higher-income households (Bundesnetzagentur, 2020a). With household electricity prices at a record high (32.63ct/kWh in 2021 and quickly increasing during the European Energy Crisis in 2022 (Bundesnetzagentur, 2022, Statistisches Bundesamt, 2022b, Guan et al., 2023)), a further across-the-board electricity price increase to cover the additional grid reinforcement cost of higher-income neighborhoods could be considered inequitable with respect to the principle of fairness according to contribution. As this grid reinforcement cost asymmetry can be traced back to higher-income neighborhoods, equitable cost allocation would require higher-income households fully bear this cost asymmetry, not affecting the electricity prices of other consumers. This effect could be aggravated further, if grid operators decide to prioritize higher income neighborhoods in their grid planning, potentially making some households pay higher electricity prices long before they can profit from more stable grids in their neighborhoods. Furthermore, this prioritization could lead to energy access equity issues between neighborhoods, as for example already observed for the case of solar PVs in the US by Brockway et al. (2021).

However, it is important to note that the rationale for the mentioned potential inequitable cost allocation is not the difference in income between the two neighborhood types but the difference in usage of the electric distribution grid as a common resource. According to the principle of fairness according to contribution (equity) (Tornblom and Foa, 1983), households in a higher-income neighborhood should rather pay grid fees which reflect the contribution to the grid reinforcement costs induced by them. We focus on mitigating policy actions directly related to households' grid cost impact, not socio-economic attributes such as income.

3.3.4 Possible mitigating policy measures

Regulators could use various policy instruments to tackle potential inequities. They may adjust the electricity tariff design, e.g, with a time-of-use tariff, to mitigate the grid load effects of EV charging, which we showed to be more pronounced for higher income neighborhoods. Another option would be to distinguish and allocate costs in smaller tariff zones. Hereby, the high investment costs of wealthier neighborhoods would not necessarily bother other neighborhoods. However, such individualized cost allocation would come with massive efforts and complexity. Last, policymakers may address the asymmetry in EV adoption and model choice between income groups. For any policy measure implemented, it is important to ensure that although EV charging poses a challenge to distribution grids, EV ownership and usage over combustion engine cars should never be discouraged.

In a time-of-use tariff, electricity prices for households increase significantly during peak load times. The increased pricing during these times allows to allocate over-proportionally more costs to the drivers of electric vehicles and keep the prices low for activities outside the peak hours. Such a tariff would furthermore reduce the overall infrastructure costs by incentivizing EV charging outside peak hours reducing simultaneous charging. A large grid operator in Denmark, for example, already employs this tariff policy, with grid tariffs more than doubling between 5 and 8 p.m. during the winter months (Radius, 2022). Cappers and Satchwell (2022) recommend similar electricity tariff adjustments to promote energy equity. This time-of-use tariff approach is easier for consumers to respond to than more dynamic electricity tariff strategies such as real-time pricing or critical peak pricing. This allows for more equitable electricity pricing across consumer groups of differing knowledge level. Policymakers should further consider alternative electricity tariff models that adjust for maximum electricity loads induced, also called demand charge rate. This demand charge rate is already in use for industrial electricity consumers and used to price their grid load impact (Bundesnetzagentur, 2020a). When incorporating a demand charge rate however, its pricing needs to be carefully calibrated to not discourage EV adoption and usage (Cappers and Satchwell, 2022). Any dynamic electricity pricing, load-based or adjusted for time, does, however, require the installation of a smart meter. The smart meter installations are, unfortunately, lagging behind. In Germany, for example, only 19% of households own any smart energy management device in 2022. Since energy companies fall behind their smart meter installation ambitions (Statistisches Bundesamt, 2022c, Handelsblatt, 2022), alternative measures are worth considering.

EV adoption greatly impacts the magnitude of the inequitable grid cost allocation. As it is not desirable to reduce overall EV adoption and limit the electrification of mobility, policymakers could reduce the inequity in cost allocation by increasing EV-related subsidies for lower-income households, where EV subsidies have shown the strongest impact (Sheldon et al., 2023). A fuel efficiency-dependent reduction in government EV subsidies based on car models could also compensate lower-income households and mitigate some of the inequities. However, the effect of model choice on grid costs is limited, as seen in Figure 3.7. Furthermore, policymakers should promote the expansion of charging stations in multi-family buildings as well as public chargers, as insufficient access to charging stations tends to limit EV adoption especially for lower income households (Römer and Steinbrecher, 2021, Cappers and Satchwell, 2022). Unfortunately, households in the lowest income classes, that can not afford an electric vehicle anyway, will not profit from any of such actions but will still face higher grid costs.

3.4 Conclusion

Our work analyzes the difference in grid reinforcement costs induced by EV charging in lower- compared to higher-income neighborhoods. In the analyzed scenario, the number of grid overloads occurring for higher-income neighborhoods exceeds those for lower-income neighborhoods by over 12-fold on average across different grid types. Hence, the stronger need for grid reinforcements puts higher-income neighborhoods at the top of grid operators' agendas, potentially limiting future charging network access in lower-income neighborhoods. While grid reinforcement costs from higher-income neighborhoods in rural grids are only 50% higher, we see a more significant effect in suburban and urban grids, with costs diverging by up to around 3,300% and 480%, respectively. For the EU, these cost asymmetries could potentially amount to €14 billion. The current policy setting would cover the related grid reinforcement costs via an across-the-board electricity price. This could be considered inequitable regarding the principle of fairness according to contribution, as these grid reinforcement costs can be over-proportionally traced back to higher-income neighborhoods. Policymakers should hence consider adopting a dynamic electricity tariff such as time-of-use or load-based pricing to prevent assigning these costs to all electricity consumers. As grid cost asymmetries are also strongly driven by EV adoption, policymakers may try to compensate for inequities with income-dependent EV subsidies or promoting charging network access for lower income groups.

Our findings on inequitable EV-related grid cost allocation contribute to the larger field of energy inequity, which has gained importance globally in recent months (Baskin, 2021, International Monetary Fund, 2022, National Conference of State Legislatures, 2022, Sackmann, 2022, Subran Ludovic et al., 2022, Henger and Stockhausen, 2022). With energy and electricity prices rapidly increasing due to the Ukraine war, lower-income households in Europe are over-proportionally affected by the rise in energy costs (International Monetary Fund, 2022, Sackmann, 2022, Subran Ludovic et al., 2022). Energy poverty is quickly becoming an issue affecting also middle-class households (Henger and Stockhausen, 2022). Targeted, income-adjusted government relief measures could be required to support lower-income households and allow equitable cost allocation (International Monetary Fund, 2022, Henger and Stockhausen, 2022). Current energy crisis relief measures are frequently still falling short of this goal (see, e.g., Scheier and Kittner (2022), Baskin (2021), National Conference of State Legislatures (2022) and Schumacher et al. (2022)).

4 The future European hydrogen market: Market design and policy recommendations

Sarah A. Steinbach and Nikolas Bunk

A key building block of the European Green Deal is the development of a hydrogen commodity market, which requires a suitable hydrogen market design and the timely introduction of related policy measures. Using exploratory interviews with five expert groups, we contribute to the sparse literature in this novel research field. We identify detailed recommendations along three core market design focus areas: Market development policy measures, infrastructure regulations, as well as hydrogen and certificate trading. Our findings provide an across-industry view of current policy-related key challenges in the hydrogen market development and mitigation approaches. Hence, we support policymakers in the ongoing detailing of their regulatory hydrogen and green energy packages. Further, we assist current and future hydrogen market players in gaining a shared understanding of which potential future hydrogen regulations to advocate and plan for.

Keywords: Hydrogen; Green hydrogen; Market design; Energy regulation; Commodity trading

4.1 Introduction

Hydrogen will play a key role in Europe's transition to green energy, aiming for net-zero carbon emissions by 2050 (European Commission, 2020a, 2021a). Enabled by the rapid cost decline of renewable energy and continued technological development, the EU aims to promote the employment of green hydrogen in multiple emission-intensive sectors to complement the electrification of fossil-fuel-based processes (European Commission, 2020a). Of highest priority is the industrial sector, where green hydrogen can play an essential role in decarbonizing steel and cement production, as well as in replacing grey hydrogen in refineries and the chemical industry (Hydrogen Europe, 2021a, Van der Spek et al., 2022, Braun et al., 2023, Egerer et al., 2024). In the transport sector, hydrogen-based fuels could be employed in road transport, such as trucks and busses, and additionally in rail, shipping, and aviation (International Energy Agency, 2021, Van der Spek et al., 2022). Green hydrogen is further explored as a clean energy carrier for heating buildings as well as for electricity storage (Zhao et al., 2018, Sachverständigenrat für Umweltfragen, 2021). Due to these promising applications, almost all EU member states see immense potential in green hydrogen and include the sustainable energy carrier in their national energy and climate plans as laid out in European Commission (2020a): By 2024, the EU aims to install at least 6 Gigawatt (GW) of renewable hydrogen electrolyzers. By 2030, 40 GW are planned. Europe is at the forefront of anticipated hydrogen investments up to 2030, along with leading in the number of announced hydrogen projects across the value chain (Hydrogen Council, 2021, Bundesministerium für Wirtschaft und Klimaschutz, 2021). Hence, in 2020, the European Commission published a hydrogen strategy with the long-term goal of implementing a liquid market with commodity-based hydrogen trading: "By 2030, the EU will aim at completing an open and competitive EU hydrogen market, with unhindered cross-border trade and efficient allocation of hydrogen supply among sectors." (European Commission, 2020a). They emphasize the high added value of a hydrogen commodity trading market, as it enables transparent and efficient hydrogen distribution, allows investment decisions based on price signals, and facilitates the entry of new hydrogen producers. However, how the European hydrogen market has to be designed to establish efficient hydrogen commodity trading still remains relatively unclear. This poses a challenge to players within the hydrogen market, who, according to Hydrogen Council (2022b), Dawin et al. (2023) and Lagioia et al. (2023), call for regulatory certainty and robust international standards and certification schemes. As existing hydrogen certification schemes are found to be unsuitable for cross-border trade, international collaboration on these measures requires more work, as outlined by International Renewable Energy Agency and RMI (2023) and World Trade Organization and International Renewable Energy Agency (2023). Institutes, such as Hydrogen Europe (2021b), Bundesverband der Energie- und Wasserwirtschaft (2021), Deutsche Energie-Agentur (2021), Hydrogen Council (2022b) and Dawin et al. (2023), urge policymakers to create regulatory certainty, lay the foundations of a hydrogen market design, create a target model, and establish a hydrogen trading system.

Although a large amount of literature about hydrogen has been published, most research focuses on the technical feasibility, the production cost or future hydrogen market sizes and resource flows (Blanco et al., 2018, Mulder et al., 2019, Blanco et al., 2022, Ikonnikova et al., 2023, Li et al., 2024). Policy aspects for hydrogen have only been covered by a limited number of recent articles, as for example by Farrell (2023) and Van der Spek et al. (2022), which have put their focus on financial support of hydrogen applications and the state of hydrogen infrastructure regulation proposals instead of the market design and trading system. Many researchers agree that hydrogen market design and regulation are currently under-researched and call for further exploration (Mulder et al., 2019, International Energy Agency, 2019, Hydrogen Council, 2022b, Blanco et al., 2022, Lagioia et al., 2023). This call for research is also of increased urgency, as Lagioia et al. (2023) find that current regulatory uncertainties significantly hold back hydrogen investments and endanger the ambitious EU 2030 decarbonization objectives.

We aim to contribute to the still sparse literature in this upcoming research field by outlining the core design criteria and attached regulation of the future European hydrogen market to establish efficient commodity trading by 2030. By drawing on analogies from the natural gas market, we analyze potential market development policy measures, evaluate which infrastructure regulations are appropriate for the hydrogen market, and investigate hydrogen and certificate trading setups. As the hydrogen market is required to develop fast and will primarily be driven by policy interventions, natural gas market regulations can not simply be replicated. Hence, we employ the Grounded Theory Method by Glaser and Strauss (1967) and Corbin and Strauss (2015), which is considered appropriate for new and under-researched topics, such as the hydrogen market design. We incorporate input from 16 across-industry expert interviews with future hydrogen market players, research institutes, and regulators to ensure a holistic perspective. Our findings support policymakers in setting the guardrails to advance hydrogen market development, market design, and infrastructure regulation. Further, we assist hydrogen market players, such as hydrogen producers, consumers, infrastructure providers, and exchanges, in gaining a common understanding of which potential future hydrogen regulations they can advocate for.

