

## Comparative Analysis of Infrastructures: Hydrogen Fueling and Electric Charging of Vehicles

Martin Robinius, Jochen Linßen, Thomas Grube, Markus Reuß, Peter Stenzel,  
Konstantinos Syranidis, Patrick Kuckertz and Detlef Stolten

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Elektrochemische Verfahrenstechnik (IEK-3)

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## Summary for Policy Makers

Electric drivetrains are key elements of low carbon energy-efficient transport based on renewable energy sources. Furthermore, a transportation system with zero local emissions will substantially improve people's quality of life, especially in urban areas currently struggling with air quality issues. Both Battery and hydrogen fuel cell electric vehicles feature these important characteristics. However, large scale integration of these vehicle technologies requires new infrastructures.

### Objective and approach

The goal of the study is to perform a detailed design analysis of the required infrastructure for supplying battery and fuel cell electric vehicles in Germany at multiple scales. The underlying question concerns the investments, costs, efficiencies and emissions for an infrastructure capable of supplying between one hundred thousand to several million vehicles with hydrogen or electricity. At present, both technologies are in the initial stage of their market development and are posed to take advantage of the unavoidable surplus electricity that characterizes renewable dominated energy systems. In any case, an effective infrastructure is required to make this energy available. However, at present the design of an applicable infrastructure is unclear. To illuminate this topic, the approach of the infrastructure analysis is transparent and the results of the analysis support a facts-based discussion which can simply be adapted to the growing level of experiences.

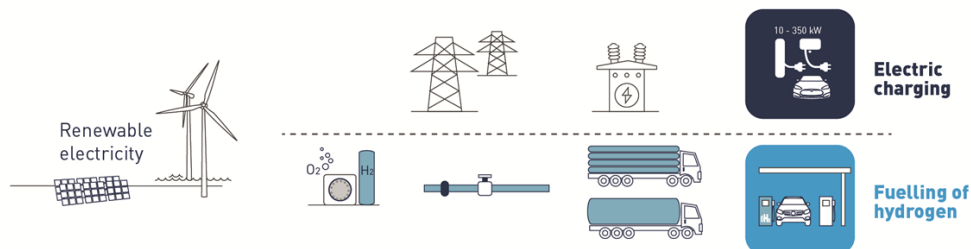


Figure 0-1: Schematic diagram of considered infrastructure set-ups.

As part of the study, an extensive meta-analysis of existing studies on infrastructure requirements for each of the technologies is performed. However, with respect to higher market penetration in particular, these studies have proven to be insufficient or contain non-transparent data. Consequently, the main body of the analysis revolves around the study's own scenario calculations for infrastructure design and techno-economic analysis.

## Results

The scenario analyses demonstrate that, for low market penetration levels of a few hundred thousand vehicles, the costs of infrastructure roll-out are essentially the same for both technology pathways. Hydrogen is found out to be more expensive during the transition period to electricity-based generation via electrolysis and geological storage, both of which are needed to access renewable hydrogen from surplus electricity. In the scenario for charging battery electric vehicles no seasonal storage option is considered and grid

electricity for charging is generated in part by non-renewable energy sources. If vehicle penetration increases up to 20 million vehicles in the base case scenario, a battery charging infrastructure would cost around € 51 billion, making it more expensive than hydrogen infrastructure, which comes in at around € 40 billion. Additionally, securing supply based on renewable electricity requires a consideration of seasonal storage options. For the 100 % excess electricity-based hydrogen production, seasonal storage capacity is set to bridge 60 days at low renewable electricity generation. An adequate solution is required to achieve the same level of security of supply for electric charging based on renewable energy sources.

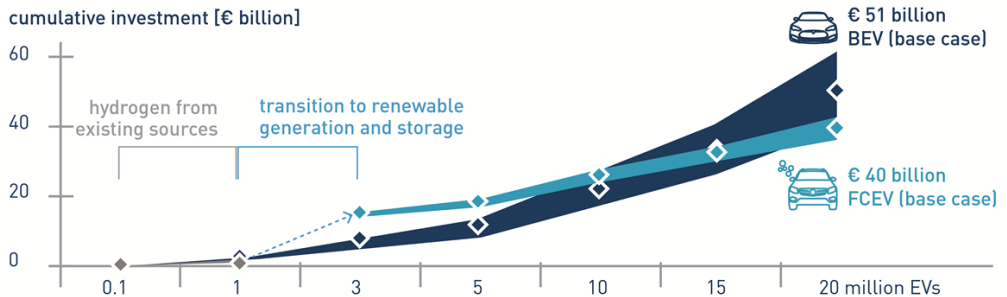


Figure 0-2: Comparison of the cumulative investment of supply infrastructures.

The mobility costs per kilometer are roughly same in the high market penetration scenario at 4.5 €/km for electric charging and 4.6 €/km for hydrogen fueling. Because hydrogen permits the use of otherwise unusable renewable electricity by means of on-site electrolysis, the lower efficiency of the hydrogen pathway is offset by lower surplus electricity costs.

For the scenario with 20 million fuel cell electric vehicles approx. 87 TWh of surplus electricity for electrolysis and 6 TWh of grid electricity for transportation and distribution are required. On the other hand, charging 20 million battery electric vehicle accounts for an electricity demand of approx. 46 TWh out of the distribution grid.

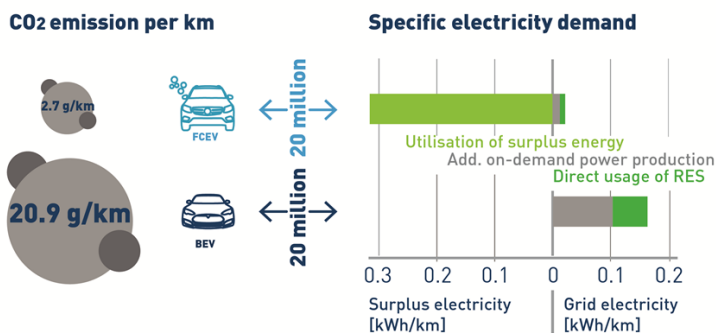


Figure 0-3: Comparison of specific energy demand and CO<sub>2</sub> emissions.

The efficiency of the charging infrastructure is higher, but limited to flexibility covering short-term periods. The available surplus energy in the assumed renewable dominated electricity scenario exceeds by factor of three to six the demand to supply 20 million electric vehicles.

According to the use of surplus electricity, renewable and fossil electricity out of the grid, the corresponding CO<sub>2</sub> balance for the high penetration scenario shows low specific emissions in comparison to the use of fossil fuels. The hydrogen infrastructure with the inherent seasonal storage option has lower CO<sub>2</sub> emissions because of the high use of renewable surplus electricity. The application of controlled charging can improve the use of surplus and renewable electricity, thus decrease specific CO<sub>2</sub> emissions of battery electric vehicles.

## Conclusions

The conclusion can be drawn that electric charging and hydrogen fueling are key to realize low carbon, clean and renewable energy based transportation concepts.

A smart and complementary combination of the electric charging and the hydrogen refueling infrastructure can join the strengths of both and can avoid non-sustainable solutions with low systems relevance or efficiency. Taking advantage of low hanging fruits like overnight charging of battery electric vehicles for short distance travel and meeting the challenges in long distance and heavy duty transport by fuel cell electric vehicle and hydrogen refueling can be beneficial with regard to systems solutions. Insofar, a hybrid strategy for the roll-out of both infrastructures will help to maximize energy efficiency and to optimize the use of renewable energy resources while minimizing CO<sub>2</sub> emissions over a broad range of purposes and transportation modes. Both infrastructures require a small amount of investment compared to other infrastructures (e.g. roll-out of renewable electricity generation or the maintenance and expansion of transportation routes, see figure 6-31).

While electric charging infrastructure allows for higher efficiency, hydrogen infrastructure roll-out for transportation enables further large-scale applications in other sectors like industry. Understanding hydrogen fueling infrastructure as energy systems solution can unleash the full potential of realizing sector coupling.

## Zusammenfassung für Entscheidungsträger

Elektrische Antriebe sind der Schlüssel zu einem klimafreundlichen Verkehr basierend auf erneuerbaren Energien. Die lokale Emissionsfreiheit des Verkehrs ist eine weitere wichtige Voraussetzung, um zukünftig die Lebensqualität vor allem in Ballungszentren erheblich zu verbessern. Sowohl Batterie- als auch Brennstoffzellen-Fahrzeuge erfüllen diese wichtigen Kriterien. Für beide Technologiepfade sind jedoch neue Infrastrukturkonzepte notwendig.

### Zielsetzung und Vorgehen

Zielsetzung der Analyse ist eine detaillierte Auslegung und Untersuchung der notwendigen Infrastrukturen für unterschiedliche Marktdurchdringungen von batterieelektrischen Fahrzeugen sowie von Wasserstoff-Brennstoffzellen-Elektrofahrzeugen in Deutschland. Die Studie beantwortet die Fragen, wie hoch die Investitionen, Kosten, Wirkungsgrade und Emissionen der jeweiligen Infrastrukturen zur Versorgung von einigen Hunderttausend bis hin zu mehreren Millionen Fahrzeugen mit Strom oder Wasserstoff sind. Aktuell stehen beide Technologien noch am Anfang ihrer Marktentwicklung und die Auslegung sowie Anpassung der benötigten Infrastruktur an die jeweilige Marktdurchdringung der Fahrzeuge ist unklar. Weiterhin müssen die Infrastrukturen auch Optionen zur Integration von Strom-Überschüssen bieten, welche zukünftig in von erneuerbaren Energien dominierten Energiesystemen entstehen werden. Die vorliegende Studie beinhaltet eine detaillierte Auslegung der Infrastrukturen und deren Komponenten unter Offenlegung der getroffenen Annahmen. Hierdurch wird eine transparente Faktengrundlage geschaffen, die mit neuen Erfahrungswerten angepasst werden kann und eine faktenbasierte Diskussion ermöglicht.

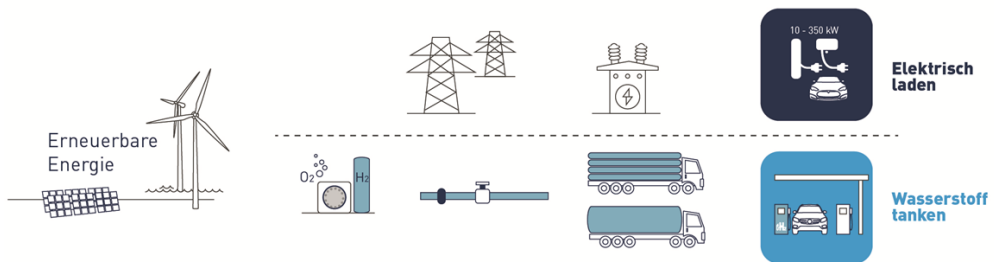


Abbildung 0-1: Schematische Darstellung der untersuchten Versorgungsinfrastrukturen.

Wichtiger Bestandteil der Studie ist eine umfangreiche Meta-Analyse von bestehenden Studien mit Aussagen zum Infrastrukturausbau beider Technologien. Basierend auf der Erkenntnis, dass vor allem für eine hohe Marktdurchdringung die existierenden Studien nicht ausreichen und die Datenlage teilweise intransparent ist, werden detaillierte eigene Szenario-Berechnungen zur Infrastrukturauslegung durchgeführt und techno-ökonomisch analysiert.

## Ergebnisse

Die Analyse der Szenarien zeigt, dass die Investitionen in den Infrastrukturausbau für beide Technologiepfade bei geringen Fahrzeugbeständen bis hin zu einigen Hunderttausend nahezu gleich sind. In der Übergangsphase erfolgt die Umstellung der Wasserstoff-erzeugung auf die ausschließliche Nutzung von regenerativem Überschuss-Strom, welche durch den Bau von saisonalen Wasserstoffspeichern zur Überbrückung von 60 Tagen flankiert wird. Das Konzept ermöglicht die Versorgung mit grünem Wasserstoff. In der Anfangsphase sind hierfür höhere Investitionen erforderlich als bei der Ladeinfrastruktur. Für das Laden der Batterie-Fahrzeuge ist in der Studie keine saisonale Stromspeicherung in der Stromversorgung berücksichtigt, die für eine sichere Versorgung mit 100 % erneuerbarem Strom notwendig wäre. Vergleicht man die kumulierten Investitionen beider Konzepte für eine hohe Marktdurchdringung von 20 Mio. Fahrzeugen, liegen die Investitionen für eine Ladeinfrastruktur mit rund 51 Mrd. € deutlich höher im Vergleich zur Wasserstoff-Infrastruktur mit rund 40 Mrd. €.

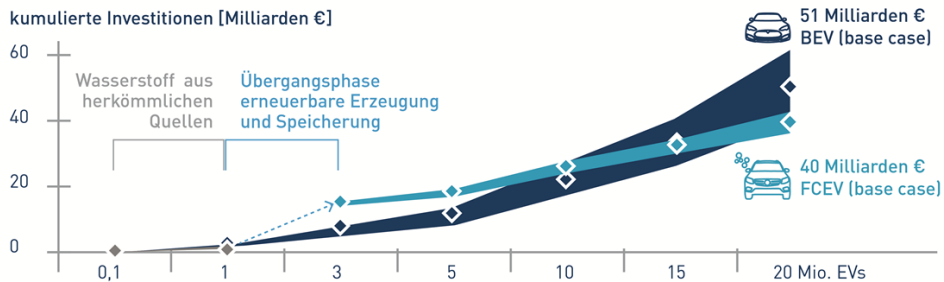


Abbildung 0-2: Vergleich der kumulierten Investitionen für den notwendigen Infrastrukturaufbau.

Die resultierenden Kilometer-spezifischen Kosten sind bei hohen Marktdurchdringungen für beide Versorgungskonzepte annähernd gleich. Sie liegen im Durchschnitt bei 4,5 €/km für das elektrische Laden und bei 4,6 €/km für den Wasserstoff. Da die elektrische Erzeugung und Speicherung des Wasserstoffs die Nutzung von sonst nicht nutzbarem erneuerbarem Strom direkt vor Ort ermöglicht, wird die geringere energetische Effizienz des Wasserstoff-Pfades annähernd durch den die niedrigeren Kosten des Überschuss-Strombezugs ausgeglichen.

Für das Szenario mit 20 Millionen Brennstoffzellen-Fahrzeugen werden 87 TWh Überschuss-Strom für die Elektrolyse und zusätzlich 6 TWh Strom aus dem Netz (Transport und Verteilung des Wasserstoffs) benötigt. Das Laden von 20 Millionen Batterie-Fahrzeugen erfordert 46 TWh Strombezug aus dem Verteilnetz. Die Effizienz der Ladeinfrastruktur und Fahrzeuge ist höher, aber die Flexibilität der Stromnachfrage ist auf kürzere Zeiträume begrenzt. Die Überschuss-Strommenge im unterstellten Energieversorgungsszenario mit hohen erneuerbaren Anteilen übersteigt den Bedarf zur Versorgung von 20 Millionen Fahrzeugen in beiden Infrastrukturfaden um den Faktor drei bis sechs.



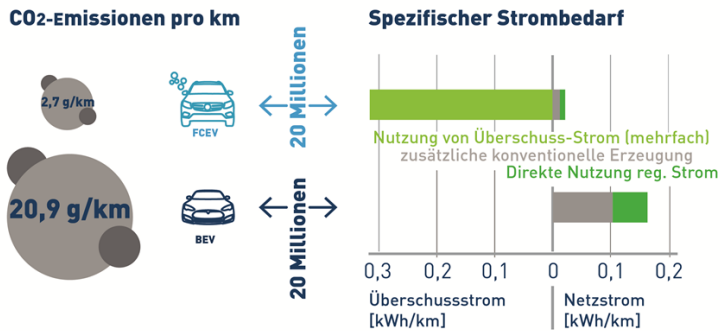


Abbildung 0-3: Vergleich der Kilometer abhängigen CO<sub>2</sub>-Emissionen und Strombedarfe bei 20 Millionen Fahrzeugen.

Durch die Nutzung von erneuerbaren Stromüberschüssen und Netzstrom mit hohen Anteilen an erneuerbaren Energien sind die kilometerspezifischen CO<sub>2</sub> Emissionen für beide Versorgungsoptionen gering im Vergleich zur Nutzung von fossilen Kraftstoffen. Die Wasserstoff-Infrastruktur mit inhärenter saisonaler Speicherung kann höhere Anteile überschüssiger, erneuerbarer Energien integrieren und ist daher bei der CO<sub>2</sub>-Reduktion im Vorteil. Jedoch kann eine auf die Verfügbarkeit von erneuerbarem Strom ausgerichtete Ladestrategie der Batterie-Fahrzeuge deren CO<sub>2</sub> Emissionen weiter mindern.

### Schlussfolgerung

Für den Verkehrsbereich ist zu schließen, dass beide Infrastrukturen wichtige Bausteine sind, um klimaverträgliche, saubere und erneuerbare Verkehrskonzepte zu realisieren.

Eine intelligente und komplementäre Kombination aus beiden Infrastrukturen kann die Stärken der Wasserstoff-Infrastruktur mit den Stärken des elektrischen Ladens verbinden und weniger zukunftsfähige Einzellösungen mit geringerer Systemfähigkeit oder Effizienz vermeiden. Vorteilhaft im Sinne von Systemlösungen kann eine Fokussierung auf das leichter zu erreichende Ziel der Übernacht-Ladung von Batterie-Fahrzeuge für den Kurzstreckenverkehr sein und die Herausforderungen im Langstrecken- und Schwerlastverkehr mit Wasserstoff anzugehen. Insofern kann eine Hybridstrategie zum Aufbau beider Infrastrukturen eine deutliche Steigerung der Nutzung von erneuerbaren Energien und der Effizienz sowie eine signifikante Minderung der CO<sub>2</sub>-Emissionen über möglichst viele Verkehrsbereiche und Einsatzzwecke hinweg ermöglichen. Die für die Realisierung notwendigen Investitionen sind für beide Infrastrukturen im Vergleich zu anderen Infrastrukturen (zum Beispiel Ausbau der erneuerbaren Stromerzeugung oder Erhalt und Ausbau von Verkehrswegen, Figure 6-31) gering.

Zwar besitzt die Ladeinfrastruktur eine höhere Energieeffizienz als der Wasserstoffpfad, allerdings wird eine Wasserstoff-Infrastruktur zukünftig als Schlüsselement zur erweiterten Nutzung von saisonalen Stromüberschüssen auch in anderen Energiesektoren z. B. Industrie gesehen. Aus Gesamtsystemsicht bietet Wasserstoff somit das Potenzial, auch sektorübergreifende Energieversorgungskonzepte (Sektorkopplung) zu realisieren.

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## 1 Introduction

The Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris in 2015 (COP21) committed to undertaking new ambitious global efforts to reduce greenhouse gas emissions (GHG) and limit global warming. By then, Germany had already established its own set of activities to support the transition from its current national energy system dominated by fossil fuels to a system with significantly fewer CO<sub>2</sub> emissions based on renewable energy, energy efficiency and energy sector coupling. The national goals for GHG reductions are stipulated in the German climate protection plan published in 2016 [1]. Other national goals for energy system transition, including detailed monitoring and measurements for this enduring process are integrated into the energy transition (Energiewende) concept [2].

Within the energy system, the transportation sector is key to achieving the ambitious climate protection goals and corresponding renewable energy goals. Important political objectives regarding transportation already form part of the Energiewende concept and aim at reducing final energy demand by 40 % compared to the year 2005. In addition, the German climate protection plan postulates a transportation system which is virtually non-reliant on fossil-based fuels and thus largely greenhouse gas-neutral by 2050. However, transportation's contribution to CO<sub>2</sub> reduction was a mere 2 % in 2015 (in relation to 1990) and thus far behind its ambitious goals. This underpins the immediate need for action.

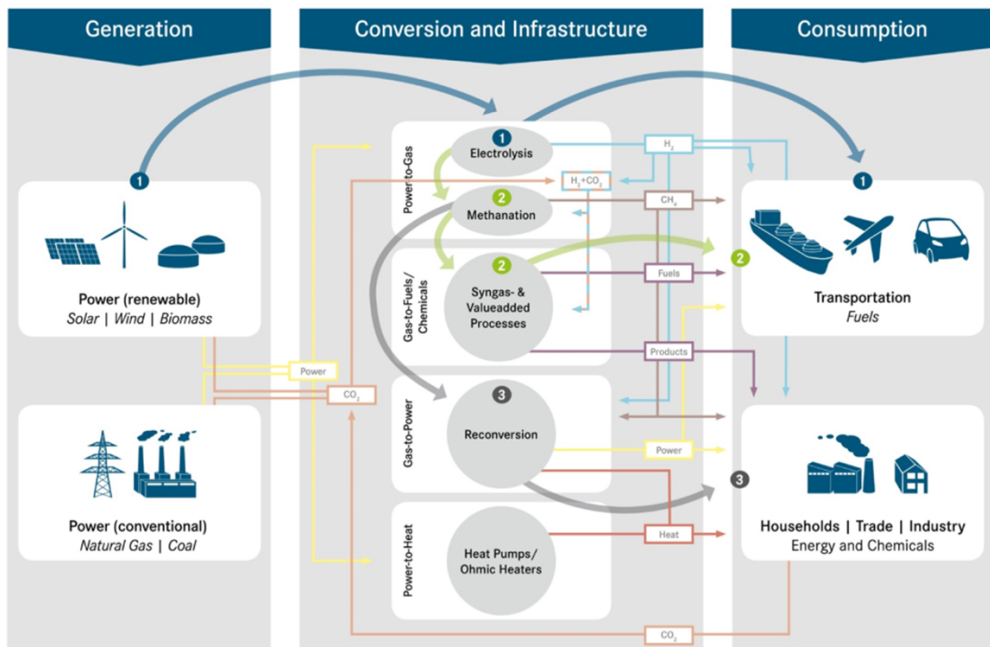


Figure 1-1: Schematic diagram of the Power-to-X concept [3].

Setting the transport sector on track towards sustainable and efficient mobility with due consideration for the social and economic criteria involved, requires a systemic approach – one that not only incorporates a change in mobility and settlement concepts, but a shift in

transportation modes (i.e. shift to rail), new fuel pathways and drivetrain concepts as well. Several studies, for instance the German Federal Government's mobility and fuel strategy [4] or the think tank Agora Verkehrswende [5], discuss future system designs of the national transportation system and consider one or more of the above-mentioned options.

An isolated analysis of the transportation sector without integration in the energy system lacks any further possibilities for say linking the two sectors. Transportation is one of the most promising elements of the so-called sector coupling concept (see Figure 1-1).

The concept of sector coupling is about adding new flexible electricity consumers to an electricity system dominated by Renewable Energy Sources (RES) generation. The non-dispatchable nature of wind and PV electricity output necessitates new flexible demand options and also storage solutions during excess situations. Shifting transport, residential, trade and industry's demand for energy away from fossil energy carriers to electricity or electricity-based fuels derived from RES can substantially reduce greenhouse gas emissions throughout the entire system [3].

If it is to produce no tailpipe emissions, especially in urban areas, and integrate renewable energy sources, transportation has no choice but to adopt electric drivetrains and electricity-based fuels. Only Fuel Cell Electric Vehicles (FCEV) and Battery Electric Vehicles (BEV) can do both and are therefore the go-to solutions. Electricity generation is the factor that determines the volume of emissions reduction and use of RES for the entire fuel chain. If the transport application requires fuels with higher energy density, like aviation or long-distance road haulage, then electricity-based hydrocarbon fuels (so called e-fuels) constitute additional options for enlarging GHG emissions reduction potential. Reaching GHG mitigation requires biogenic or captured CO<sub>2</sub> (e.g. power plants, industry or ambient air). The disadvantages of the e-fuel concepts, such as harmful local emissions and a drop in overall efficiency, will however be continuously improved but still remain [6].

Having grown over centuries, the transportation fuel supply chain comprises an extensive global infrastructure that includes exploration, conditioning, transport and distribution. To some extent, a shift to clean fuels like hydrogen and electricity will require new infrastructures and smart transition strategies. Even if the investments in new refueling or charging infrastructures are small in comparison to the volume of money required to replace the current vehicle stock with improved drivetrains [7], they still represent a major obstacle in the years ahead. On the one hand, appropriate infrastructure has to be in place to sustain acceptance for FCEV and BEV market penetration. But on the other, installing infrastructure before market penetration has reached a certain threshold will lead to these infrastructures being underutilized.

To be able to make a decision on the right strategies for tomorrow's fueling infrastructure, it is imperative to have fact-based knowledge about the level of investment required for hydrogen fueling and electric charging for varying levels of vehicle market penetration.

## 2 Objectives of the Study

Infrastructure investments are one of the main obstacles on the road to an energy switch to hydrogen and electricity, and thus to a green transportation system. Hence this study's focus on a comparative analysis of cumulative infrastructure costs for both fuel pathways. The object of the investigation is the passenger car sector in Germany. Germany is selected as a case study for an energy system soon to be dominated by renewables and passenger cars because of its high relevance for CO<sub>2</sub> emissions.

The study takes as its starting point a SWOT (Strengths, Weaknesses, Opportunities and Threats) analysis of infrastructure set-ups for FCEV fueling and BEV charging. The SWOT analysis aims at identifying and describing the implications, relationships and consequences involved in the establishment of these new infrastructures (see Chapter 4).

The subsequent quantitative infrastructural analysis entails a meta-analysis of published studies containing data on infrastructure costs. For high market penetration scenarios in particular, the literature review only revealed aggregated and in part non-transparent information. To fill this gap of information in literature, a comprehensive techno-economic analysis was conducted, taking account of different levels of FCEV and BEV market penetration (see Chapter 5).

For a detailed comparison of both infrastructures, the study applies detailed techno-economic models for infrastructure design and cost assessment. In order to deliver transparent and comparative results, the analyses use the same scenario assumptions for electricity generation, transport demand and additional boundary conditions like fuel or CO<sub>2</sub> certificate prices. The impacts of different electric vehicle market penetration levels on infrastructure costs can be gauged by varying the assumed rolling stock of FCEV or BEV.

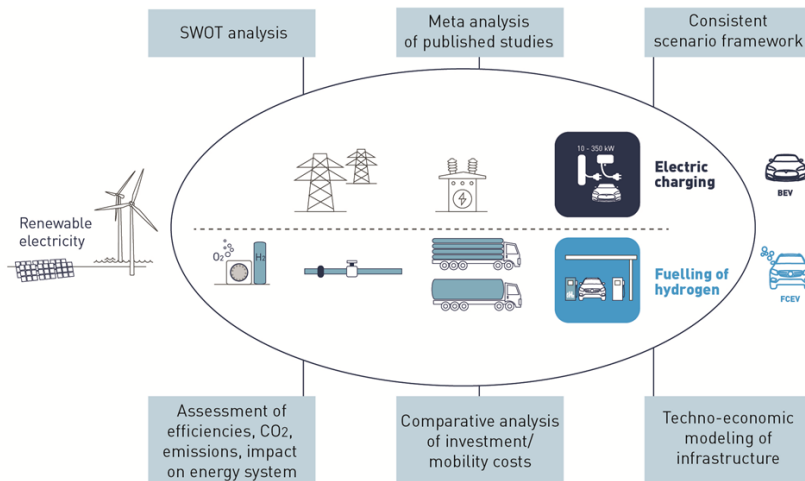


Figure 2-1: Study objectives.

Based on the scenario calculations, the infrastructure costs, mobility costs, efficiencies and CO<sub>2</sub> emissions for the hydrogen refueling and electric charging infrastructures respectively are discussed. The resulting impacts on renewable electricity generation, transport and distribution as well as possible system services are explained in detail in Chapter 6.

### 3 Status Quo of Hydrogen Fueling and Charging Infrastructures

The current status of alternative fuel infrastructures varies worldwide. Market penetration depends on political and industrial strategies for example, but also on incentives schemes, the design of national energy systems, and historical factors.

The EU Alternative Fuels Infrastructure Directive (2014/94) concerns the concerted development of infrastructure for alternative fuels within the EU. This directive provides the framework for establishing a charging and fueling infrastructure for hydrogen, electricity, compressed natural gas (CNG) and liquefied petrol gas (LPG). By 2016, Member States were obliged to have set up a national strategy for the development of alternative fuels and infrastructures. The time schedules for infrastructure build-up vary depending on fuel and vehicle type and on transport applications between 2020 and 2030.

Overall, the German government aims at installing 5,000 public fast charging stations (Mode 3 and Mode 4) and 10,000 public slow charging points (Mode 2) before 2020. Additionally, every freeway service station is to be equipped with fast charging options. The government's goal for hydrogen refueling is 400 filling stations by 2023 [8]. The German government has - already established support programs for both infrastructure developments.

#### 3.1 Hydrogen Fueling

By the end of 2016, some 213 public hydrogen filling stations were in operation for fueling approx. 2500 FCEV worldwide. More stations exist but with limited or no public access, like depot fueling stations for commercial vehicle fleets or industrial trucks. Based on the total number of hydrogen fueling stations worldwide (not number of dispensers), Japan is currently leading the field with 44 % followed by the USA (17 %) and Germany (13 %). Most of the filling stations for FCEV passenger cars offer hydrogen at 700 bar [9]. A detailed survey of current and future filling station concepts and sizes as well as corresponding norms and standards can be found in Adolf et al. [10].

At present, the spatial distribution of FCEVs in operation corresponds to the distribution of filling stations. For instance in the USA, the filling stations and FCEVs are concentrated in California, which has ambitious goals for a clean transportation system [9].

In Germany, the hydrogen fueling station network comprised 30 stations by mid-June 2017. At that time, an additional 27 HRS were under construction or being planned [8].

Figure 3-1 points out the intended site distribution for fueling station roll-out. The priority is on large urban areas and their connecting corridors. To enhance confidence in the new fueling infrastructure, consumers can track the status of most hydrogen stations in Europe live online [11].

At present, getting hydrogen from the production sites to the filling stations is done by means of liquid tank trailers and compressed gas tube trailers or pipelines. The choice of delivery mode depends on the distance between the production site and filling station and on demand for hydrogen as well as various site-specific conditions (e.g. existing infrastructure, space requirements), local conditions and economic criteria. In addition, several filling stations produce their hydrogen on site by electrolysis or small-scale gas reforming.



Figure 3-1: Roadmap for hydrogen refueling stations in Germany [12].  
(copyright by H2 MOBILITY Deutschland, 2017)

The most economically efficient option for transporting large amounts of hydrogen over long distances are point-to-point pipeline systems [13]. Table 3-1 shows the length of hydrogen pipelines in operation worldwide by mid-2017. More than half of the total length is located in the United States.

Table 3-1: Existing Hydrogen Pipelines 2017, May [9], [14], [15].

Region	km
U.S.	2,608
Europe	1,598
of which in Germany	340
Rest of World	337
World total	4,542

The current hydrogen pipelines are concentrated between large production sites and hydrogen users in chemical and petrochemical plants. Parts of these hydrogen pipelines have already been in operation for several decades.



### 3.2 Electric Charging

The current development of electric charging options is quite dynamic and corresponds to the rising stock of BEV and Plugin Hybrid Electric Vehicles (PHEV). By the end 2016, the total BEV and PHEV vehicle stock came to about 2 million worldwide and was largely concentrated in China (32 %) followed by the United States (28 %) [16]. At 3.6 %, Germany's share of the world's electric vehicle stock is low (share of German total passenger car stock to worldwide stock approx. 5 %).

The number of electric chargers already installed in different countries and the various charging modes are summarized in Figure 3-2. According to the international standard of the International Electrotechnical Commission (IEC) 61851-1 the different charging modes are categorized in slow charging (Mode 1 and 2), fast charging (Mode 3 (AC) and Mode 4 (DC)) and the corresponding communication and safety systems. The charging power for Mode 1 and Mode 2 chargers is below 22 kW (3 phase AC charging). At present, the IEA statistic [16] only refers to publicly accessible chargers, which means home charging options are not included.

The rollout of slow and fast charging options reveals the dynamic development underway worldwide. Leading countries in the period till 2016 in absolute number of chargers are China, the United States and the Netherlands. Regarding installed fast charging options (Modes 3 and 4), China exhibits the highest dynamic and absolute number of installed charging options. The different expansion levels of charging infrastructure in the various countries are influenced strongly by political and industrial strategies and incentive schemes.

Up till June 2015, approx. 5,600 publically accessible charging points for normal charging as well as some 100 DC fast charging points were available in Germany [17]. At the end of 2016, the number of publicly accessible charging points increased to 7,407, including 292 DC fast charging points. Charging points are available at some 3,206 charging stations [18].