Our work is structured as follows. In Section 4.2, existing literature on market design, the natural gas market and the future hydrogen market is laid out. Section 4.3 details the methodology employed and describes our interview process. Section 4.4 outlines our results, which are discussed in Section 4.5, while Section 4.6 concludes.

4.2 Theoretical background

Literature suggests that more mature European energy markets should be analyzed to develop a suitable hydrogen market design. The natural gas market is often suggested to be used as an analogy, mainly due to the physical similarities of both gases and the potential of using retrofitted natural gas pipelines for hydrogen transport in order to save infrastructure cost (Adam et al., 2020, Cerniauskas et al., 2020, Neuhauser et al., 2020, Deutsche Energie-Agentur, 2021, Hydrogen Europe, 2021b, Van der Spek et al., 2022). Hence, we first provide an overview of key market design aspects within the energy sector and the European natural gas market. Next, we review the current state of the hydrogen market literature to derive the research gap addressed.

4.2.1 Energy market design and the case of natural gas

For many energy markets, policymakers step into the role of market designers. As laid out in the reviews of Kominers et al. (2017) and Roth (2018), market design is a relatively young field of economics that aims to leverage economic theory to improve the function of real-world markets. Building upon a detailed understanding of the functioning of particular markets, market designers, often governments, can optimize non-efficient markets or rebuild them from scratch (Roth, 2018). This can include redesigning the rules that guide market transactions as well as the infrastructure that enables those transactions, addressing a broad range of market failures (Roth, 2007, Vazquez and Hallack, 2015). Roth (2018) and Mulder et al. (2019) name examples of market failures, such as information asymmetry, investment hold-ups due to high uncertainty, and economies of scale when one player dominates a market with high fixed costs. Ringler et al. (2017) define the objective of energy market design as creating a regulatory framework in which market participants' behavior supports the achievement of energy policy targets. As there is often no one-size-fits-all market design solution, Vazquez and Hallack (2015) call to explore differing design choices regarding their impacts on several costs and benefits.

When detailing the market design and attached regulations for a heavily used energy carrier with multiple applications, such as natural gas and hydrogen in the future, there are several key aspects to consider. One key aspect given by Vazquez and Hallack (2015) and Roth (2018) is transmission infrastructure regulation and access. The transmission infrastructure is often at some point opened to third parties, the so-called third-party access (TPA), to foster competition, as for example in the First Gas Directive described by Cronshaw et al. (2008). Transmission infrastructure can either be owned by integrated energy producers or unbundled, meaning that the infrastructure operator is separated from the producer and thus allows competitors to enter the former natural monopoly network (Cronshaw et al., 2008, Vazquez and Hallack, 2015). This unbundling ensures transparent and non-discriminatory access for all potential suppliers within the market.

A second key aspect of market design is the trading setup. The natural gas market represents an example of commodity trading in Europe. Commodities are unrefined or refined raw materials like agricultural products, metals, or energy carriers like natural gas or crude oil (Büsch, 2013, Priolon, 2019). Within the energy sector, a commodity is a tradable unit of energy within a physical network during a specific period (Bundesverband der Energie- und Wasserwirtschaft, 2021). What characterizes a commodity is laid out in detail by Priolon (2019). Commodities are traded on world or regional markets, where trading (e.g., on energy exchanges) can be unrelated to the physical settlement. According to Peck and Shell (1990), a perfectly competitive and thus liquid commodity market is characterized by a high trading volume, many suppliers and buyers, and full transparency (Roth, 2018, Mulder et al., 2019). Easily accessible infrastructure for communication and exchange of goods is required (Neuhauser et al., 2020). In the case of natural gas, it is typically traded Over-the-Counter (OTC) or on energy exchanges like the EEX (Burger, 2014). In Europe, the OTC market, on which parties find either bilateral agreements or align via broker platforms, is significantly larger (ACER, 2019, Trinomics and LBST, 2020). In contrast, exchanges work with standardized contracts, eliminate credit risk, and are preferred for derivative products like futures (Burger, 2014).

For gas or power markets, Vazquez and Hallack (2015) highlight the need to define how commodity trading reflects infrastructure limitations. A point-to-point model, zone model or postage stamp model are possible (Schwintowski, 2014, Robinius et al., 2014, Robinius, 2015). In the point-to-point model, every trading transaction is based on a specific source-drain connection. Contracts are settled on predefined paths, with transport distances determining the transportation fee (Schwintowski, 2014). In this model, however, substantial transaction costs occur due to high amounts of complex contracts and insufficient competition (Robinius et al., 2014). The access model with the highest trading flexibility but also the lowest technical feasibility would be the postage-stamp model detailed in Robinius et al. (2014) and Robinius (2015). The postage-stamp model suggests that market participants can freely inject or withdraw an energy carrier, such as natural gas, within the network. Similar to postage stamps, distances are irrelevant, and trading flexibility is high. Nevertheless, as infrastructure and puffer reserves are not unlimited, this model is complex to implement on a cross-border scale. As a compromise, the zone model reflects capacity restrictions (Robinius et al., 2014). For this purpose, the market is separated into zones in which the postage stamp model is applied. In each zone, balancing group managers and market zone coordinators ensure a supply and demand balance (Haucap et al., 2011). Hence, technical feasibility is given, injection and withdrawal contracts can be booked separately via the Virtual Trading Point (VTP), and trading is flexible across zones (Robinius et al., 2014). In the European natural gas market, policymakers replaced the point-to-point model with the entry-exit model, an example of a zone model, where the market zones roughly align with the national markets of an EU member state (Robinius et al., 2014, Chyong, 2019).

Similarly to electricity generation, Hydrogen Europe (2021b), Bundesverband der Energie- und Wasserwirtschaft (2021) and International Renewable Energy Agency and RMI (2023) emphasize the need for regulation on the certification of green house gas (GHG) emissions of the hydrogen produced. Such certification could be introduced as a mass balance system or as a book and claim system similar to the electricity sector (Council of the European Union and European Parliament, 2018, Hydrogen Europe, 2021b, White et al., 2021, Deutsche Energie-Agentur, 2022). Furthermore, due to the current high uncertainty in future hydrogen market development, Dawin et al. (2023), Lagioia et al. (2023) or Farrell (2023) call for political support measures, including direct financial support.

4.2.2 Hydrogen market development phases and suggested approaches for related regulation

Currently, hydrogen is mainly produced directly at its application locations, which are concentrated in Germany and the Netherlands (Forschungsgesellschaft für Energiewirtschaft, 2019, Bundesverband der Energie- und Wasserwirtschaft, 2021, Hydrogen Europe, 2021a, European Commission, 2021b). Therefore, the hydrogen infrastructure in Europe is still limited today and based on long-term bilateral contracts (Sachverständigenrat für Umweltfragen, 2021). Although researchers do not all agree on the expected time horizons, they agree on core hydrogen market developments, which can be summarized in three stages. Furthermore, the literature provides first suggestions on hydrogen market regulation relevant to each stage.

In the first stage, from now until around 2025, the main objective of the emerging hydrogen economy is to showcase its scalability and facilitate the decarbonization of the existing hydrogen production (European Commission, 2020a, Hydrogen Europe, 2021b). To support this objective, the EU Commission plans for at least 6 GW of installed green hydrogen electrolyzer capacity and to produce up to one million tons of clean hydrogen yearly by 2024 (European Commission, 2020a). Isolated hydrogen islands are expected to emerge. These so called hydrogen valleys or ecosystems will include local hydrogen production, transportation, and consumption (Neuhauser et al., 2020, PWC, 2021, Bundesverband der Energie- und Wasserwirtschaft, 2021). The hydrogen demand is driven by industry sectors that use hydrogen today and/or feel a strong need to decarbonize, like refineries, the chemical industry, and steel producers (European Commission, 2020a, Van der Spek et al., 2022, Braun et al., 2023, Egerer et al., 2024). Bilateral and long-term contracts will dominate in these localized markets (PWC, 2021). The literature recommends introducing a hydrogen certification scheme to provide GHG emissions transparency (Hydrogen Europe, 2021b, Bundesverband der Energie- und Wasserwirtschaft, 2021, European Commission, 2020a, Mulder et al., 2019, Trinomics and LBST, 2020, White et al., 2021, International Renewable Energy Agency and RMI, 2023). The specific decision regarding whether to implement a mass balance system, as outlined in Article 30 of the second Renewable Energy Directive (RED II), or to adopt a book and claim system similar to the electricity sector, remains subjects of ongoing deliberation (Council of the European Union and European Parliament, 2018, Hydrogen Europe, 2021b, White et al., 2021, Deutsche Energie-Agentur, 2022). Additionally, the geographic scope of the certificates is yet to be defined. Diverse opinions are expressed concerning the market access model. While the European Hydrogen Strategy laid out in European Commission (2020a) argues for a point-to-point access model to be adopted initially, other institutes, for example Bundesverband der Energie- und Wasserwirtschaft (2021), advocate for introducing a small entry-exit system early on.

During the second phase, spanning approximately from 2025 to 2030, the European Hydrogen

Strategy in European Commission (2020a) sees hydrogen as an integral component of an interconnected energy system, aiming for renewable hydrogen electrolyzer capacities of at least 40 GW and the production of up to ten million tons of green hydrogen by 2030. They expect that green hydrogen will achieve cost competitiveness with fossil fuel alternatives. Beyond industrial applications, hydrogen is predicted by European Commission (2020a) and Van der Spek et al. (2022) to see increased utilization in the transportation sector, electricity generation for balancing renewable-based systems, and heating in residential and commercial buildings. A hydrogen pipeline network, consisting mainly of reassigned natural gas pipelines connecting member states, will emerge (European Commission, 2020a, Wang et al., 2020, Kotek et al., 2023, Braun et al., 2023, Bundesnetzagentur, 2024). Although the literature does not agree on a specific timeline, there is consensus regarding the necessity of regulations concerning access to transportation assets like pipelines and storage (e.g., unbundling, TPA) to achieve the economies of scale that typically characterize energy markets (Mulder et al., 2019, European Commission, 2020a, Trinomics and LBST, 2020, Bundesnetzagentur, 2020c, PWC, 2021, Bundesverband der Energie- und Wasserwirtschaft, 2021, Hydrogen Europe, 2021b, Agora, 2021, Van der Spek et al., 2022, Braun et al., 2023). The current regulatory proposal Council of the European Union (2023a) suggests unbundling as the default model while allowing the independent transmission system operator model under certain conditions that are yet to be clearly defined.

In the third phase, from around 2030 onwards, hydrogen will be utilized in all relevant hard-to-decarbonize sectors (European Commission, 2020a, Van der Spek et al., 2022, Braun et al., 2023). A mature European hydrogen backbone is envisaged to connect hydrogen ecosystems and transport hydrogen cross-border by 2040 (Wang et al., 2020, Kotek et al., 2023, Braun et al., 2023). Market consolidation will push the hydrogen market to be transparent and liquid, with prices driven by global supply and demand in the long term (Bundesverband der Energie- und Wasserwirtschaft, 2021, Hydrogen Europe, 2021b, PWC, 2021).

4.2.3 Relevance of hydrogen market design research and need for action

A multitude of literature has been published about hydrogen, covering several research fields laid out in Blanco et al. (2018) and Blanco et al. (2022). Hydrogen market researchers, however, find that research focuses mainly on the technical feasibility and the production cost (Mulder et al., 2019, Blanco et al., 2022). More recent studies also cover developing estimations for the future global hydrogen market sizes and resource flows as well as modeling hydrogen trading (e.g., Nuñez-Jimenez and de Blasio (2022), Ikonnikova et al. (2023), Liu et al. (2023), Zhang et al. (2023), Zhu et al. (2023), Li et al. (2024)). Many studies about the expected development phases of the hydrogen market were published, which discuss first approaches for related regulation and deduct that hydrogen commodity trading might play a role from the year 2030 onwards (Section 4.2.2). However, even if production is efficient and hydrogen is socially beneficial, Hydrogen Council (2022b), Dawin et al. (2023) and Lagioia et al. (2023) agree that developing an efficient hydrogen market requires a suitable design and trading system. Lagioia et al. (2023) find that current regulatory uncertainties impede hydrogen market investments and put the ambitious EU 2030 decarbonization objectives at risk. There is a consensus that market design issues for hydrogen are currently under-researched and require further exploration (e.g., Mulder et al. (2019), International Energy Agency (2019), Hydrogen Council (2022b), Blanco et al. (2022)). Only a few recent articles cover hydrogen market design and policy aspects. Farrell (2023) performed a multidisciplinary literature review covering policy design for green hydrogen. However, they focus their analysis on the cost-competitiveness of hydrogen applications and related policy financial support. Van der Spek et al. (2022) are covering the state of hydrogen infrastructure regulation proposals and analogies to the natural gas market. They call for more precise infrastructure regulation, especially for higher hydrogen shares within the grid.

To contribute to the under-researched field of hydrogen market design and regulation, we investigate how the European hydrogen market should be designed based on learnings from the natural gas market as laid out in Section 4.2.1. Specifically, we analyze which infrastructure regulations are necessary for the hydrogen market and if they can be translated from the natural gas market. Additionally, we explore suitable market development policy measures as well as hydrogen and certificate trading setups. For the market design decisions, it is important to consider that the hydrogen market is just emerging and its fast market development will be strongly driven by EU regulations and sustainability targets. In contrast, the natural gas market mainly developed organically over decades, and regulations were introduced in hindsight. Hence, transferring learnings from the natural gas market can be complex.

4.3 Methods

We aim to identify core market design choices for a well-working future European hydrogen market and efficient commodity trading. As the literature on this topic is sparse, we employ the Grounded Theory Method (GTM). The GTM, introduced in Glaser and Strauss (1967) and further detailed in Corbin and Strauss (1990) and Corbin and Strauss (2015), represents an adequate research method to analyze new and emerging topics, such as the hydrogen market design. The GTM is especially suitable for studies based on qualitative data, which can come from various sources, with interviews representing a standard data collection procedure. Moreover, the GTM can be used as a foundation for further studies using quantitative measures and is therefore particularly suitable for under-researched fields. Based on the GTM, Gioia et al. (2013) developed a holistic approach for inductive concept development that simultaneously exhibits a high standard for rigor. Their approach consists of four core steps and represents a suitable research method for our inductive analysis in combination with the tools of the GTM of Glaser and Strauss (1967). The first step of their methodology is the research design, including a well-defined research question. In the second step, the data collection, Gioia et al. (2013) suggest conducting semi-structured interviews. The third step is analyzing the collected data to create a data structure, representing emerging concepts and their relationships. In the fourth and last step, the generated and analyzed data is transformed into a theory grounded in the data. The following subsections are derived from the steps of the above-stated inductive methodology of Gioia et al. (2013), including key elements of Glaser and Strauss (1967), and provide detailed explanations of our research approach and its implementation.

4.3.1 Data collection

For our identified research topic of hydrogen market design, we next need to generate data through semi-structured interviews. We employ the theoretical sampling approach to select adequate interview partners, following the GTM of Glaser and Strauss (1967). The question, "Who is in a position to answer my questions or provide the insights that I seek?" as posed by Rowley (2012), resulted in five expert groups: utility companies, industrial companies of high-priority hydrogen applications, energy exchanges, government and research institutes, and the energy sector focus of consulting companies. These expert groups represent future hydrogen producers, transmitters, traders, certifiers, buyers, and regulators. This approach is in line with Glaser and Strauss (1967), which suggests that the primary criterion for selecting comparison groups is their relevance for advancing emerging categories. The interviewees were selected and prioritized on the following interview recruiting criteria: having valuable expertise in the hydrogen market and/or commodity trading, contributing to variation in future hydrogen market roles, contributing to variation in organization types, contributing to gender balance and contributing to generation balance. The selected expert groups were further recently confirmed as the most relevant stakeholders by Schlund et al. (2022), who performed a stakeholder analysis for the German hydrogen market, which was published after our interviews.

Based on these interview recruiting criteria, own research, and contacting relevant organizations through industry collaboration partners, we identified 46 potential interviewees in these highly specialized fields. We focus our interviewees on German organizations, as Germany represents the largest European country in hydrogen demand today and will become even more relevant on a global scale until 2030 as well as 2050 (Hydrogen Europe, 2021a, Hydrogen Council, 2022a, Braun et al., 2023). Furthermore, many of the interviewed organizations represent large leading players in European or even global markets. After prioritizing 33 particularly suitable candidates, we and our industry collaboration partners reached out via e-mail. Additionally, we contacted potential interview partners via LinkedIn.

In total, we conducted 16 expert interviews. The suitability of these experts for answering our research questions was additionally supported during the introductory stage of our interviews. All interviewees stated that their organizations perceive hydrogen as an essential strategic topic and expect significant market developments within the following years. Therefore, their organizations already started with organizational structuring measures (e.g., creating hydrogen departments) and operative preparation (e.g., conducting pilot projects) to perform well in the future hydrogen market. As shown in Table 4.1, we conducted the most interviews with experts from the industry sector, including one certification service provider. The reason is that the industry sector is quite diverse, representing future hydrogen producers, certifiers, and buyers. More concentrated sectors, such as exchanges and utilities, are hence represented with fewer interviewees. Moreover, the distribution between 15 male interviewees (94 %) and one female interviewee (6 %) seems uneven. However, this number closely correlates with the three women identified within the 46 potential interviewees. One reason for this phenomenon is that we interviewed mainly senior managers, and in energy-related sectors, the share of women in senior management positions is lower than 14% (Pilgrim et al., 2021).

Table 4.1: Characterization of the research sample.

Category	Characteristic	Number	in %
Organization	Industry (ID)	5	31
	Institute (IS)	4	19
	Utility (U)	3	19
	Consulting (C)	3	25
	Exchange (E)	1	6
Gender	Male (M)	15	94
	Female (F)	1	6

As we promised anonymity to the interview partners, we used codes for each interviewee. The first letters represent the organization type, and the numbers represent the interview order. The code's last letter, "F/M", stands for female or male. For example, ID08M means the eighth interviewee is from the industry sector and is male. With this coding, the information on the interviewees is limited, but quotes in Section 4.4 can still be put into context.

For the GTM, Corbin and Strauss (2015) emphasize that the interview type should allow flexibility as the objective is to create a theory. As mentioned by the authors, it is advantageous to maintain consistency over the covered concepts in the interviews. Hence, we chose semi-structured interviews for our approach, as they allow for consistency without limiting additional topics or the necessity to follow a specific sequence. This approach aligns with Rowley (2012), who recommends semi-structured interviews for researchers who require flexibility, comparability, and a relatively simple interview form.

Literature provides differing opinions on conducting a literature review before the interviews. While Glaser represents the original opinion from 1967 that literature review increases bias, other researchers, including Strauss, argue that, especially for semi-structured interviews, consulting literature without judging its conclusion helps broaden the mind and discover new insights (Glaser and Strauss, 1967, Heath and Cowley, 2004, Gioia et al., 2013, Corbin and Strauss, 2015). As the topics analyzed in this work are rather complex, we conducted a literature review before the interviews.

We divided the semi-structured interview guideline into an intro, four main question sections, and an outro. The main part covers the topics of commodity trading, analogies to the natural gas market design, trading system, and model hydrogen market design. Following Rowley (2012), the semi-structured interview guideline was tested and adjusted before interviewing the first experts. The interviews were conducted between January 19th and March 1st 2022 using the video conference tool Zoom. The interview language was German. More than 11 hours of audio material was produced, with an average interview duration of 43 minutes (ranging from 33 to 56 minutes). Following Gioia et al. (2013), we modified the semi-structured interview guideline several times during the interview process. Additionally, we adjusted the interview guideline to the expected level of expertise of the interview partner. A version of the final general interview guide is attached in Section A.8 of the Appendix.

In line with Gioia et al. (2013), we anonymized all interviews for privacy protection and reduction of potential biases. To further encourage interview partners to share their perspectives openly, we granted full confidentiality at the beginning of the interview and gave an overview of the research project beforehand. Furthermore, interviewees could skip questions if they did not feel in the position to answer them.

4.3.2 Data analysis

As typical for the GTM, we use an iterative approach. Data collection and analysis are ongoing parallel processes to create concepts, categories, and core categories until theoretical saturation is reached and the theory can be articulated (Corbin and Strauss, 1990). Following the suggestions and transcription rules of Gläser and Laudel (2009), we transcribed the conducted interviews completely. We used standard orthography, did not transcribe filler words, non-verbal expressions, pauses, or repetitions without specific purpose, and marked incomprehensive parts with brackets.

Coding represents the fundamental analytics process of the GTM, which Corbin and Strauss (1990) differentiate into three steps. Open coding, also called first-order analysis by Gioia et al. (2013), aims to break down the data analytically. While constantly comparing observations, conceptual labels are assigned to text segments. Within the next step, the second-order analysis, categories are connected and hypothetical patterns emerge, which are verified against incoming data. The last step, selective coding, aims to distill and aggregate the emergent categories even further. This results in core categories representing central phenomena. We used the qualitative data analysis software MAXQDA to apply the described coding approach. In total, 17 categories and four core categories emerged. Section 2.3 presents the four core categories and the associated categories in detail.

Regarding the proper number of interviews for the GTM, Corbin and Strauss (2015) suggest that primary saturation is reached when no new concepts are emerging. As shown in Figure 4.1, the number of new concepts decreased significantly after the sixth interview, with only a few new concepts emerging in the last interviews. This observation aligns with Guest et al. (2006), who explored that elements for main themes are found already during the first six interviews, and saturation is usually reached within twelve interviews.

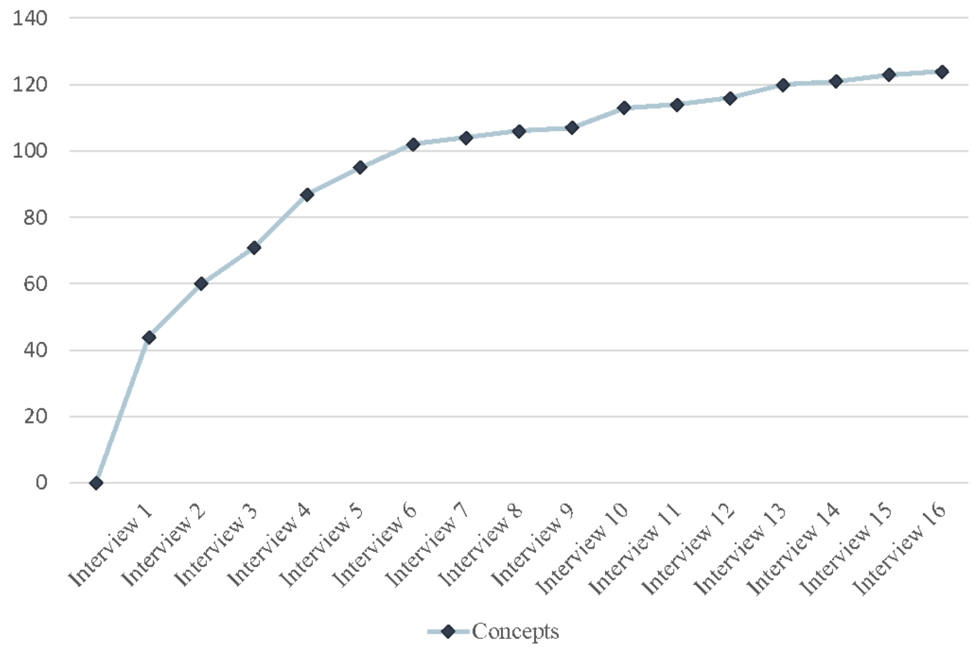


Figure 4.1: Saturation of concepts derived from the interviews.