According to the National Electric Mobility Platform Report [17], Germany requires 1,400 DC fast charging points for 2017 and some 7,100 for 2020. Current development of DC fast charging stations is lagging behind these plans.

Compared to the official register of charging options [18], open access platforms for chargers have higher numbers of charging options. The inconsistency of data can be explained by the different status quo of charger notifications and the mixture of public and private charging options. These open data platforms offer live information about charger location and availability along with additional information, like charging power or possible payment schemes.

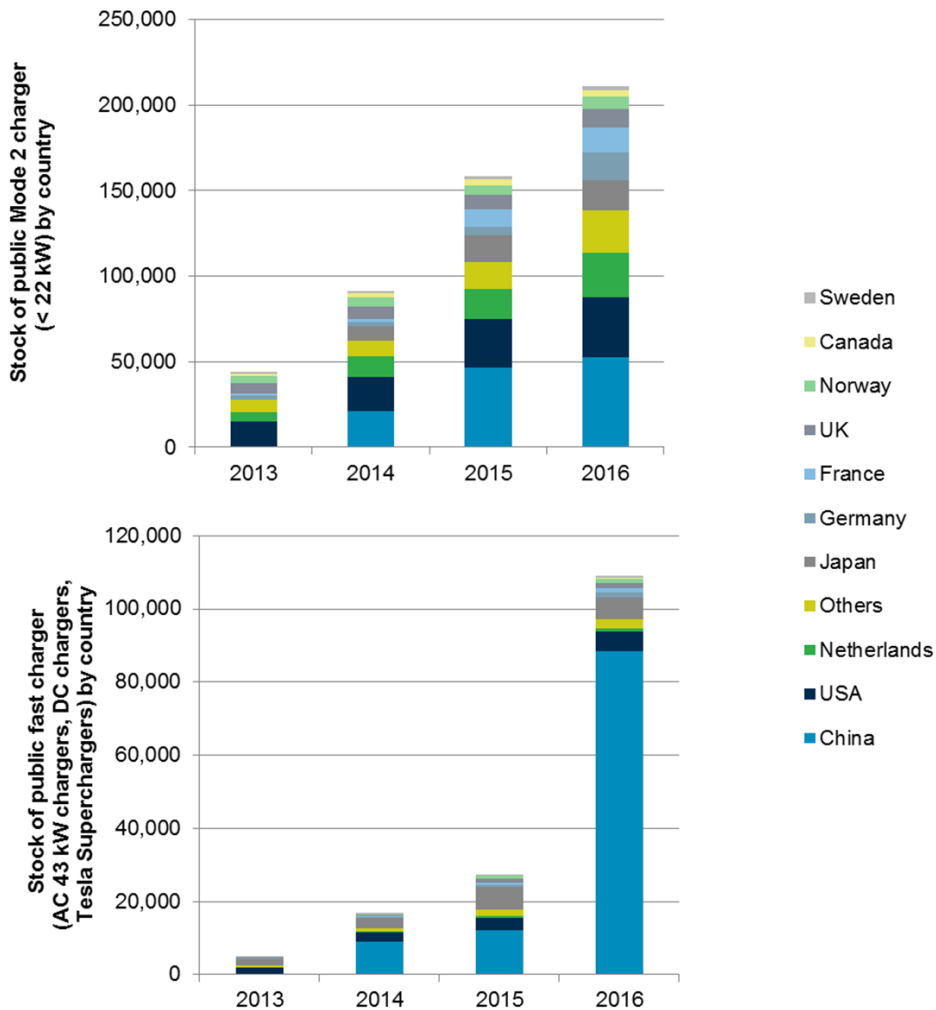


Figure 3-2: Worldwide charging infrastructure development for selected countries [16].

Figure 3-3 shows the number of electric vehicles served by one public slow charger (Mode 2) for selected countries in Europe. In Norway, with its high electric vehicle market penetration, one public charger supplies an average of up to 14 vehicles.

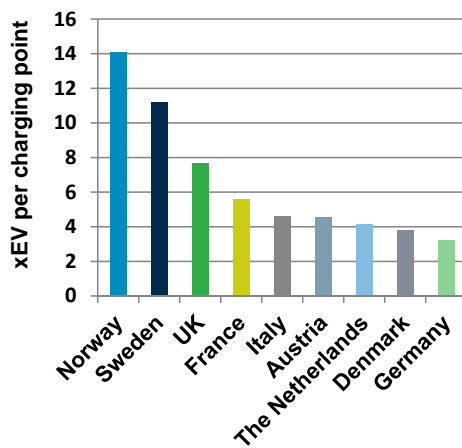


Figure 3-3: Average number of supplied electric vehicles per public charging infrastructure (Mode 2 – 4), end of 2016 for selected European countries [19].

In Germany, one public charger serves approximately only three PHEV or BEV. The diagram reveals the trend that with higher market penetration the utilization of public charging infrastructure will increase.

## 4 SWOT Infrastructure Analysis

The transportation sector is pivotal to transforming energy systems into more sustainable forms. However, besides having the capacity to easily integrate renewable energies and reduce CO<sub>2</sub> emissions, there are various other requirements that future transportation must satisfy. For a start, it has to be economically feasible and widely accepted throughout society. SWOT methodology promotes transportation sector development by giving a better understanding of the implications, relationships and consequences of infrastructure decisions. By analyzing and comparing the various infrastructure models for BEVs and FCEVs, it creates a basis for assessments and discussions.

This chapter provides a brief introduction to the SWOT approach and explains how and to what extent it is applied in this particular case. Then a discussion of the SWOT results, starting with a description of influencing factors of equal relevance to both the BEV and FCEV infrastructures follows. Issues that impact on the two infrastructures in different ways are then discussed separately and displayed in the Figures.

### 4.1 SWOT Methodology

The first thing the SWOT methodology does in a strategic decision-making process is to give organizations a conceptual framework for situation analysis. This means that it takes a predefined set of objectives or desired targets and categorizes favorable and unfavorable internal and external factors according to their strengths, weaknesses, opportunities and threats (SWOT). An organization's strengths and weaknesses are its signature traits that reveal certain advantages or disadvantages compared to competitors. As internal factors that depend solely on the stakeholder's qualities and resources, strengths and weaknesses must be carefully differentiated from opportunities and threats, which are external factors and determined by the environment the organization is embedded in. Thematic examples of opportunities and threats include economic development, social changes, new technologies or political orientation, etc. Strengths and opportunities help a stakeholder achieve its objectives while weaknesses and threats hinder target attainment. Just how significant the results of the situation analysis are, depends on how relevant the influencing factors are and how exhaustive the list of factors is. However, it is not possible to draw any conclusions simply from the length or order of a list within a given category.

The second thing SWOT methodology does is to aid the development of strategies that leverage individual capabilities and resources and so realign the organization's operations, ultimately transforming it into the desired state. In this context, matching the four aspects of the analysis – strengths, weaknesses, opportunities and threats – is a means of identifying strengths that can be harnessed to realize opportunities or counter threats and thus single out weaknesses with great risk potential.

### 4.2 Scope of Analysis

Although the SWOT approach is most commonly used for organizations, here it lends structure to the supply infrastructure analysis of the study. Defining the BEV and the FCEV infrastructures as separate starting points, we conducted two SWOT analyses listing their respective major internal and external factors. When these meet in the confrontation matrix, the result is a unitary basis for comparison. In this context, it should be noted that although

the environmental conditions are the same in both cases, they can well represent an opportunity or a threat, depending on the infrastructure type concerned. Following SWOT analysis, this chapter examines the different aspects of the BEV and FCEV fuel infrastructures. Vehicle technologies are not core of the analysis. A detailed interpretation of results and a series of recommendations are given at the close of the study.

### **4.3 Common Aspects of FCEV Hydrogen Supply and BEV Charging Infrastructure**

Individual technical characteristics aside, the fact that the targeted objectives and requirements apply to both infrastructures leads to a number commonalities. However, when deciding on whether or how to develop infrastructures, it is not enough to simply weigh up or compare the attributes they share. For this reason, these attributes are discussed below in parallel to the SWOT analyses.

Regarding strengths, both alternative fuel options have the potential to become key drivers of energy transition within the transport sector in Germany. Both are able to utilize renewable electricity, enabling sector coupling and emission-free transportation. A shift in fuel supply infrastructure towards energy systems based on renewable electricity will increase total demand for electricity. At the same time, it will raise the potential for integrating even more renewably electricity, thus reducing the need for renewable curtailment overall. This is especially advantageous in energy systems with high surplus electricity generation. Since both infrastructures are able to harness local renewables as primary energy carriers in the fuel supply chain, they offer great potential for increasing geopolitical fuel supply security by reducing crude oil or fossil fuel imports. In short: this could significantly reduce overall reliance on imported energy.

A weakness common to both alternatives is that they require a fundamental change in the existing fuel supply infrastructures. This is especially true compared to power-to-liquids or biofuels, for example, which largely rely on existing infrastructure, especially for fuel transport, distribution and retail.

An opportunity for both infrastructures is that politics and society widely accept and support the energy transition process in general, resulting in a positive investment climate and the generation of alternative fuel supply systems – also with support from existing government programs. Another opportunity is that Germany already has the technical know-how and key industrial players required to strengthen local industrial actors across the global market, thus enabling them to keep most of the added value inside Germany.

Such a significant change in the fuel supply infrastructure can only work if a consistent political and regulatory framework is in place. Major changes, such as a halt in the energy transition process, would constitute a significant threat to the build-up and operation of alternative fuel infrastructures. Moreover, new investors and corresponding investment models are vital for ensuring the funding of alternative fuel infrastructures. From an investor's perspective, poor infrastructure utilization is seen as a threat because it impacts negatively on the return on investment. However, government support, as well as financing models based on public-private partnerships, could reduce the level of risk perceived. Moreover, poor infrastructure utilization also correlates with limited FCEV and BEV availability.

## 4.4 Hydrogen Infrastructure

The results of the SWOT process regarding the analysis of the hydrogen supply infrastructure are summarized in Figure 4-1. As stated before the focus is on the analysis of supply infrastructures and not on the corresponding vehicle technologies. All bullet points of the strengths, weakness, opportunities and threats of the hydrogen infrastructure are explained in more detail in this section.

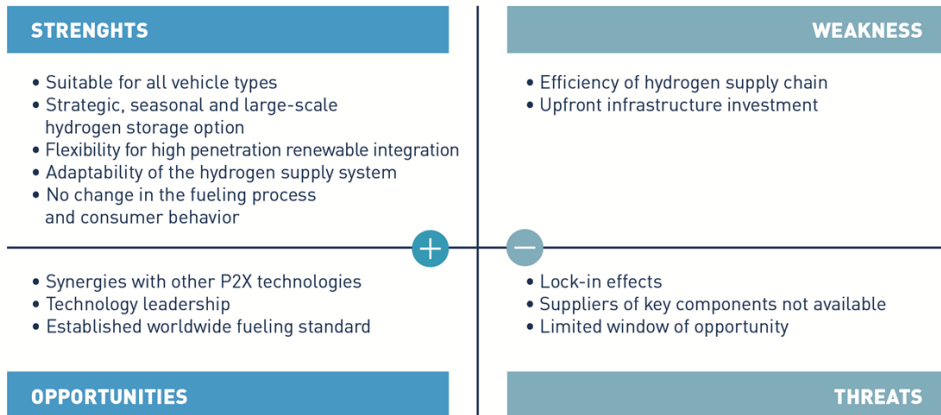


Figure 4-1: SWOT analysis of FCEV hydrogen supply infrastructure.

### Strengths

#### *Suitable for all vehicle types:*

With its high energy density, hydrogen can be used for all vehicle types, from small passenger cars to long distance trucks. But it does not stop there – hydrogen infrastructure also has the potential to supply other modes of transport such as ships or trains.

#### *Strategic, seasonal and large-scale hydrogen storage options:*

The option of large-scale hydrogen storage is inbuilt. The state-of-the-art use of salt caverns for hydrogen storage allows for cost-efficient seasonal storage and the build-up of a strategic fuel reserve. Seasonal storage is a key feature of a secure fuel supply, providing a solution to fluctuating renewable energy sources and periods of low renewable electricity generation.

#### *Flexibility option for renewable electricity integration:*

In the context of demand-side management (DSM), hydrogen production by electrolysis is a key enabler of flexibility. It can act as controllable load, making it easier to handle the integration of fluctuating renewable energies. Centralized hydrogen production close to renewable production centers could also reduce the demand for extensions in the transmission grid by integrating renewable electricity production into a hydrogen gas grid. In principle, it would also be possible to deliver other ancillary services through vehicle-to-grid solutions but limited to shorter time periods.

#### *Adaptability of the hydrogen supply system:*

A hydrogen supply system adapts well to different demand situations and other boundary conditions. For a start, different hydrogen production pathways are possible. During the market introduction phase especially, existing hydrogen production facilities and pipelines can be integrated into the FCEV supply infrastructure. At present, the use of existing natural gas pipelines for transporting hydrogen is subject to research and development. This can be an interesting option for further use of no longer required parts of the natural gas pipeline system. Both centralized hydrogen production, and decentralized on-site hydrogen production at fueling stations are feasible. The option of centralized production in close proximity to renewable production centers allows for economies of scale. From pipelines to trucks or even ships, multiple transport and distribution alternatives are conceivable, offering customized solutions for different scenarios. This high level of adaptability can be considered a key advantage, especially for the market rollout of hydrogen.

#### *No change in the fueling process and consumer behavior:*

Hydrogen refueling is similar to the conventional fueling process which means consumers do not have to alter their behavior and are therefore not affected by the fuel change. Vehicles can run for the same distances as their conventional counterparts and get refueled at the same fueling stations and time, albeit at a different pump. As a result, hydrogen-powered vehicles do not need separate fueling stations and new sites for retail.

### **Weaknesses**

#### *Efficiency of hydrogen supply chain:*

In terms of efficiency, BEVs use electricity directly and are ahead of the hydrogen fuel supply chain and fuel cell drivetrain. This translates into a higher specific electricity demand per kilometer.

#### *Upfront infrastructure investment:*

Even though a very low number of FCEVs are on the road, they still require a certain basic hydrogen infrastructure in order to operate. The upshot is a relatively high upfront infrastructure investment. Combined with poor infrastructure utilization, return on infrastructure investment thus faces a 'valley of death' during FCEV market rollout. Synergies with existing hydrogen infrastructure are country-specific and depend on existing applications. However, in most cases, a completely new hydrogen infrastructure is required, including renewable hydrogen production, transport, distribution and retail.

### **Opportunities**

#### *Synergies with other power-to-x (PtX) technologies:*

Hydrogen is set to play a key role in future energy systems involving high shares of renewable energy. Synergies with other PtX technologies could be exploited, too. Take power-to-hydrogen-to-power applications for instance, which utilize hydrogen as a seasonal storage system. Salt cavern storage capacities could be harnessed to guarantee security of supply for both fuel and electricity. Hydrogen production, transportation and further processing are essential parts for power-to-liquid (PtL) concepts, too. Power-to-chemicals opens the opportunity to target non energetic applications by integrating renewable electricity

to chemical products. The projected synergies concern technology learning curves and economies of scale.

*Technology leadership:*

There are currently a limited number of industrial players within the hydrogen economy but this offers an opportunity for countries and companies to seize technology leadership and push ahead with the creation of a large-scale hydrogen fueling infrastructure. Nevertheless, this can also be considered a threat in terms of first-mover investments.

*Established worldwide fueling standard:*

The operation of hydrogen fueling stations is standardized pursuant to the Worldwide Hydrogen Fueling Protocol, SAE J2601, which establishes the process conditions for hydrogen fueling, such as fuel delivery temperature, maximum flow rate, rate of pressure increase and end pressure. Such a standard is considered to be a basic condition for global FCEV market penetration.

## **Threats**

*Lock in-effects:*

The development of a hydrogen supply infrastructure might cause lock-in effects should the transmission and distribution equipment become obsolete or if transport and delivery structures cannot be combined arbitrarily with other fueling options. By switching from one fuel option to another one, parts of the installed fossil infrastructure will depreciate and lead to a lock-in to existing infrastructures. This is a large handicap for a fuel switch.

*Suppliers of key components not available:*

The key components of hydrogen infrastructure are currently available as custom-made solutions for large-scale electrolysis or as a small batch series for fueling station equipment only. The limited numbers of industrial players that provide hydrogen infrastructure solutions along with these technologies' diverging levels of market readiness hinder so far a cost-efficient infrastructure rollout.

*Limited window of opportunity:*

The ongoing development of competing technologies and alternative fuel supply chains will open up a limited window of opportunity for introducing hydrogen as a fuel. Buying in liquid hydrogen from the global market competes with local hydrogen production. However, a hydrogen transport and distribution infrastructure is always compatible, regardless of the source or state of aggregation. Limited FCEV market availability and the absence of a hydrogen fueling infrastructure in neighboring countries will have a negative influence on the window of opportunity.

## **4.5 Charging Infrastructure**

The results of the SWOT analysis for the electric charging infrastructure are presented in the same structure like for the hydrogen infrastructure (Figure 4-2) and all aspects are explained in detail.



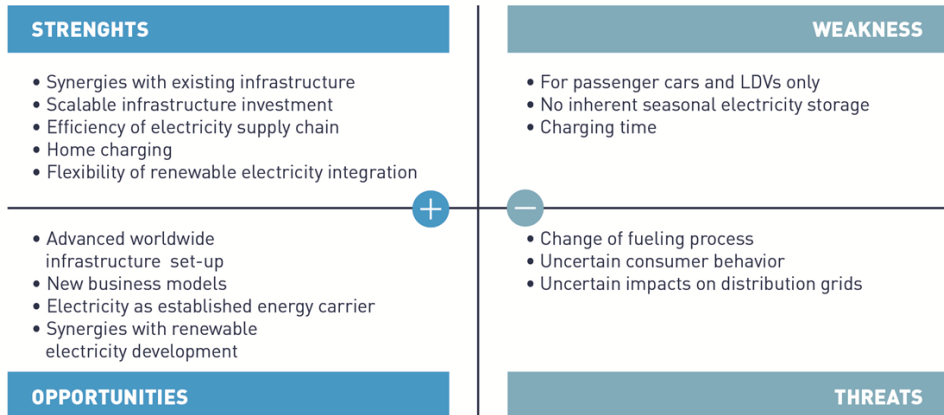


Figure 4-2: SWOT analysis of BEV charging infrastructure.

## Strengths

### *Synergies with existing infrastructure:*

As long as grid capacities are not exceeded and the stability of the grid can be guaranteed, the existing electricity transport and distribution infrastructure can handle the additional electric load caused by charging BEVs. In short, there is no need for a completely new electric grid. Further synergies arise if existing car parks and garages are equipped with charging stations. In this way, the BEV infrastructure can easily be extended, concomitantly limiting the demand for new public charging locations.

### *Scalable infrastructure investment:*

Building up a demand-oriented charging infrastructure will be quick and easy and vital grid extensions can be implemented as required. The number of public charging stations and the volume of related investments are limited, especially during the rollout phase. State-of-the-art charging stations are available from multiple providers as standard solutions.

### *Efficiency of the electricity supply chain:*

BEVs' direct use of electricity makes them more efficient than the hydrogen fuel supply chain and fuel cell drivetrains. This leads to lower specific electricity demand over the full fuel chain per kilometer.

### *Home charging:*

In addition to public charging, BEVs can be home-charged in private parking spaces. The home charging concept allows for the integration of local renewable electricity and increased self-consumption, e.g., from photovoltaic systems. Emergency charging could also be enabled with standard power sockets. The extent of public and private charging infrastructure and the amount of public and private investments depend on the users' charging behavior.

### *Flexibility option for renewable electricity integration:*

Controlled charging adds flexibility to the grid and can be used to reduce and more evenly distribute peak charging loads. BEV charging demand can be partly matched with renewable electricity production, allowing for demand-side management. Depending on local

circumstances, controlled charging could also reduce the need for extending the distribution grid. In principle, ancillary services, like vehicle-to-grid solutions, are possible but limited to shorter time periods.

## **Weaknesses**

*Suitable for passenger cars and light duty vehicles only:*

The charging infrastructure can only be used for passenger cars and light duty vehicles. An additional infrastructure or additional fuel is required for long distance goods transport by heavy duty vehicles.

*No inherent seasonal electricity storage:*

Seasonal storage capacities are required in scenarios involving a high share of renewable energies in order to secure electricity supply. As the batteries of BEV are designed to fit daily mobility needs they cannot offer additionally capacity for seasonal electricity storage. Therefore, the security of BEV supply depends on how secure the electricity supply is. For high shares of variable renewable electricity only a seasonal storage option can guarantee security of supply by maximizing at the same time the use of renewable electricity. The low efficiency of the required chemical energy storages - only option with adequate storage capacity - reduces overall BEV efficiency.

*Charging time:*

Average BEV charging time is higher than the average FCEV fueling time. Fast charging with very high power ratings of up to 350 kW could reduce the time required. However, for the majority of BEVs, today fast charging is not seen as the standard due to higher costs and battery lifetime-reduction stress.

## **Opportunities**

*Advanced worldwide infrastructure set-up:*

At present, a worldwide BEV charging infrastructure is under development. The increasing number of installed charging stations around the globe allows for the exploitation of technology learning curves and economies of scale. Having access to a public charging infrastructure in neighboring countries would make trans-national journeys a reality. However, it is necessary to continue and improve current efforts addressing issues such as standards, compatibility issues as well as payment and billing systems on a transnational level.

*New business models:*

The emergence of a charging infrastructure, together with the ongoing digitalization process, is set to engender new business models by giving end consumers access to financial incentives and new services, such as free charging at work, in supermarkets or garages and enabling spatially independent self-consumption for vehicle charging and vehicle-to-grid services.

*Electricity as an established energy carrier:*

Electricity is an energy carrier that has been well-established for decades in the end-consumer sector. Consumers are familiar with the use of electricity for various everyday

applications and are well able to handle plug-in electrical devices and know the risks involved.

*Synergies with renewable electricity development:*

The increasing shares of renewable energy sources in the energy sector necessitate grid reinforcements and additional storage systems – infrastructural developments that also serve the electric transport sector to a certain extent. Other synergies derive from additional grid reinforcements for the transport sector as a result of ongoing planning processes and surveys; e.g. concerning storage system locations and power line corridors. Usually, the transport sector only has to pay for some of the grid reinforcement costs.

## **Threats**

*Change of fueling process:*

BEV charging differs from the conventional refueling process. This impacts charging behavior and thus needs to be aligned. A change in driving and mobility behavior might be required.

*Uncertain user behavior:*

Demand for slow and fast-charging public infrastructures depends significantly on the BEV users' charging behavior. Given the extent to which home and private charging options are being used, there is a risk that public charging infrastructure might be over-dimensioned. In such a case, low utilization would lead to refinancing problems for infrastructure investments.

*Uncertain impacts on distribution grids:*

Uncertainties regarding future charging behavior and the impact of controlled charging measures make it difficult to assess the impacts on distribution grids. Grid reinforcements are set to become necessary because of the transport sector's additional demand for power output.

## 5 Meta-Analysis of Scenario Studies

The first objective of the meta-analysis is to identify studies that deal with FCEV and/or BEV infrastructure set-ups. Second, it conducts a comparative assessment of the quantitative results for selected parameters from these studies. A key aspect of the meta-analysis is the analysis of infrastructure development for various FCEV and BEV penetration scenarios. Section 5.1 describes the approach used in the meta-analysis while sections 5.2 and 5.3 then present the results of the comparative assessment of a hydrogen supply infrastructure and an electric charging infrastructure. A detailed description of the identified studies can be found in the Appendix to this study.

The meta-analysis is also useful for placing the results of the calculations presented in this study into the broader context of studies available.

### 5.1 Approach of the Meta-Analysis

Different criteria are applied to select the studies used in the meta-analysis. To ensure comparability of results, the focus is placed on studies that deal with Germany and include quantitative results for infrastructure set-up. To put the results for Germany into a broader context, the analysis also includes studies focusing on the international level (European Union, worldwide). The meta-analysis also identifies and describes studies that analyze other countries' infrastructures, or that only present qualitative results. However, these studies are excluded from the quantitative assessment, but introduced in the appendix of the report (see chapter 9). A total of 79 literature sources were screened, resulting in the selection of 25 suitable studies for the meta-analysis.

The literature analysis revealed some highly diverse information. Moreover, only a few studies exist that present quantitative results for infrastructure set-ups in a transparent and reasonable manner. Most of the studies contain aggregated results only and, in many cases, the basic technical and cost assumptions are not provided in full. The quantitative component of the meta-analysis therefore focuses on the following parameters: number of hydrogen fueling stations needed and number of charging points as well as the cumulative investment required for set-up. The literature offers a relatively good source of information for these parameters. However, the data here is not sufficient for any further analysis or comparison of other parameters; e.g., hydrogen pipeline length or the number of trucks for hydrogen transport. Thus, seeing as this is not possible, it does not form part of the meta-analysis.

Importantly, the meta-analysis shows that studies dealing with electric charging infrastructure for high penetration scenarios of electric vehicles are lacking in the literature. Uncertainties exist, especially regarding demand for fast-charging infrastructure and impacts on the distribution grid, but also with regard to grid reinforcement measures. There is thus great demand for future research in this context. Furthermore, most studies limit themselves to assessing charging infrastructure demands. Only a small number of studies examine the related investments required for building infrastructure.

### 5.2 Comparison of Studies: Hydrogen Infrastructure

The studies dealing with the hydrogen supply infrastructure considered in the meta-analysis are listed in Table 5-1. This Table shows whether or not the study has quantitative results and whether these results have been considered in the quantitative component of the meta-

analysis. A total of 12 studies from literature are identified. The following section analyzes and compares the results from six studies in detail. A description of the studies, as well as further details regarding their respective scope, important assumptions and methodology, is included in the Appendix (see chapter 9).

Table 5-1: List of studies considered in the meta-analysis of the hydrogen supply infrastructure.

Author(s)	Title	citation	Quantitative results
Arnhold, O.	Energie – und Verkehrswende: Synergien nutzen und Risiken erkennen	[20]	No
Arnhold, O., et al.	Energiewende im Verkehr - Welche Auswirkungen haben Batterie- und Brennstoffzellenfahrzeuge auf das Energiesystem?	[21]	No
Samsatli, S., et al.	Optimal design and operation of integrated wind-hydrogen-electricity networks for decarbonising the domestic transport sector in Great Britain	[22]	No
Ball, M.	Integration einer Wasserstoffwirtschaft in ein nationales Energiesystem am Beispiel Deutschlands	[23]	No
Robinius, M.	Strom- und Gasmaktdesign zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff	[24]	Yes
Noack, C., et al.	Studie über die Planung einer Demonstrationsanlage zur Wasserstoff-Kraftstoffgewinnung durch Elektrolyse mit Zwischenspeicherung in Salzkavernen unter Druck	[25]	No
Seydel, P.	Entwicklung und Bewertung einer langfristigen regionalen Strategie zum Aufbau einer Wasserstoffinfrastruktur	[26]	Yes
GermanHy	Woher kommt der Wasserstoff in Deutschland bis 2050?	[27]	Yes
Shafiei, E., et al.	Energy, economic, and mitigation cost implications of transition toward a carbon-neutral transport sector: A simulation-based comparison between hydrogen and electricity	[28]	No
Stolzenburg, K., et al.	Integration von Wind-Wasserstoff-Systemen in das Energiesystem	[29]	Yes
Mc Kinsey	A Portfolio of Powertrains for Europe: a Fact Based Analysis	[30]	Yes
Hydrogen Council	How hydrogen empowers the energy transition	[31]	No
IEA	Energy Technology Perspectives 2012 Pathways to a Clean Energy System	[7]	Yes

Figure 5-1, offers a comparison of the total number of public hydrogen fueling stations and the amount of vehicles per station for various scenarios, depending on the number of FCEVs. The analysis features data from five studies. The study from McKinsey [30] relates to the EU27, including Norway and Switzerland, which explains the higher number of fueling stations (18,200) and higher number of FCEVs in comparison to the four other studies that all pertain to Germany. Passenger car stock in Germany is 45.8 million in 2017 [32] and in the EU, including Norway and Switzerland, 205 million in 2015 [33]. The number of conventional fueling stations in Germany is 14,510 in 2017 [34]. In the EU, including Norway and Switzerland, it is 120,728 in 2016 [35].

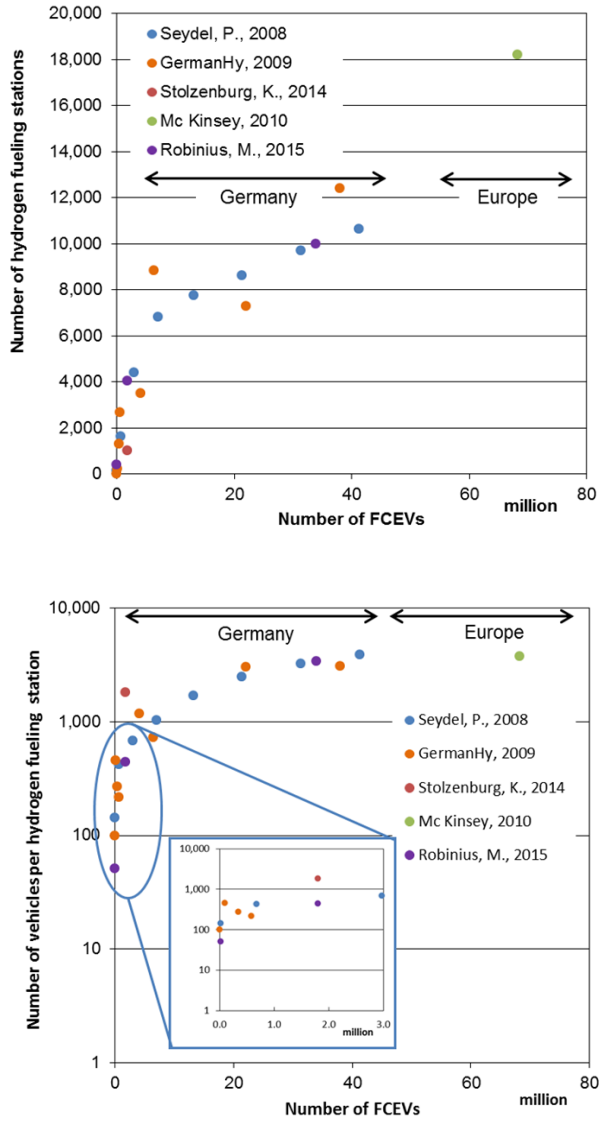


Figure 5-1: Number of public hydrogen fueling stations (top) and number of vehicles per hydrogen fueling station (bottom) depending on the number of FCEVs.

A consistent finding across all studies is that the number of fueling stations increases in keeping with the rise in FCEV stock. This is a reasonable finding, as an increasing number of FCEVs requires a tighter network of fueling stations to cover refueling needs. In the early introduction phase especially when there are low numbers of FCEVs, the number of public hydrogen fueling stations varies significantly depending on the scenario. This is based on

different assumptions and coverage approaches for the early stages of market rollout highlighting the high uncertainty related to the infrastructure set-up.

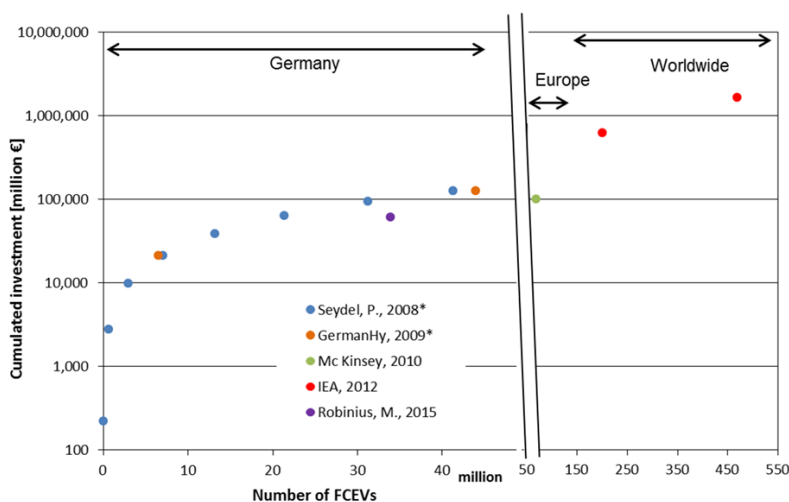
According to the scenarios analyzed, high FCEV stocks (of around 20-40 million vehicles) will necessitate approx. 10,000 fueling stations across Germany. This figure also corresponds to the total number of 9,000 fueling stations for Germany by 2050 quoted in a report by the Environment Ministry [36]. These figures both work on the assumption that the downward trend of recent years will persist in future.