4.4 Results

Four core categories emerged throughout the qualitative data analysis of the 16 conducted interviews: hydrogen market development, hydrogen value chain, Hydrogen market design and regulations, and hydrogen and certificate trading. Each core category includes different categories containing the occurring concepts. The included concepts occurred in various interviews to ensure representativity. The first two core categories were covered to put our main findings into context. Hence, related results can be found in Section A.9 of the Appendix.

4.4.1 Hydrogen market design and regulations

First, we focus on the design of future hydrogen regulation and point out the parallels to the natural gas market. We cover appropriate market development policy interventions, infrastructure regulations, and associated risks.

Regarding the feasibility of transferring regulation from the natural gas to the hydrogen market, U10M says that "(...) the natural gas market works well and you start by taking as much of it as feasible" (U10M: 15). U14M agrees and states that "(...) of course, you can see analogies because it is a gaseous energy carrier in both cases. And a number of regulations can certainly be made similar." (U14M: 13). C01M, IS05M, and IS13M go even further and propose merging the natural gas and hydrogen market regulations to exploit synergies. However, the interviewees also observed some differences and advise profiting from the lessons learned in deregulating the natural gas market. U12M has "(...) doubts as to whether all the regulations that we have applied to deregulate a developed market, as happened in natural gas or electricity, will be effective in a market ramp-up phase." (U12M: 29). IS05M adds that "(...) hydrogen can already start at a very high development level. So you do not make this whole journey over 30 to 40 years as we had with natural gas." (IS05M: 11). Another difference is the market scope that, according to our experts, will become global much earlier on than the natural gas market.

4.4.1.1 Market development policy measures

The interviewed experts support that policy measures will play an integral role in ensuring a timely hydrogen market ramp-up, as hydrogen will be "(...) a politically organized ramp-up and market." (IS15F: 5). U14M agrees and adds that "green hydrogen will not develop in a purely market-driven way. Politicians have to give it a little push. Otherwise, it will not work." (U14M: 7). When asked about suitable policy measures to support the hydrogen market development, our interviewees recommended the instruments of direct industry subsidies, a CO_2-price increase, contracts for difference (CfD), adjusted green electricity taxation and hydrogen usage quotas for selected applications. These instruments do, however, not always work in an additive way, as "(...) there are reciprocal relationships between the instruments. This does not necessarily contribute to efficiency and clarity about the individual instruments. I would always prefer few instruments, so that it becomes efficient, but then please implement them effectively and with full also political support." (IS05M: 27).

Policymakers can make the supply and usage of hydrogen more attractive by improving their business case through direct industry subsidies. Despite knowing that operational expenditure (OPEX) will be high, the interviewees strongly recommend focusing on capital expenditure (CAPEX) subsidies. C01M advises avoiding repeating the mistake of long-term financial subsidy support as occurred through Germany's Renewable Energy Sources Act. IS13M supports this statement and adds: "Suppose a project cannot cover its running costs despite the change in the government-induced price and a CAPEX subsidy. Then, frankly, I think the project is so bad that it should be left alone." (IS13M: 15).

Additionally, the interviewed agree on a "(. . .) CO_2 price increase. Thereby, you make the competition, the fossil competition, more expensive, and then you close the gap to renewable hydrogen" (U14M: 11), which would support the use of green hydrogen to become "(. . .) an economically viable model." (ID08M: 35). However, a CO_2 price increase alone might not suffice and might disadvantage German and European companies on a global scale. E04M advises that"(. . .) the CO_2 price is not enough; we need further incentives." (E04M: 27). C01M sees a challenge to European companies in global competition, as "(. . .) we will probably not have reached a global minimum CO_2 price by COP50 [United Nations Framework Convention on Climate Change in 2050]." (C01M: 25). Therefore, a possible additional or alternative instrument is using "(. . .) [Carbon] contracts for difference [CCfD], but not necessarily for energy, but also for steel or green methanol. (. . .) The difference to the world market price is then compensated so that the industries do not put themselves in a worse position in competition than others." (U14M: 11). As soon as "(. . .) foreign countries follow us, (...) then we will also be able to bring down these Contracts for Difference because then we will end up on the level playing field again." (ID06M: 29). Another measure with which policymakers can influence green hydrogen prices is reducing related taxation. Especially tax reduction on renewable electricity could have a strong effect as "(. . .) the electricity procurement costs are the decisive criterion, and (. . .) the goal is to get green energy to the consumer as cost-effectively as possible (. . .)." (ID08M: 37). ID06M adds that hydrogen should "(. . .) preferably not be burdened by any tax, government levy, or similar." (ID06M: 11). Another measure that creates pressure for future hydrogen applying industries is based on the introduction of quotas, e.g. for green steel production. The experts suggest extending existing quotas, for example, in the refinery industry. IS05M mentions that introducing such quotas, however, has to be linked to hydrogen availability.

4.4.1.2 Infrastructure regulation

While the interviewees largely agree on the regulation of the hydrogen transportation system in its target state, recommendations for the ramp-up phase are less clear. U12M states: "I am not sure whether we should have something like a virtual trading point right from the start or whether we should use point-to-point transports at the beginning." (U12M: 29). U10M agrees and adds: "I think it's probably hard to transfer the system one-to-one in the beginning, especially if we still have certain subnetworks. (...) I believe that in the long term, we should definitely strive for an entry-exit model." (U10M: 19).

The interviewees advocate for TPA. E04M specifies that "(. . .) the infrastructure access (. . .) must be non-discriminatory, (...) which means that there must also be a hydrogen network manager, as in the natural gas sector." (E04M: 19). Additionally, balance energy is required. Another central infrastructure regulation aspect is unbundling. Our experts generally support the approach of vertical unbundling without a clear consensus about the regulation's introduction time. Some interviewees, like U10M, suggest applying unbundling in the early stages and transferring the regulation from the natural gas market. U12M supports this proposition and stresses that the current players in natural gas, who might also provide the hydrogen infrastructure, are already unbundled. Others fear that unbundling might discourage the development of the required hydrogen infrastructure and production. C01M is concerned "because what certainly does not work economically is if company A builds up an expensive infrastructure in such an ecosystem with electrolysis capacities and network, (...) and then shortly afterward, company B can say: that is great, everything is there, there is free network access, (...) I will now put new electrolysis next to it, and company A has a stranded investment." (C01M: 21). To address this fear, C01M and IS13M can picture "(. . .) a time window of 5 to 10 years in which we allow transmission system operators to deviate from these unbundling regulations and also become hydrogen producers or hydrogen users. But it is clear from the onset that these parts of the company will be sold to other market players after this limited period." (IS13M: 19). With this approach, the companies "(. . .) can at least calculate an overall business case for a number of x years." (C01M: 21).

C03M and IS05M explain that pipeline fees might become a challenge during the market ramp-up phase while volumes are low. IS05M criticizes the too-small cross-subsidization planned in the new gas directive and suggests that a unit of capacity in natural gas should be priced the same as a hydrogen unit. IS13M agrees that cross-subsidization is a fair solution. He explains that in the beginning, natural gas consumers could subsidize the hydrogen transport costs and later receive a subsidy through hydrogen transport costs. Because of blending opportunities, it is a "(. . .) very important point to create regulatory measures for feeding hydrogen into the natural gas networks (. . .)." (IS13M: 25). Those measures should mainly focus on an EU-wide maximum feed-in hydrogen concentration (e.g., 10 %) and rules on who is authorized to feed in which volumes. For the next years, however, there is consensus among the interviewees that blending of natural gas and hydrogen is infeasible on a large scale as the industry asks for pure hydrogen. ID06M states figuratively: "It is really like pouring champagne into sparkling water when champagne is expensive and in short supply." (ID06M: 13).

4.4.1.3 Associated risks

Our experts share associated reservations and potential risks regarding the future design and implementation of policy measures. They fear the current hydrogen market uncertainty due to lack of regulation might persist for too long and slow down the market development and infrastructure buildup. U14M underlines that "we need perspective, reliability, and stability. You can live with many regulations, good or bad. You have to rely on the fact that they will last when we make investment decisions." (U14M: 35). U10M shares this assessment and says that "(. . .) the more regulatory certainty there is, the easier it will be for the market players." and "the sooner there is security, and the sooner the decisive parameters are set, the faster the market ramp-up could succeed." (U10M: 21). Furthermore, C03M and IS15F worry that subsidies might be mainly invested into a few, potentially infeasible business models for hydrogen applications. Policymakers might not focus their financial support decision on "(. . .) Where can I generate the most impact and the fastest growth with the least funding? And where (...) can I keep the companies under competitive pressure to innovate to remain competitive?" (IS15F: 23). They highlight that such inefficient business models could emerge through long-running funding (e.g., OPEX subsidies).

Another emerging topic is the perceived risks that too strict regulation might carry. Firstly, to mitigate potential market development challenges, the interviewees advocate for a step-wise approach in introducing some regulation. According to the interviewees, "(...) it is crucial during the transition period not to interpret the rules too strictly" (U10M: 56). C01M even suggests that "(. . .) in the beginning, monopoly positions in quotation marks, or closed ecosystems will probably be necessary to reach a certain maturity of the technology and the application because I just have a closed business case." (C01M: 25). At the same time, many interviewees emphasize that competition is crucial for a decrease of hydrogen prices and that competition should be ensured by "(...) market concentration and monopoly control." (C01M: 37). IS05M raises the concern that very strict European hydrogen standards could lead suppliers to transport their hydrogen to other regions with lower requirements. E04M emphasizes that other hydrogen colors than green can help support the market ramp-up. Still, "(...) it must be ensured that, if we accept blue and green hydrogen at the same time, there is no lock-in effect that would allow such a coexistence." (C16M: 51). Another substantial aspect for which many of our experts are convinced that the regulations are too strict is the delegated act of the RED II. While they agree that electricity for hydrogen production should be of renewable origin, the interviewees are certain that the regulatory guidance of geographical correlation, especially temporal correlation, and the element of additionality will harm the green hydrogen market ramp-up. IS15F explains that this means that hydrogen production can only occur when nearby, and at the time of hydrogen production, electricity from the associated PPA renewable energy system (RES) plant is available. IS13M criticizes the additionality rule, which leads to missing out on using the RES capacity during high electricity generation and low electricity demand periods. U14M agrees with this criticism and alludes to the lengthy planning and installation period for new RES of seven to eight years.

4.4.2 Hydrogen and certificate trading

The following presents the advantages and the prerequisites for hydrogen commodity trading. Moreover, the development of hydrogen trading and the trading system are addressed.

Hydrogen trading will increase hydrogen market efficiency as "(...) not everyone who needs hydrogen has to produce it themselves. And not everyone who has produced more hydrogen than they need must now try (...) to consume it themselves." (IS13M: 15). The interviewees believe that exchange-based commodity trading ensures market access, "(...) price transparency and (...) liquidity (...)." (E04M: 5). "In addition to all the other advantages that an energy exchange offers, there is the whole topic of hedging risks. (...) Especially in these young markets, this is a decisive advantage." (E04M: 7).

In agreement with many other interviewees, ID02M defines the prerequisites for hydrogen commodity trading as the following three aspects: “That a supply and demand market develops, that it can be transported, and that there (. . .) is clear labeling for the quality.” (ID02M: 23). Policy measures have a strong influence on market development and thus trading volume. C16M states, “(. . .) if there is to be a market, it needs its logistics behind it, which also enables the trade of this product (. . .).” (C16M: 23). Further, “it would be important that a distinction between the hydrogen qualities is possible (. . .) and an exchange would have to allow this distinction.” (ID08M: 23).

Our experts predict that hydrogen “(...) will definitely become a tradable commodity” (U10M: 25), for which trading will be established between 2030 and 2035. However, this development will take time and higher available volumes, as the hydrogen market “(. . .) will be more of a bilateral market at the beginning and less of a trade market.” (U12M: 15). E04M suggests that a more transparent hydrogen pricing estimation could be achieved by creating a hydrogen price index based on bilateral contracts. C01M also sees advantages in such indices, which make it “(. . .) possible that a financial trade will start, which will certainly not be quite as good as a physical trade (. . .) but you can at least establish a proxy trading on the index.” (C01M: 17). Further, “(. . .) exchange trading plays an important role right from the start in creating price transparency and (. . .) also developing the market. And liquidity then builds up as a result. That can happen right now. As I said, actively accompanying the market ramp-up.” (E04M: 5). C01M is sure that as soon as hydrogen “(. . .) has arrived in the real economy, there will be a market, and it will automatically find its way to the exchange. In Europe, we have at least three large energy exchanges that are also looking for new business models with the EEX, Nordpool, and ICE (. . .).” (C01M: 27).

Strong analogies between the natural gas and hydrogen market regarding the trading system were explicitly pointed out by 13 of the 16 interviewees. C01M is “(. . .) sure there will be a similar structure as in the natural gas market where there are different time periods that are traded in the futures markets and then some spot market for short term balancing of supply and demand.” (C01M: 31). Next to trading on energy exchanges, OTC trading is expected to be established. Hydrogen derivatives also have to be considered as the hydrogen economy grows, as imported hydrogen “(. . .) is often not hydrogen itself, but ammonia or methanol. So then we actually get additional markets.” (ID08M: 21).

For the critical hydrogen trading prerequisite of distinguishing hydrogen's different types and associated GHG emissions via certificates, two approaches were proposed. IS07M and IS13M advise the use of mass balancing to ensure that in addition to the production, GHG emissions caused by other factors, like transportation, could be considered. E04M counters, however, that "(...) out of a trading view, a market ramp-up can only work if there is trading with guarantees of origin [GO]. That means to trade product and origin separately." (E04M: 21). The majority of the interviewees shares this suggestion which corresponds to the book and claim approach. This approach allows for simple balancing and straightforward tradability according to E04M. Regarding the regional scope of the certificate system, the interviewees advise that "(...) we should try to establish an EU-wide system and then, of course, also strive to establish it globally as a standard (...) to create as few barriers as possible (...)." (U10M: 31).

4.5 Discussion

We conducted 16 semi-structured interviews with five different groups of potential hydrogen market stakeholders. Although the interviewees' backgrounds were heterogeneous, we identified a consensus on crucial market design topics among the interviewees. The interviewees emphasize that policymakers must decide on fundamental market design choices and regulations before significant investments can be made and the hydrogen market ramps up further. We found that recommendations for regulation and policy measures have strong interdependencies. Hence, developing a holistic understanding of the hydrogen market's functioning and development is necessary for creating a suitable market design with efficient hydrogen commodity trading. Our expert interviews confirmed three potential hydrogen market development phases described for example in European Commission (2020a), Neuhauser et al. (2020) and Wang et al. (2020). Regional hydrogen hubs develop until 2025, which then merge into clusters with increasing hydrogen amounts until 2030-2035. Our interviewees expect a mature, international hydrogen commodity market characterized by a distinct infrastructure and liquidity to emerge between 2030 and 2035. We identified three core areas to be covered in the European hydrogen market design and policy measures to support market development and establish efficient hydrogen commodity trading from 2030-2035 onwards. We illustrated the key results in Figure 4.2 below.

Core market design and policy areas	Ramp-up and transition phase (until 2030/2035)	Commodity market phase (from 2030/2035)
Market development policy measures	• Support investments by reducing regulatory uncertainty • Allow other hydrogen colors apart from green • Focus direct industry support on CAPEX investments • Revisit strict green electricity criteria in RED II regarding correlation and additionally	• Support clear focus on green hydrogen • Repeal monopoly positions to support hydrogen production competition
	• Support business case of green hydrogen applications through CO2 price increases, CCfD, electricity taxation benefits and/or hydrogen usage quotas	
Infrastructure regulation	• Cross-subsidize hydrogen infrastructure through natural gas while pipelines below capacity	• Determine EU-wide feed-in regulations in natural gas infrastructure, including hydrogen concentration rules and injection authorization
	• Transfer key regulations from natural gas market, such as TPA, unbundling, and entry-exit system; either in early market phases or after an communicated transfer period before market liberalization	
Hydrogen and certificate trading	• Use hydrogen price indices as preliminary trade price orientation • Increase market efficiency through continued development of hydrogen exchange offering	• Trade hydrogen similar to natural gas on energy exchanges and OTC, including a spot market, derivatives and futures • Leverage hydrogen exchange for hedging opportunities, price transparency and liquidity
	• Launch an at least EU-wide GO scheme separate from physical hydrogen delivery through a book and claim system	

FIGURE 4.2: Core hydrogen market design criteria and policy measures.

In addition to the subsequent detailed discussion comparing our findings to the literature, Section A.9.3 in the Appendix provides a further graphical comparison.

4.5.1 Market development policy measures

Our experts strongly recommend that policymakers quickly create planning certainty from the political side, as it is essential for market players to start executing investments and overcome challenges such as the chicken-and-egg problem in the market ramp-up. This finding aligns with current hydrogen literature, which supports that policymakers can significantly influence hydrogen market development and underline the urgency of setting a regulative framework and creating investment incentives (Neuhauser et al., 2020, Bundesnetzagentur, 2020b, Hydrogen Europe, 2021b, Van der Spek et al., 2022, Dawin et al., 2023, Lagioia et al., 2023).

To support market development, the hydrogen strategy in European Commission (2020b) mentions the option to provide direct industry funding support, for example, in the form of Important Project of Common European Interest (IPCEIs). Our interviewees suggest focusing on providing direct industry support on CAPEX instead of OPEX. This recommendation contradicts Neuhauser et al. (2020), Hydrogen Europe (2021b) and Agora (2021) that state that subsidies should address CAPEX and OPEX. However, our experts indicate that the prerequisite for financial support should be a solid operational business model.

Our interviewees stress that policymakers must ensure the operative feasibility of hydrogen production requirements. However, Article 27 in the delegated act of RED II (Council of the European Union and European Parliament, 2018) requires that the green electricity from RES and hydrogen production must correlate geographically and temporally, and only electricity from additionally built RES can be used starting in 2026. Such strict regulations might significantly aggravate hydrogen production capacities and delay market development. Hence, we recommend that policymakers revise this article and suspend such requirements until a more mature hydrogen market has emerged. This recommendation agrees with the plead of other associations, such as Neuhauser et al. (2020) or Deutsche Energie-Agentur (2022), to mitigate or drop those strict regulations. A very recent analysis by Ruhnau and Schiele (2023) on the effects of this strict hourly simultaneity requirement also argues for its relaxation, as a more flexible definition can reduce hydrogen cost while not leading to increased power sector emissions. In their most recent amendment of RED II in October of 2023 (Council of the European Union and European Parliament, 2023), the Council of the European Union agrees to evaluate the impact of this additionality and temporal and geographical correlation rule on the availability and affordability of hydrogen by July 2028. While the agreement to evaluate this issue is positive, given the long planning times of hydrogen projects, the persisting uncertainty of this regulation might still impede hydrogen market growth.

In line with the existing literature, we suggest CCfD in specific sectors with intense international competition, where the CO_2 price might be insufficient for the profitability of using hydrogen-based production methods instead of conventional production (European Commission, 2020b, Hydrogen Europe, 2021b, Sachverständigenrat für Umweltfragen, 2021, Deutsche Energie-Agentur, 2021). Our findings also match the literature suggesting introducing quotas for specific materials that can be produced using hydrogen, such as fuels, steel, or fertilizers (European Commission, 2020b, Deutsche Energie-Agentur, 2021, Sachverständigenrat für Umweltfragen, 2021, Hydrogen Europe, 2021b). Besides direct industry support, CCfD, and quotas, European Commission (2020b) declares it a critical action to explore additional support instruments. Our analysis identified two supplementary measures to foster hydrogen market development. Firstly, introducing higher CO_2 prices increases green hydrogen applications' competitiveness over conventional production methods. Researchers and organizations agree with the significant effects of CO_2 pricing and emphasize the need for a more internationally consistent CO_2 pricing scheme (Neuhauser et al., 2020, Deutsche Energie-Agentur, 2021). Secondly, in line with Neuhauser et al. (2020), Sachverständigenrat für Umweltfragen (2021), Hydrogen Europe

(2021b) and Agora (2021), we suggest repealing all taxes, levies, and duties on green electricity used to produce green hydrogen. As green electricity represents one of the main cost drivers for green hydrogen production, this measure allows for more competitive hydrogen prices and, thus, for an acceleration of market development.

4.5.2 Infrastructure regulation

Building upon Robinius et al. (2014), Mulder et al. (2019), Neuhauser et al. (2020) and Van der Spek et al. (2022) that expects infrastructure regulation analogies to the natural gas market, we analyzed which regulations should be transferred to the hydrogen infrastructure market design. As in previous studies, our interviewees confirm that hydrogen will mainly be transported by a pipeline network, for which also existing natural gas pipelines could be retrofitted (European Commission, 2020a, Neuhauser et al., 2020, Wang et al., 2020, Kotek et al., 2023, Braun et al., 2023). We suggest cross-subsidies between hydrogen and natural gas infrastructure, which is controversially discussed in Bundesnetzagentur (2020b), Agora (2021), Monopolkommission (2021) or Pielow (2021). Infrastructure cross-subsidization avoids high hydrogen pipeline fees during the early market stages and hence accelerates the market ramp-up. Therefore, our interviewees advocate for this approach, arguing that although natural gas customers initially incur higher costs, hydrogen could again cross-subsidize gas infrastructure costs in the long run.

Our experts advocate for certain key regulations to be introduced analogous to the natural gas market. Requiring TPA ensures transparent and non-discriminatory access for all future hydrogen suppliers. Unbundling avoids monopolies throughout the hydrogen value chain, and the entry-exit system provides operational feasibility and trading flexibility for hydrogen transport. These recommendations can also be found in the Mulder et al. (2019), Trinomics and LBST (2020), Bundesnetzagentur (2020b), Bundesverband der Energie- und Wasserwirtschaft (2021), Hydrogen Europe (2021b) and Agora (2021). We answer the open question about regulation introduction time in the literature with two options. Either regulation should be introduced from early on to maximize planning certainty or after a predetermined grace period to advance market development.

While our experts agree that blending hydrogen in the natural gas network is inefficient and hydrogen should be primarily used in its pure form in the following years, we find that EU-wide feed-in regulation, as called for by Trinomics and LBST (2020), Bundesnetzagentur (2020b) and

Hydrogen Europe (2021b), should still be introduced in the long run. As the literature suggests, policymakers should cover the permitted concentration of hydrogen within the natural gas grid. The latest regulatory proposal Council of the European Union (2023b) suggests an upper limit for blending of 2% hydrogen. Moreover, we recommend that regulation should clearly define which players are authorized to inject which amounts of hydrogen.

4.5.3 Hydrogen and certificate trading

Our experts confirm that the hydrogen commodity trading system should be designed analogous to the natural gas trading system, including OTC trading, energy exchanges, a spot market, and a future market (Mulder et al., 2019, Trinomics and LBST, 2020, European Commission, 2020a, Bundesverband der Energie- und Wasserwirtschaft, 2021). Additionally, instead of entering a developed hydrogen commodity market, energy exchanges can actively accompany the hydrogen market development by providing hedging opportunities, liquidity, and transparency. Moreover, we find that a hydrogen price index launched by energy exchanges can play a significant role already in the early market stages, as recommended by Trinomics and LBST (2020). Accurate price indices based on price estimates and, later on, information from bilateral contracts can provide price transparency in the ramp-up phase of the market, thereby increasing trading volumes. The EEX supports this approach and launched the first market-based index for hydrogen, HYDRIX, in 2023 (European Energy Exchange, 2023).

Our interviewees agree with the suggestion of EU-wide certificates reflecting GHG emissions laid out in European Commission (2020b). To support a global hydrogen market and significant expected imports, we suggest a certification scheme that is at least EU-wide and ensures international interoperability. We contribute to answering the question of which certification system should be applied for hydrogen. Mulder et al. (2019), Bundesnetzagentur (2020b), Bundesverband der Energie- und Wasserwirtschaft (2021), Hydrogen Europe (2021b), Agora (2021) and International Renewable Energy Agency and RMI (2023) support the book and claim system as adequate tracking models for tracing renewable hydrogen along the value chain. The European Commission, however, suggests the mass balance system in RED II (Council of the European Union and European Parliament, 2018, Deutsche Energie-Agentur, 2022, Council of the European Union, 2023a). However, to allow for greater flexibility and efficient commodity trading, our analysis concludes that the physical hydrogen products and the certificates should not be linked. Instead, the book and claim system based on GOs should be introduced, similar to the case of renewable electricity.