The specific number of vehicles per hydrogen fueling station also increases significantly as FCEV stocks rise. This is due to higher fueling station utilization. During the FCEV market introduction phase in particular, fueling station utilization is low; e.g., the number of vehicles frequenting fueling stations is low.

High FCEV stocks equate with a relatively stable number of vehicles per fueling station, somewhere in the range of 2,500-3,500 across all scenarios, including the figure cited by McKinsey [30] for the European level. This is a robust value. The average value for scenarios of  $\geq 20$  million FCEVs is 3,211 FCEVs per hydrogen fueling station.

Figure 5-2, Figure 5-3 and Figure 5-4 analyze the volume of investment required to set up a hydrogen infrastructure. The analysis looks at data from five studies. The study by McKinsey [30] relates to the EU, including Norway and Switzerland. The IEA study [7] relates to the global level as seen in the high number of FCEVs in the scenarios in comparison to the other three studies that all pertain to Germany.

Figure 5-2 depicts cumulative hydrogen infrastructure investment, depending on the number of supplied FCEVs. The required investment for hydrogen infrastructure increases in line with the number of FCEVs. However, the studies differ significantly in terms of the volume of investment due to several basic assumptions they make.



\*: Including investment for power plants for upstream electricity generation

Figure 5-2: Cumulative hydrogen infrastructure investment depending on the number of supplied FCEVs.

A key assumption influencing required total hydrogen production investment concerns power plant investment for upstream electricity generation. Power plant investment is included in Seydel [26] and GermanHy [27]. Here too, assumptions regarding the development of the hydrogen production mix are also major influencing factors. Seydel [26] considers hydrogen production from fossil sources in combination with carbon capture and storage (CCS). In contrast, Robinius [24] focuses on hydrogen production from surplus renewable electricity. In the early phases of market introduction especially, when hydrogen demand is low overall, several scenarios give some thought to harnessing hydrogen from existing sources (e.g., industrial by-product). With increasing hydrogen demand, this option becomes less important and hydrogen production is dominated by other fossil or renewable sources, depending on the scenario. The question whether the power plant investments are included in the cost analysis or not depends on the way the system boundaries are defined. Both approaches are reasonable. However, the different practices in the literature make it difficult to compare the results for cumulated hydrogen infrastructure investment. For transparency's sake, there is the need for future scenario studies to explain in detail the approach and key assumptions for the cost assessments.

To account for these various basic assumptions and the related impacts on the required cumulative investment, Figure 5-3 divides infrastructure investment for different scenarios into the following categories: “hydrogen production”, “hydrogen transport and distribution” and “hydrogen retail/filling”.

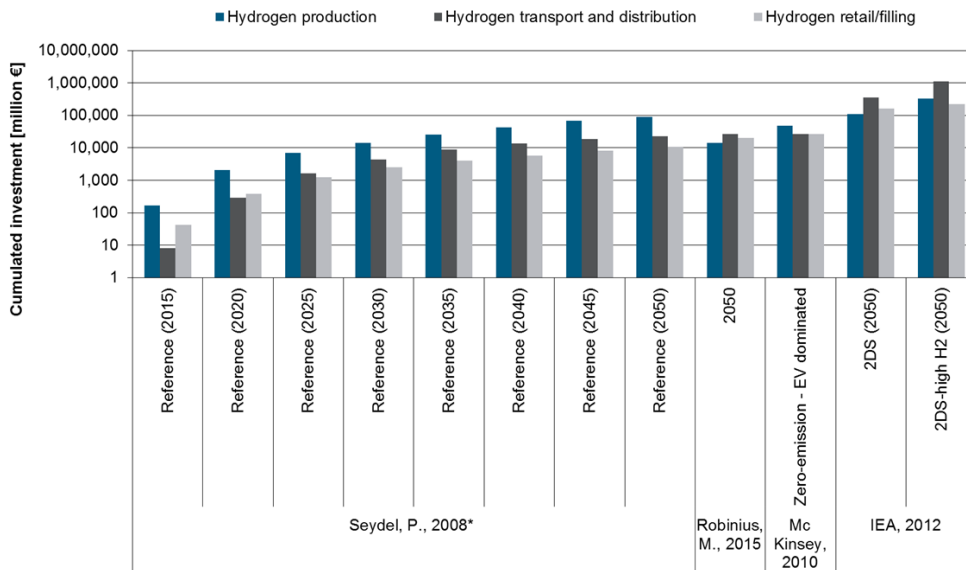


Figure 5-3: Split of cumulative hydrogen infrastructure investment into the categories “hydrogen production”, “hydrogen transport and distribution” and “hydrogen retail/filling” for different scenarios.

\* Including investment for power plants for upstream electricity production.

The above analysis shows that the inclusion of power plant investment for upstream electricity production in Seydel [26] results in total investment being dominated by investment in the category ‘hydrogen production’. Investment in the other two categories pursuant to



Seydel [26] is comparable to the other scenarios. This can be seen from a comparison of the 2050 scenarios in Seydel [26] and Robinius, M. [24] (see Figure 5-3). In particular, investment in hydrogen transport and distribution in the two scenarios is virtually on the same level, indicating quite a robust result for a high FCEV penetration scenario. Both scenarios are based on a pipeline system for hydrogen transport and distribution. The comparison of the investment split in Robinius [24] and the IEA [7] shows that, in both scenarios, investment in hydrogen transport and distribution accounts for the highest share of total investment (see Figure 5-3).

Figure 5-4 illustrates the specific cumulative hydrogen infrastructure investment per FCEV depending on the number of FCEVs. Specific cumulative investment per FCEV reported in McKinsey [30] and Robinius [24] are around the same magnitude, namely € 1,500-1,800 per FCEV. In the other scenarios, specific investment is relatively stable at € 3,000 per FCEV. This higher figure can be explained in part by the fact that Seydel [26] and GermanHy [37] include investments for power plants. Another reason concerns the differences in infrastructure demand and requirements at the global level in comparison to Germany on its own.

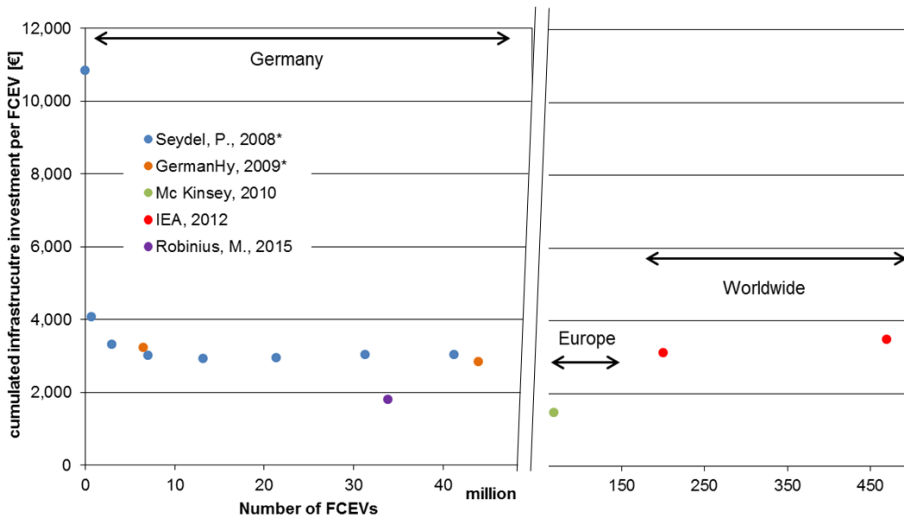


Figure 5-4: Specific cumulative hydrogen infrastructure investment per FCEV depending on the number of FCEVs.

\* Including investment for power plants for upstream electricity production.

In general, decreasing specific cumulative investment per FCEV at the same time as increasing FCEV stock might be expected due to the learning curve and the effect of economies of scale. However, the diverse basic assumptions in the selected scenarios lead to that this effect is only partially visible. In particular the scenario Seydel [26], a significant decrease in the cumulative investment per FCEV after the early market introduction phase is observed. The specific cumulative investment per FCEV with ongoing infrastructure developments and an rising numbers of FCEVs slightly increases. This can be explained by a partial change in the hydrogen production mix in the underlying scenario [26].

### 5.3 Comparison of studies: Charging Infrastructure

The studies dealing with electric charging infrastructure considered in the meta-analysis are listed in Table 5-2. This Table indicates whether or not quantitative results are available in the study and whether they have been taken into account in the quantitative component of the meta-analysis. In total, 12 studies were identified in the literature. The following section analyzes and compares the results from six of these studies in detail. A description of the studies with further details regarding their respective scope, important assumptions and methodology is included in the Appendix (see chapter 9).

Several results of the quantitative assessment relate to the number of BEVs. In the context of the meta-analysis, the number of BEVs is defined as the sum of plug-in hybrid electric vehicles (PHEVs), range extender electric vehicles (REEVs) and BEVs. This is because not every study differentiates between different types of electric vehicles.

Table 5-2: List of studies considered in the meta-analysis of electric charging infrastructure.

Author(s)	Title	Citation	Quantitative results
Plötz, P., et al.	Markthochlaufszenarien für Elektrofahrzeuge	[38]	No
Funke, S. A., et al.	Addressing the Different Needs for Charging Infrastructure: An Analysis of Some Criteria for Charging Infrastructure Set-up	[39]	Yes
Gnann, T., et al.	A Model for Public Fast Charging Infrastructure Needs	[40]	No
Anderson, J., et al. Soylu, T., et al.	Laden 2020	[41], [42]	Yes
NPE	Ladeinfrastruktur für Elektrofahrzeuge in Deutschland	[17]	No
NPE	Fortschrittsbericht 2014 – Bilanz der Marktvorbereitung	[43]	No
Schroeder, A., et al.	The economics of fast charging infrastructure for electric vehicles	[44]	No
Mc Kinsey	A Portfolio of Powertrains for Europe: a Fact Based Analysis	[30]	Yes
BDEW	Aktualisierung und Fortführung der Studie "Die zukünftige Elektromobilitätsinfrastruktur gestalten"	[45]	Yes
UBA	Treibhausgasneutrales Deutschland im Jahr 2050	[46]	No
UBA	Erarbeitung einer fachlichen Strategie zur Energieversorgung des Verkehrs bis zum Jahr 2050	[36]	Yes
Grube, T., et al.	Kosten von Ladeinfrastrukturen für Batteriefahrzeuge in Deutschland	[47]	Yes

Figure 5-5 shows a comparison of the number of vehicles per private charging point (AC) for different scenarios. The comparison is based on data from four studies. Private charging points are located on private property at home (parking space, garage). In the study by BDEW [45], charging points on company depots are also considered as private charging points and included in the analysis and in the data in Figure 5-5. AC wall box systems are considered a private charging technology. In most cases, the charging power is assumed to be 3.7 kW, but there is no need for any limitation. For BEVs with high battery capacities, higher levels of charging power at private wall box systems might be reasonable. Charging points for on-street parkers ("Laternenparker") are considered public charging points, as they are located on public property and are publically accessible. This type of charging is therefore not included in the analysis or in data in Figure 5-5.

A consistent finding across all studies is that all scenarios assume a high availability of private charging points. In fact, the scenarios differ only marginally; e.g. varying assumptions regarding the availability of private parking spaces. The availability of private charging points tends to decrease with increasing BEV stock, regardless of the availability of private parking spaces. This is evidenced by the increasing number of vehicles per charging point, e.g., the scenarios in UBA [36] and Grube et al. [47]. The main reason for assuming this high availability is that the majority of early adopters have access to private parking places for home charging. As BEV market penetration increases, the share of BEV owners with private parking places decreases. According to statistical investigation “Mobilität in Deutschland, 2008” [48], approx. 70 % of vehicle owners in Germany have access to overnight parking on private property. Assuming this value is the lowest boundary for private parking spaces equipped with a charging point, this results in a ratio of 1.43 vehicles per private charging point (see the 2050 scenario from UBA [36] in Figure 5-5).

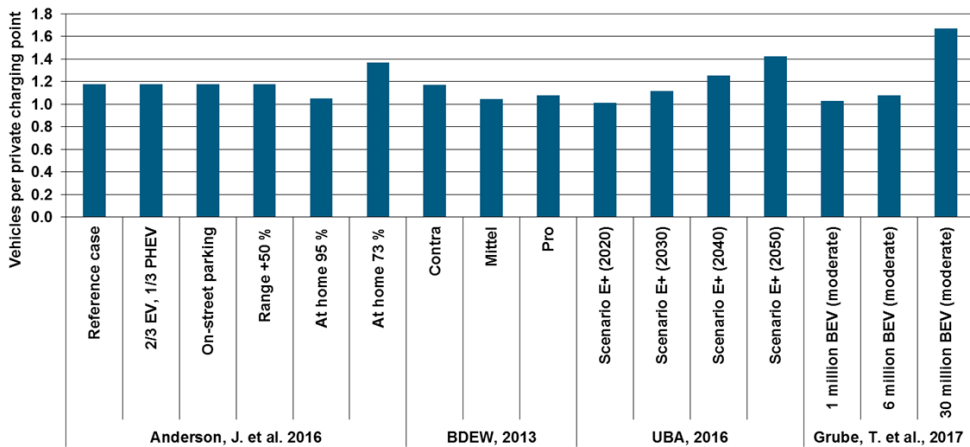


Figure 5-5: Comparison of vehicles per private charging point (AC charging) for different scenarios.

\* Charging points for on-street parkers (“Laternenparker”) are considered as public charging points.

A comparison of the number of vehicles per public/semipublic normal charging point (AC) for different scenarios is shown in Figure 5-6. As the name implies, public chargers are located in public spaces, e.g., public carparks. Semipublic chargers are found for instance in garages or supermarkets. Charging points for on-street parkers (“Laternenparker”) are considered as public charging points and included in the data in Figure 5-6. The selected studies give the AC charging power for public/semipublic normal charging points as 3.7 to 22.2 kW. The lower value is mostly for on-street charging points.

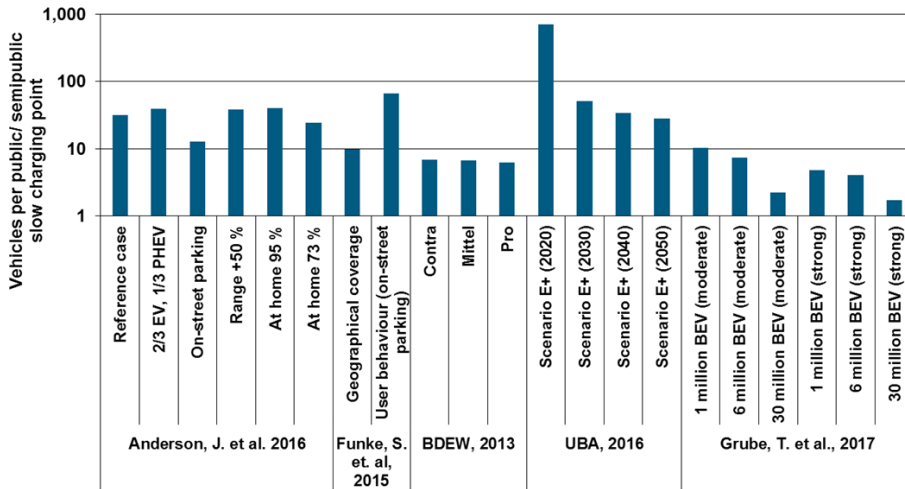


Figure 5-6: Comparison of vehicles per standard public/ semipublic AC charging point for different scenarios.  
 \* Charging points for on-street parkers are considered public charging points.

The extent of public/semipublic normal charging infrastructure varies significantly from one scenario to the next, mainly as a result of the different assumptions regarding demand for this infrastructure. This becomes clear on comparing values in BDEW [45], UBA [36] and Grube et al. [47]. It can be stated that in the scientific literature, large uncertainties exist regarding demand for public/semipublic charging infrastructure. Further research and the integration of real-world utilization data from countries with high BEV shares (e.g., Norway) is needed to better address this point in future. Furthermore, differences in the approaches used to determine the type of charging infrastructure can be observed, e.g. demand-oriented and geographical (see Funke et al. [39]). Having said this, approaches based on geographical coverage only play a minor role in scientific studies.

A general finding that can be derived from Figure 5-6 is that the availability of public/semipublic normal charging infrastructure increases with larger BEV market penetration. This is evidenced by the decreasing number of vehicles per charging point (see UBA [36] and Grube et al. [47]). The high number of charging points and the low ratio of vehicles per point in the 30 million BEV scenario by Grube et al. [47] is attributed to the extensive use of on-street charging points. In the other scenarios, this charging option plays only a minor role or is even nonexistent.

A comparison of the number of vehicles per public/semipublic fast charging point (AC/DC) for different scenarios is shown in Figure 5-7. The power output for fast charging ranges from 50 to 300 kW in the selected studies. All studies consider fast charging essential for long-distance traffic.

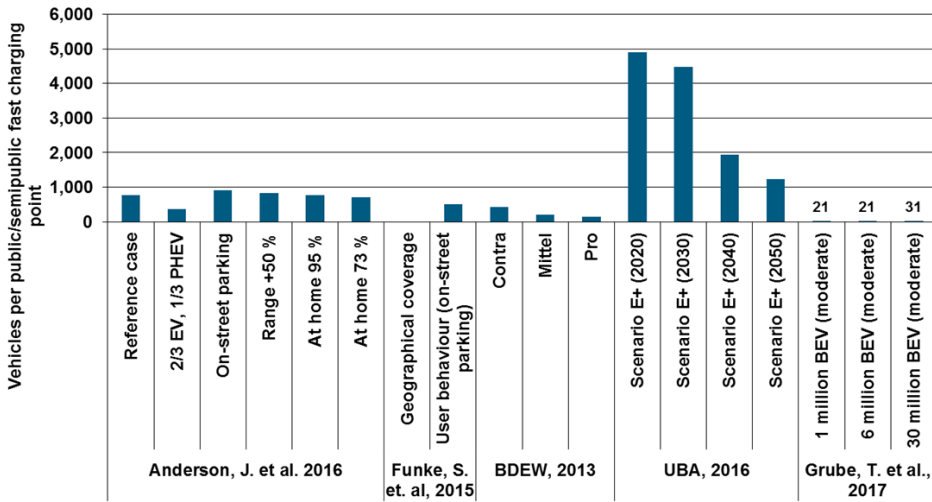


Figure 5-7: Comparison of the number of vehicles per public/semipublic fast charging point (AC/DC) for different scenarios.

As with normal charging infrastructure, the extent of public/semipublic fast charging infrastructure also varies significantly depending on the scenario. Again, the main differences result from different assumptions regarding demand for charging infrastructure (cf. BDEW [45], UBA [36] and Grube et al. [47]). In particular Grube et al. [47] assume a high number of fast charging points compared to the other studies/scenarios. This is expressed by a low number of vehicles per fast charging point (high fast charging availability), which increases slightly from approx. 21 to 31 as BEV stock goes up. These values are significantly lower in comparison to the other scenarios. One reason for this is that, unlike the other studies, Grube et al. [47] consider fast charging stations on motorways and additional semipublic fast charging options e.g. in cities.

The UBA scenario [36] assumes a relatively low number of fast charging points and a high number of vehicles per rapid charger. In UBA [36] and BDEW [45], the availability of a public/semipublic fast charging infrastructure tends to increase as BEV stock grows. This can be seen in the decreasing number of vehicles per charging point (see Figure 5-7). In the UBA report's [36] scenario for the year 2050, the number of vehicles is comparable to the scenarios envisioned by Anderson et al. [41]. However, it must be noted these figures relate to a significantly smaller BEV stock (one million BEVs).

A comparison of specific investment for public/semipublic normal charging infrastructure per vehicle is shown in Figure 5-8. This comparison only includes two studies. This is because the literature cited does not contain any data on cumulative investment in public/semipublic normal charging infrastructure. In general, it can be stated that only a few studies quantify the required infrastructure investments. In particular, in the case of high BEV penetration scenarios, the literature contains almost no information about the level of investment required.

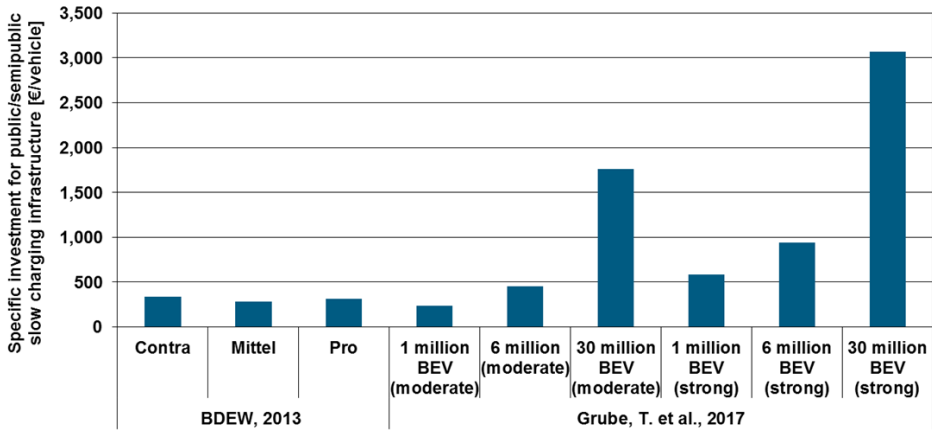


Figure 5-8: Comparison of the specific investment for public/semipublic slow charging infrastructure per vehicle.  
\* Charging points for on-street parkers are considered as public charging points.

Specific investment per vehicle in BDEW [45] and the 1 million BEV scenarios from Grube et al. [47] are in the same range.

In the scenarios depicted by Grube et al. [47], specific investment per vehicle tends to increase as BEV stock grows, in keeping with the rising number of charging points per vehicle. Charging points for on-street parkers are an important factor here. In the 30 million BEV scenarios, specific investment per vehicle increases significantly when grid-reinforcement measures are considered in the total infrastructure investment.

A comparison of specific investment for public/semipublic fast charging infrastructure per vehicle is given in Figure 5-9.

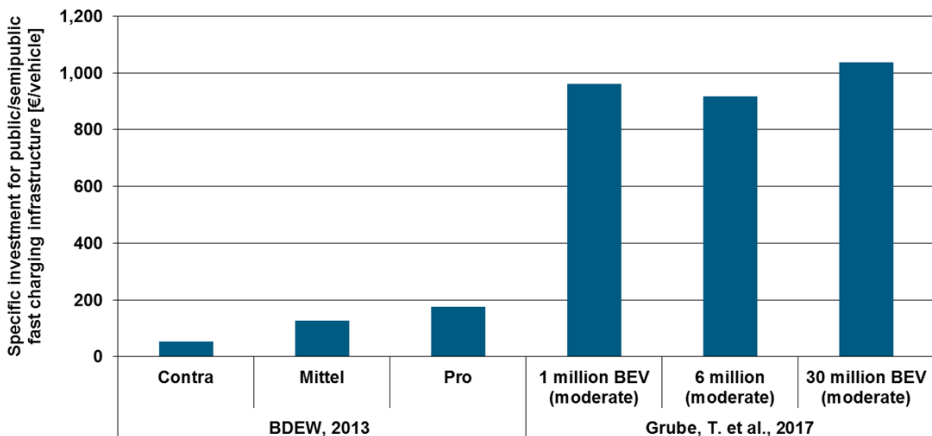


Figure 5-9: Comparison of the specific investment for public/semipublic fast charging infrastructure per vehicle.

The substantially higher number of fast charging points per vehicle noted in Grube et al. [47] in comparison to BDEW [45] (see Figure 5-7) is the main reason for the significantly higher

specific fast charging infrastructure investment per vehicle. Another important factor is that Grube et al. [47] takes account of grid-reinforcement measures and related investments whereas BDEW [45] does not. In BDEW [45], specific investment per vehicle increases in accordance with BEV stock growth and the increasing number of fast charging points per vehicle (see Figure 5-7). In Grube et al. [47], specific investment per vehicle remains virtually constant with increasing BEV stock.

Figure 5-11 points out the comparison of cumulative and specific investment per BEV for the charging infrastructure – in relation to the number of BEVs. Cumulative investment includes both the investment for public/semipublic normal and fast charging infrastructure. The investment required for private charging infrastructure is not included. The analysis also includes a scenario from McKinsey [30] concerning the EU, including Norway and Switzerland. This explains the high number of BEVs in the analyzed scenario.

A general finding is that cumulative investment increases as BEV stock goes up. The total cumulative investment cited in Grube et al. [47] results from different assumptions regarding the number of charging points per vehicle in the two scenarios considered (moderate vs. strong development).

Demand for a public charging infrastructure and the investments tend to increase as BEV stock rises. This is seen in growing specific investment per BEV with increasing BEV stock (Figure 5-10).

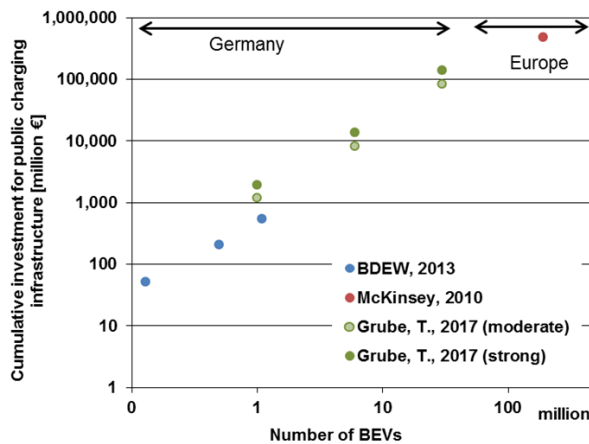


Figure 5-10: Comparison of the cumulative investment for public/semipublic normal and fast charging infrastructure depending on the number of BEVs.

According to BDEW [45], specific cumulative infrastructure investment per BEV is approx. € 500 per BEV, which is stable for small BEV stocks (Figure 5-11). The highest values for specific investment per BEV occur in the 30 million BEV scenario described in Grube et al. [47]. The main reason for this is that, in this study, total infrastructure investment takes account of additional grid reinforcements as well as a significantly higher number of charging points (on-street charging and additional fast charging).

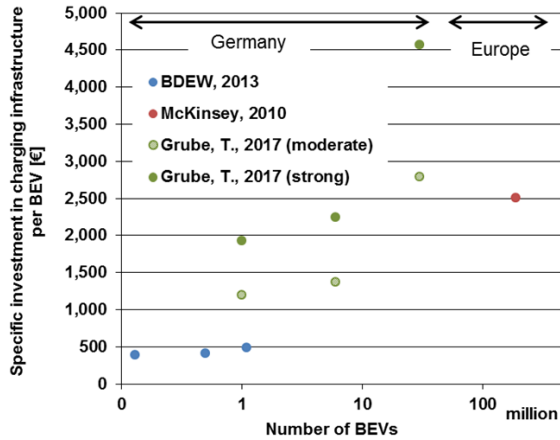


Figure 5-11: Comparison of specific investment per BEV for public/semipublic normal and fast charging infrastructure depending on the number of BEVs.

In general, increasing specific charging infrastructure investment per BEV in line with rising BEV stock is reasonable due to additional investments in grid reinforcements. In this context, expected increases in future charging power constitute an important trend. However, great uncertainty exists regarding the extent of the grid reinforcement measures required. Therefore, further research is necessary.





## 6 Detailed Modeling of Infrastructures

This section describes in detail the approach of the study to analyze cumulative investments in hydrogen fueling and electric charging of passenger cars in Germany. The distinctive aspect of the assessment is the uniform setting of parameters for market penetration, for the electricity generation and for transportation scenarios of both infrastructures types.

Section 6.1 explains the methodical background and the scenario assumptions, while sections 6.2 and 6.3 present the modeling of infrastructures and their assessment. Chapter 6 concludes with a comparison of results pertaining to investment, energy demand and CO<sub>2</sub> emissions (section 6.4).

### 6.1 General Methodical Approach

Any consideration of renewable energy in the transport sector requires a careful analysis of electricity demand and generation, whereby high spatial and temporal resolution is indispensable. For the present study, the installed capacities of renewable power generators was designed to achieve an 80 % reduction in CO<sub>2</sub> emissions compared to the reference year 1990 for Germany. This scenario, which is presented in detail in sub-section 6.1.1, also includes the determination of curtailed energy relative to energy demand and supply patterns and grid constraints. Finally, assumptions relevant to vehicle utilization and to the economic assessment are described in sub-sections 6.1.2 and 6.1.3 respectively.

#### 6.1.1 Electricity Demand and Generation Scenario

Since infrastructure costs for both technologies depend heavily on the characteristics of the available electricity systems and their design, it follows that the investigated scenario should be detailed with respect to temporal and spatial resolution. Moreover, considering the same power sector scenario makes for a better evaluation and comparison of the two technologies. The following section describes how the various power system components are modeled, including power grid topology, demand and generation patterns, and electricity market modeling. Due to limited computational resources and data availability, the power flow model only focuses on the transmission level, and therefore ignores any limitations and constraints that might arise at the distribution level and which could have a greater impact on BEV integration (see chapter 6.3).

In the context of this study, the term 'residual load' refers to the difference between electricity demand and potential generation from RES, including wind, solar, hydro and bioenergy and imports and exports. Residual load profiles were calculated for each hour and municipality of Germany for the scenario using methodologies that harness corresponding technologies with the desired accuracy. After this aggregation process, the residual load is either positive or negative for different regions and time periods. Geographical differences can be balanced to a certain extent using the transmission grid, depending on the grid's transfer capacities. Nevertheless, the likelihood of achieving a perfect balance is very low. In this case, the remaining positive residual load implies there is a need to operate non-RES power plants or seasonal storage while the remaining negative residual load implies that available power cannot be consumed and can therefore be stored, transformed or curtailed.

### 6.1.1.1 Installed Generation Capacities

Based on current tendencies and international agreements for reducing GHG emissions, it can be assumed that the key drivers for designing a sustainable electricity scenario are significantly lower GHG emissions from power generation (i.e., significant less use of coal as primary carrier), as well as the use of wind turbines and photovoltaics (PV) as the dominant technologies for generating electricity from renewable sources. Moreover, the majority of conventional power plants are expected to be fueled by natural gas due to lower specific CO<sub>2</sub> emission factors and the higher flexibility which are better able to adapt to fluctuating demand. The development of renewable electricity generation is in line with the approach of Robinius [24].

#### Onshore:

In view of current developments in wind electricity generation, including the economies of scale already achieved with wind turbines, this technology will be one of the most significant electricity generation technologies in future. Estimating the total installed capacity for future scenarios is challenging however due to each turbine's high level of dependency on local wind conditions and the need to correlate these different generation patterns.

The selected scenario for this study is as follows: a total installed capacity of 170 GW, whereby the addition of any extra wind turbines takes existing turbines into account. New sites are selected by excluding ineligible land, i.e. protected areas, security barriers around other infrastructure and settlements, etc., and by exploiting places with the best levelized cost of electricity (LCoE) – based on local wind conditions over an entire year and the power curves of five typical wind turbine technologies. Figure 6-1 shows those areas of land in Germany considered eligible for wind turbine installations.

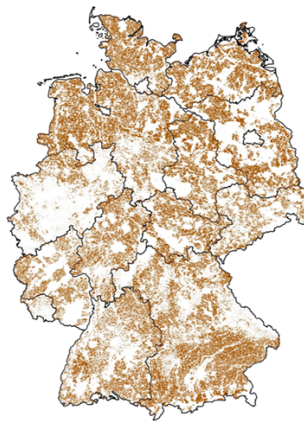


Figure 6-1: Eligible land (colored areas) for onshore wind generation in Germany according to the scenario assumptions [24].

#### Offshore

Similarly to onshore electricity generation, the performance of offshore wind turbines depends on local wind conditions and typical turbine power curves. Additional turbine placement by 2050 merely considers the existing infrastructure, as well as the distances

between the turbines to avoid shading effects that reduce power generation potential. A total of 59 GW installed offshore wind is assumed for the electricity generation scenario.

### **Solar power (PV)**

In contrast to modeling power generation from wind, photovoltaic system modeling (PV) uses simpler approaches. The smaller capacities of individual photovoltaic installations, in conjunction with the smaller spatial variability of key generation factors, primarily irradiation, permit a more statistical analysis of PV generation that is capable of producing accurate results above a specific level of spatial aggregation.

In order to incorporate the current status of PV installations, existing projects were identified using the Energy Map [49] and aggregated at the municipality level. The individual generation profiles were determined by distributing the national PV generation profile obtained from the European Network of Transmission System Operators (ENTSO-E) [50] according to the installed capacities. The additional capacities for the scenario followed the existing distribution pattern but also respected any potential regional saturation. From the total availability of 117 GW calculated by the model, 55 GW are selected for the scenario.

### **Hydro**

Although power generation from hydro plants constitutes one of the most significant renewable sources both globally and within Germany, its further development is considered limited, mainly because of the high dependency on geomorphological conditions and the intense impact on local ecosystems. Since most hydro potential in Germany has already been exploited, it is assumed that the same infrastructure will be present in future without any significant differences. Therefore, a total installed capacity of 5.6 GW is assumed.

### **Biomass**

Bioenergy is a contributor to regional residual load profiles. From a technological point of view, power generation from bioenergy in the form of biomass and biogas is considered a flexible power source, since the fuel can be stored and consumed when needed. However, within the current legal framework, bioenergy is operated independently of the electricity market with a guaranteed tariff. Therefore, bioenergy-fueled power plants are included in the residual load profiles as fixed generation but are not included in market operation.

The spatial distribution of the installed capacities is based on the Energy Map [49], aggregated at the municipality level. The selected generation scenario does not incorporate any potential growth from today's values, thus remaining at approximately 7 GW overall.

Table 6-1 shows the total installed capacities by technology, including the potential for annual electricity generation and respective hours of maximum capacity operation (full load hours). It can be observed that the dominant technology, both in terms of installed capacity and produced electricity is wind, followed by PV, which exhibits, the lowest amount of full load hours however.

Table 6-1: Installed capacity, produced electricity and full load hours of renewable electricity generation of various RES technologies for the 2050 scenario.

Type of RES	Installed capacity [GW]	Produced electricity [TWh]	Average full load hours [h]
Wind (onshore)	170	350	2,057
Wind (offshore)	59	231	3,927
PV	55	47	851
Hydro power	6	21	3,788
Biomass	7	44	6,577

As with RES installed capacities, estimating the status of conventional power plants for future scenarios is difficult, since most network development plan reports do not go beyond 20 years and the replacement, decommissioning or construction of new power plants is difficult to predict. In this study, the term 'conventional power plant' refers to all fossil-fueled power plants distinguished only by the primary energy source, i.e., hard coal, lignite, natural gas and oil, as well as by the technology type, i.e., steam turbine for coal and open-cycle or combined-cycle for natural gas and oil. Assuming an average life expectancy of 40 years for coal-fired power plants and the fact that current plants are already around 30 years old on average (according to Markewitz et al. [51]), a scenario for the future electricity generation have to rely highly on trends and corresponding market analysis.

The assumed power plant deployment in this scenario conservatively based on existing installations and the projected capacities of scenario B2035 as per the Network Development Plan for 2030 from Germany's Bundesnetzagentur or Federal Network Agency [52]. Information on the existing power plant fleet can be obtained from the Bundesnetzagentur [53] and the Federal Environment Office [54], which list all power plants larger than 10 MW with accurate geographical coordinates and other parameters, like commissioning year and technology, etc. The two databases have since been merged to form the Open Power System Data platform [55], which also enables direct access to the merged dataset.

Assuming that any new power plants will most likely be located close to or on top of existing ones due to existing fuel provision and grid infrastructure as well as electricity demand requirements, existing power plants were simply scaled to meet the total projected capacities in the B2035 scenario [52]. Figure 6-2 shows the spatial distribution of the conventional power plants considered for the electricity scenario in this study.

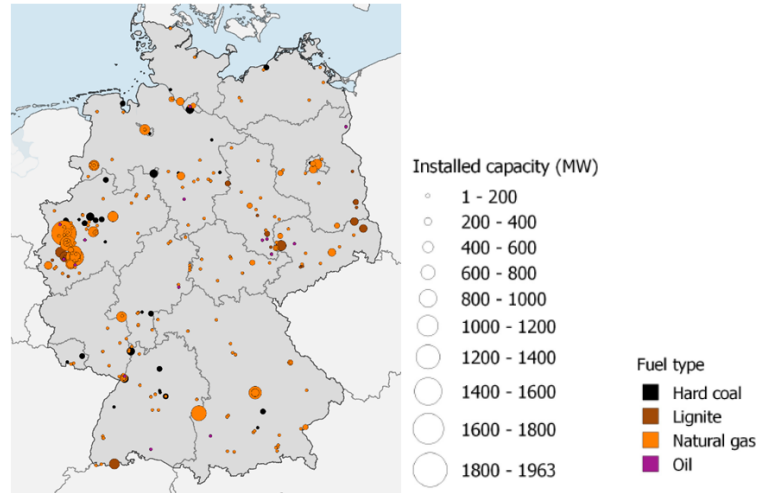


Figure 6-2: Conventional power plants in Germany with locations matching existing infrastructure, but with scaled capacities used for the 2050 scenario.

Moreover, Table 6-2 shows the average technical characteristics that were used to model the power plants' behavior in the electricity market. Fuel prices, as well as the CO<sub>2</sub> price (76 €/t), are taken from PROGNOS [56] for the year 2050. Power plant efficiencies were determined using a combination of estimated values from the OPSD platform [55], which either uses internal sources or calculates them based on statistical information [57], and a similar in-house approach. With no detailed plan for the individual power plants, the efficiencies remain the same as for 2015. The relatively low efficiency of natural gas generators is due to the most frequent open-cycle technology that allows the fastest reaction to fluctuating load. Nevertheless, despite the high cost of CO<sub>2</sub> emissions, natural gas plants remain slightly more expensive in terms of marginal cost of generation.

Table 6-2: Total installed capacities and technical parameters of fossil power plants in the scenario.

	Total capacity [GW] [52]	Average efficiency	Fuel price [€/MWh] [56]	Specific emission factors [t <sub>co2</sub> /MWh] [58]	O&M cost [€/MWh] [59]	Average Marginal cost [€/MWh]
Lignite	9.3	0.402	12.6	0.384	3.68	107.99
Hard coal	10.8	0.415	15.8	0.337	3.59	103.8
Natural gas	41.5	0.443	30.99	0.201	2.26	110.83
Oil	0.9	0.421	73.61	0.264	27.97	251.06

### 6.1.1.2 Demand and Residual Load Profiles

Merely determining the installed capacities does not suffice in order to capture the intra-day dynamics of electricity demand and variable RES generation and to calculate all system states for the investigated scenario. Therefore, for all of the quantities involved, hourly values were generated at the municipal level and then aggregated to the county level. Together with

the Voronoi tessellation this allows for a more accurate distribution of the profiles to the grid nodes.

For onshore and offshore wind farms the same methodology is applied. Electricity generation depends only on the wind speed conditions for each turbine. Wind data from the DWD weather stations [60] are interpolated to estimate the average hourly wind speed profiles at a turbine's height and, based on the turbine's power curve, a power generation profile is calculated. As described in the scenario design section, PV generation is calculated by using the national generation profile and scaling to installed capacity. Despite local discrepancies due to local weather conditions, like cloudiness or temperature, average behavior at the county level is not expected to deviate significantly. For hydro generation, the study leveraged the high correlation with rainfall to form the basis of local generation profiles. Nevertheless, fixed behavior was selected to avoid having to include storage modeling which would have involved prohibitive amounts of computation time. Biomass generation is assumed to be constant over the year due to current market conditions.

For positive residual load, electricity demand is also modeled in high spatial and temporal detail using a top-down methodology [61] in which the reported profiles of vertical load from each of the four transmission system operators (TSOs) in Germany [62] are distributed to the municipality level based on different criteria amongst others the local annual gross domestic product [63]. However, besides the reported values totaling 463.1 TWh, consideration was given to additional load originating from various sources, such as transmission losses and non-distinguishable onsite industrial production, as well as consumption by trains. Total electricity demand resulted in a higher value of 528 TWh which is a more accurate representation of electricity consumption in Germany in 2013 [64].

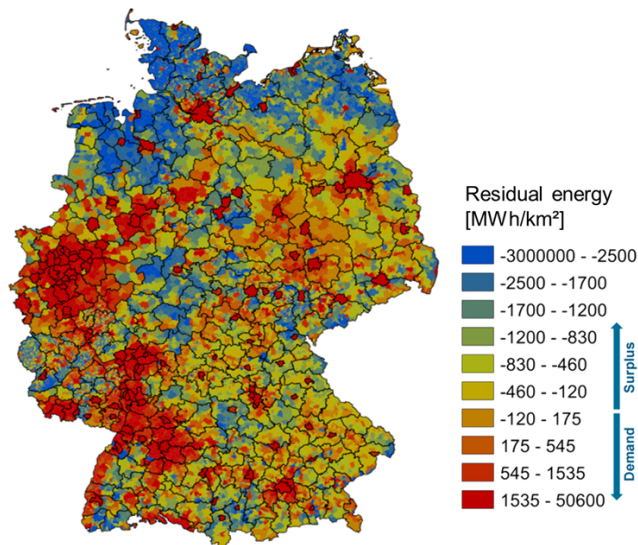


Figure 6-3: Spatial distribution of the total residual load density without grid restrictions (residual load includes electricity demand, generation of wind, solar, hydro and bioenergy, as well as imports and exports). [3]

The last part of the residual load is made up of imports and exports to neighboring countries. The study assumes electricity import and export situation of 2013 to identify the maximum potential of the residual load. On the other hand, Germany's a complete isolation would also be unrealistic, considering its central geographical location and vast number of interconnections. By way of small inclusion of power trading, and assuming that similar trends will also be followed in the future, historical values of imports and exports were taken from ENTSOE [50] and assigned to the counties that form part of this network.

Finally, residual load was calculated for each municipality and time step, whereby imports contribute to negative residual load and exports to positive residual load, which means they behave like additional load. Temporally aggregated residual load density is shown in Figure 6-3. The highest positive density is located near urban areas, while the highest negative density is located in the north, where most wind turbines are installed. The profiles are then assigned to electricity grid nodes, setting the boundary conditions for electricity market simulation, which also defines the power flows across the system.

#### **6.1.1.3 Electricity Grid and Market Modeling**

One of the major limitations of modeling power systems at the node level is the lack of publicly available data. One of the most reliable open network models is that developed by Scigrid [65]. Scigrid uses the geospatial data available from the Open Street Map (OSM) community [66] and takes a heuristic approach to generating a network with accurate geographical information and a minimum set of parameters, including voltage level, length, number of circuits and number of conductors. Network generation according to Scigrid only considers those elements belonging to so-called relationships. Nevertheless, grid representation improves in those areas that have this attribute. Since Germany has one of the most comprehensive open datasets, Scigrid produces the most reliable results for this area. However, the applied grid model in this study is checked against the VDE/FNN map [67], as well as by using a 2015 benchmark scenario. Despite being physically non-intuitive, transformers between the 220 and 380 kV lines are not included in the model due to a lack of available information. In particular, any lines that meet in the same substation or T-junction are considered to be electrically connected, since mere knowledge of geographical information is not sufficient for this purpose. The final grid version of 2015 was further enhanced with new or upgraded lines and HVDC links based on the B2025 scenario of the NEP [68], which constitutes a moderate projection of the future German grid and includes the four HVDC corridors. Moreover, all the projects of common interest reported by the European Commission that lie in the German region were incorporated. The final 2025 version is illustrated in Figure 6-4. Further long-term developments beyond 2030 cannot be safely estimated at this detailed level, since no grid development plans have been conducted for such cases.



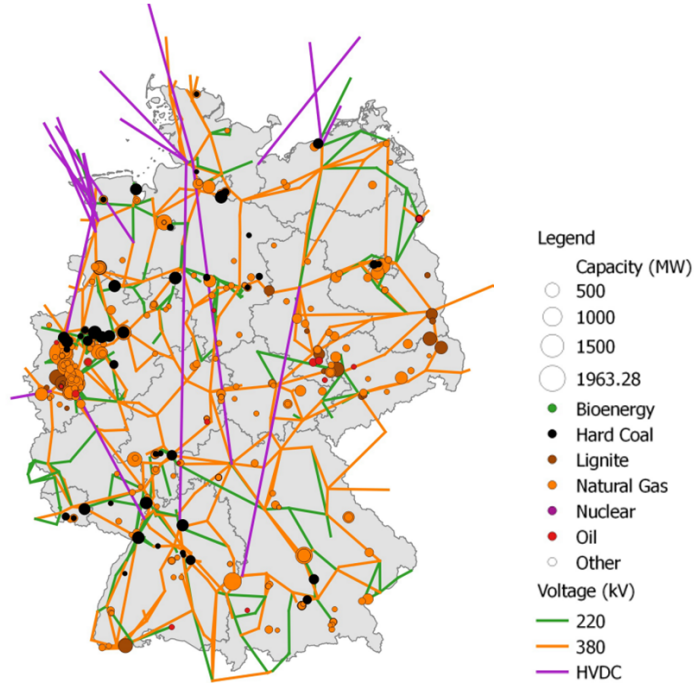


Figure 6-4: The transmission grid for Germany according to scenario B2025 of the NEP [68]. The lines are only represented as point-to-point connections for a better visualization of the electrical topology.

Traditionally, power flow equations can be described by either the non-linear AC formulation or the linear DC formulation. Computational constraints and data availability mean that full AC modeling of power flow equations are beyond the scope of this study. Therefore, DC approximation is selected. Moreover, because it increases the voltage level, the DC load-flow approach is best suited to the transmission level under investigation (see Syranidis et al. [69]). The minimal parameters required for this approach are the line reactances that define the flow interactions and thermal capacities limiting maximum current flows in high voltages. The reactances depend primarily on the geometry of the tower, while thermal capacities also depend on the weather conditions. Nevertheless, considered constant, the two values for a typical tower configuration were taken from the literature [70].

One further challenge that stems from the lack of information about lower voltage level topologies concerns the allocation of the regional profiles to the network nodes. This study selected a simplified approach, wherein the regional profiles are first aggregated to the county level, such that most of the regions include at least one transmission node, excluding the T-junctions. All other types of nodes could potentially be connected to a lower voltage level, and are hence considered valid candidates for the assignment of residual load which is done by distributing each regional profile uniformly to its enclosed nodes. For regions without nodes, the whole profile is assigned to the node that is closest to the region's centroid.

The dispatch model consists of an integrated optimization approach that combines an electricity market with perfect competition conditions and a re-dispatch scheme based on the minimization of total operating costs. The two elements are combined in a single optimization formulation, where the objective function requires total operating system costs to be minimized for every time step. The selected time step is one hour, which suffices for assuming quasi-static system conditions while also allowing a sufficient description of the intra-day dynamics posed by the high variability of wind and PV generation, as well as electricity demand.

The optimization variables consist of the power plants' generation outputs. Zero costs are set for generation from renewable energy sources and a constant marginal cost for conventional power plants in order to obtain a linear objective function. Generation capacities at conventional plants depend solely on the installed capacity, assuming unlimited fuel availability. However, as discussed previously, corresponding capacities for the variable RES technologies (i.e. wind turbines and photovoltaics) are determined by local weather conditions for each time step. These varying available capacities, which are calculated exogenously, are then imported into the optimization as fixed but time-varying constraints.

The second type of constraints concerns transmission grid limitations. The study takes account of the nominal capacity of lines and a simple approach of security constraints. Hence, the grid's capability to address the power inputs is overestimated in comparison to real operational conditions. On the other hand, this approach yields conservative results for curtailments and hydrogen production potential, which are expected to be higher in reality. The entire method is most commonly referred to as DC optimal power flow (DCOPF) and is based on an operational cost minimization objective.

Since the model is only designed for a single market region, power trading with neighboring countries cannot be directly included in the optimization process. However, the German electricity system constitutes a core element of a highly meshed, interconnected system with complicated behavior and control. Therefore completely neglecting international power trading would also lead to significant discrepancies compared with real-life conditions.

#### **6.1.1.4 Calculation of Curtailments**

Applying the model on the electricity scenario reveals a large amount of curtailments originating primarily from the poor temporal correlation between wind generation and electricity demand, as well as from the transmission grid's constraints as seen in Figure 6-5.

The reason for the high amount of unusable renewable electricity is the temporal mismatch between generation and demand. Even a perfect transmission grid (copper plate) will not solve the problem of renewable electricity curtailment as long as there are no new highly flexible consumers available. In the electricity scenario, it is assumed that there are no additional flexible demand options beyond hydrogen and charging infrastructure for transportation. The demand for electricity stays at the 2013 level while increases in electricity demand due to new consumers offset the increasing efficiency of applications. The import and export situation is also fixed to the conditions of the reference year and does not change in the scenarios. Against this backdrop, the scenario study then proceeds to analyze the possible impact of supplying BEV with electricity and FCEV with hydrogen in the light of new flexible demand options

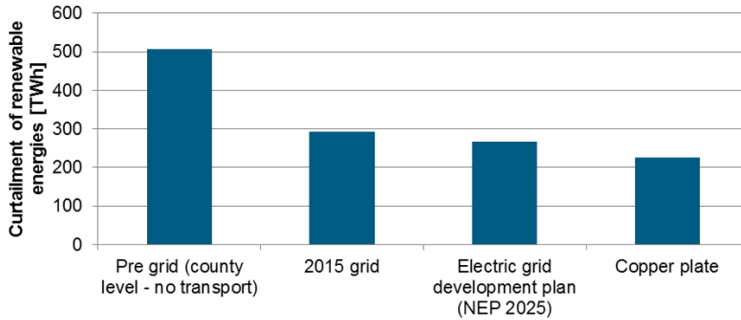


Figure 6-5: Curtailment of renewable electricity for different transmission grid scenarios.

The analysis of each node of the transmission grid with respect to the number of curtailment incidents and the corresponding amount of energy reveals that only a few nodes undergo frequent significant curtailments (Figure 6-6).

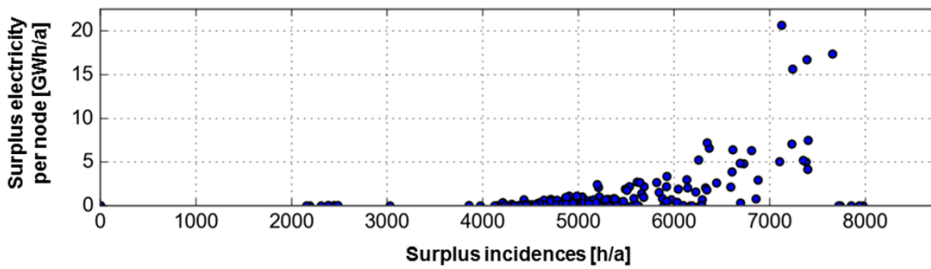


Figure 6-6: Nodal analysis of surplus electricity and temporal appearance over the year.

These nodes are interesting candidates for power-to-hydrogen applications, since the use of installed electrolyzers would be high and result in improved economic conditions.

### 6.1.2 Transportation Scenario

This study considers three different market penetration scenarios for BEVs and FCEVs. For the sake of comparability, annual mileage and the number of vehicles are assumed to be the same for both while annual mileage is set at 14,000 km based on today's average [48]. Specific energy consumption projections for the vehicle types were based on the New European Driving Cycle (NEDC) and set at 0.65 kg of hydrogen per 100 km for FCEVs [71]. With regard to BEV energy demand, the study assumed an increase in battery capacity from 25 kWh in the 0.1-million BEV scenario to 75 kWh and 100 kWh respectively in the 20-million BEV scenario (see section 6.3 for further information on the BEV base cases). The resulting BEV energy demand as a function of BEV mass was determined using the simulation model according to Grube [72]. The 20 million BEV scenario resulted in 30.8 TWh of additional electricity demand, while the FCEVs scenario required 1.8 million tons of hydrogen, as shown in Table 6-3.

Table 6-3: Total energy consumption per scenario for BEVs and FCEVs.

		BEV		FCEV	
Scenario	Annual mileage	Specific electricity consumption Ref75   Ref100	Total electricity consumption Ref75	Specific hydrogen consumption	Total hydrogen consumption
[# of vehicles]	[km/year]	[kWh/100 km]	[GWh/year]	[kg H <sub>2</sub> /100 km]	[1000 t/year]
100,000	14,000	11.1   11.1	154	0.65	9.1
1,000,000	14,000	11.5   11.9	1540	0.65	91
20,000,000	14,000	12.3   13.3	30,800*	0.65	1,820

\*losses of charging and electric grid not included

To simplify the description of the detailed assumptions and corresponding results, in sections 6.1 to 6.3 the market penetration scenarios in Table 6-3 are described in depth. For the market penetration of 3, 5, 10 and 15 million each BEVs or FCEVs vehicles the designs and analysis of infrastructures is performed, too. The aggregated results of these scenarios form part of Section 6.4.

For the distribution of electric vehicles in Germany, a cluster-based sigmoidal curve approach by Robinius et al. [73] is applied. It is assumed that the market for electric vehicles will start developing in six German metropolitan areas, similar to H2 MOBILITY [12]. Each district has a startup year depending on the proximity to the metropolitan areas. Neighboring regions will start earlier, while more remote regions later on. After this startup year, the number of electric vehicles will rise in keeping with the sigmoidal curve up to a maximum vehicle share of FCEVs [37].

With regard to hourly resolution, the FCEV charging infrastructure analysis in this study assumes continuous demand over the entire year. The BEV infrastructure also factors in hourly load profiles, as shown in Figure 6-7 [74].

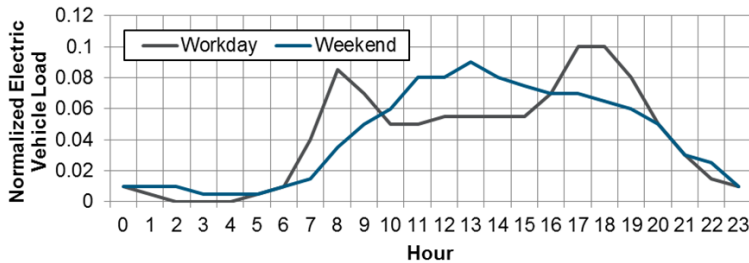


Figure 6-7: Electric load profile separated by workday (Monday to Friday) and weekend [74].

Monday to Friday thus accounts for 73.9 % of the overall load, while Saturday to Sunday for 26.1 % [75]. Controlled charging of BEV can shift charging demand over the day and mitigate load peaks. This is not part of the analysis.

### 6.1.3 Economic Assumptions for Infrastructure Calculations

This chapter concerns the economic assumptions and methods used in the infrastructure calculations. The costs considered in this study do not take taxes, margins, fees or levies into account.

#### 6.1.3.1 Investment Cost Impacts from Scaling and Learning

This study looks at two different types of infrastructure investment effects, namely scaling and learning. As the capacity of a chemical plant or conversion unit increases, specific investment cost decreases. This is due to higher output quantities compared to fixed costs [76]. These scaling effects are taken into account by applying a scaling function to different technology investments:

$$I_1 = I_0 * \left( \frac{C_1}{C_0} \right)^\alpha$$

$I_0$ : Reference cost;  $I_1$ : New cost;  $C_1$ : Upscaled capacity;  $C_0$ : Reference capacity;  $\alpha$ : Scaling factor

Furthermore, investment costs decrease with higher cumulated capacities due to accumulating technology experience [76, 77]. Learning effects are typically displayed as a percentage reduction of previous costs for each doubling of experience [77]:

$$I_1 = I_0 * (1 - \beta)^{\log_2 \left( \frac{V_1}{V_0} \right)}$$

$V_1$ : New installed capacity;  $V_0$ : Base installed capacity;  $I_0$ : Base cost;  $I_1$ : New cost;  $\beta$ : Learning rate

Similar to Creti et al. [78], we assumed a learning rate of 6 % for important FCEV and BEV infrastructure components. According to McDonald and Schrattenholzer [77], this is a conservative assumption for energy technologies.

#### 6.1.3.2 Electricity Prices

The assumed electricity prices are based on own assumptions and on Eurostat [79]. The electricity price is scaled to annual consumption and type of consumer (Table 6-4). The electricity price for industrial consumers with the highest consumption rates starts at 6 €/ct/kWh. This price matches the assumed levelized costs of electricity for wind onshore turbines at appropriate locations [24].

Table 6-4: Electricity price scenario for households and industrial consumers in Germany based on own assumptions and Eurostat (excluding taxes and levies) [79].

Annual consumption of electricity	Electricity price [€/ct/kWh]
households < 5 MWh	15.73
industrial consumption < 20 MWh	14.43
20 MWh < industrial consumption < 500 MWh	11.73
500 MWh < industrial consumption < 2 000 MWh	9.84
2 000 MWh < industrial consumption < 20 000 MWh	8.68
20 000 MWh < industrial consumption < 70 000 MWh	7.19
70 000 MWh < industrial consumption < 150 000 MWh	6.00

## 6.2 Hydrogen Infrastructure

This chapter describes the modeling of hydrogen infrastructure for FCEVs. The resulting infrastructure design corresponds to the already introduced electricity scenario, as well as the underlying assumptions for different degrees of FCEV market penetration in Germany.

### 6.2.1 Modeling of Hydrogen Infrastructure Pathways

Given the variety of technologies available, there are multiple potential hydrogen supply chain pathways. Reuß et al. [80], like Yang and Ogden [81], show that the cheapest delivery mode is influenced by various factors, such as consumption and transport distance. The calculation of overall supply chain cost breaks the supply chain down into single modules. This is based on four key steps [80]: Production, storage, transport and fueling.

For 0.1 and 1 million FCEVs, it is assumed that current production facilities – steam methane reforming (SMR) and by-product hydrogen from chlor-alkali electrolysis (CAE) – will provide adequate quantities of hydrogen fuel. In the scenario with 20 million FCEVs, hydrogen is produced from surplus electricity that cannot be used in the electric grid. This means the infrastructure needs additional storage facilities to bridge the temporal gap between hydrogen demand and production. This study considered five hydrogen transport pathways:

- GH<sub>2</sub> pipeline: Gaseous hydrogen (GH<sub>2</sub>) transportation via pipeline
- GH<sub>2</sub> trailer: GH<sub>2</sub> transportation via trailer
- LH<sub>2</sub> trailer: Liquefied hydrogen (LH<sub>2</sub>) transportation via trailer
- GH<sub>2</sub> pipe/trailer: Pipeline network for the transmission of GH<sub>2</sub> to the hub of a district and GH<sub>2</sub> trailer transportation for “the last mile” to the fueling station.

An overview of all pathways considered in the study is shown in Figure 6-8.

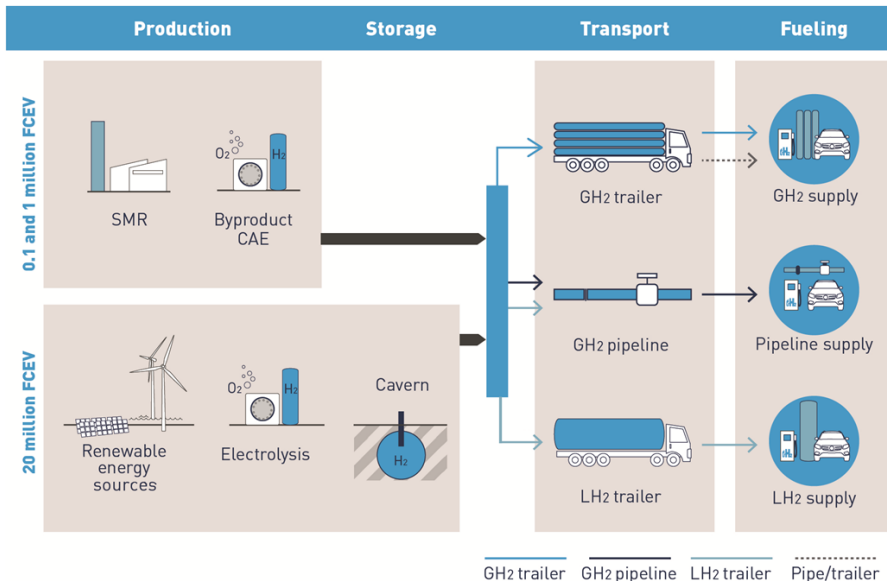


Figure 6-8: Schematic figure of investigated pathways.

Table 6-5 shows the main techno-economic assumptions that impact all considered pathways for production, transport, distribution and fueling.

Table 6-5: General assumptions for all modules.

Full load hours electrolysis	[h/a]	4,500	Weighted Average Cost of Capital (WACC)		8 %
Surplus electricity cost	[€/kWh]	0.06	Diesel cost	[€/l]	1.2
H <sub>2</sub> price SMR/by-product	[€/kg]	2	Driver wage [82]	[€/h]	35
Storage days <sup>a</sup>	[days]	60	Natural gas cost	[€/kWh]	0.04
Storage part <sup>b</sup>	[1/year]	30 %	Water cost	[€/m <sup>3</sup> ]	4

<sup>a</sup> [24]. <sup>b</sup>Share of hydrogen that must be stored before transportation [83].

### 6.2.1.1 Hydrogen Production

The hydrogen production facilities vary in the three scenarios depending on the corresponding demand of the assumed FCEV market penetration scenario (see Table 6-6). For low market penetrations of FCEVs, hydrogen can be produced with existing steam methane reforming technology and as a byproduct (of chlor-alkaline electrolysis in the chemical industry).

Table 6-6: Hydrogen production per scenario.

Scenario	Total demand [kt/a]	SMR [kt/a]	Byproduct CAE [kt/a]	Electrolysis [kt/a]
0.1 million FCEV	9.1	4.6	4,6	0.0
1 million FCEV	91.0	45.5	45.5	0.0
20 million FCEV	1,820.0	0.0	0.0	1,820.0

Therefore, we chose the six biggest merchant hydrogen plants with steam methane reforming (SMR) and compressed gas hydrogen output and byproduct production (BP) based on the data from the Hydrogen Analysis Resource Center [84]. Table 6-7 lists the six locations and associated production types, with maximum capacity assumed.

Table 6-7: Hydrogen production per site location (scenario 0.1 and 1 million FCEV).

Location	Ingolstadt	Leuna	Brunsbüttel	Hürth	Bitterfeld	Leuna
Type	SMR	SMR	SMR	BP	BP	BP
Capacity [t/year]	16,500	16,500	16,500	6,300	21,350	21,350

Clean transportation systems required low carbon fuels based on RES. Therefore, higher FCEV penetration scenarios have to shift to hydrogen production by electrolysis based on renewable electricity. The 20-million vehicle scenario is thus based on hydrogen production by water electrolysis. The electricity required for this process is assumed to be supplied from surplus renewable energy occurring at locations with high levels of renewable power production [24, 80]. Next to the availability of surplus energy, the full load hours of electrolysis plants are one of the main key parameters that determine hydrogen's cost. Therefore, full load hours play an important role alongside total surplus power.

In the assumed power generation scenario (see section 6.1.1) the electrolysis plants are located next to grid nodes with an adequate surplus profile. To select potential electrolysis sites, we evaluated the hydrogen production potential of each node by full load hours as well as by total production potential. For this study, there were two main constraints: More than 1.82 million tons of hydrogen must be produced per year to meet hydrogen demand for 20 million FCEVs. This corresponds to a minimum of 86.6 TWh of electricity, assuming an electrolysis efficiency of 70 %. Furthermore, electrolysis capacity must be above 10 MW to avoid extremely small units. With these constraints, the maximum full load hours amount to 4,500 h and an installed electrolysis power of 21.7 GW based on the available surplus electricity. This could supply up to 1.9 million tons of hydrogen from 47 electrolysis sites. Figure 6-9 shows the distribution of these locations along with the corresponding capacity of the electrolysis site.

Clearly, the north of Germany has much greater electrolysis potential compared to the south, where there are only small locations with less than 100 MW. This is chiefly due to the assumed electricity scenario with high installed capacities of offshore and onshore wind in the north of Germany. Due to congestions in distribution grids, further potential locations for producing hydrogen can be of interest in future.