4.6 Conclusion

We investigate the core market design criteria and market development regulation for an efficient hydrogen commodity market in Europe. Based on an inductive approach of the GTM, we conducted 16 semi-structured interviews with different players along the hydrogen value chain to provide a holistic perspective. We enhance the sparse literature on hydrogen market design, which other researchers could further expand by gaining insights from non-European experts or through quantitative methods such as surveys. We identified three core areas to be covered in the European hydrogen market design and policy measures to support market development and establish efficient hydrogen commodity trading from 2030-2035 onwards: Market development policy measures, necessary infrastructure regulations, and functioning hydrogen and certificate trading setups. We present several new findings and implications on controversially discussed hydrogen market design questions. Policymakers need to urgently reduce regulatory uncertainty, provide direct financial support through CAPEX subsidies, and push the profitability of hydrogen business models through, e.g., a CO_2 price increase, contracts for difference, tax breaks, or quotes. Additionally, policymakers should avoid very strict green electricity regulations, such as in Article 27 of the delegated act (RED II), as they might slow down the hydrogen market ramp-up. As for the natural gas market, fundamental regulations such as third-party access, unbundling, and the entry-exit system should be introduced. Such regulation should be either introduced early on or after a grace period to push market development. Cross-subsidization of infrastructure between natural gas and hydrogen and EU-wide feed-in regulations in natural gas infrastructure should be explored. Energy exchanges can play a fundamental role in the hydrogen market development by introducing hydrogen price indices and providing hedging opportunities, liquidity, and price transparency. The book and claim system on at least an EU scale should be used to represent the sustainability of hydrogen. Our findings are especially relevant for policymakers, as we provide guidance on appropriate measures to support hydrogen market development, market design as well as infrastructure regulation. The results further support gas and future hydrogen infrastructure providers in gaining a more detailed understanding of potential future infrastructure governance and regulation. Our analysis can accelerate market development for future hydrogen producers and consumers by giving clear recommendations on which regulation they can advocate and plan for. Energy exchanges can leverage our findings to define their offering in the emerging hydrogen market.

5 | Conclusion

5.1 Summary of research findings

This dissertation encompasses three essays that address challenges accompanying the decarbonization approaches of the transport and industry sector. We investigate the challenges of grid stability, renewable energy integration, and energy inequity caused by mobility electrification and address the regulatory uncertainty that hinders the hydrogen market ramp-up. In each essay, we derive policy implications from our findings.

Essay I analyzes the effectiveness of decentralized electricity generation using residential PV and BESS in mitigating grid reinforcement costs caused by EV charging. Our findings show that PV (and BESS) installations reduce overloads and associated grid reinforcement expenses in all tested scenarios and area types. By quantifying the impact of PV-EV synergies on grid costs, we contribute to the existing literature in the field of PV and EV interaction. While we use a German context as an illustrative example, our methodology is adaptable to almost any region. In rural grids, a single PV and BESS system could potentially save nearly €450 in grid reinforcement costs at a 20% EV penetration level. However, higher EV penetrations require inevitable grid reinforcements in rural areas. Suburban and urban grids begin experiencing failures at 60% EV penetration but could save up to €380 per PV and BESS system. Extrapolating these findings to the scale of the German grid suggests potential savings of up to €3.2 billion. Hence, we urge policymakers to explore these cost-saving effects further and consider the societal impacts of decentralized energy systems in their policy frameworks. The cost savings could be leveraged for subsidies for battery storage or west-oriented PV systems, which improve alignment with evening EV charging peaks. Policymakers could also create targeted additional financial support measures for households in bottleneck areas. Moreover, the savings from grid reinforcement costs could be allocated to low-interest PV financing or affordable rental options, especially for lower-income households. Embracing decentralized residential electricity generation may offer broader benefits, such as enhanced energy security and grid stability. Nonetheless, PV and BESS systems are not a universal solution and may require complementary electricity saving and load peak reduction measures, especially during winter, such as smart charging or dynamic pricing strategies during peak hours, to maximize their cost-saving effectiveness.

Essay II quantifies the imbalance in EV-charging-related grid reinforcement costs between lower- and higher-income neighborhoods. Our analysis reveals that higher-income neighborhoods experience over 12 times more grid overloads than lower-income neighborhoods across various grid types. Consequently, the stronger need for grid reinforcements puts higher-income neighborhoods at the top of grid operators' agendas, potentially limiting future charging network access in lower-income areas. While grid reinforcement costs for higher-income neighborhoods are 50% higher in rural areas, the disparity is even more pronounced in suburban and urban areas, reaching up to approximately 3,300% and 480%, respectively. At the EU level, these cost discrepancies could potentially reach €14 billion. In the current tariff setting, these grid reinforcement costs would be covered through an across-the-board electricity price increase. This approach may be viewed as inequitable regarding the principle of fairness according to the contribution, as these grid reinforcement costs can be disproportionately traced back to higher-income neighborhoods. Policymakers should consider implementing dynamic electricity or grid cost tariffs like time-of-use or load-based pricing to prevent burdening all electricity consumers with these costs. Since EV adoption strongly influences grid cost asymmetries, policymakers could explore income-dependent EV subsidies or promote charging network access for lower-income groups to address the identified inequities. Our findings on inequitable EV-related grid cost allocation contribute to the broader discourse on energy inequity, which has gained global importance in recent years. With energy and electricity prices rapidly increasing due to the Ukraine war, lower-income households in Europe are disproportionately affected by the increased energy costs. With energy poverty affecting lower-income and even middle-class households, government relief measures tailored to income levels may be necessary to ensure equitable cost allocation and alleviate the financial strain on vulnerable households. Current energy crisis relief efforts often fall short of addressing these goals.

In Essay III, we detail the core market design criteria and market development regulation for an efficient hydrogen commodity market in Europe. Employing the inductive approach of the GTM and based on 16 semi-structured interviews of organizations across the hydrogen value chain, we offer a comprehensive perspective, enriching the limited literature on hydrogen market design. We identify three key areas essential to be covered in the European hydrogen market design: Market development policy measures, necessary infrastructure regulations, and hydrogen and certificate trading. Our study provides novel insights and implications on controversially discussed hydrogen market design questions. We urge policymakers to promptly address regulatory uncertainty, provide direct financial support through CAPEX subsidies, and push the profitability of hydrogen business models through, e.g., a CO_2 price increase, contracts for difference, tax breaks, or quotes. Additionally, we stress the importance of avoiding overly strict green electricity use regulations, such as in Article 27 of the delegated act (RED II), as they could impede hydrogen market growth. Drawing parallels to the natural gas market, we advocate introducing fundamental regulations like third-party access, unbundling, and the entry-exit system. Such regulation should be introduced either early on or after a grace period, allowing faster market development. Cross-subsidization of infrastructure between natural gas and hydrogen, along with EU-wide feed-in regulations, should be explored. Energy exchanges can play a crucial role in facilitating hydrogen market development by introducing hydrogen price indices and offering hedging opportunities and price transparency. The adoption of a book and claim system on at least an EU scale should be introduced to represent the sustainability of hydrogen. Our findings offer valuable guidance for policymakers, aiding in the development of effective measures to support hydrogen market growth, market design, and infrastructure regulation. Additionally, we aid natural gas and future hydrogen infrastructure providers in gaining a more detailed understanding of potential future infrastructure regulation. Leveraging our recommendations, energy exchanges can tailor their offerings to meet the emerging demands of the hydrogen market.

5.2 Future research

In my research projects presented in this dissertation, I cover multiple challenges arising in road transport electrification and hydrogen market development. These challenges include maintaining grid stability, improving renewable energy integration, ensuring energy equity, and mitigating market uncertainty. I also provide related policy measure recommendations. These new upcoming challenges and related mitigating policy measures are, however, very complex. Therefore, various related research questions still need to be covered. Below, I describe some of these open research topics related to each essay.

Essay I recommends supporting residential PV and battery systems to mitigate the negative grid stability impacts of increased EV adoption. While we simulate EV charging data based on real-life mobility behavior, future works could leverage the exponential uptake in EV sales of the past year to create new empirical EV mobility and charging data sets that do not only reflect the early adopter population group as in earlier years. As the number of residential PV installations, especially battery systems, has also increased tremendously in the last year (see, e.g., Bundesnetzagentur (2024) and Weniger et al. (2024)), a large-scale PV-EV interaction trial could be introduced to enhance current simulation-based approaches. Moreover, one could extend our analysis by combining our approach with research on optimized PV and battery sizing, as, for example, explored in ElNozahy et al. (2015b). We also recommend combining PV and battery systems with dynamic tariffs to further enhance their peak shaving effectiveness. This approach was recently investigated by Morell-Dameto et al. (2023), who found that certain dynamic network charges can support peak shaving and complement the PV and EV interaction.

In Essay II, we uncover a potential for inequitable grid reinforcement cost allocation caused by the higher EV charging loads of above-average income neighborhoods. Our analysis could be complemented by investigating the grid reinforcement cost impact of other socio-economic factors such as education, occupation, age or gender to improve the accuracy of grid reinforcement cost projections. As data at the intersection of mobility data and socio-economic data is sparse, one could again leverage the tremendous recent uptake in EV adoption to further enhance our understanding of the effects of socio-economic factors on EV charging. Our analysis further discusses appropriate electricity and grid cost tariff designs to mitigate grid reinforcement costs and support energy equity. This topic has gained popularity in the last year, with multiple researchers and organizations investigating the most suitable dynamic grid cost tariff approaches for these goals (see, e.g., Morell-Dameto et al. (2023), ACER (2023), Schittekatte et al. (2023) and Turka et al. (2024)). Turka et al. (2024) reference our findings in Essay II and search for an electricity tariff design that accounts for efficiency and equity. They recommend separating energy charges from network charges.

Essay III provides market design and regulation recommendations for the future European hydrogen market. These findings could be extended to other geographies or tested by quantitative methods such as surveys. As we aimed to provide a holistic perspective on key market design choices, future works could dive deeper into the implementation details of individual discussed regulatory measures. In recent months, the research field of hydrogen market design and regulation has gained momentum, as the EU is detailing the specifications of the European hydrogen market design (European Commission, 2023). Especially the correlation and additionality requirements of hydrogen production of RED II, as well as aiming for a holistic perspective on the future hydrogen market, are in focus (Giovanniello et al., 2024, Kemmerzell et al., 2024).

5.3 Concluding remarks

This dissertation offers new knowledge and solutions to future challenges associated with decarbonizing the transport and industry sector through mobility electrification and hydrogen use. Building upon a thorough literature review, I uncover that these two main emission mitigation strategies create new challenges: ensuring grid stability, optimizing renewable energy integration, mitigating the potential for energy inequity, and limiting market uncertainty. Within each essay, I analyze the impact of a selection of these challenges and derive related policy and regulatory measures accordingly.

Within Essay I, I focus on grid stability and renewable energy integration. In our work, PV and battery systems have the potential to significantly reduce EV-related grid costs while promoting renewable energy usage in all testes settings. Therefore, we recommend that policymakers promote residential PV and battery system installations through targeted subsidies and low-cost financing or rental options. In Essay II, I analyze the aspects of grid stability and energy equity. We find that the increased EV charging needs of higher-income neighborhoods could cause a potential inequitable grid cost allocation. Hence, mitigating measures such as dynamic electricity and grid tariffs or income-dependent subsidies should be explored. In Essay III, I aim to support the mitigation of market uncertainty in the emerging European hydrogen economy by deriving detailed hydrogen market design and regulation recommendations. We cover the areas of market development regulation, infrastructure regulation, and hydrogen and certificate trading.

With this dissertation, I offer policymakers, energy market players, and other researchers insights into significant upcoming challenges in the clean energy transition and promising mitigation approaches. Through these contributions, I wish to support advancing policy and research driving the clean energy transition and tackling climate change.

Appendix

A.4 Additional input data used in Essay I

A.4.1 Household size and households per building

Table A.1: Average distribution of household size per area type in Bavaria, Germany (Bayrisches Landesamt für Statistik, 2021).

Persons per household	Rural	Suburban	Urban
1	35%	40%	54%
2	35%	33%	27%
3	14%	12%	10%
4	12%	11%	7%
5 or more	4%	4%	2%

Table A.2: Average distribution of households per building in Bavaria, Germany (Statistisches Bundesamt, 2021).

Households per building	Rural	Suburban	Urban
1	70%	55%	53%
2	17%	13%	10%
3-6	9%	16%	14%
7-12	3%	12%	15%
13 or more	1%	4%	8%

A.4.2 Available rooftop area for PV installations

Table A.3: Average available rooftop area for PV installations (Mainzer et al., 2014).

Building type	**Flat roof**	**Slanted roof**
Single-household buildings	$38\,\mathrm{m}^2$	$33\,\mathrm{m}^2$
Double-household buildings	$38\,\mathrm{m}^2$	$38\,\mathrm{m}^2$
Multi-household buildings	$36\,\mathrm{m}^2$	$60\,\mathrm{m}^2$

A.5 Additional results derived in Essay I

A.5.1 Overload analysis

Table A.4: Average number (#) of line overloads in rural area.

Penetration level			**Average # of overloads in lines**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	0	0	0	0
20%	20%	2	-	-	-	0
20%	20%	3	-	0	-	0
40%	20%	2	0	0	0	2
40%	20%	3	0	0	0	1
40%	40%	1	1	0	1	2
40%	40%	2	0	0	0	1
40%	40%	3	0	-	0	1
60%	40%	2	3	0	2	7
60%	40%	3	1	0	1	5
60%	60%	1	4	2	4	10
60%	60%	2	3	0	2	7
60%	60%	3	1	0	1	4

Table A.5: Average number (#) of transformer overloads in rural area.

Penetration level			**Average # of overloads in transformer**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	2	1	1	6
20%	20%	2	1	0	1	4
20%	20%	3	0	0	0	2
40%	20%	2	13	1	11	42
40%	20%	3	6	1	4	30
40%	40%	1	20	11	21	50
40%	40%	2	14	1	11	36
40%	40%	3	2	0	1	22
60%	40%	2	54	4	40	118
60%	40%	3	17	1	11	78
60%	60%	1	80	45	83	152
60%	60%	2	52	4	38	103
60%	60%	3	12	0	8	52

Table A.6: Average number (#) of line overloads in suburban area.

Penetration level			**Average # of overloads in lines**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	0	0	0	0
20%	20%	2	0	0	0	0
20%	20%	3	0	0	0	0
40%	20%	2	1	0	1	4
40%	20%	3	1	0	1	3
40%	40%	1	2	1	2	4
40%	40%	2	1	0	1	4
40%	40%	3	1	0	0	3
60%	40%	2	8	1	5	21
60%	40%	3	4	1	2	17
60%	60%	1	10	4	10	24
60%	60%	2	6	0	4	20
60%	60%	3	2	0	1	15

Table A.7: Average number (#) of transformer overloads in suburban area.

Penetration level			**Average # of overloads in transformer**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	-	-	-	-
20%	20%	2	-	-	-	-
20%	20%	3	-	-	-	-
40%	20%	2	0	-	-	0
40%	20%	3	0	-	-	0
40%	40%	1	0	-	0	0
40%	40%	2	-	-	0	0
40%	40%	3	-	-	-	0
60%	40%	2	0	0	0	1
60%	40%	3	0	-	0	1
60%	60%	1	0	0	0	1
60%	60%	2	0	0	0	1
60%	60%	3	0	0	-	1

TABLE A.8: Average number (#) of line overloads in urban area.

Penetration level			Average # of overloads in lines			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	0	0	0	1
20%	20%	2	0	0	0	1
20%	20%	3	0	0	0	1
40%	20%	2	2	1	2	6
40%	20%	3	2	1	2	6
40%	40%	1	4	2	3	8
40%	40%	2	2	0	2	5
40%	40%	3	1	0	1	5
60%	40%	2	8	1	7	22
60%	40%	3	5	1	4	21
60%	60%	1	11	8	14	26
60%	60%	2	7	1	7	20
60%	60%	3	3	1	3	18

Table A.9: Average number (#) of transformer overloads in urban area.

Penetration level			**Average # of overloads in transformer**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	0	0	0	0
20%	20%	2	0	0	0	0
20%	20%	3	0	0	0	0
40%	20%	2	1	0	1	3
40%	20%	3	0	0	0	3
40%	40%	1	1	1	1	3
40%	40%	2	1	0	0	2
40%	40%	3	0	0	0	2
60%	40%	2	4	0	3	15
60%	40%	3	2	0	1	14
60%	60%	1	6	3	6	15
60%	60%	2	4	0	3	12
60%	60%	3	1	0	1	10

A.5.2 Reinforcement cost analysis

TABLE A.10: Average grid reinforcement costs in rural area.

Penetration level			Average grid reinforcement costs			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	€10,680	€8,578	€10,717	€21,595
20%	20%	2	€6,443	€674	€6,867	€17,802
20%	20%	3	€2,713	€67	€1,962	€13,073
40%	20%	2	€24,739	€11,075	€24,004	€28,033
40%	20%	3	€18,951	€6,371	€16,422	€27,517
40%	40%	1	€26,523	€23,801	€26,213	€28,273
40%	40%	2	€24,149	€5,152	€23,403	€27,479
40%	40%	3	€10,559	€607	€8,381	€24,347
60%	40%	2	€29,670	€17,175	€28,874	€31,775
60%	40%	3	€25,631	€5,715	€23,991	€30,345
60%	60%	1	€30,300	€28,501	€30,828	€32,203
60%	60%	2	€29,573	€15,291	€28,585	€31,003
60%	60%	3	€16,618	€3,399	€12,676	€27,533

Table A.11: Average grid reinforcement costs in suburban area.

Penetration level			**Average grid reinforcement costs**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	€288	€140	€264	€1,068
20%	20%	2	€255	€22	€127	€864
20%	20%	3	€71	€18	€62	€807
40%	20%	2	€3,119	€1,099	€2,982	€8,491
40%	20%	3	€1,707	€1,091	€1,552	€7,367
40%	40%	1	€3,450	€1,630	€3,263	€10,254
40%	40%	2	€2,322	€230	€2,691	€7,882
40%	40%	3	€1,060	€65	€936	€5,015
60%	40%	2	€18,948	€2,897	€16,986	€49,074
60%	40%	3	€10,938	€1,878	€8,986	€39,699
60%	60%	1	€29,914	€11,020	€26,191	€50,788
60%	60%	2	€16,779	€1,800	€12,208	€44,692
60%	60%	3	€5,580	€286	€5,148	€26,104

TABLE A.12: Average grid reinforcement costs in urban area.

Penetration level			**Average grid reinforcement costs**			
EV	***PV (& BESS)***	**Case**	***March***	***June***	***September***	***December***
20%	20%	1	€297	€107	€235	€1,562
20%	20%	2	€183	€5	€184	€863
20%	20%	3	€113	€5	€123	€783
40%	20%	2	€5,258	€1,594	€5,070	€13,625
40%	20%	3	€4,221	€973	€3,752	€12,547
40%	40%	1	€8,072	€4,462	€7,523	€15,935
40%	40%	2	€4,846	€1,419	€4,851	€12,436
40%	40%	3	€1,591	€527	€1,680	€8,595
60%	40%	2	€25,516	€3,529	€25,714	€50,469
60%	40%	3	€13,986	€2,399	€12,333	€41,945
60%	60%	1	€32,647	€18,712	€33,642	€58,171
60%	60%	2	€24,491	€2,850	€22,591	€47,354
60%	60%	3	€8,702	€992	€8,882	€35,002

A.6 Additional input data used in Essay II: Household size and households per building

TABLE A.13: Average distribution of household size per area type in Bavaria, Germany (Bayrisches Landesamt für Statistik, 2021).

Persons per household	**Rural**	**Suburban**	**Urban**
1	35%	40%	54%
2	35%	33%	27%
3	14%	12%	10%
4	12%	11%	7%
5 or more	4%	4%	2%

Table A.14: Average distribution of households per building in Bavaria, Germany (Statistisches Bundesamt, 2021).

Households per building	Rural	Suburban	Urban
1	70%	55%	53%
2	17%	13%	10%
3-6	9%	16%	14%
7-12	3%	12%	15%
13 or more	1%	4%	8%

A.7 Additional results derived in Essay II: Breakdown of grid reinforcement costs asymmetries

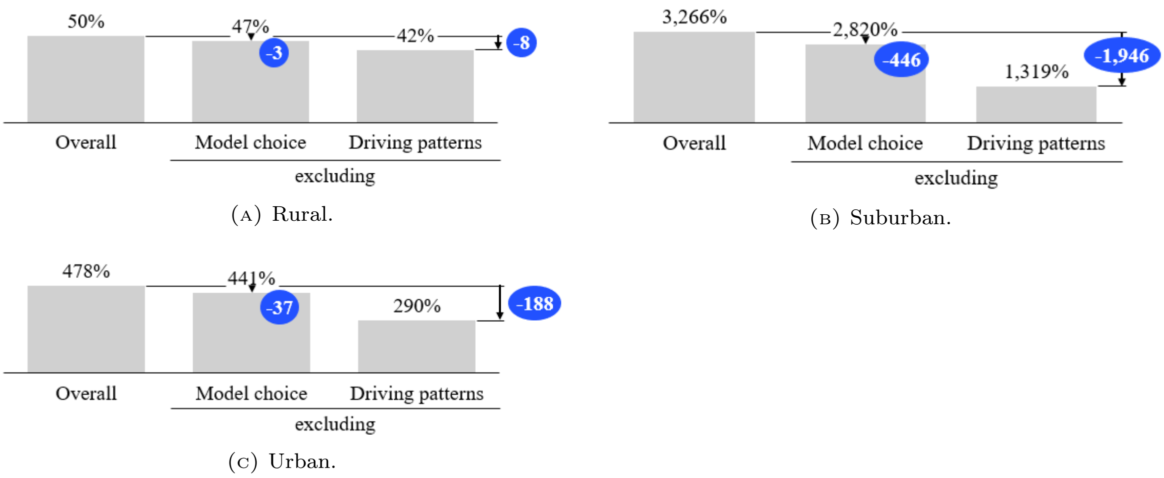


Figure A.1: Breakdown of grid reinforcement costs asymmetries for all area types.

A.8 General final semi-structured interview guideline used in Essay III

Aufnahme starten

Einführungsfragen/Wasserstoffverwendung/Chancen

- Welche **Rolle** spielt Wasserstoff **aktuell** bei UX?
- Was bestehen bei UX für **Pläne** hinsichtlich der Rolle von Wasserstoff und lassen sich diese Pläne in konkrete **Zeithorizonte** einteilen?
- Was sind **Gründe für die Abweichung** zwischen der aktuellen Rolle und der zukünftigen Rolle von Wasserstoff bei Ihnen im Unternehmen?
    - Bezüglich des Erreichens eines hohen **Volumens** wird häufig vom **Henne-Ei-Problem** gesprochen. Wie kann dieses Problem Ihrer Meinung nach gelöst werden?
    - Was sind geeignete **Maßnahmen auf Angebot- und Nachfrageseite**?
    - Wie beurteilen Sie die Notwendigkeit von **politischen Interventionen** (z.B. Subventionen, Quoten) dabei?
- Welche **Chancen und Vorteile** sehen Sie im Allgemeinen für Europa in der Etablierung eines effizienten Wasserstoffmarkt?

Commodity-Trading:

- Welche konkreten **Vorteile** sehen Sie in einer Entwicklung von Wasserstoff hin zu einem **Commodity-Handelsprodukt**?
- Was sind die **Voraussetzung** für die Entwicklung von Wasserstoff hin zu einer Commodity?
- **Wann** erwarten Sie, dass Wasserstoff **effizient** als Commodity **gehandelt** wird?

Analogien Gasmarktdesign:

- Welche **Analogien und „Lessons learned“** gibt es, z.B. hinsichtlich wesentlicher regulatorischer Rahmenbedingungen wie der Entflechtung und dem diskrimminierungsfreien Zugang, zwischen dem Gasmarkt und dem Wasserstoffmarkt?
- **Zu welchem Zeitpunkt** sollten Regulierungen eingeführt werden?
- **Welche Regulierungen** werden notwendig sein, um Monopole aufzuheben und den Wettbewerb durch den Zugang der Infrastruktur durch andere Marktteilnehmer zu erhöhen (z.B. **Entflechtung und Third Party Access**)?