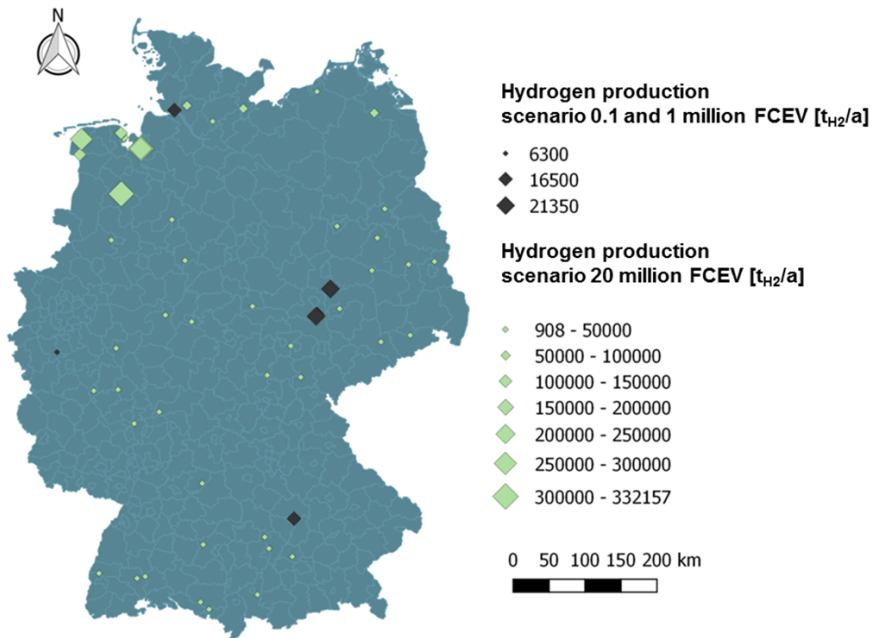


Figure 6-9: Locations of hydrogen production facilities for 0.1 and 1-million FCEVs scenario (black) and 20 million FCEVs scenario (light green). The electrolysis locations for the 20 million FCEVs are based on grid nodes with high surplus energy.

Furthermore, the large electrolysis plants are located at the grid nodes of offshore grid connections. This means that at these locations, onshore as well as offshore power accumulates, resulting in even higher renewable electricity at single nodes. Table 6-8 shows the assumed techno-economic parameters for calculating the cost of electrolysis.



Table 6-8: Techno-economic electrolysis parameters [24, 29, 85].

Pressure Out	[bar]	30	Invest	[€/kW]	516 <sup>a</sup>
Water Demand	[m <sup>3</sup> /kg]	0.01	Depreciation Period	[years]	10
Electricity Demand	[kWh/kg]	47.6	O&M (Operation and Maintenance)	[1/year]	3 %

<sup>a</sup> Electrolysis-specific investment is calculated with 6 % learning rate compared to 28 GW of electrolysis power installed for 500€/kW similar to Robinus et al. [24]

## Storage

Large-scale storage options for renewably produced hydrogen are essential due to fluctuating power production from renewable energy sources. Reuß et al. [80] show that underground gas storage facilities have the highest economic potential. Meanwhile, Schiebahn et al. [85] outline different types of underground storage, like depleted oil and gas fields, aquifers and salt caverns. Both references show that salt cavern structures are the most suitable storage options due to the small amount of cushion gas requirements (20-35 %) and their chemical inertia. Nevertheless, salt caverns depend on the availability of underground salt structures. In Germany, salt deposit structures mainly occur in the north, as shown in Figure 6-10.

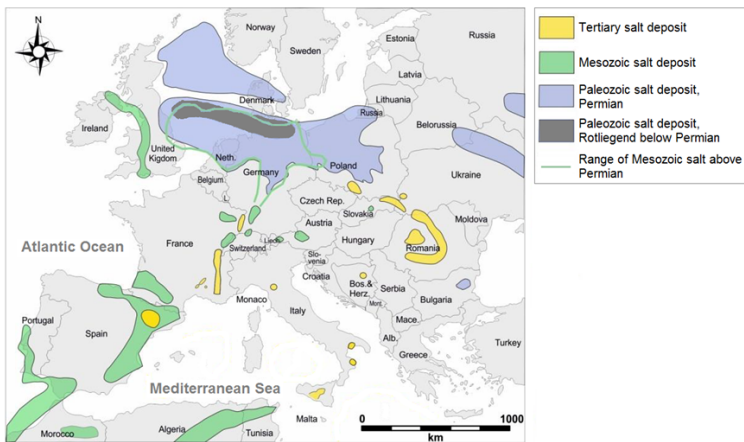


Figure 6-10: Potential salt cavern underground gas storage sites, modified from [86].

Therefore, electrolysis locations located in the south of Germany will require additional seasonal storage options. In this study, pipeline tube-storage is assumed as a second storage option. Table 6-9 shows all techno-economic parameters of the storage module.

Table 6-9: Techno-economic storage parameters.

	unit	Salt cavern storage <sup>a</sup>	Tube storage <sup>b</sup>
Storage Pressure	bar	60-150	15-250
Investment $I_0$	€	81,000,000	250
Capacity $C_0$		500,000 [m <sup>3</sup> ]	1 [kg]
Scaling factor $\alpha$		0.28	1
Depreciation Period	year	30	20
O&M	[1/year]	2 %	2 %

<sup>a</sup> Assumptions, derived from Acht [87]. <sup>b</sup> Own calculations based on [29, 88, 89, 90]

### 6.2.1.2 Transport and Distribution

The current state-of-the-art in hydrogen transportation is based on three modes: Hydrogen pipeline, tube or container trailers for gaseous compressed hydrogen or the transport of liquid cryogenic hydrogen [10]. Yang and Ogden investigated a variety of hydrogen transportation techniques and showed that their application depends on transportation distance and overall demand. They demonstrated that the rising economic potential of hydrogen pipeline grids corresponds to increasing hydrogen demands. Reuß et al. [80] explicitly consider the hydrogen supply chain for transportation and show that even alternative carriers, such as liquid organic hydrogen carriers, have potential for small-scale storage.

### Hydrogen Pipeline Methodology

The methodology used to calculate hydrogen pipelines is derived from the work of Krieg [91] and Baufumé et al. [92], whereby the latter determines the shortest distance between production and consumption via existing infrastructure corridors. Thus, the existing lines of the high pressure natural gas grid and rail network are used as potential routes for the hydrogen pipeline grid. Ignoring these input routes, the shortest connection between the source and sink could cross areas restricted for infrastructures, like nature protection areas [91]. Krieg distinguishes furthermore between the transmission and distribution grid.

A transmission grid connects sources and so-called hubs. Hubs represent secondary sources and are allocated to the centroid of the 402 analyzed district areas for Germany within the scope of modeling. Distribution grid calculations determine the direct connection between the hubs and the fueling stations. Fueling stations located along freeways are connected directly to the hub, whereas district fueling stations are connected to metropolitan areas, then to urban areas and, finally, to rural areas. Since it is not possible to install the distribution pipeline along existing natural gas pipeline routes, detour factors are added depending on the pipeline end points (see Table 6-10).

Table 6-10: Pipeline detour factor matrix for distribution pipelines based on Krieg [91].

Region	Rural	Urban	Metropolitan
Rural	1	1.25	1.5
Urban	1.25	1.5	1.75
Metropolitan	1.5	1.75	2

The total cost of pipeline networking was calculated by minimizing pipeline capacities at fixed sources and sinks. For pipeline cost calculation, the cost function derived by Krieg [91] computes the specific cost per kilometer of a pipeline using the diameter  $D$ , whereby the minimal diameter permitted is 100 mm [91].

$$Invest \left[ \frac{\text{€}}{\text{m}} \right] = Invest_A * D^2 + Invest_B * D + Invest_C$$

Other relevant techno-economic parameters for calculating the cost of a pipeline network are given in Table 6-11.

Table 6-11: Pipeline techno-economic parameters [83, 93].

Pressure	[bar]	70-100	Invest <sub>A</sub>	€/mm <sup>2</sup>	0.0022
Depreciation Period	[year]	40	Invest <sub>B</sub>	€/mm	0.86
O&M	[1/year]	4 %	Invest <sub>C</sub>	€	247.5
Density <sup>a</sup>	[kg/m <sup>3</sup> ]	5.7	speed	m/s	15

<sup>a</sup>Based on a minimal pressure of 70 bar and an average temperature of 15°C

## Hydrogen Trailer Supply

The distribution of hydrogen by truck mainly depends on the distances between sources and sinks. Since the trailers have fixed batch capacities, they do not profit from increasing hydrogen demand. For this study, the distance between a fueling station and its hydrogen source was calculated directly via geographical information systems (GIS). Since real routing over streets involves greater distance compared to a direct connection, a detour factor of 1.3 was assumed. Optimization led to each fueling station being assigned a corresponding production site. This minimizes the overall distances driven while taking account of each location's maximum production capacity. Cost calculation is similar to Teichmann et al. [82] and dependent on the kilometers driven, as well as the time taken.

We considered two different trailer options: Compressed gas composite trailer supply at 500 bar and liquefied hydrogen trailer supply. At present, 500 bar trailers are expensive because composite storage vessels are not mass produced. However, they have high cost reduction potential at higher production rates. Table 6-12 shows the relevant assumptions for the truck transportation calculations.

Table 6-12: Techno-economic parameters for truck and trailer transportation.

	unit	Truck [94]		unit	Trailer GH <sub>2</sub> [95, 96]	Trailer LH <sub>2</sub> [95, 97]
Investment	[€]	160,000	Investment	[€]	660,000	860,000
Depreciation Period	[year]	8	Depreciation Period	[year]	12	12
Utilization	[h/year]	2,000	Utilization	[h/year]	2,000	2,000
O&M	[1/year]	12 %	O&M	[1/year]	2 %	2 %
Diesel consumption	[l/km]	0.35	Payload	kg	1100	4,500
Speed <sup>a</sup>	[km/h]	50	Net capacity	kg	1000	4,300
Toll	[€/km]	0.13	Loading time	h	1.5	3

<sup>a</sup> Average truck driving speed varies in different studies between 35 km/h and 70 km/h depending on rural or urban streets [82]. This study does not differentiate between rural and urban streets and assumes an average speed of 50 km/h.

### 6.2.1.3 Fueling of Hydrogen

Today's hydrogen fueling stations are still expensive. Bonhoff [98] estimates about € 1 million per station in 2016 without installation, but this may decrease by 40 % to € 600,000, through 2020. H2 MOBILITY [99] refers to four different types of fueling stations, as seen in Table 6-13. It is projected that up to 400 fueling stations will be built by 2023 as initial hydrogen infrastructure. Melaina et al. [100] state that, as the number of fueling stations and their maximum fueling capacity increase, this will generate additional cost reduction potential due to learning effects and increased station capacity. In addition to the costs, the number of vehicles covered per fueling station will increase with the number of FCEVs, as is shown in Figure 5-1. This impacts the utilization rate of a fueling station and consequently leads to increased hydrogen sales per station.

Table 6-13: Performance specification of different hydrogen fueling station sizes based on H2 MOBILITY [99].

	Size of hydrogen fueling station			
	XS	S	M	L
Number of fueling positions	1	1	2	4
Maximum number of fueling processes per day	10	38	75	180
Maximum hydrogen throughput per day [kg/day]	80	212	420	1000

Table 6-14 shows the assumed number of fueling stations and investment cost per station for each scenario in this study. While the utilization rate of each station is still low with 0.1 million vehicles, it rises to 71.2 % for the 20-million FCEVs scenario which corresponds well to the assumed 70 % utilization rate for L-Type stations defined by H2 MOBILITY [99]. Fueling station investment costs are increasing, but non-linearly due to learning and scaling effects.

Table 6-14: Fueling station design capacities and costs per scenario.

Scenario	# of fueling stations	Ø station capacity [kg/day]	Ø utilization rate	Avg. investment per station <sup>a</sup> [€]
0.1 million FCEV	400	212	29.4 %	999,000
1 million FCEV	1000	420	59.3 %	1,460,000
20 million FCEV	7000	1000	71.2 %	2,240,000

<sup>a</sup> Fueling station investment is calculated based on a scaling factor of 0.7 and a 6 % learning rate (detailed information can be found in section 6.1.3.1). The baseline is assumed to be 400 fueling stations with 212 kg/day capacity at € 700,000 investment cost, plus 30 % installation cost.

Fueling station locations have already been explained in section 6.2.1.2. This study does not consider different fueling station costs for varying supply modes. The only difference at the station is the electricity required for compression up to 900 bar. Liquid hydrogen requires less energy for dispensing compared to gaseous compression. Nevertheless, liquid hydrogen entails more hydrogen losses due to boil-off and leakage. For comparison, Table 6-15 shows the techno-economic parameters for the fueling station types.

Table 6-15: Techno-economic parameters for fueling stations based on their supply mode.

	unit	Pipeline supplied	GH <sub>2</sub> trailer supplied	LH <sub>2</sub> trailer supplied
Electricity consumption	[kWh/kg]	2.0 <sup>a</sup>	1.9 <sup>a</sup>	0.6 <sup>a</sup>
Hydrogen losses		0.5 %	0.5 %	3 %
Depreciation period	[years]	10		
O&M	[1/year]	5 %		

<sup>a</sup> Based on 2015 specific electricity consumption for pipeline-supplied fueling station compression of 1.6 kWh/kg (Trailer supplied: 1.5 kWh/kg), drawing on DOE values [95] plus an additional 0.4 kWh/kg of electricity consumption for hydrogen precooling [101].

#### 6.2.1.4 Conversion and Conditioning

Besides the all-important hydrogen supply chain, it is vital to consider technologies for hydrogen conditioning. Both gaseous and liquid hydrogen transport are part of the analysis. Therefore, compression and liquefaction facilities had to be taken into account. Compressor energy demand in this study was calculated with an isentropic compressor efficiency of 88 % in line with input and output pressures. Hydrogen liquefaction is currently highly energy-intensive, with energy demands of up to 30 % of hydrogen lower heat value. Nevertheless, the 2008 Nexant Report [102] showed that the efficiency of a liquefaction plant improves with higher plant capacities. The IdealHy study [103] in particular claimed an energy demand of 6.78 kWh/kg (~20 % of hydrogen LHV) at a plant capacity of 50 tons of hydrogen liquefied per day. For simplification, this value is fixed, even though plants of these scales and efficiencies do not exist today. Reuß et al. [80] show that the investment cost assumptions in comparable literature sources have risen over the past ten years. Therefore, this study considered the 2013 values from IdealHy [103] to be the most reasonable. Table 6-16 outlines additional assumptions for the techno-economic calculation of these technologies.

Table 6-16: Techno-economic parameters for hydrogen conversion technologies.

	unit	Compressor [102]	Liquefaction [103]
Investment $I_0$	[million €]	0.015	105
Capacity $C_0$		1 [kW]	50 [t/day]
Scaling factor $\alpha$	[-]	0.6089	0,66
Depreciation Period	[years]	15	20
O&M	[1/year]	4 %	8 %
Electricity Demand	[kWh/kg <sub>H2</sub> ]	<i>variable</i>	6.78
Losses		0.5 %	1.65 %

## 6.2.2 Results of Hydrogen Infrastructure Analysis

This section shows the results of different analysis types, starting with total infrastructure investment followed by the specific hydrogen costs at the fueling station (well to tank) and, finally, an analysis of the different pathways' energy consumption.

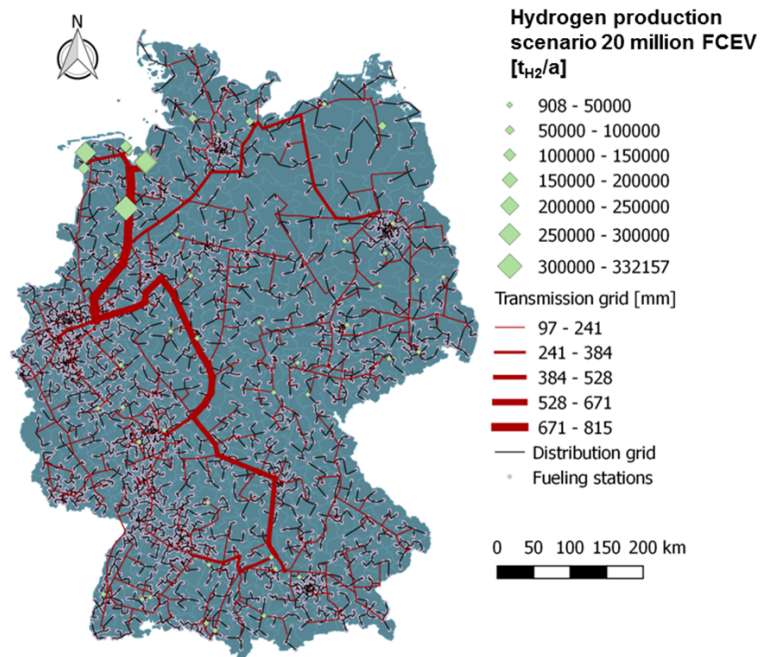
Figure 6-11: Resulting hydrogen infrastructure for 20 million FCEVs and GH<sub>2</sub> pipeline supply.

Figure 6-11 shows the design for the hydrogen infrastructure based on pipelines for transmission and distribution in the scenario for 20 million FCEV in Germany and the hydrogen production based on surplus of renewable electricity. The large renewable hydrogen productions sites in the North of Germany and the high hydrogen demands in the metropolitan areas dominate the pipeline design.

### 6.2.2.1 Comparison of Infrastructure Investment

The estimated cumulative infrastructure investment includes investments in the hydrogen production plants (electrolysis), compressors, salt caverns, pipelines, trucks, trailers and fueling stations. Figure 6-12 shows that, in both low market penetration scenarios (0.1 and 1 million FCEVs), cumulative investments for pipeline supply is significantly higher than for trailer supply. The GH<sub>2</sub> trailer pathway requires slightly lower cumulative investment and thus represents the cheapest pathway for 0.1 and 1 million FCEVs compared to the LH<sub>2</sub> trailer. This changes significantly in the 20 million FCEV scenario where the combination of a GH<sub>2</sub> pipeline and trailers appears to entail the lowest cumulative investment. Obviously, the pipeline supply mode has high fixed investment, which does not rise linearly with increasing utilization. Nevertheless, the pipe/trailer pathway has a lower cost than a nationwide pipeline grid. Regarding this issue, the distribution ("last mile") of hydrogen by GH<sub>2</sub> trailer involves lower investments compared to a pipeline distribution grid. Another interesting point is the relationship between the GH<sub>2</sub> and LH<sub>2</sub> trailers. The LH<sub>2</sub> trailer requires fewer investments than the GH<sub>2</sub> trailer for 20 million FCEVs, while both low market penetration scenarios had opposite results. To explain this, it is necessary to examine the underlying production scenarios. Due to the different sites at which hydrogen is produced, the distances between production plants and fueling stations vary. In particular, distances increase with renewable hydrogen generation from electrolysis plants, since they are primarily situated in the north of Germany. By comparison, existing SMR, as well as byproduct facilities, are more widely distributed and closer to centers of fuel consumption.

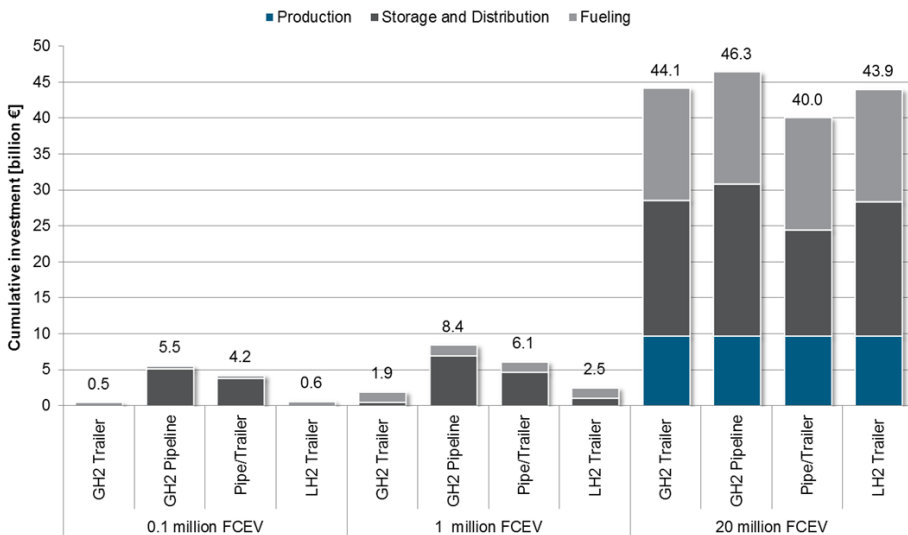


Figure 6-12: Cumulative investment costs for all investigated hydrogen supply chain architectures applied to three scenarios; the 0.1 and 1-million FCEV scenarios do not include investment costs for hydrogen production from SMR or byproducts due to the utilization of existing plants.

Figure 6-13 breaks the cumulative investment cost down into specific investment per FCEV. Similar to Figure 6-12, pipeline supply – nationwide as well as in combination with trailer supply – is much more expensive than trailer supply for a small number of FCEVs on the

market. Nevertheless, specific investment per vehicle reveals a substantial overhead for the 0.1-million FCEV scenario which is caused by the fueling stations.

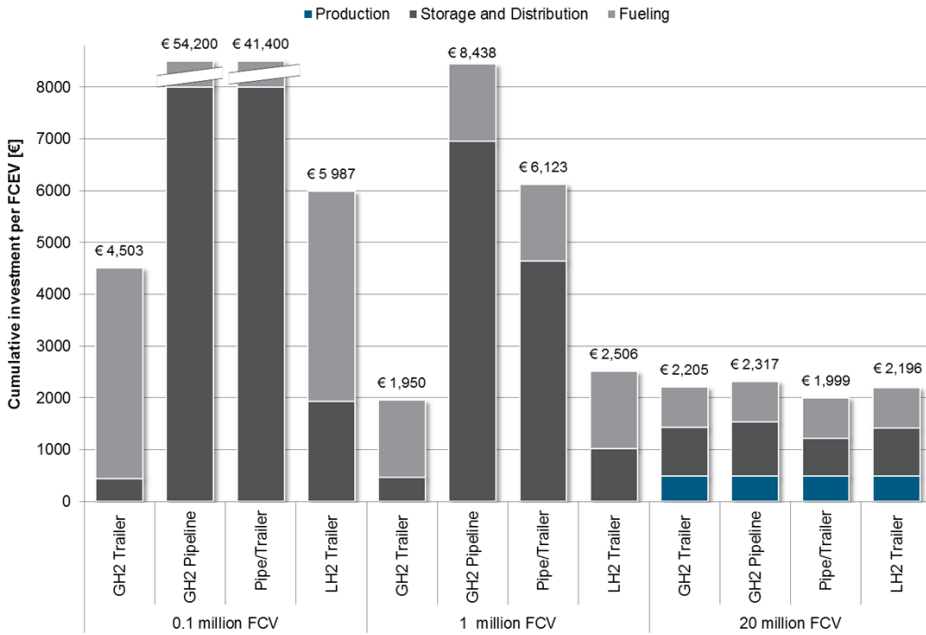


Figure 6-13: Specific investment cost per vehicle for all investigated hydrogen supply chain architectures applied to three scenarios; the 0.1-million and 1-million FCEV scenarios do not include investment costs for hydrogen production from SMR or byproducts due to the utilization of existing plants.

### 6.2.2.2 Specific Fuel Costs

The specific fuel costs include alongside the cumulative investment costs fixed expenses for operation and maintenance, as well as energy-related expenses. Figure 6-14 explains that both pipeline transmission scenarios generate similar fuel costs, with 21.4 €/kWh for the pipeline/trailer combination and 21.7 €/kWh for the GH<sub>2</sub> pipeline pathway in the 20 million FCEV scenario. While Figure 6-13 shows higher investment costs for the GH<sub>2</sub> pipeline compared to LH<sub>2</sub> trailer supply, Figure 6-14 indicates cheaper specific costs for energy-related expenses.

Lower FCEV market penetrations again show similar behavior compared to cumulative investments. Neither pipeline scenario is competitive in this respect. In particular, cost in the 0.1 million FCEV scenario is driven to a great extent by capital expenditure, with a high share of fueling costs due to the low utilization of hydrogen fueling stations (approx. 29 %). Nevertheless, the 1 million FCEV scenario exhibits an already competitive cost for both trailer supply modes due to the higher fueling station utilization rate of 59.3 %.

Comparing the specific expenses for hydrogen production, it is obvious that the shift to water electrolysis from renewable electricity surplus is more expensive compared to SMR and byproduct hydrogen. The major cost drivers here are the price of electricity used for



electrolysis and the investment in electrolysis. In contrast to some studies of the meta-analysis in chapter 5 with low or even negative electricity prices for electrolysis (revenues of systems services), a price of 6 €/kWh is assumed for surplus electricity in the base case scenario.

Expenses for storage and distribution drop significantly with the pipeline-based pathways. The LH<sub>2</sub> trailer mode benefits from rising hydrogen demand and from the increasing capacity of the liquefaction plants. In contrast, the GH<sub>2</sub> trailer demonstrates slightly increased cost for storage and distribution with an increasing FCEV fleet. As was mentioned in section 6.2.1., the comparability of the three scenarios is limited due to the different locations of hydrogen production (SMR/byproduct and electrolysis). Furthermore, the seasonal storage required for renewable hydrogen production is included only for the 20 million FCEV scenario.

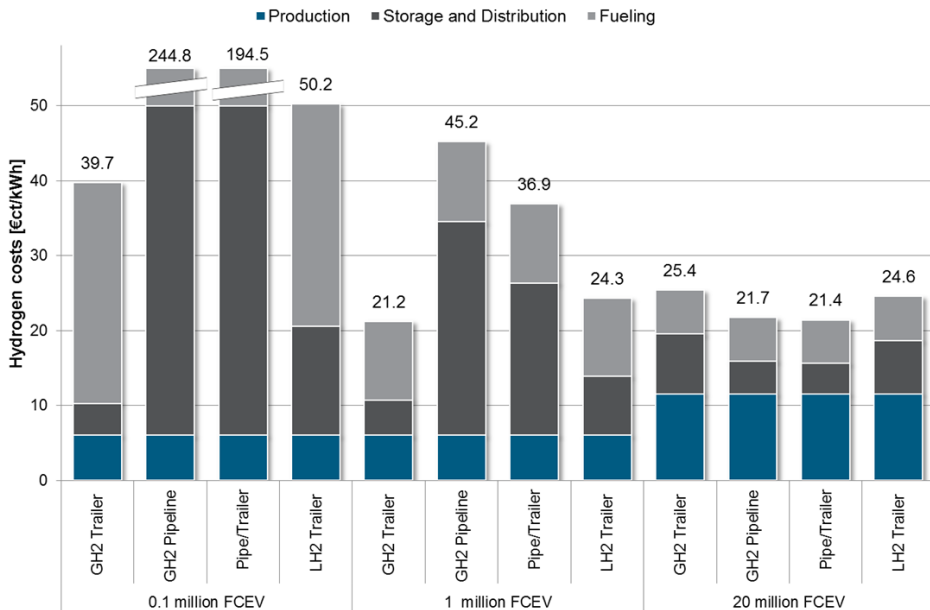


Figure 6-14: Specific hydrogen costs per kWh lower heat value at the fueling station for three scenarios: 100,000 FCEVs, 1 million FCEVs and 20 million FCEVs; the different production modes (SMR/byproduct vs. renewable electrolysis) lead to limited comparability between the 0.1 or 1-million FCEV scenario and the 20-million FCEV scenario.

### 6.2.2.3 Energetic Analysis

This study investigates the energy demand of different transportation modes based on the 20 million FCEV scenario. Figure 6-15 presents the results of the energetic analysis. The energy used is separated as follows: surplus electricity from renewable sources, electricity supplied by the electrical grid and diesel as fuel for trucks. Hydrogen as transportation fuel for heavy duty trucks is not assumed in the scenarios to prepare a worst case assessment. Using hydrogen or liquid fuels based on renewable electricity for trucks will improve the use of RES and decrease CO<sub>2</sub> emissions of this pathway.

The major share of consumed energy comes from renewable surplus electricity with 1.45 kWh/kWh<sub>H2</sub> (corresponding to the gravimetric demand of 48.4 kWh/kg<sub>H2</sub>). Comparing this value to the electrolysis assumption of 47.6 kWh/kg<sub>H2</sub> from Table 6-8, electrolysis has the highest energy demand in the overall supply chain in all pathways. Regarding general efficiency, the GH<sub>2</sub> pipeline pathway appears to be the most efficient, followed by the pipeline/trailer pathway, meaning energy consumption only appears to arise from the compression of hydrogen. The trailer pathways are both less efficient due to the additional energy demand either for fuel for the GH<sub>2</sub> trailer truck or for liquefaction for LH<sub>2</sub> transport.

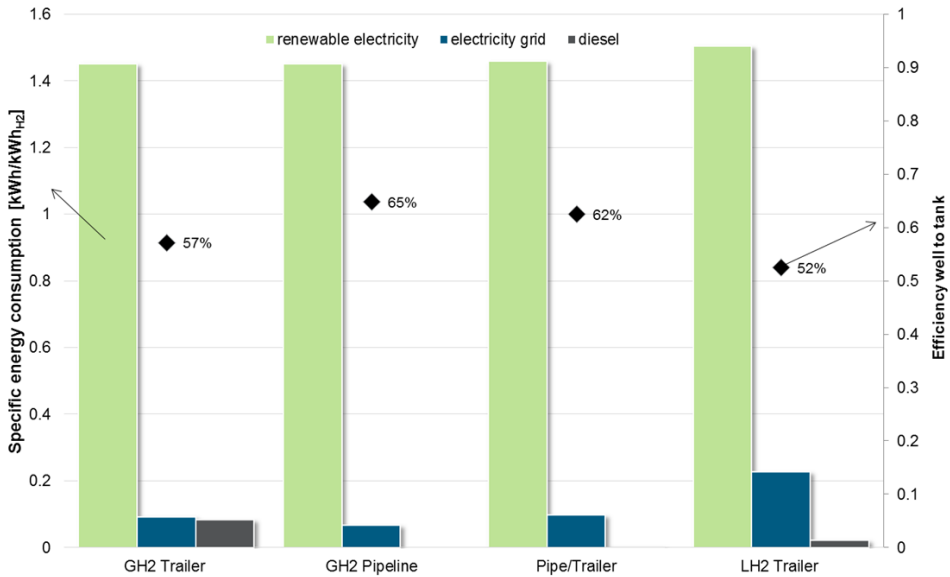


Figure 6-15: Specific energy demand per kg of hydrogen for 20-million FCEV scenario

Starting from the specific energy demand, it is worth looking at the overall energy demand as well. Table 6-17 shows total consumption of surplus electricity, grid electricity and diesel. The used surplus electricity of 88.1 TWh accounts for 33.1 % of the potential curtailment of 266 TWh according to the assumed electricity scenario. This would amount to € 5.3 billion additional revenue by additional selling of surplus electricity for the power sector each year.

Table 6-17: Overall energy consumption of 20 million FCEVs for different pathways

	Surplus Electricity [TWh]	Grid electricity [TWh]	Diesel [million l]
GH2 Trailer	88.1	5.60	463.2
GH2 Pipeline	88.1	4.08	0.0
Pipe/Trailer	88.5	5.93	16.0
LH2 Trailer	91.3	13.80	121.4

Nevertheless, all pathways consume grid electricity, too. At the top of the list is the LH<sub>2</sub> trailer supply with an additional electricity demand of 13.8 TWh, which breaks down to 1.6 GW of additional base load. It is assumed that the electricity demand for hydrogen liquefaction and further conditioning steps are taken directly from the electric grid and no surplus electricity is used. Comparing this value with the assumed total electricity consumption of 528 TWh for Germany without FCEVs, this accounts for 2.6 % of additional electricity demand. Diesel consumption is highest for GH<sub>2</sub> trailer supply, with an overall demand of 463 million liters. Compared to overall fuel consumption of 21,843 million liters [104] for heavy goods transportation in 2015, this amounts to 2.1 % additional fuel consumption.

### 6.2.3 Sensitivity Analysis

A comprehensive sensitivity analysis was conducted to determine the impact of various parameters on the design and costs of the hydrogen infrastructure. It involved comparing different results, adding intermediate stages at 3, 5, 10, and 15 million and calculating the pipe/trailer supply chain.

The parameter variations of the pipe/trailer pathway include:

- Price for surplus electricity: 4 €/kWh and 6 €/kWh  
The base case price for surplus electricity is set at 6 €/kWh. This was the upper boundary and a conservative estimation compared to levelized cost of electricity from onshore wind energy as well as the level of high competitiveness compared to other storage technologies.
- Fueling station and electrolysis investment cost: +/- 20 % investment  
Figure 6-12 shows that the two main relevant parameter for investments are the base invest for fueling stations and electrolysis, the sensitivity analysis varied the cost for these two by +/- 20 %.