  - Welche Regulierungen sehen Sie im Rahmen des Third Party Access, um diskriminierungsfreien Zugang gewährleisten zu können (z.B. **Bilanzierungssystem, Regelenergie**)?
- Für verstärkten Wettbewerb war im Erdgasmarkt der Umstieg des Zugangsmodell vom Punkt-zu-Punkt Modell, also einer klaren Quelle-Senke-Beziehung, zum **Entry-Exit Modell**, bei dem Gas an jedem beliebigen Punkt ein- und ausgespeist werden kann. **Welches Zugangsmodell** halten Sie für den Wasserstoffmarkt angemessen und warum?
  - Wie kann der **Handel von Wasserstoff dabei über Marktgebiete** hinweg funktionieren?
- Welchen Einfluss sehen Sie in der potenziellen **Verwendung von Erdgaspipelines** für das Wasserstoffmarktdesign und die Entwicklung hin zu einer Commodity?

Handelssystem/Börse:

- Wie beurteilen Sie die **Notwendigkeit und Aussicht von Börsenkontrakten** für Wasserstoff und worin liegt der Mehrwert?
- Sehen Sie **Marktplätze** (z.B. Börse, OTC), **Handelsprodukte** (z.B. Spot, Futures) und die Möglichkeit Handelsgeschäfte sowohl **finanziell als auch physisch** zu erfüllen analog zum Gasmarkt oder wird es Unterschiede geben? Falls ja welche?
- Inwieweit sehen Sie einen Bedarf nach **Zertifizierungen oder Herkunftsnachweise** für die verschiedenen Farben des Wasserstoffes und deren unterschiedlichen CO2-Ausstöße?

Musterwasserstoffmarkt/Kriterien/Entwicklung:

- Wie sieht Ihrer Meinung nach die **optimale Wertschöpfungskette** und deren **Funktionsweise** für einen effizienten Wasserstoffmarkt aus? Skizieren Sie diese gerne gedanklich.
- Welche wesentlichen **Entwicklungsstufen mit welchen Zeithorizonten** hin zu diesem Musterwasserstoffmarkt erwarten Sie für Europa?
- Was sind Ihrer Meinung nach die **Kernkriterien**, damit sich ein effizienter Wasserstoffmarkt mit Wasserstoff als Commodity etablieren kann?
- Sehen Sie dabei bestimmte potenzielle **Gefahren**, die unbedingt vermieden werden müssen?

Bonusfragen

- Welche weiteren Gedanken würden Sie gerne noch zu diesem Thema teilen?
- Welche anderen Fragen wären zu diesem Thema noch interessant und hätten gestellt werden können?

Ende

- Bedankung
- Angebot Ergebnisse zu teilen
- LinkedIn Vernetzung

A.9 Additional results derived in Essay III

A.9.1 Hydrogen market development

We first share our interviewees' perspectives on the hydrogen market drivers, challenges, and development phases. Unsurprisingly, sustainability and decarbonization are the most commonly mentioned drivers for the hydrogen market development. "It is clear that without hydrogen, all studies, all institutes agree, it will not be possible to achieve the climate policy goals by 2050." (IS15F: 15). IS07M stresses the urgent need for an expanded hydrogen market by saying: "We do not have time either, so we can not say we will try it out again for another 50 years, but we want to get it up and running in the next five years." (IS07M: 13). The interviewees emphasize that hydrogen demand is further driven by end-users who increasingly ask for sustainable products. The interviewees expect rapid development in hydrogen technologies with scalability as the main driver. U14M lets us know that "according to our analyses, I do not think we have a major bottleneck [in the development of technology]." (U14M: 17). C03M adds that this development will be driven by the fact that "(...) cost degressions are expected (...), and on the other hand (...) natural gas has become incredibly expensive." (C03M: 11). The experts see the policymakers' support as another driver and observe that "(...) hydrogen experiences a great attention politically. And somehow, the politicians in Berlin and Brussels also want hydrogen." (IS15F: 31). Besides the political support, energy partnerships between countries and cooperation between organizations and companies will further advance the hydrogen market development. Regarding the hydrogen color code, the interviewees agree that green hydrogen is the long-term goal and the only option to achieve the sustainability goals. However, blue hydrogen can be used as a transition medium to satisfy the high expected demand in the upcoming years.

One key issue slowing down the market development is "(...) actually the chicken-and-egg problem. The off-takers say we want to demand hydrogen, the producers say we would produce something, but who starts?" (U10M: 46). Nonetheless, they emphasize that the current high costs of hydrogen compared to its conventional alternatives limit its applications, as industries and companies in strong global competition will not purchase hydrogen. Apart from the production costs, "(...) the logistics of transporting hydrogen are very expensive today." (ID02M: 11). Another challenge "(...) in Europe and especially in Germany is uncertainty for investments. The big core problem is that we are in the energy sector. That means we are talking about investment cycles of 30 to 60 years. Everything that goes hand in hand with uncertainty, especially in capital-intensive industries, is a poison for the ultimate implementation of projects." (ID09M: 5).

Regarding the hydrogen market development phases, our interviewees agree with the findings in the literature as laid out in Section 4.2.2. The interviewed experts predict that within the next years, "(...) there will initially be submarkets, island markets, which are characterized by little or no liquidity and few participants." (E04M: 5). They suggest "(...) build[ing] an ecosystem locally with hydrogen production, storage, distribution, and consumption in one place, and then you can make the breakthrough that you can scale it up." (ID02M: 15). This phase is characterized by ID02M as the "(...) Valley of Death. So this time where everyone pays, on the manufacturer side, on the transport side, on the user side." (ID02M: 17). This view is shared by ID06M, who adds: "The transition phase is much more challenging than the design of the final state." (ID06M: 13). As the next phase, the interviewees expect that "(...) these clusters become somewhat larger islands, then there is connectivity between the islands, and at some point, you have reached a stage where you have such a backbone then, that may be in 2030." (IS05M: 7). By this time, they predict green hydrogen to become competitive with grey hydrogen. Imports will play an increasingly important role. "From 2030 onwards, I would like to talk about an international hydrogen market, which will, of course, bring about another change." (C03M: 9). In this international hydrogen market, the pipeline network and derivatives imports will increase further.

A.9.2 Hydrogen value chain

This section gives the interviewees' perspective of hydrogen's value chain. We focus on green hydrogen, as the EU strongly prioritizes this hydrogen type. The interviewees agree that the amount of RES has to be expanded. The experts see the possibility of establishing Power Purchase Agreements (PPA) between RES operators and hydrogen producers. Hydrogen might grant Europe higher energy independence, but the interviewees agree that imports from non-EU regions will still be necessary. C16M confirms that "[at least] Germany will not be able to meet this demand itself and will therefore have to import." (C16M: 43).

Another key part of the value chain is the required infrastructure for hydrogen distribution and storage. "There is still some disagreement about the infrastructure. Are we going to build our own infrastructure or are we going to use the natural gas network?" (C16M: 9). ID06M shares the following answer: "(...) this transition phase is characterized, by the fact that we have to have two dedicated distribution networks, (...) [and a] gradual replacement of the natural gas network." (ID06M: 13). The main benefit of using natural gas pipelines is that it "(...) is possible at a quarter (...) of the cost (...) compared to what you have to spend for new pipelines." (ID02M: 31). The natural gas pipeline network is confirmed to be a huge asset. "For gas transmission system operators, hydrogen is strategically a very important issue in order to ensure or defend the value of the asset base." (C01M: 7). Sufficient storage represents "(...) the next step towards a liquid market." (U12M: 33).

The interviewees have a clear view of prioritized hydrogen applications. They "(...) see hydrogen being used most where there are few alternatives to decarbonization. Hydrogen is still a valuable commodity, at least for the next few years" (U10M: 42). According to the interviewed experts, the steel industry should have highest priority, as it "(...) is difficult to decarbonize the steel industry in any other way than via green hydrogen (...)." (ID08M: 39). ID06M supports this claim "(...) because there are relatively few locations, large consumers (...) and the process is highly effective (...) in terms of CO_2 savings." (ID06M: 13). Within the cement industry, "(...) the theoretical potential is great, the practical potential from the discussions in which we also sit on various committees is currently estimated to be rather low." (ID11M: 7). Still, hydrogen has the potential to reduce 40% of the GHG emissions emerging in the production process. Furthermore, hydrogen has increased potential in areas "(...) such as material use in chemical or petrochemical processes." (C01M: 5). U14M considers refineries one of the most interesting applications to replace biofuels in refineries and says, "(...) you can also use green hydrogen instead of biofuels, (...) that would actually become economical very quickly because you are not competing with gray hydrogen here, but with biofuels, and they are also expensive (...)." (U14M: 29). The interviewees "(...) think it [(hydrogen)] is particularly interesting when it comes to fertilizers (...)" (IS07M: 29). IS13M adds that "(...) ammonia for fertilizer production is one of the largest consumers of natural gas (...)." (IS13M: 3) and rising natural gas prices push fertilizer producers towards alternative fuels. Regarding using hydrogen in the mobility sector, the interviewees share the opinion that hydrogen "(...) is conceivable in the case of heavy goods traffic or long-distance buses or trains." (ID08M: 45) as well as for ships and airplanes. Re-electrification is an application given a low priority because "the efficiency over the entire chain from green electricity back to green electricity is extremely poor, even compared to other technologies (...)" (C01M: 5). Furthermore, the experts suggest that "it is not yet clear to what extent hydrogen will actually be used in the heating market in the future" (U12M: 23).

A.9.3 Graphical comparison of our findings from Essay III and key hydrogen market design and trading literature

Hydrogen Market Design Criteria	Key Finding	Core Literature on Hydrogen Market Design Topics Addressed in this Study																			Average
		European Comission (2020a)	Council of the European Union (2018)	Council of the European Union (2023)	Council of the European Union (2023b)	Council of the European Union (2023a)	Bundesverband der Energie- und Wasserwirtschaft (2021b)	Mulder (2019)	Hydrogen Europe (2021b)	Trinomics / LBST (2020)	Neuhauser (2020)	Bundesnetzagentur (2020b)	Agora (2021)	Deutsche Energie-Agentur (2022)	IRENA (2023)	Ruhnau (2023)	Farell (2023)	Van der Spek (2023)	Dawin (2023)	Lagoia (2023)	
Political Support and Market Development	Investment Certainty by Politics	+	/	/	+	+	/	+	+++	+	+++	+++	/	/	/	/	+++	+++	+++	+++	+++
	Focus Direct Financial Support on CAPEX	/	/	/	/	/	/	/	---	/	---	/	---	/	/	/	+	/	/	/	---
	Revision of Green Electricity Criteria	/	/	?	/	/	/	/	/	/	+	/	/	+	/	+++	/	/	/	/	+
Infrastructure Regulations	Feed-in Regulations in Natural Gas Infrastructure	+	/	/	+++	/	+	/	+++	/	+++	+++	/	/	/	/	/	+++	/	/	+++
	Cross-Subsidization with Natural Gas	/	/	/	-	/	/	/	/	/	/	-	+	/	/	/	/	/	/	/	?
	Introduction (Time) of Key Regulations	+	/	/	+	+	+++	+	+	+++	/	+	+	/	/	/	/	/	/	/	+
Hydrogen and Certificate Trading	Price Indices for Price Transparency	/	/	/	/	/	/	/	/	+	/	/	/	/	/	/	/	/	/	/	/
	Market Efficiency through Energy Exchanges	+	/	/	+	+	+	+	/	+	/	/	/	/	/	/	/	/	+	/	+
	Certificate Trading based on the Book and Claim System	/	---	/	/	---	+++	+++	+++	/	/	+++	+++	---	+	/	/	/	/	/	+

Legend	+++ = strongly agree	+ = rather agree	- = rather disagree	--- = strongly disagree	? = unclear	/ = no information found

Figure A.2: Graphical comparison of our findings and key literature.

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