Figure 6-16 points out the varying cumulative investment. The main difference in investment is caused by the fueling station and entails a spread of costs between € 37 and € 43 billion for 20 million FCEV.

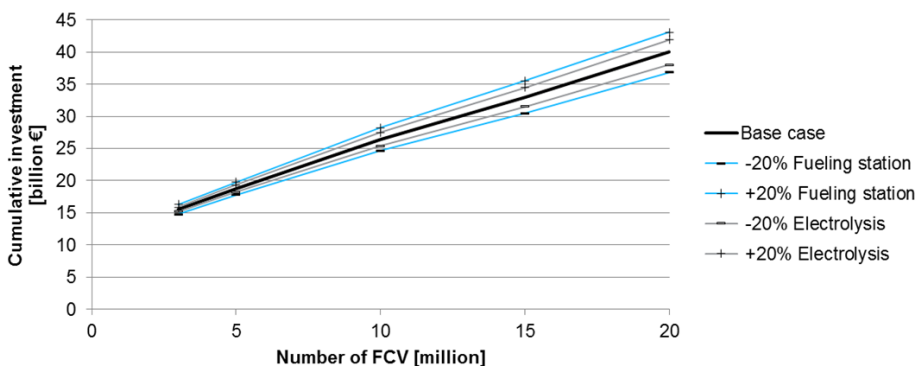


Figure 6-16: Sensitivity analysis for renewable hydrogen supply chain for 3 to 20 million vehicles

Figure 6-17 indicates that the main driver of hydrogen costs is the electricity price at the electrolysis location. By changing the costs for surplus electricity to 4 €/kWh the mobility costs are reduced from 4.6 to 4.0 €/km.

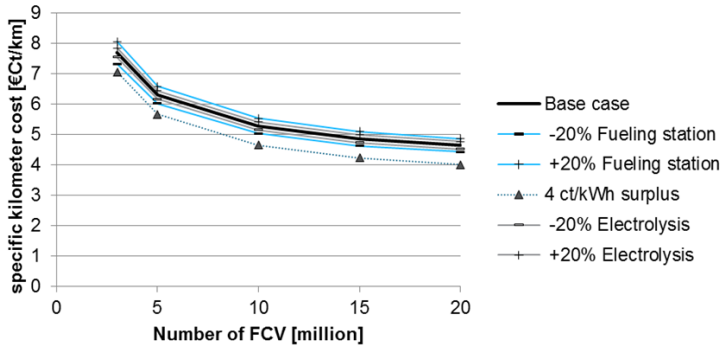


Figure 6-17: Sensitivity analysis for renewable hydrogen supply chain from 3 to 20 million vehicles

#### 6.2.4 Summary and Conclusions for Hydrogen Fueling Infrastructure Analysis

The goal of this chapter is to determine the cumulative infrastructure investment cost and the specific hydrogen cost as well as to perform an energetic analysis of hydrogen infrastructure for different levels of FCEV market penetration. The results show that low market penetrations of FCEVs should be supplied by trailer-based hydrogen transportation due to the low infrastructure investments compared to pipeline pathways. Regarding high penetrations of up to 20 million FCEVs, pipeline-based pathways are most preferred from an economic as well as ecological point of view, as they entail the lowest hydrogen cost while being most energy efficient.

Taken together, these findings provide an outline for a hydrogen infrastructure development strategy: Starting with GH<sub>2</sub> trailer supply for low penetrations will keep the costs low. With rising hydrogen demand and explorations of new hydrogen production locations, single pipeline projects can bypass long distance transportation by GH<sub>2</sub> trailers without changing the actual fueling station design. This strategy offers the lowest investment cost during market introduction while avoiding new green field investments at high market shares.

At present, the use of existing natural gas pipelines for transporting hydrogen is subject to research and development. This can be an interesting option for further use of no longer required parts of the natural gas pipeline system and for reduction in pipeline investment.

With 20 million FCEV, the resulting hydrogen infrastructure has 19.2 GW of electrolysis capacity (~€ 9.6 billion), 300,000 t of hydrogen storage capacity (~€ 5.1 billion), 12,400 km of hydrogen transmission pipeline (~€ 5.9 billion), 3,000 trucks with 500 bar composite vessel trailers (~€ 2.4 billion), compressor power of 500 MW (~€ 1.5 billion), and 6,977 fueling stations (€ 15.6 billion).

The results of the hydrogen infrastructure analysis make it obvious that the major obstacle for cost-competitive FCV hydrogen is the generation of sufficient initial hydrogen demand for reasonable utilization of the infrastructure as a whole. Fuel cell buses, trucks or trains could thus boost market introduction by generating initial hydrogen demand.

### 6.3 Charging Infrastructure

The purpose of assessing battery charging infrastructures is to specify the investment requirements of a fully-fledged charging infrastructure for battery electric vehicles (BEVs), as well as the specific electricity cost for all charger types. The assessment focuses on BEV charging in cities and on freeways. The analysis distinguishes between overnight (Mode 1 and Mode 2), public (Mode 3) and commercial fast charging (Mode 4) in cities and on freeways. Analogous to the hydrogen fueling infrastructure analysis, this assessment is based on three scenarios for BEV fleets in Germany: 0.1 million BEV, 1 million BEV and 20 million BEV. Although there were no specific timeframes for the scenarios, some consideration was given to the use of time-dependent parameters, such as population and car ownership statistics, as well as the expected timely development of technical parameters. While the first two scenarios assume that all BEVs have an overnight charging option, the 20 million BEV scenario assumes a BEV fleet share charged with Mode 3 and Mode 4 chargers only.

#### 6.3.1 Modeling of Charging Infrastructure

Many parameters influence the estimation of BEV charging infrastructure requirements. The major assumptions of the assessment in this study are described below. The most relevant endogenous parameters are:

- Fleet size and distribution amongst settlement types
- Share of overnight charging sites in garages or on-street and their actual utilization
- Allocation of charged energy at overnight, public and commercial charging points
- Number of private and public charging points per BEV
- Net electricity cost
- Annual mileage and BEV fuel economy
- Further parameters relevant to investment calculations (see Table 6-18)

The following input parameters for Germany are used specifically for analyzing charging infrastructure requirements on freeways:

- Freeway lengths
- Traffic volume classes

The hardware considered in this study includes the actual chargers and transformers in the distribution grid, low and medium voltage cables and energy management systems. Low voltage (LV) cables are only counted for the freeway analysis; in cities, the study does not include cable extensions but assumes existing LV cables had sufficient capacity for BEV charging.

#### 6.3.2 Charging Options and Cost Assumptions

Regarding the charging option assumptions for BEV drivers in the three scenarios, the following section focuses on the capacity and costs of the anticipated charger hardware and network components. It is assumed that BEVs have the option to recharge at:

- Overnight locations at home or on-street in residential areas (Mode 1 and Mode 2)
- Public Mode 3 chargers in cities, and
- Public Mode 4 chargers in cities or on motorways

While in the first two scenarios of 0.1 million and 1.0 million BEVs, the assumption is that all cars would have access to an overnight charging location, in the 20-million BEV scenario BEVs must also be marketable to car owners who may not have this option. With respect to later comparisons of our results with literature data, home chargers are only defined as private chargers. All the others – on-street chargers (Mode 1 and 2), public chargers (Mode 3) and Mode 4 commercial quick chargers in cities and on freeways – are defined as public. Semi-public chargers, such as chargers on company depots or at car parks are not specifically considered in this study.

Table 6-18 gives detailed data on the cost assumptions in this study. The values are based on the literature [105, 106, 107, 108, 109], assuming a learning factor of 6 % set in accordance with the FCEV fueling infrastructure.

Table 6-18: Cost assumptions for BEV charging infrastructure analysis.

Own assumption based on information given in [105, 106, 107, 108, 109]; charger investment based on data compiled in the meta-analysis of scenario studies (chapter 5). Increase in charger cost in 20-million BEV scenario due to the higher power output.

Component investment	unit	Baseline	0.1 million BEV	1 million BEV	20 million BEV
<b>Chargers</b>					
Home charger M1+M2	€/unit	732	688	891	1.252
Overnight street charger M1+M2	€/unit	2200	2.002	2.205	2.566
(Semi-) public charger M3	€/unit	4000	2.632	3.309	4.512
Public charger M4	€/unit	45,000	36.660	42.751	53.580
Motorway charger M4	€/unit	45,000	36.660	42.751	53.580
<b>Energy management systems (EMS)</b>					
EMS, large city	€/unit	2,000,000	1,983,056	1,880,000	1,394,080
EMS, medium-sized town	€/unit	250,000	247,882	235,000	226,646
EMS, small town	€/unit	250,000	247,882	235,000	213,050
EMS, rural municipality	€/unit	250,000	247,882	235,000	213,048
<b>Transformers</b>					
Controllable distribution grid transform.	€/unit	22,000	22,000	22,000	20,680
<b>Electric lines, city</b>					
Medium-voltage overhead lines	€/km	15,000	15,000	15,000	15,000
Medium-voltage undergrounding	€/km	80,000	80,000	80,000	80,000
Low-voltage undergrounding	€/km	68,500	68,500	68,500	68,500
<b>Electric lines, Motorway</b>					
Medium-voltage undergrounding	€/km	80,000	80,000	80,000	80,000
Low-voltage undergrounding	€/km	68,500	68,500	68,500	68,500

Charger power is assumed to increase from the 0.1 million BEV and 1.0 million BEV scenarios – likewise set with respect to proximity in time – through to the final 20 million BEV scenario. Home and street charger power increases from 3.7 kW to 11 kW, Mode 3 city chargers from 22 kW to 40 kW and Mode 4 commercial chargers in cities as well as freeway chargers from 150 to 350 kW, resulting in higher charger investment (Table 6-18, far right column).

Charging power was chosen with consideration for a 20-80 % SOC increase within the defined periods of time: Mode 1 and Mode 2 home and overnight on-street charging within 5 hours, Mode 3 city charging within 1.5 hours and Mode 4 fast charging in cities or on motorways within 10 minutes. With respect to BEV marketability, an increase in average battery capacity must be expected. One major challenge here is the competitive operational range of BEVs. We assume a nominal range value of 500 km related to the fleet size of 20 million BEVs. This would translate into a battery capacity of up to 100 kWh (see Figure 6-18) in the 20-million BEV scenario. This parameter turned out to be decisive for charger cost, which makes up a significant share of total charging infrastructure costs. Two base cases with respect to battery capacity are defined: 75 kWh and 100 kWh. 75 kWh would allow for an operational range of 500 km, assuming average electricity use of 15 kWh/100 km. This is considered realistic for urban and extra-urban driving. For freeway driving, even greater consumption must be considered, resulting in 20 kWh/100 km in this study. The battery capacity would then be 100 kWh, again allowing for an operational range of 500 km. These battery capacity values are high compared to values based on nominal consumption of 11 kWh specified in this study according to Grube [72], because the operational range should be for realistic drive patterns, i.e. ones that include the operation of onboard consumers, such as air conditioning and long-distance driving at elevated speed. Figure 6-18 displays the battery capacities for both base cases and all BEV fleet scenarios.

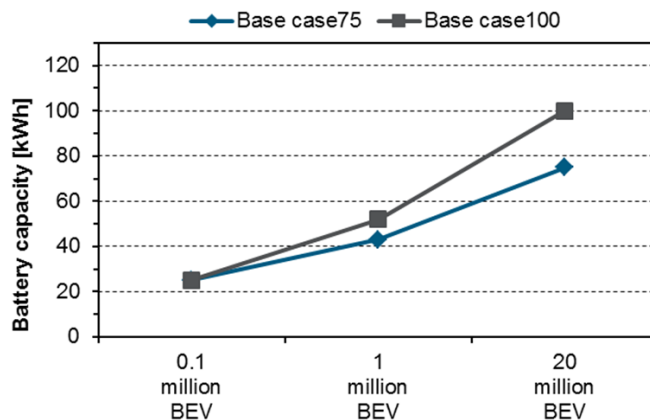


Figure 6-18: Assumed battery capacity increase in the scenarios considered.  
Base case75: with 75 kWh/BEV; Base case100: with 100 kWh.

### 6.3.2.1 Infrastructure Requirements in Cities

Figure 6-19 points out the decisive parameters for the calculations of the distribution of charger types: (i) BEV fleet distribution amongst settlement types; (ii) the availability of overnight charging sites at home or on-street in residential areas; (iii) car users' selection of charging options (Modes 1 & 2 for overnight charging and Modes 3 & 4 for city and freeway charging); (iv) BEV charging site occupation; and (v) grid extension requirements. Figure 6-20 (left) displays our assumptions of BEV fleet distribution by settlement types. Fleet shares are assumed to be equal for large cities and medium-sized towns. In contrast, small towns are expected to have lower BEV shares in the 0.1-million BEV and 1-million BEV

scenarios. In rural areas, BEVs reach a significant share in the 20-million BEV scenario only. The total BEV count by settlement type is shown in Figure 6-20 (right).

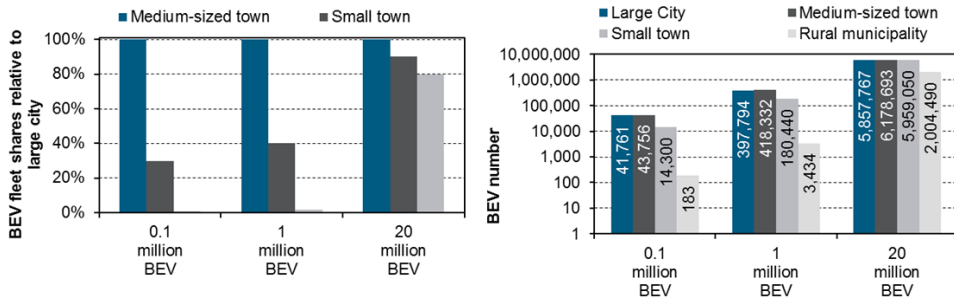


Figure 6-19: BEV fleet shares in Germany by settlement type, relative to large cities (left). Number of BEVs in Germany by settlement type (right).  
Source: own assumption and calculations based on [110, 111].

Figure 6-20 shows the resulting distribution of the BEV fleet for the different market penetration scenarios according to the county level. High numbers of BEV are concentrated to metropolitan areas.

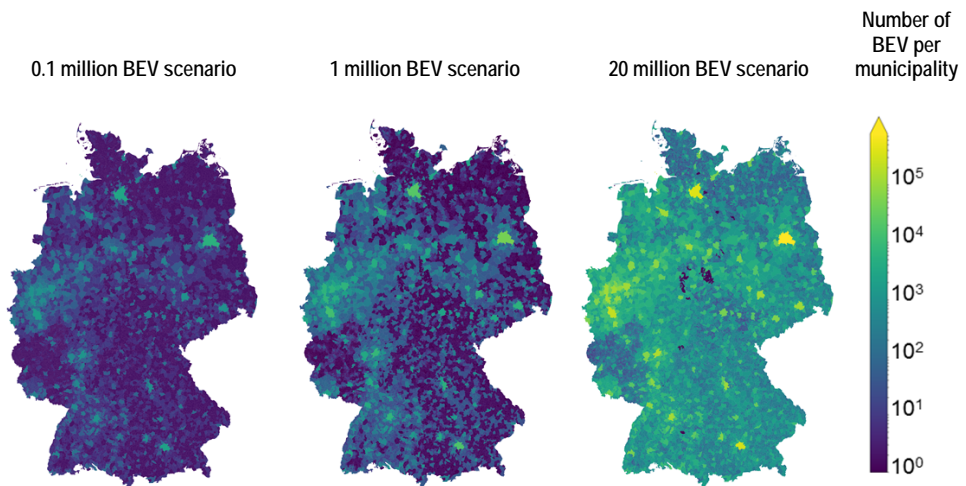


Figure 6-20: BEV fleet in Germany on county level for the base case scenario 0.1, 1 and 20 million vehicle.  
Source: own assumption and calculations based on [110, 111].

As mentioned above, overnight charging is limited in the 20 million BEV scenario. The number of overnight chargers was determined on the basis of information given in Plötz et al. (2013) [112]. In their study, the distribution of overnight parking is shown as percent values. Home chargers correspond to the sum of values labeled parking at home ("Garage" and "Parkplatz am Haus"), street chargers correspond to the values labeled in the vicinity ("In der Nähe"). In the study this information is used in combination with the total car fleet according to the three scenarios in order to determine the number of BEVs with an



overnight charging option. In addition, we defined a utilization factor that is 100 % for the first two scenarios and for all settlement types. This value dropped to 50 % in the 20-million BEV scenario in large and medium-sized cities and to 60 % and 80 % in small towns and rural municipalities, respectively. A generally higher coverage of overnight – particularly home – charging in non-urban areas is expected. Considering the total BEV fleet in Germany, the number of cars with an overnight charging option decreases from 100 % in the first two scenarios to 56 % in the 20 million BEV scenario. Using these parameters and data, it is possible to calculate the required number of charging points for home charging and on-street charging in residential areas.

In a second step, the required number of public Mode 3 chargers is determined. These are assumed to function as a casual charging option in cities, e.g., close to shopping centers. These chargers are expected to have a higher charge power compared to overnight chargers, due to lower average BEV residence time. However, BEV drivers are assumed to leave their cars for longer periods at the charge point than required for charging, which means utilization is still low. Specific investment is lower due to lower charging power compared to fast chargers. In our base case, we assume one Mode 3 charger per 20 BEVs in all scenarios.

Finally, the demand for Mode 4 quick-chargers is estimated. We started out by determining the number of internal combustion engine vehicles (ICEVs) that are served today by one fuel dispenser. In Germany 2017, 14,531 fueling stations are available for 45.8 million passenger cars [32], [34]. With an estimated average of six dispensers per station, statistically, one dispenser serves 517 cars. While in the case of ICEVs, one dispenser roughly has a capacity of eight ICEVs per hour, this value would decrease to two-three BEVs assuming longer residence times of up to 30 min. Moreover, the number of charge point contacts increases by a factor of two, assuming that ICEVs have twice the operational range compared to BEVs in the long term. Our calculations based on these assumptions resulted in a BEV-per-charge-point ratio of 29, 43 and 65 in the three scenarios 0.1 million BEV, 1.0 million BEV and 20 million BEV, respectively. We are aware that BEVs with an overnight charging option would rarely make use of Mode 4 fast chargers. However, the scaling procedure described here would be reasonable for covering situations in which there might be demand for intensive fast charging, e.g., immediately before or on holidays or during a holiday season.

### **6.3.2.2 Infrastructure Requirements on Freeways**

The freeway infrastructure component analysis was performed separately in this study. The endogenous input parameters considered are listed in Table 6-19.

The total freeway length in Germany is, at present, roughly 13,000 km, with another 450 km set to be added through to 2040. On freeways, faster driving speeds results in reduced BEV range. This is important when dimensioning infrastructure. Based on the simulation results, fuel economy on freeways is assumed to be 21 kWh/100 km, reducing the applicable BEV range to 59 km, 202 km and 416 km in the 0.1 million BEV, 1 million BEV and 20 million BEV scenarios, respectively. Given the total number of service stations in Germany (“Raststätte” and “Autohof”), the average distance between sites is 30 km.

Table 6-19: Parameters for the assessment of charging infrastructure on freeways.

Charging takes place at service stations directly on the freeway (Raststätte: one per freeway direction) and at service stations without direct access to the freeway (Autohof: one for both directions, typically located in business parks not more than 1 km from freeway).

Scenario	0.1 million BEV	1 million BEV	20 million BEV
Total autobahn length, km	13,335	13,545	13,790
Net BEV range on freeways, km	59	202	416
Charging location distance on freeways	30	30	30
Charger power, kW	150	150	350
Share of freeway chargers (Raststätte)	47 %	47 %	47 %

The share of freeway chargers is relevant because of the increased demand for network components. Regarding electricity supply, freeway service stations typically have a medium voltage connection in place already.

In order to determine the capacity of charging locations across German freeways traffic volume classes (Verkehrsmengenklassen, VMK) are used. VMK values result from the German traffic counting system which allocates traffic densities on German freeways to 10 classes, VMK 1-10, whereby VMK 1 has the lowest traffic density of less than 500 cars/h and VMK 10 the highest with more than 4500 cars/h. According to Figure 6-21, the highest occurrence relates to VMK 3-5, with volumes of 1,000-2,500 cars/h. In total, VMK values are available for 874 freeway segments. Hourly traffic volumes as well as duration are available as curve-based information for each segment. This allows for characterization in terms of short-distance (local) and long-distance (e.g., holiday) traffic. This information was used to define a correction factor that increases the expected charging demand on freeway segments by long-distance traffic. This correction factor ranges between 10 % and 25 %, depending on the individual segment characteristic.

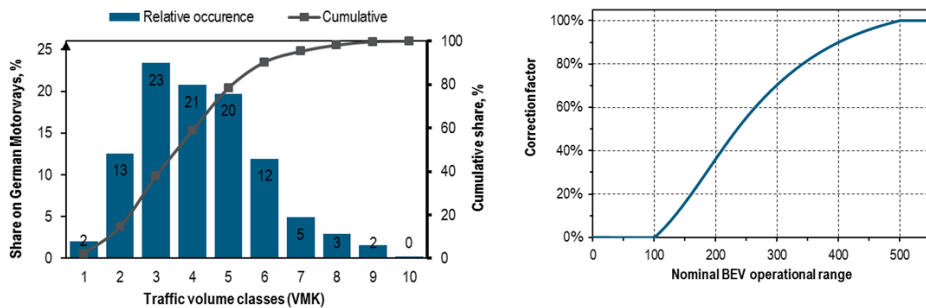


Figure 6-21: Left: distribution of traffic volume classes (Verkehrsmengenklassen, VMK) on German freeways.

Own calculations on the basis of information given in Fitschen and Normann [113, 114, 115].

Right: Correction factor for share of BEVs on German motorways depending on BEV range.

Own assumption based on information given in Schubert [116].

In the early stages of market introduction, it is assumed that BEVs would be statistically underrepresented on freeways due to low operational range. Accordingly, the BEV share is expected to increase in line with the operational range. At a nominal value of 500 km and

above, a reduced BEV share on freeways is not considered. Figure 6-21 (right) shows this correction factor based on data in Schubert [116].

Using the length of freeway segments for each traffic volume class and the statistical occurrence of BEVs, together with BEV range on freeways, it is possible to determine the number of charge points for each service station. The total for Germany is shown in Figure 6-22 (left and center column). Figure 6-22 (right column) displays the volume of additional transformers required.

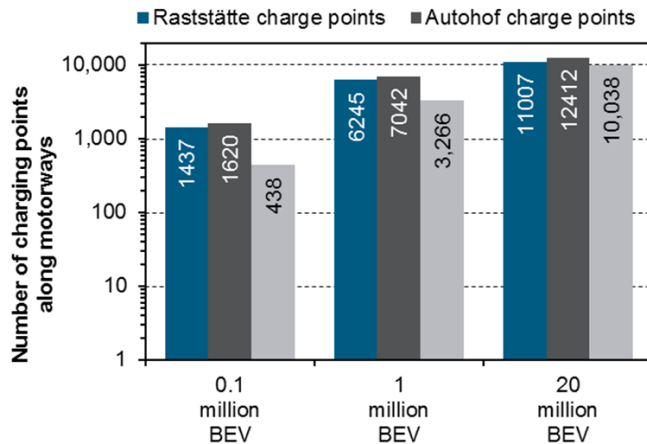


Figure 6-22: Number of charge points at service stations (Raststätte and Autohof) along freeways and number of controllable distribution grid transformers (RONT) required for connecting the chargers.

Source: own calculations based on the assumptions in this study.

### 6.3.2.3 Results of BEV Charging Infrastructure Analysis

Using the information given above, the number of chargers and the required investments are calculated. The total number of charge points and the BEV-per-charge-point ratios are displayed in Figure 6-23. Overnight charging points range from 0.1 to 11.2 million units in the scenarios under consideration. Public Mode 3 charge points are the second highest with 5,000-1,000,000 units, followed by public Mode 4 charge points in cities with 2,785-221,032 units and, finally, freeway Mode 4 charge points with 3,057-23,419 units. The freeway charge points are higher in the first scenario because a basic coverage for long-distance driving was assumed with an average of 1-2 charge points at each service station. With respect to the BEV-per-charge-point ratio, Figure 6-23 (right) shows that overnight chargers are installed 1:1 in the first two scenarios. This value increases to 2 in the 20-million BEV scenario due to the limited availability of overnight charging sites in the case of high BEV market shares. The number of BEVs served by one public Mode 4 charger in cities increases in the scenarios from 36 to 90. The reason for this is that as the operational range increases, the number of charging contacts decreases, which in return raises the capacity of each charging point. The highest ratio of BEV per charging point was for the Mode 4 freeway chargers, which reached a value of 854 in the 20-million BEV scenario.

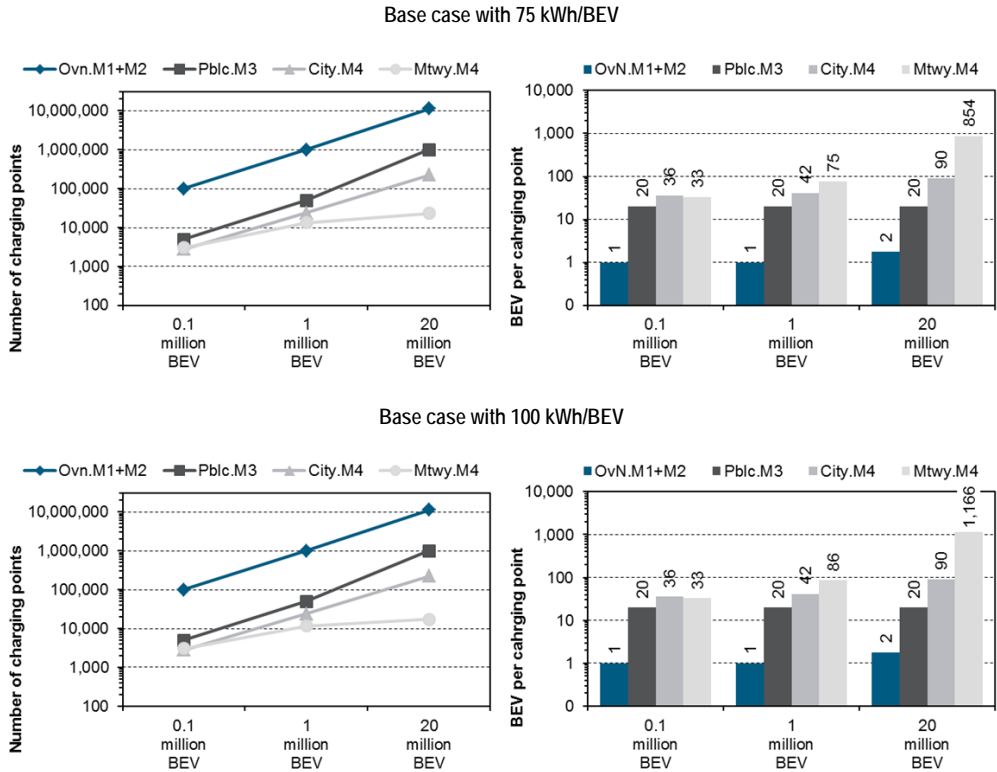


Figure 6-23: Number of chargers in Germany.  
by charger type (left) and number of BEV served per charger type (right).  
OvN.M1+M2: Mode 1 and Mode 2 overnight chargers at home or on-street; Pbhc.M3: Mode 3 public chargers in cities; City.M4: Mode 4 quick chargers in cities; Mtwy.M4: Mode 4 chargers on freeways.  
Source: own calculations based on assumptions in this study.

The cumulative investment in the BEV charging infrastructure is shown in Figure 6-24 (left). € 50.5 billion and € 62.3 billion would be required for the largest BEV fleet according to the 20-million BEV scenario related to the base cases with 75 kWh and 100 kWh battery capacity, respectively. Figure 6-24 (right) shows the specific requisite investment per BEV. This value decreases for the 100 kWh base case (top) from the 0.1-million BEV to the 1.0-million BEV scenario and then increases in the final 20-million BEV scenario. This decrease can be explained by learning effects that lower charger investment. The later increase in BEV-specific investment is caused by elevated charger investment due to the higher charger power required for larger batteries. Due to the lower battery capacity in the 75 kWh reference case, increases in charger power and thus charger investment are lower. Specific requisite investment is therefore not decreased in the 20 million BEV scenario.

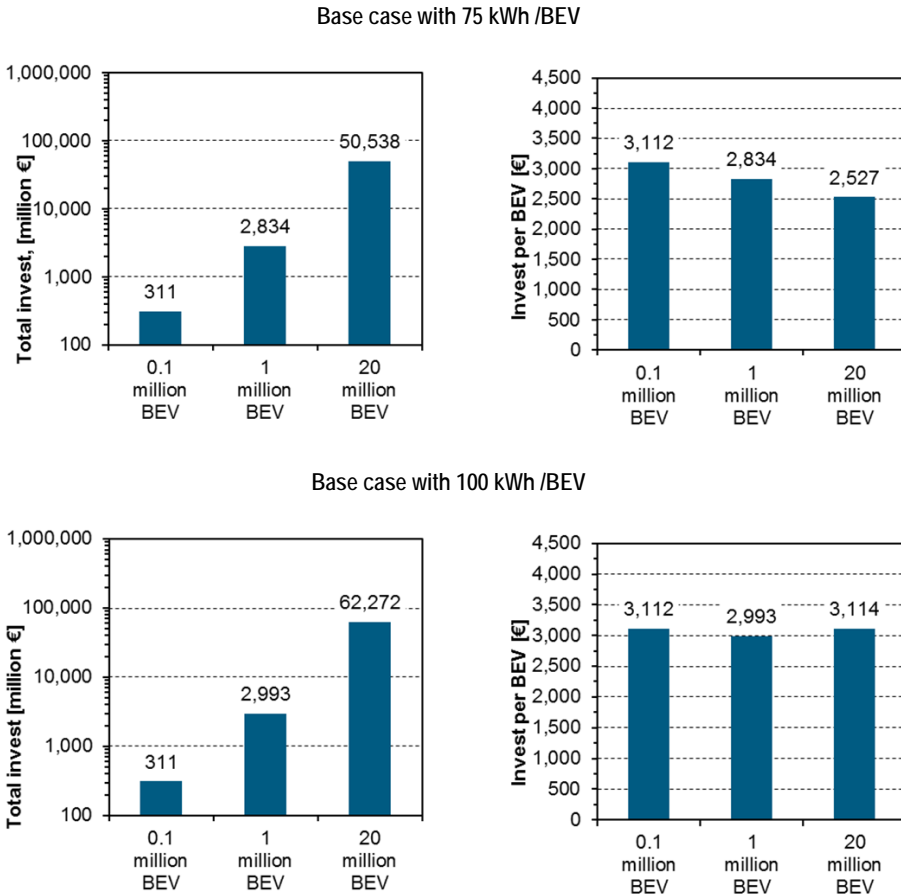


Figure 6-24: Total (left) and specific (right) investment of BEV charging infrastructure for the three scenarios under consideration.

Source: own calculations based on assumption in this study.

Figure 6-25 displays the cost distribution for all scenarios. According to our definitions, the extension of the distribution grid in cities is only considered in the 20-million BEV scenario; the other two scenarios show a low level of investment for transformers and cables to be installed for freeway chargers. Charger investment peaks at 95 % and 94 %, respectively. With regard to the 20-million BEV scenario, this share decreases to 73 % due to further installation of grid components in cities.

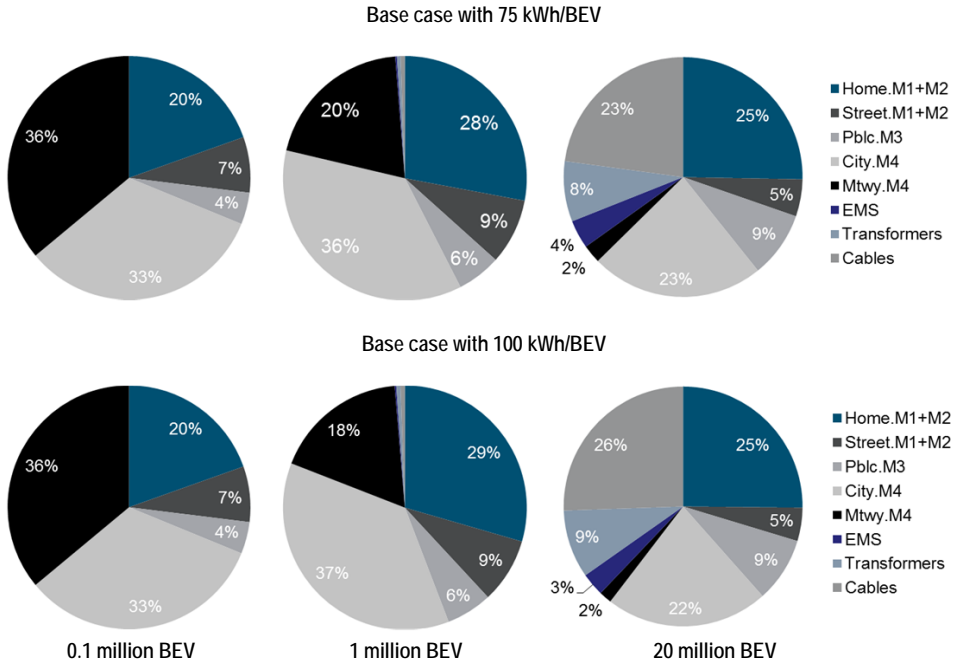


Figure 6-25: Investment shares by infrastructure component for the three scenarios under consideration. Grid investment neglected in the 0.1-million BEV and 1.0-million BEV scenarios. Source: own calculations based on assumptions in this study.

Figure 6-26 shows the energy shares by charger type used as the basis for calculating specific electricity cost. The utilization of overnight chargers decreases because, on the one hand, the mileage share on freeways increases with battery capacity and, on the other hand, the availability of overnight charging sites is significantly lower in the 20 million BEV scenario compared to the other two scenarios. Charged energy is, consequently, shifted to Mode 4 city and freeway chargers.

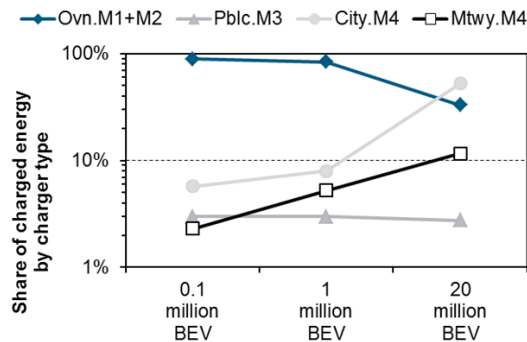


Figure 6-26: Share of charged energy by charger type. Average values with respect to charge patterns that differ by settlement type.

Total electricity cost was determined on the basis of investments shown in Figure 6-24 (left) and on further assumptions about the discount rate (8 %, see Table 6-5), operational lifetime (10 years for chargers and 20 years for grid components) and individual operation cost factors (Figure 6-27). Net electricity cost (before a BEV charging infrastructure) are calculated without taxes and levies based on electricity for households and industrial consumers according to Table 6-4.

Figure 6-27 shows that electricity costs are highest for the two Mode 4 charging options in cities and on freeways, respectively, owing to the comparably low utilization in the low market share scenarios.

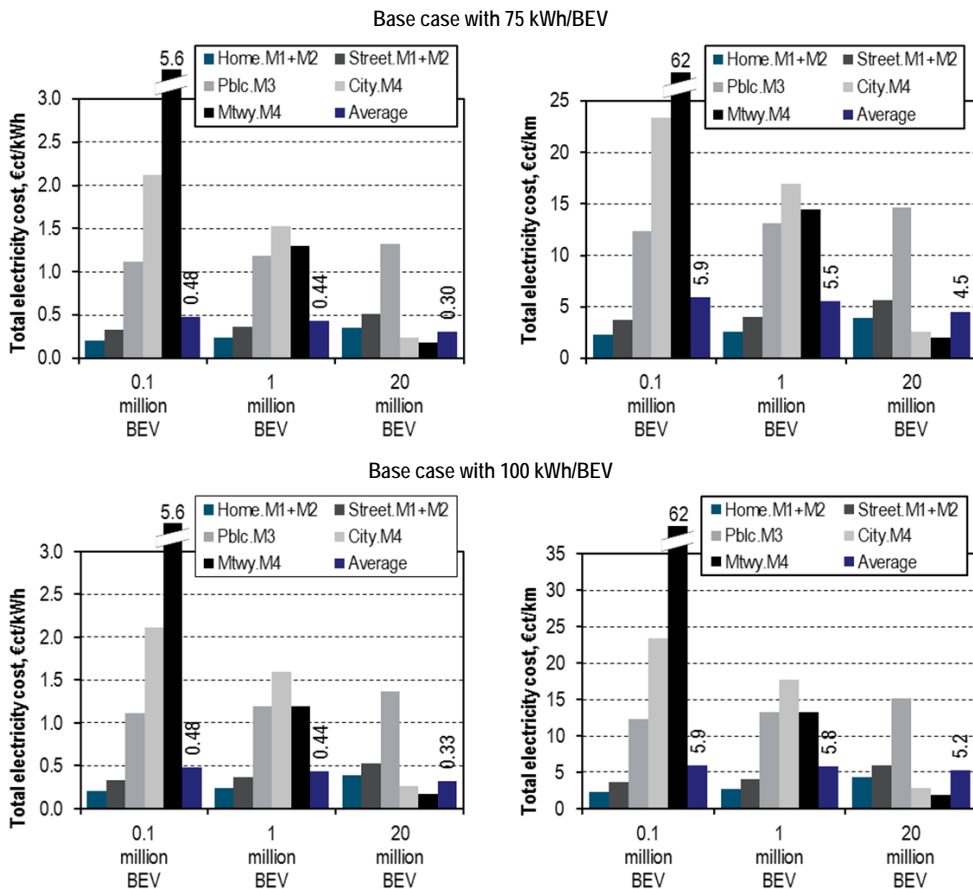


Figure 6-27: Total cost of electricity for BEV charging (left) and variable fuel cost of BEV driving (right) by charger type per km driven based on nominal fuel economy of 11 kWh/100km.

In the 20 million BEV scenario, Mode 4 charging costs are lowest due to higher utilization. Mode 3 city charging cost is high in all cases because of low utilization (see Figure 6-26). In the 20 million BEV scenario, charging at Mode 3 city chargers becomes even more expensive due to higher charger cost caused by higher power requirements. The average

cost of charging decreases from the 0.1 million BEV scenario to the 20 million BEV scenario because of higher infrastructure utilization and lower investment costs due to learning effects. Comparing the two BEV base cases of 75 and 100 kWh respectively, the total costs of electricity ranges from 3.0 to 3.3 €/kWh. Based on the nominal BEV fuel economy, the variable cost of BEV driving is 4.5 to 5.2 €/100 km. These values correspond to the 20 million BEV scenario.

#### 6.3.2.4 Sensitivity Analysis Mode 4 chargers

The variation of parameters supports the identification of most important parameters of the calculations and their impact on the results. For charging infrastructure, one of the major factors is the number of Mode 4 chargers in cities.

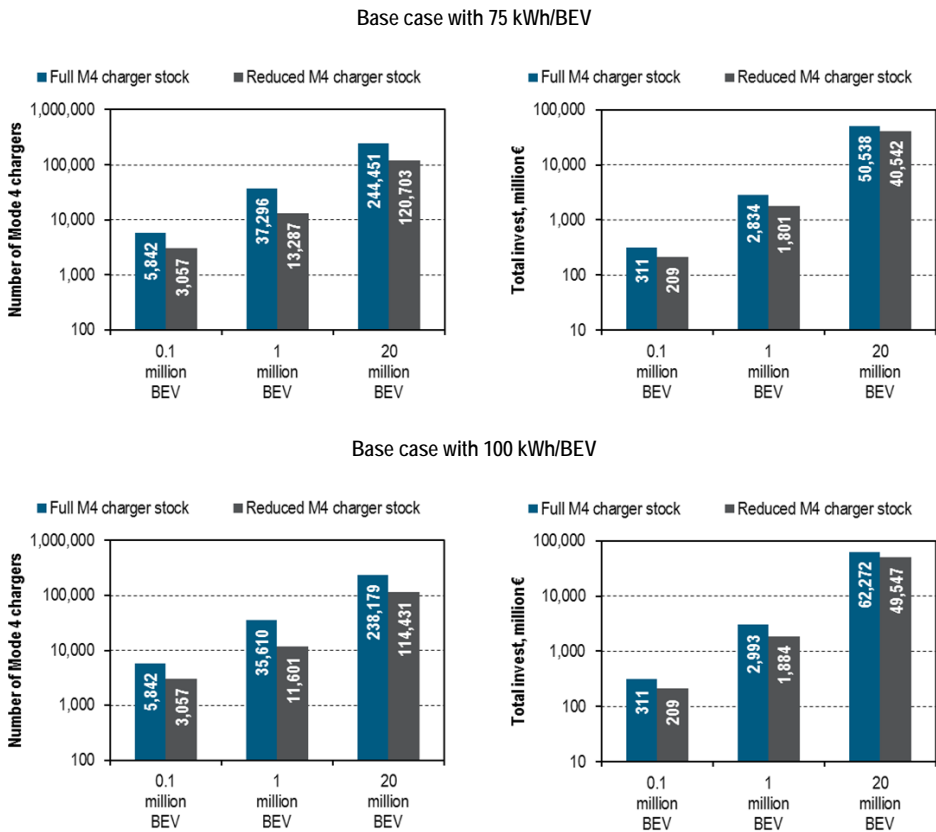


Figure 6-28: Number of Mode 4 chargers (including chargers on freeways) in Germany and resulting total infrastructure investment.

As compared to the baseline case, the number of Mode 4 chargers was decreased. For further information, see text.

In order to show the sensitivity of results regarding this parameter, an additional scenario is created in which the number of M4 city chargers is reduced such that only BEVs without an overnight charging option are considered. That means all other BEVs are assumed to charge



at their overnight chargers, at Mode 3 chargers in cities or on freeways. In the 20-million BEV scenario, 11.2 million BEVs have an overnight charging option available while 8.8 million BEVs have to recharge at public or commercial chargers. The number of Mode 4 freeway chargers remained constant. The respective Mode 4 charger fleet range is shown in Figure 6-28 (left) and the resulting total infrastructure investment in Figure 6-28 (right). According to the Figure, total investment for the reduced number of Mode 4 chargers ranges from € 41- € 51 billion and € 50- € 62 billion for base cases with 75 kWh and 100 kWh per BEV, respectively.

### 6.3.3 Impacts on Transmission Grid and REN Generation

Figure 6-29 show the impact of different BEV scenarios on the transmission grid, whereby impact is assessed by measuring the additional High Utilization Incidents (HUI) posed by greater electricity demand. HUI occur when a transmission line is loaded with more than 70 % of its maximum power capacity for at least one hour of the year, while the total number of HUIs refers to a whole year. A line loading over 70 % would indicate a potential threat of cascading failure events that could jeopardize the stability of power system operations. All the additional HUIs shown in Figure 6-29 correspond to the scenario without BEVs. In the map, the 100,000, 1-million and 20-million BEV scenarios are compared to the scenario without BEVs. The resulting differences in HUI numbers stand for increases or decreases in power line utilization. However, the illustration does not show the critical parts of the network, but only the difference in utilization resulting from integrating BEV vehicles into the system.

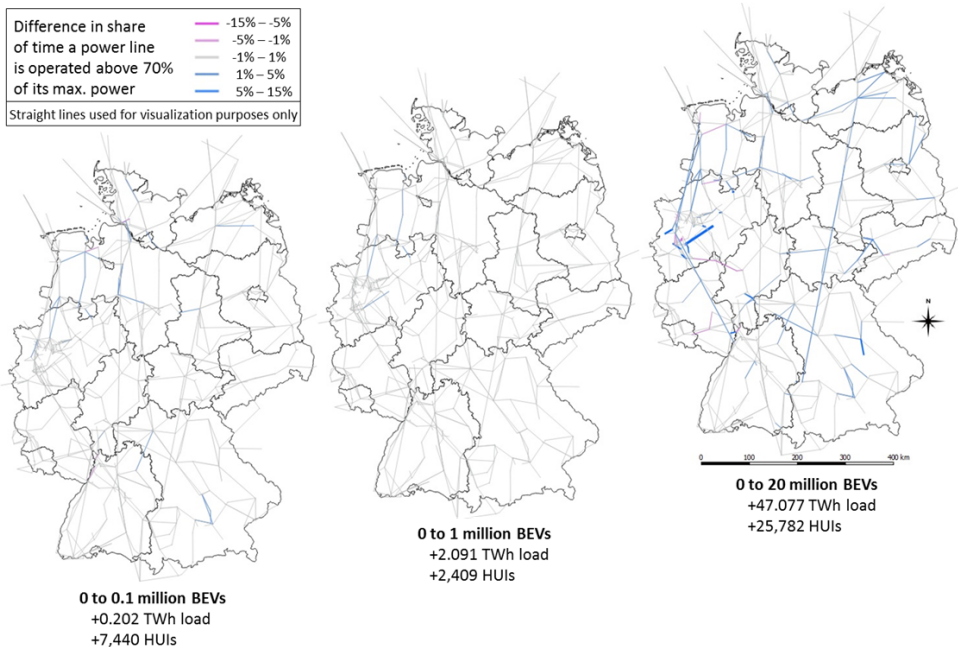


Figure 6-29: High utilization incidents (HUI) in the electric transmission grid for different BEV stocks.

It can be observed that the changes for the 100,000 and 1 million BEV scenarios are mostly within the range of a 1-% increase or decrease. Only when comparing the 0 and 20-million BEV scenario can significant changes be seen, whereby most of them correspond to an increasing number of HUIs. The small changes in the number of HUIs indicate that the impact of the additional BEV load does not jeopardize the transmission grid infrastructure. This is in contrast to the distribution grid where high shares of BEVs depending on the grid topology can have high impacts. The degree of distribution grid enhancement depends e.g. on the number of vehicles and chargers, penetration of controlled and fast charging.

Figure 6-30 depicts electricity generation for the scenario without BEV in comparison to the scenario with 20 million BEVs. Moreover, it shows the change in total curtailments and the positive residual load. The changes for the 0.1 and 1 million BEV scenarios are insignificant in comparison to those for the 20 million BEV scenario. In all cases, it becomes evident that operating BEVs can decrease RES curtailments by absorbing more energy (9.8 % for the 20 million case); however, this also further increases demand for the operation of fossil fuel plants (15.6 % for the 20 million case). The increase in positive residual load means that the CO<sub>2</sub> emissions to some extent are shifted from the transportation to the power sector.

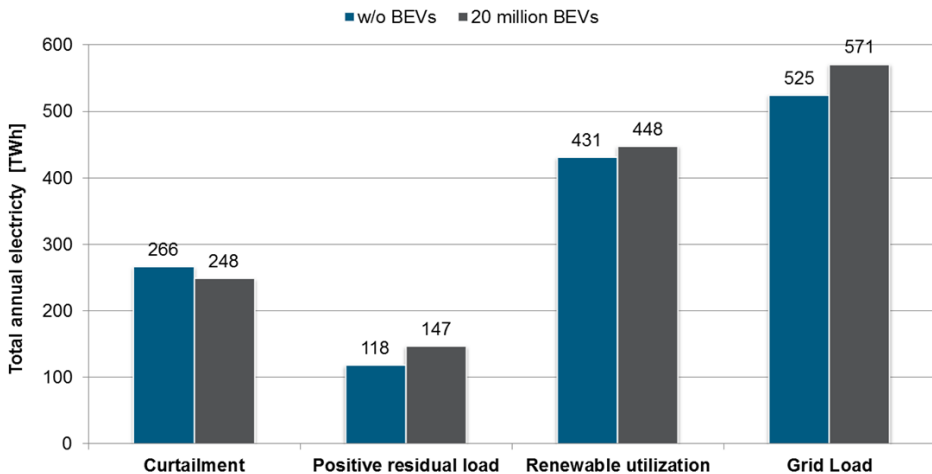


Figure 6-30: Curtailment, residual load, renewable generation and grid load for the 0 and 20-million BEV scenario. Import and export of electricity is assumed to be constant.

#### 6.3.4 Summary and Conclusion for Electric Charging Infrastructure

Section 6.3 aimed to examine the investments required for setting up a charging infrastructure for BEV in Germany. Besides grid components such as transformers and cables, the analysis considered Mode 1 and Mode 2 overnight chargers as well as Mode 3 and Mode 4 public and commercial fast chargers respectively. Home charging will dominate the early stages of market introduction but that this is likely to decrease when BEV market shares rise, as not all passenger cars will have the option of home charging option. The analysis looked at three different BEV fleet scenarios, namely 0.1, 1.0 and 20 million BEVs.

The assumption of a large fleet means that BEV performance must be comparable to today's situation, in particular with regard to operational range and charge time. This is translated into a battery capacity that increases with the market share and into charge time targets that are most stringent for commercial Mode 4 quick chargers, with 10 min charge time for an SOC shift from 20-80 %. Maximum charger power according to our analysis is 360 kW for a battery capacity of 100 kWh. As charger cost increases with charger power, investment in chargers was found to be decisive for overall infrastructure cost.

Total investment demand for the 20-million BEV scenario was determined to be in the range of € 50.5 to 62.3 billion for the two base cases with 75 and 100 kWh BEV battery capacity. In a separate case with a reduced number of Mode 4 chargers in cities, infrastructure investment ranges between € 40.5 and € 49,5 billion. We found that charging infrastructure in cities dominates the total investment demand for Germany. Based on capital costs derived from the investments, and also including operational and net energy costs, we determined the average specific electricity cost without taxes to be 0.30-0.33 €/kWh for the two base cases with 75 and 100 kWh BEV battery capacity. These values apply to the 20 million BEV scenario. It has to be noted that, besides capital and operational expenditure, the annual distribution of charged energy amongst the different charging options is decisive for the specific electricity cost.

As yet, a variety of parameters that have a severe impact on investment requirements are still vague and need further detailed assessment. Such parameters include, for example, charging behavior of future drivers in relation to today's situation with gasoline and diesel car mileage but also future car-driving patterns, taking account of emerging trends in car sharing, autonomous driving and city traffic regulation policies. This may have an impact on the amount and distribution of private, semi-public and public chargers in cities.

With respect to component scaling, it is important to note that nominal passenger car fuel economy values are used for the analysis. However, such values are significantly higher for realistic driving patterns – particularly for driving on freeways – also considering onboard heating and cooling requirements. Consequently, infrastructure components might need to be scaled higher compared to the results in this study. Moreover, charged energy could be increased for realistic fuel economies, leading to increased electricity turnover and lower specific electricity cost per kWh but higher cost per km.

Future energy systems that are required to handle large quantities of variable renewable energies will require large-scale energy storage in the terawatt hour range. From today's perspective and in contrast to the analysis of FCEV fueling infrastructure, this issue cannot properly be addressed purely by battery-electric vehicles. Future work could, however, focus on charging options that ensure a high coverage of renewables, as this is expected to be a major motivation for BEV deployment.

## 6.5 Comparison of Results: Charging and Hydrogen Fueling Infrastructure

This section brings together the major results from Sections 6.2 and 6.3, namely investment and specific cost per energy unit delivered or per kilometer driven. Moreover, it presents the specific energy demand and GHG emissions for both infrastructure alternatives. It should be noted in this connection that BEV charging infrastructure does not provide energy storage on a large scale. In contrast, the hydrogen infrastructure considered in this study already features built-in supply security based on a 60 day storage capacity.

By way of comparison, Figure 6-31 displays the cumulative investments required for both infrastructure types, including the individual range of results and mean average values. In the case of a very small vehicle fleet of 0.1 million cars, the investments in BEV charging and hydrogen fueling infrastructures are virtually equivalent, albeit with an advantage for hydrogen fueling infrastructure as of 1.0 million cars. As more cars enter the market, investment in hydrogen fueling infrastructure temporarily goes up owing to the generation of electrolyzer capacity and hydrogen storage. However, for scenarios with high market penetration, i.e. 15 and 20 million vehicles, the hydrogen fueling infrastructure demonstrates some clear advantages thanks to the widespread use of its fueling infrastructure which is comparable to today's conventional system. Quick vehicle fueling and long refueling intervals combined with the relatively cost-effective and high fueling capacity of hydrogen stations all contribute to lower infrastructure cost. Fast charging of BEV, however, requires higher investment to generate sufficiently high charging power.

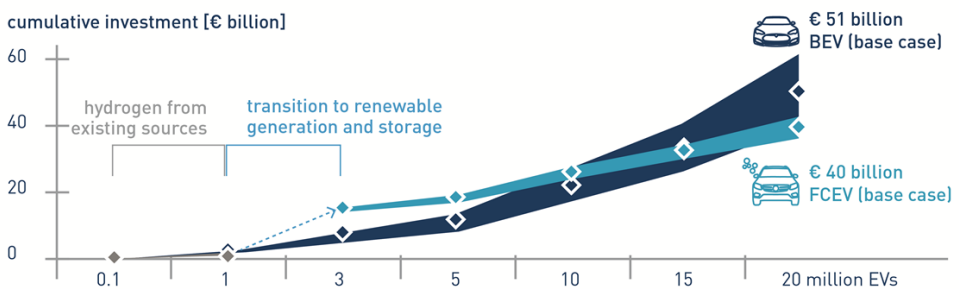


Figure 6-31: Comparison of the cumulative investment of the supply infrastructure for fueling FCEVs and charging BEVs.

Seen in the context of the overall transition of the energy systems, i.e. the switch to an energy system powered chiefly by renewable energy, the levels of investment required for the fueling and charging infrastructures are actually quite low. According to the values presented in Figure 6-32 even the sum of both infrastructure types (€ 91 billion) considered in this study is considerably lower than the € 374 billion required for the assumed renewable electricity generation scenario in this study. Electric grid enhancement according to Germany's grid development plan through to 2030 is estimated at approximately € 34 billion alone, putting it in the same range as our result for the FCV fueling infrastructure, which amounts to € 40 billion. For instance, the investments in the current federal transportation infrastructure plan are substantially higher.

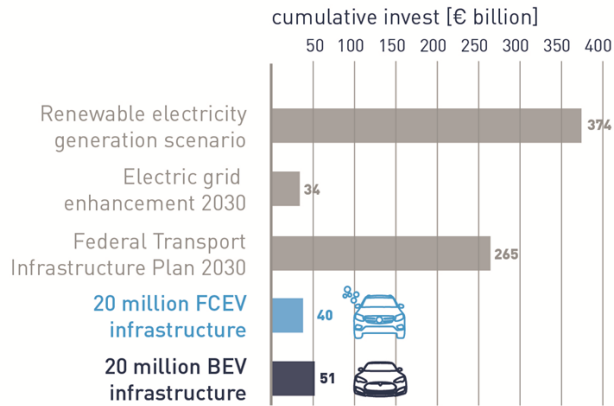


Figure 6-32: Comparison of cumulative investment for different infrastructures.  
(assumed investment for the renewable electricity generation scenario: wind onshore 170 GW @ 1000 €/kW // wind offshore 59 GW @ 2500 €/kW // PV 55 GW @ 1000 €/kW)

The results pertaining to investment in BEV charging and hydrogen fueling infrastructure are used to estimate specific mobility cost based on the fuel economy assumptions in our scenario setting (see section 6.2 and 6.3). This includes all energy costs as well as annualized infrastructure cost. Margins and taxes, fees and vehicle cost are not considered.

Figure 6-33 plots the results from the two assessments. As can be seen, mobility costs are comparable when the number of vehicles exceeds 10 million, with slight advantages for BEVs. In the case of very small vehicle fleets, i.e. 0.1 million cars, BEV fuel costs are significantly lower compared to FCEVs. However, as of a vehicle fleet of 1 million cars already, FCEV fuel costs are found to be in the same range as BEV costs. The increase between 1 and 3 million cars is a result of the switch from byproduct and reformer hydrogen to the exclusive utilization of renewable energy for hydrogen production via electrolysis, which requires additional investments for electrolysis and hydrogen storage.

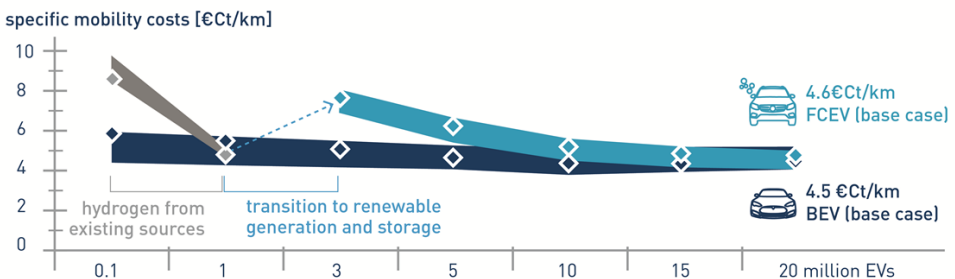


Figure 6-33: Comparison of specific mobility costs (including all energy costs and annualized infrastructure costs; no margins, no taxes, no fees and no vehicle costs).

On the one hand, this shows that market introduction with available low-cost hydrogen can be accomplished in a cost-effective manner. On the other hand, if purely renewable hydrogen is the ultimate goal, then a temporary cost increase cannot be avoided.

This is different with BEVs, however, as the energy is taken from the electricity grid and, according to our scenario setting, they do not include a large-scale storage element. If BEV charging are to feature the same degree of supply security, mobility costs would also increase significantly due to the additional investments that would have to be made for large-scale storage and to offset the efficiency losses brought about by storage cycles.

Mobility costs for the hydrogen pathway could be lowered further still by adding new hydrogen consumers to raise infrastructure usage – like trains, buses, trucks or industry. Spreading cumulative investment across more applications can bring down fuel specific costs. For BEV infrastructure, controlled charging that takes account of the current grid load can reduce grid stress, and also some of the additional costs of distribution grid enhancement.

Besides infrastructure cost, other decisive parameters when evaluating infrastructure alternatives are energy efficiency and greenhouse gas (GHG) emissions. Based on our scenario assumptions according to section 6, it is possible to determine the total specific energy demand and GHG emissions per kilometer.

Figure 6-34 (right) presents the results (for the 20 million car scenario) of specific energy demand per kilometer. Hydrogen fueling does not harness much electricity from the grid but instead uses surplus electricity from renewable power generation.

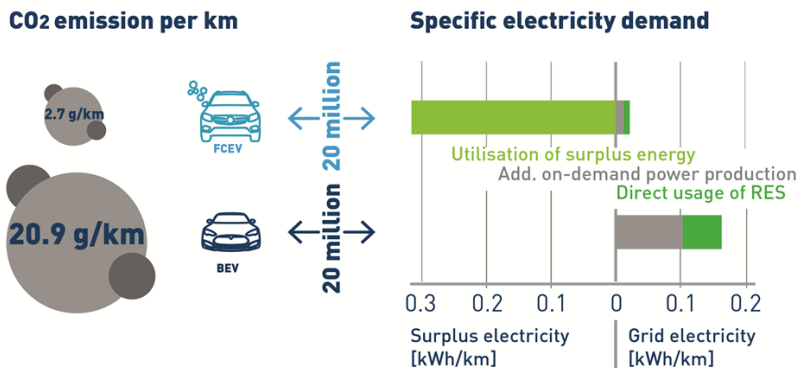


Figure 6-34: Comparison of specific energy demand and CO<sub>2</sub> emissions per kilometer related to the 20 million cars scenario.

Specific GHG emissions are determined in correlation with specific energy demand and considering emissions factors for grid electricity. The values for the 20 million car scenario are displayed in Figure 6-34 (left). Given our assumption that, in this scenario, hydrogen production is based on 100 % renewable energy sources, GHG emissions result exclusively from infrastructure components that use grid electricity; for example, for compressing hydrogen. In contrast, BEVs are charged directly from the conventional electricity grid,

without any particular preference for renewable energy. The average electricity mix of the assumed scenario is thus decisive for the GHG balance.

In conclusion, market introduction can be achieved cost effectively – not only for BEV, but also for FCEV – when low-cost hydrogen from byproduct sources or from natural gas reforming is used. GHG emissions must be considered in this case. Fleet size also influences the total investments and mobility cost increases in both infrastructure options. However, the switch to purely renewable hydrogen production assumed here means that cost increases are more significant due to additional investment in electrolyzers and storage. Thus, mobility costs also increase for FCEVs, but only during a transitional period. In the long term however, hydrogen refueling infrastructure requires less investment compared to the BEV charging infrastructure.

Another key factor that must be considered here is the level of infrastructure utilization, not only with respect to fleet size or total, i.e. region-wide, capacity, but regarding the actual amount of time of cars spend at the charging point. However, the future charge patterns of BEV drivers are still uncertain which begs the question as to what extent expensive high-power quick chargers will be required.

In contrast to FCEV, BEV face more difficulties in terms of reliance on purely renewable energy sources. This includes the issue of large-scale electricity storage which is not considered in our assessment. More investments for the required storage would drive up mobility costs and additional storage cycles would lower efficiency.

Finally the total investments required are low compared to the renewable power generation scenario. Both FCEV and BEV are likely to be required for future transport, because of their different characteristics with respect to efficiency, operational range and fueling or charging time. Apart from very small fleet sizes, the specific (per vehicle) infrastructure investment and mobility cost are relatively stable.

## 7 Summary and Conclusions

### Summary

#### *Motivation*

Electric drivetrains are key elements of low carbon energy-efficient transport based on renewable energy sources. Furthermore, a transportation system with zero local emissions will substantially improve people's quality of life, especially in urban areas currently struggling with air quality issues. Both battery and hydrogen fuel cell electric vehicles feature these important characteristics. However, large scale integration of these vehicle technologies requires new infrastructures.

#### *Objective*

The goal of the study is to perform a detailed design analysis of the required infrastructure for supplying battery and fuel cell electric vehicles in Germany at multiple scales. Germany is selected as the location as it is an ideal case study for an energy system soon to be dominated by renewables. The underlying question concerns the investments, costs, efficiencies and emissions for an infrastructure capable of supplying between one hundred thousand to several million vehicles with hydrogen or electricity. At present, both technologies are in the initial stage of their market development and are posed to take advantage of the unavoidable surplus electricity that characterizes renewable dominated energy systems. In any case, an effective infrastructure is required to make this energy available. However, at present the design of an applicable infrastructure is unclear. To illuminate this topic, the approach of the infrastructure analysis is transparent and the results of the analysis support a facts-based discussion which can simply be adapted to the growing level of experiences.

#### *Approach*

The approach involved the application of spatially and temporally resolved models for infrastructure development and scenario calculations for different levels of electric vehicle market penetration. In order to deliver transparent and comparative results, the analyses applied the same scenario assumptions with regard to electricity generation and passenger car transport to both infrastructures.

#### *Results for investments and costs*

The scenario analyses demonstrate that, for low market penetration levels of a few hundred thousand vehicles, the costs of infrastructure roll-out are essentially the same for both technology pathways. Hydrogen is found out to be more expensive during the transition period to electricity-based generation via electrolysis and geological storage, both of which are needed to access renewable hydrogen from surplus electricity. In the scenario for charging battery electric vehicles no seasonal storage option is considered and grid electricity for charging is generated in part by non-renewable energy sources.

If vehicle penetration increases up to 20 million vehicles in the base case scenario, a battery charging infrastructure would cost around € 51 billion, making it more expensive than hydrogen infrastructure, which comes in at around € 40 billion. Additionally, securing supply



based on renewable electricity requires a consideration of seasonal storage options. For the 100 % excess electricity-based hydrogen production, seasonal storage capacity is set to bridge 60 days at low renewable electricity generation. An adequate solution is required to achieve the same level of security of supply for electric charging based on renewable energy sources. For both infrastructures, investment in rollout is low compared to other infrastructures, like roll-out of renewable electricity generation capacities or the maintenance and extension of transportation routes.

A sensitivity analysis of important parameters is carried out to examine various uncertainties in investment calculations. It revealed that, in the case of hydrogen infrastructure, investments in hydrogen fueling stations and subsequent specific investments in electrolysis have the highest impact. With regard to electric charging, it is the number of fast chargers (Mode 4) and the maximum power output capacity that exhibits the highest sensitivity regarding cumulative investment.

The analysis of mobility costs includes electricity prices for surplus electricity (6 €/kWh) and grid electricity prices (6 to 15.7 €/kWh, excluding taxes and levies) depending on power requirements and annual consumption. All investments pertaining to hydrogen generation, transport and distribution and to BEV-related grid extension and chargers are taken into account. Because the focus is on infrastructure requirements, vehicle investments does not form part of the analysis.

The underutilization of infrastructure and the lower energy efficiency of the hydrogen conversion chain result in higher mobility costs for low FCEV penetration scenarios. The increasing number of BEVs leads to rising numbers of fast chargers, which subsequently results in higher power demand and distribution grid enhancement.

The mobility costs per kilometer are roughly same in the high market penetration scenario at 4.5 €/km for electric charging and 4.6 €/km for hydrogen fueling. Because hydrogen permits the use of otherwise unusable renewable electricity by means of on-site electrolysis, the lower efficiency of the hydrogen pathway is offset by lower surplus electricity costs.

### ***Results for energy efficiency and CO<sub>2</sub> emissions***

For the scenario with 20 million fuel cell electric vehicles approx. 87 TWh of surplus electricity for electrolysis and 6 TWh of grid electricity for transportation and distribution are required. On the other hand, charging 20 million battery electric vehicle accounts for an electricity demand of approx. 46 TWh out of the distribution grid. The efficiency of the charging infrastructure is higher, but limited to flexibility covering short-term periods. The available surplus energy in the assumed renewable dominated electricity scenario exceeds by factor of three to six the demand to supply 20 million electric vehicles.

According to the use of surplus electricity, renewable and fossil electricity out of the grid, the corresponding CO<sub>2</sub> balance for the high penetration scenario shows low specific emissions in comparison to the use of fossil fuels. The hydrogen infrastructure with the inherent seasonal storage option has lower CO<sub>2</sub> emissions because of the high use of renewable surplus electricity. The application of controlled charging can improve the use of surplus and renewable electricity, thus decrease specific CO<sub>2</sub> emissions of BEV.

## Conclusions

The conclusion can be drawn that electric charging and hydrogen fueling are key to realize low carbon, clean and renewable energy based transportation concepts.

Achieving the goal of renewable electricity generation in line with the Energiewende calls for a significant enlargement of wind and PV capacities. Without new flexible demand options, structural changes in energy systems will lead to high renewable curtailments due to a lack of temporal and spatial fitting demand. Hydrogen produced by electrolysis and the controlled charging of electric vehicles will play an important role in integrating large amounts of otherwise curtailed renewable electricity.

A smart and complementary combination of the electric charging and the hydrogen refueling infrastructure can join the strengths of both and can avoid non-sustainable solutions with low systems relevance or efficiency. Taking advantage of low hanging fruits like overnight charging of battery electric vehicles for short distance travel and meeting the challenges in long distance and heavy duty transport by fuel cell electric vehicle and hydrogen refueling can be beneficial with regard to systems solutions. Insofar, a hybrid strategy for the roll-out of both infrastructures will help to maximize energy efficiency and to optimize the use of renewable energy resources while minimizing CO<sub>2</sub> emissions over a broad range of purposes and transportation modes. Both infrastructures require a small amount of investment compared to other infrastructures like roll-out of renewable electricity generation or the maintenance and expansion of transportation routes.

While electric charging infrastructure allows for higher efficiency, hydrogen infrastructure roll-out for transportation enables further large-scale applications in other sectors like industry. Understanding hydrogen fueling infrastructure as energy systems solution can unleash the full potential of realizing sector coupling.

## Need for further research

The study reveals a need for further research and scenario analyses, especially for different market penetration levels and resulting transition strategies that embrace new energy supply infrastructures as part of sector coupling. An isolated analysis of the transportation sector without integrating the energy system does not systematically link the various sectors to create win-win situations.

In contrast to FCEV fueling, BEV charging requires a change in current user behavior. In particular, the number of chargers, siting and frequency of use are a source of high uncertainties given the lack of practical experience. Fast charging is seen as an important option for creating acceptance as it extends the range of battery electric vehicles. Above all, further detailed investigation is required into high market penetration of electric vehicles and into the design of financing concepts as well as the impact of fast charging on energy efficiency and on enhancement of the electric distribution grid.

Changes in user patterns caused by different mobility and vehicle ownership concepts as well as the possible trend to autonomous driving will impact both infrastructures. However further research, development projects and living labs are needed to investigate the impact of these concepts on future supply infrastructures.



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## 9 Appendix

### Brief description of analyzed infrastructure scenario studies of the meta-analysis chapter 5.2

**Arnhold, O., Energie – und Verkehrswende: Synergien nutzen und Risiken erkennen [20] und Energiewende im Verkehr - Welche Auswirkungen haben Batterie- und Brennstoffzellenfahrzeuge auf das Energiesystem? [21]**

[20] and [21] present an analysis of the peak load of filling stations located on German freeways, irrespective of the share of BEVs and FCEVs, whereby an optimization model is applied to design the filling station of the future. Components of future filling stations include electrolyzers, hydrogen storage systems, stationary battery storage systems, photovoltaic and wind energy, as well as a connection to the electricity grid. The highest peak loads occur for a homogenous fleet of 100 % BEVs. An increasing share of FCEVs significantly reduces the peak load, while mobility costs increase. Hybrid BEV/FCEV filling stations are found to significantly reduce the peak load of filling stations. The key components for reducing the peak load of filling stations are stationary batteries and hydrogen storage systems, as they can serve as energy buffer units.

Furthermore, the German transport sector's additional electricity demand (individual mobility) is analyzed on a national level using an optimization model that determines the installed power plant capacities and power plant utilization. In this scenario, the power plants supply the electricity, including additional electricity demand, for the transport sector. The analysis is based on a regional distribution of electricity charging and H<sub>2</sub> filling stations and on assumptions regarding the share of vehicles with at-home charging capacity. Due to the higher efficiency of BEVs in comparison to FCEVs, the additional demand for electricity to power the transport sector increases as the share of FCEVs goes up. On the other hand, higher shares of FCEVs lower demand for storage systems in the power system due to the flexibility of electrolyzers in combination with hydrogen storage systems. Additional storage systems are required in the 100 % BEV scenario compared to the reference case excluding electricity demand of the transportation sector. The additional flexibility provided by electrolyzers also allows for a reduction of renewable curtailment in comparison to the 100 % BEV scenario. BEVs can also make the electricity system more flexible to a certain extent due to load management (controlled charging). However, this is considered limited in comparison to the flexibility provided by electrolyzers and hydrogen storage. In a 50:50 scenario (50 % BEVs and 50 % FCEVs), renewable curtailment can even be reduced in comparison to the reference case. The 50:50 scenario combines the advantages of both technologies. The higher efficiency of BEVs reduces the demand for additional renewable generation capacities while FCEVs add additional flexibility to the system.

**Samsatli, S., Optimal design and operation of integrated wind-hydrogen-electricity networks for decarbonizing the domestic transport sector in Great Britain [22]**

[22] concerns an approach for determining the optimal design and operation of integrated wind-hydrogen-electricity networks for supplying the transport sector with renewable hydrogen. The analysis is based on an optimization model developed specifically for this purpose. The integrated system comprises wind turbines; electrolyzers and fuel cells, compressors and expanders; pressurized vessels and underground hydrogen storage;

hydrogen pipelines and electricity overhead/underground transmission lines; and hydrogen filling stations and distribution pipelines. The model is applied to Great Britain as a case study. In the considered scenarios, Great Britain's entire energy demand for the domestic transport sector is supplied by a wind-hydrogen-electricity network.

The spatial distribution and temporal variability of energy demands and wind availability were considered in detail in this model which also divides Great Britain into 16 regional zones. Electricity supply from wind and hydrogen demand is analyzed at an hourly resolution. The suitable sites for wind turbines were identified using GIS by applying a total of 10 technical and environmental constraints that determined the maximum number of new wind turbines that can be installed in each zone. Hydrogen demand is derived from statistical vehicle utilization data and aggregated for the 16 zones, the objective being to minimize the total cost of the required wind-hydrogen-electricity network while satisfying the demand of the domestic transport sector. The model simultaneously determines the optimal number, size and location of each technology, examines whether energy should be transmitted as electricity or hydrogen, and looks at the structure of the transmission network and the hourly operation of each technology and so on. The distribution costs are based on the number of filling stations and length of the distribution pipelines. Hydrogen transport by trucks is not considered.

The results indicate that all of Britain's domestic transport demand can be met by on-shore wind through appropriately designed and operated hydrogen-electricity networks. Within the set of technologies considered, the optimal solution is to build a hydrogen pipeline network in the south of England and Wales; supply the Midlands and Greater London with hydrogen from the pipeline network alone; use Humbly Grove underground storage for seasonal storage and pressurized vessels at different locations for hourly balancing, as well as seasonal storage; Northern Wales, Northern England and Scotland are to be self-sufficient and generate and store all of the hydrogen locally. These results may change with the inclusion of more technologies, such as electricity storage and electric vehicles.

As a result, the integrated wind-hydrogen system is designed with consideration of different scenarios. Regarding the hydrogen infrastructure, this study calculates the length of the hydrogen transmission and distribution network, as well as the number of filling stations. A key finding from the scenario analysis is that both transmission and storage are required to cover demand in the 16 zones. In the scenarios, the pipeline transmission system is only required to supply the southern part of the UK. In this part, some zones are not able to meet hydrogen demand from local wind energy generation, even under consideration of energy storage options. Due to the distributed wind energy and hydrogen generation considered and the possibility of high voltage electricity transmission across different zones, several zones are self-sufficient and the total length of the required hydrogen pipeline system is relatively small. Large-scale underground hydrogen storage also plays an important role in the context of hydrogen transmission systems operation. In self-sufficient zones, seasonal hydrogen storage is required to balance fluctuating wind electricity generation and hydrogen demand.

#### **Ball, M., Integration einer Wasserstoffwirtschaft in ein nationales Energiesystem am Beispiel Deutschlands [23]**

The study [23] develops an optimization model to analyze the build-up of a hydrogen supply infrastructure for the transport sector in Germany. The time-horizon for infrastructure build-up is the period 2015-2030. With the developed tool, it is possible to derive the optimal cost strategy for hydrogen market introduction. Synergies as well as interactions with the existing

energy system are also analyzed. This model embraces the entire hydrogen value chain, from hydrogen production (including centralized and on-site production), transport, distribution, liquefaction and filling. Hydrogen transport and distribution options, trucks (liquefied hydrogen) and pipelines are also considered in the model's approach. The choice of transport medium is mainly determined by the distance to be covered. The distance between hydrogen sources and sinks is analyzed with the help of a geographical information system. Furthermore, the study considers fuel cell and hydrogen combustion engine vehicles. With regard to vehicle type, it distinguishes between passenger cars, light commercial vehicles and busses.

The geographical and time-dependent infrastructure build-up is modeled on exogenous spatiotemporal demand for hydrogen. Hydrogen demand is based on the population and area-wide vehicle distribution. A distinction between urban and rural areas is also considered in the approach. The urban areas considered correspond to the German federal states (except Bremen and Saarland, which are analyzed together with adjacent surrounding states). An additional eight urban areas are also considered.

Key results from the infrastructure build-up analysis are that, in the early hydrogen market introduction phase, hydrogen is transported from a single centralized production site via trucks to other regions in combination with on-site hydrogen production. For the year 2020 (scenario URBAN), it is concluded that in urban areas with relatively high hydrogen demand, demand is met by local large-scale production. The hydrogen filling stations in these urban areas are directly connected to the production site via pipelines. Smaller cities and rural areas with low hydrogen demand are supplied by on-site hydrogen production. The build-up of a pipeline system that supplies adjacent regions from one central production site is also underway. Nevertheless, the across-area transport of hydrogen by pipelines is less important in comparison to on-site production and urban production sites. Different infrastructure scenarios are compared in terms of total costs for hydrogen supply. However, only graphical results, including a breakdown of the total costs (production, liquefaction, transport, distribution and filling), are available in the study. No additional information regarding the number of filling stations and filling points, as well as the number of trucks and pipeline lengths, is provided. Regarding the preferable transport option, it is stated that pipeline transport is the superior option for large transport volumes and long distances, as well as for short distance transport (< 20 km). Correspondingly, truck transport is the better option for long distance transport and low transport volumes.

The total costs for the hydrogen supply are calculated on basis of the infrastructure analysis. The cumulative investment (only graphical results are available), as well as specific hydrogen supply costs (€/kWh), are presented. Cost components taken into account are hydrogen production, liquefaction, transport, distribution and retail. Hydrogen production accounts for the major share of cumulative investment, followed by hydrogen retail (fueling stations).

### **Robinius, M., Strom- und Gasmarktdesign zur Versorgung des deutschen Straßenverkehrs mit Wasserstoff [24]**

The study identifies and develops a market design that is characterized by high market penetration levels of renewable electricity generation, supplemented by the use of hydrogen in the transport sector. Therefore, it looks at potential electricity and gas markets, as well as the most important potential share and stakeholders of a hydrogen infrastructure. The

assumed energy supply scenario is dominated by 170 GW onshore and 60 GW offshore wind capacity. This necessitates large amounts of surplus power to meet the assumed hydrogen demand in 2052 of 2.93 million tons, with an installed electrolysis capacity of 20 GW in 15 different counties of Germany. The study calculates the requisite hydrogen pipeline transport and distribution infrastructure from hydrogen production by electrolysis to 9,968 hydrogen fuel stations. These calculations indicate the need for a 12,104-km transmission pipeline, which will cost an estimated € 6.7 billion. For distribution, a total length of 29,671 km will be required at an estimated cost of € 12 billion.

Furthermore, the profitability of an electricity and gas market designed to supply the German transport sector with hydrogen is demonstrated for three different scenarios distinguished by their respective input parameters.

**Noack, C., Studie über die Planung einer Demonstrationsanlage zur Wasserstoff-Kraftstoffgewinnung durch Elektrolyse mit Zwischenspeicherung in Salzkavernen unter Druck. Stuttgart, Deutsches Zentrum für Luft- und Raumfahrt e.V. [25]**

In Noack [25], a model-based scenario analysis is presented that compares a central hydrogen production and storage infrastructure with on-site production and storage infrastructure at filling stations. These scenarios consider different hydrogen utilization scenarios for the years 2030 and 2050. Hydrogen is used as a long-term storage option for renewable energy and as an alternative fuel in the transport sector. The study examines the impacts that the integration of renewable hydrogen production and storage infrastructure will have on Germany's future electricity supply system.

The results show that electricity for hydrogen production comes mainly from additional photovoltaic and wind energy capacities. One advantage of centralized hydrogen production is the availability of large-scale hydrogen storage options in salt caverns in northern Germany, which are co-located with wind energy production facilities. This is especially interesting for renewable energy integration. An important factor in this context is wind energy curtailment due to transport capacity restrictions in the electricity grid arising from delayed or only partially feasible grid extension. In a central hydrogen production scenario, curtailment is significantly reduced. Another advantage of centralized hydrogen production and storage is the significantly larger storage capacity which offers additional flexibility with respect to renewable energy integration compared to the limited on-site storage possibilities at fueling stations. Nevertheless, centralized hydrogen production also involves partly higher utilization of electricity grids which are used to supply the electrolyzers from decentralized grid-connected renewable generation capacities. Additionally, centralized hydrogen production would also lead to higher infrastructure-related costs, namely for hydrogen transport and distribution. However, this point is only mentioned from a qualitative angle and not further analyzed in the study.

**Seydel, P., Entwicklung und Bewertung einer langfristigen regionalen Strategie zum Aufbau einer Wasserstoffinfrastruktur [26]**

Seydel [26] presents an approach for analyzing the construction of a hydrogen infrastructure with due consideration for regional aspects. Based on a geographical information system (GIS), it simulates regional hydrogen demand and the development of hydrogen fueling stations and assesses the regional primary energy potentials for hydrogen production,

possible sites for hydrogen production and transport distances for pipelines and trucks. This information is coupled with an optimization model to analyze infrastructure development. Different scenarios for the hydrogen infrastructure in Germany are developed and the results compared.

The analysis looks at different hydrogen production pathways and the import of liquefied hydrogen. The model also offers a choice between centralized and on-site hydrogen production via electrolysis and steam reforming. Hydrogen transport is possible via pipelines and trucks (gaseous / liquefied). The model analysis is based on the period 2015 to 2050. The vehicle stock analysis assumes that vehicles with hydrogen-combustion engines will play an important role initially. However, in 2050 only 7 % of new cars are predicted to be H<sub>2</sub>-ICEVs and the fleet will be dominated by FCEVs. In 2050, total hydrogen passenger car stocks will amount to approx. 38 million vehicles. The study calculates the number of hydrogen filling stations according to regional hydrogen demand (reference scenario) or exogenously by adding to the model. The rationale for the second assumption is that even for early hydrogen market introduction, a minimum number of filling stations is required to stimulate hydrogen demand.

The results of the scenario analysis show that regional hydrogen market introduction in demand centers is the most reasonable strategy in terms of cost efficiency. In demand centers, hydrogen transport and distribution via pipeline transpires as the preferable option at a fairly early stage. In rural areas, liquid hydrogen transport is considered to be the best transport option for a fairly long period, especially for the hydrogen market introduction phase. Liquid hydrogen transport is considered the best 'bridge technology' en route to a pipeline transport system. Truck transport of gaseous hydrogen is not amongst the chosen optimization models. It is estimated that pipeline infrastructure development will begin 10-15 years after the market introduction of hydrogen fuel, driven by increasing hydrogen demand. It is anticipated that rising demand for hydrogen will trigger a shift from on-site hydrogen production to large-scale centralized production. As a result, the amount of hydrogen transported across regions will also increase significantly. The reference scenario up till 2050 provides for the establishment of a dense pipeline network that covers almost all of Germany. The cumulative investments in infrastructure build-up, as well as specific costs for hydrogen supply, are further key parameters. Cumulative investment is dominated in all periods by investments related to hydrogen production.

### **BMVBS & NOW, GermanHy - Woher kommt der Wasserstoff in Deutschland bis 2050? [27]**

The scenario study GermanHy analyses the potential and challenges of hydrogen as an energy carrier and its integration into the German energy system. Because of the high dependence and low energy efficiency of the transport sector, the analysis focuses on the introduction of hydrogen in transportation, in particular passenger cars, light-duty vehicles and buses. Under a given set of framework data, like the cost of primary energy carriers, CO<sub>2</sub> reduction goals and assumptions concerning hydrogen production costs, the optimization model calculates cost-efficient hydrogen pathways with time horizons through 2020, 2030 and 2050. The analysis of hydrogen transportation and distribution from production sites to places of consumption is integrated into the model. The scenario calculations underscore the impacts on mobility costs, CO<sub>2</sub> emissions, the share of renewable energy and dependency on energy imports in a hydrogen-dominated system.

The study defines three different energy supply scenarios, including hydrogen for transportation, in order to analyze possible hydrogen production pathways and the potential of primary energy carriers. A road transportation scenario determines possible hydrogen demand, including spatial resolution and different time steps of the scenario. A GIS-based modeling tool is used to identify the infrastructure required for production, transport and distribution, resulting in a cost-optimized hydrogen generation, transport and distribution system.

**Shafiei, E., Energy, economic and mitigation cost implications of transition toward a carbon-neutral transport sector: A simulation-based comparison between hydrogen and electricity [28]**

Shafiei [28] presents a target-driven scenario analysis of transitional hydrogen and electricity pathways to a near carbon-neutral transport sector in Iceland. Three transition pathways are compared: electricity (EV), hydrogen (H<sub>2</sub>) and mixed hydrogen-electricity (EVH<sub>2</sub>). The analysis assumes an accelerated transition towards hydrogen-powered and electric vehicles through stringent policies and the banning of fossil-fueled vehicles from 2035. The transition pathways are compared in terms of fleet mix, infrastructure development, energy demand, emissions reduction, transition costs/benefits and mitigation cost.

For the electric vehicle pathway, it is assumed that 50 % of light-duty vehicle owners can access a private parking space and that each EV adopter would install a private charging point. The cost of the private charging point is included in the purchase price of BEVs. Cost data and assumptions for cost reductions for public (62.5 kW) and private charging points (3.6 kW) are provided. For the hydrogen pathway, the study assumes on-site hydrogen generation (alkaline electrolysis) and storage at filling stations. Cost and performance data as well as assumptions for future cost reductions for hydrogen production, compression, storage and dispensing are also provided in the report.

The report includes assumptions regarding vehicle fleet development (including light and heavy-duty vehicles), but only presents graphical results for the market share evolution of different vehicle types and does not state the numbers of vehicles in absolute terms. In all cases, a constant growth of the vehicle fleet is assumed until a saturation point is reached. The development of a charging and hydrogen supply infrastructure is introduced to the model exogenously by introducing constant numbers of charging points and fueling stations each year.

Key results from the analysis are that the EV pathway is the most attractive in terms of total fuel supply cost, while the H<sub>2</sub> pathway is the most expensive. The most important impact factor in this context is the significantly lower alternative fuel supply cost for electric vehicles in comparison to hydrogen vehicles. Nevertheless, except for a short market introduction period, the refueling infrastructure cost for electric vehicles is considered to be slightly more expansive than a hydrogen fueling infrastructure. The main driver here is the installation of large numbers of fast charging points. In comparison to fuel supply costs, infrastructure costs play only a minor role. Also, the EV pathway exhibits a lower mitigation potential, as it is not possible to meet the carbon-neutrality target in comparison to the other two pathways, which are both able to meet this target.

## **Stolzenburg, K., Integration von Wind-Wasserstoff-Systemen in das Energiesystem – Abschlussbericht [29]**

The aim of this study [29] is to analyze the techno-economic conditions for the operation of large-scale wind-hydrogen systems in Germany in the year 2030. The study focuses on the long-term storage of hydrogen and related impacts on the electricity transmission grid, offering a perspective for the cost-efficient operation of wind-hydrogen systems. To reach this goal, it considers the use of hydrogen fuel in the transport sector, as well as the participation of wind-hydrogen systems in the electricity spot and reserve markets. It is assumed that hydrogen will be produced from excess wind electricity generation, which is defined as electricity generation from renewable energies exceeding demand and/or which cannot be integrated into the transport grid due to transport capacity restrictions. The following description focuses on the use of hydrogen as a fuel.

In the chosen approach, the regional use of hydrogen as a fuel is coupled to large-scale hydrogen storage locations in salt caverns in northern Germany. The large-scale storage systems are also located close to the wind energy production centers in the region. It is assumed that hydrogen will be delivered to a maximum distance of 300 km from the storage locations. Trailer transport of gaseous hydrogen (1 t H<sub>2</sub>, 500 bar) from the storage locations to the hydrogen filling stations is also considered. Other transport options (pipelines, liquid hydrogen trucks) are not included in the analysis. However, the study does mention that liquid hydrogen transport by truck could reduce the required number of trailers by a factor of four due to the larger energy density of liquefied hydrogen and related increased transport capacity.

Due to the regional approach, hydrogen supply is limited to northern Germany. Nevertheless, major demand centers (such as the metropolitan regions of Hamburg, Berlin and the Rhine-Ruhr-Area) would be covered by this approach. It is assumed that the hydrogen in these areas is generated by five wind-hydrogen systems equipped with large-scale underground storage facilities and filling stations for the trailers.

Different types of wind-hydrogen systems are analyzed. Type “K” is used solely for the supply of hydrogen as a fuel, while type “G” is a combined option for both fuel supply and re-electrification. The report details the techno-economic parameters for the different system components of wind-hydrogen systems. In the following, only “G”-type systems are considered in the description. Regarding FCEV market penetration, the scenario in Germany by 2030 is 1.8 million. The hydrogen demand of these vehicles is calculated on the basis of specific hydrogen consumption, irrespective of the average driving distance and vehicle segment.

The cost efficiency of wind-hydrogen systems is assessed based on a reference price analysis. The reference price is defined as the end-consumer hydrogen price at the filling station or as the hydrogen production price from natural gas steam reforming. In the first case, a fixed end-consumer hydrogen price of 10 €/kg H<sub>2</sub> is assumed. Presupposing specific costs for hydrogen transport and costs for the installation and operation of filling stations, a target price for hydrogen production from wind-hydrogen systems is calculated (approx. 6 €/kg<sub>H<sub>2</sub></sub>). The scenario analysis considers different modes of operating wind-hydrogen systems (e.g., market-based operation vs. surplus electricity only). Cost-efficient systems operation is possible when the hydrogen production price is below the reference price. The scenario analysis shows that, in many cases, wind-hydrogen systems are able to meet the reference price of 6 €/kg<sub>H<sub>2</sub></sub>. Key impact factors include the electricity price, as well as full-load



hours of operation. In all cases, an exemption from electricity grid fees for the operation of wind-hydrogen systems is assumed.

In the case of market-based operation, five wind-hydrogen systems would be able to supply some 0.9 million FCEVs in northern Germany (50 % of total FCEV stock in 2030). Supply based on excess electricity only is not possible, as the availability of excess electricity is below the electricity requirements for fuel supply.

### **Brief description of infrastructure scenario studies analyzed in the meta-analysis Section 5.3**

#### **Fraunhofer ISI, Markthochlaufszzenarien für Elektrofahrzeuge [38]**

This study [38] details cost data for the charging infrastructure for 2013 and 2020. Different charging options are considered (e.g., private wall boxes, private and public charging stations with different charging power and number of charging points). Additionally, a scenario for the development of primary charging points is presented, whereby only charging at home (for private electric vehicle owners) or on-site parking (for commercial electric vehicle owners) and on-street parkers (without access to private parking space) are considered. The results show that, under the given assumptions, the amount of primary charging points is directly proportional to the number of electric vehicles. An additional build-up of public charging infrastructure is not considered. Furthermore, on-street parkers only show limited economic potential, which is expressed by the low number of charging points for this group. More details regarding charging infrastructure demand of on-street parkers is provided by Funke et al. [39] (see the following chapter).

#### **Fraunhofer ISI, Funke, S. A. et al. [39]**

Funke et al. [39] present an analysis of the criteria for charging infrastructure set-up. Based on the existing infrastructure, the study compares a coverage and a demand-oriented approach for determining future charging infrastructure demand. One key finding of the analysis is that it is difficult to determine the number of charging stations needed on a large scale (e.g., on a country-wide scale) on the basis of local user demand. The number of charging stations in a coverage-oriented approach depends on the area and maximum distance between two charging stations. In the analysis, three area types (core cities, condensed areas, rural areas) are distinguished with different maximum distance values. In contrast, the demand-oriented approach considers user behavior. In this case, the required public charging infrastructure is directly related to the number of on-street parkers (1.5 % of electric vehicle owners) without access to private charging points. The demand for a public fast charging infrastructure is estimated based on the number and distance of long-distance driving events. According to the authors, the results of these two approaches should be considered as rough estimates that provide an order of magnitude for public charging infrastructure demand [39].

According to Funke et al. [39], one important advantage of battery-electric vehicles compared to hydrogen-powered vehicles is the possibility of using the existing electricity infrastructure in households for charging. It is stated that the majority of electric vehicles could be operated without additional public charging infrastructure. However, public charging infrastructure is also considered important for the large-scale diffusion of electric vehicles and because of the need for interim charging possibilities, also for EV owners without private charging

possibilities. According to X [117], the general aim of a public charging infrastructure is to provide a social infrastructure that guarantees a minimum standard of service at low cost to the widest possible public. Using a solely demand-oriented approach to determine the required charging infrastructure might not be in line with the requirements of a social charging infrastructure [39].

**Fraunhofer ISI, Gnann, T. et al. [40]**

A method and model for determining the demand for a public fast charging infrastructure is presented by Gnann et al. [40]. The approach is applied to Germany as a case study and is based on a large database of driving profiles. Using a TCO (total cost of ownership) model, the study identifies the electric vehicle as the best drivetrain option. This approach first quantifies the share of electric vehicles in the total stock and then analyzes the electric vehicle driving profiles to calculate the days on which the electric driving range is exceeded. The reason being: long-distance travel determines the need for fast charging. The number of fast charging points required – based on the number of fast charging events – is computed with a queuing model that draws different assumptions regarding, e.g., tolerated waiting time and mean charging time, independent of charging power. The approach presented enables the number of charging points to be calculated, irrespective of the charging power. By way of simplification, the model assumes that fast charging events are equally distributed over the year and between all charging points. The model therefore does not reflect the geographical correlation of electric vehicles and charging points and does not differentiate between urban or rural areas [40].

**DLR, Laden 2020 [41]**

This study [41] presents an approach for determining demand for an EV charging infrastructure. A methodology was developed to calculate the number of charging points for electric vehicles used for daily driving (short-distance) and also long-distance driving. The results of the study correspond to one million electric vehicles in Germany in 2020. The study considers passenger cars and light-duty commercial vehicles. Furthermore, it identifies the major impact factors that determine demand for public charging infrastructure.

The methodology for determining charging infrastructure demand is based on a demand-driven approach that takes account of individual driving behavior determined on the basis of regular user panels and interviews. Driving behavior is thus the basis for individual vehicle utilization and resulting charging demand per vehicle. The results are aggregated to determine the charging demand of the complete fleet of electric vehicles. The charging profiles are used to ascertain the time-dependent amount of charging vehicles per charging type and location. These profiles define the required number of charging points according to charging type.

In a follow-up publication [42] to the project “Laden 2020”, the number of public charging points (normal charging for daily travel) for one million EVs in Germany by 2020 is recommended to be between 14,700 and 29,500. Charging infrastructure demand is primarily influenced by the amount of on-street parkers and fleet composition. It is stated that on-street charging in residential areas dramatically increases the total infrastructure. Considering this point, and the low utilization of an on-site charging infrastructure, a system without on-street charging is recommended.

### **NPE, Ladeinfrastruktur für Elektrofahrzeuge in Deutschland [17] and NPE, Fortschrittsbericht 2014 – Bilanz der Marktvorbereitung [43]**

This report [17] provides an overview of the existing publicly-accessible charging infrastructure for electric vehicles in Germany. Furthermore, the required investment for the further build-up of the charging infrastructure through 2020 is analyzed with consideration of cost-reduction potentials. A detailed overview of actual and future costs (CAPEX and OPEX) for different charging technologies is presented.

[43] presents results from a study by BDEW and Kearney [45] (see below) regarding demand for charging infrastructure. The results assume 1,134 million electric vehicles in 2020. The results (scenario Pro) include public and private charging points for normal and fast-charging. The required number of fast charging points is identical to the number in [17] (7,100 fast charging points). Assuming the build-up of 5,700 DC fast charging points from 2017 to 2020, the required investment adds up to € 140 million (with 24,000 per charging point / charging station).

Considering the basic data in [17], total investment for the build-up of 7,100 DC fast charging points through to 2020 amounts to approx. € 171 million (with € 35,000 per charging point / charging station through to 2017). If this figure is extrapolated to the 1,134 million electric vehicles in Germany through to 2020 [118], the required investment for building up a fast charging infrastructure can be estimated at € 151 per electric vehicle. However, this estimate does not consider a capacity utilization analysis of the fast charging points.

### **DIW, The economics of fast charging infrastructure for electric vehicles [44]**

This study concerns the economics of a public fast charging infrastructure for Germany and provides a detailed analysis of the costs and revenues incurred by operating an EV charging station. The key drivers of revenue are the tariffs (potentially with mark-up), the capacity and utilization rates, which are estimated on the basis of assumptions for EV charging and driving behavior. Cost components include initial capital expenditure (CAPEX) and operational expenditures (OPEX) comprising electricity cost, maintenance and other operational costs (O&M). The economic evaluation of charging station operation is confined to the CHAdeMO standard (62.5 kW DC charging socket) [44]. The profitability of an investment in fast charging infrastructure is analyzed from the viewpoint of a charging infrastructure operator (e.g., electric utility). The study lists a full range of information on charging station cost data for six different charging options, ranging from 250 kW super-fast DC public charging to 3.6 kW Level II AC home charging. One key finding is that the required investment for setting-up a charging infrastructure depends strongly on the need for upstream grid reinforcement. It is assumed that the investments required for grid reinforcement increase with increasing charging power, whereby no grid reinforcement is required for home charging options. The study also presents a simplified approach to determining charging infrastructure demand based on charging capacity that uses the maximum number of charging vehicles per day for different charging station types. In this approach, the number of required charging stations depends directly on the power rating of the charging station and the number of electric vehicles. As a consequence, the number of charging stations required decreases as the charging power rating increases. Private home charging has the highest number of charging stations (3.6 kW AC), whereby an electric vehicle to charging station ratio of 1:1 is assumed. The study also compares the investments required for different charging infrastructures, albeit, only homogenous systems composed of a single charging type. A mixture of different charging options is not considered. As a result, the most cost-effective charging

infrastructure option is provided by fast charging stations due to the high vehicle charge capacity per day [44].

### **A Portfolio of Powertrains for Europe: A Fact-Based Analysis [30]**

This study [30] compares four different powertrains – BEVs, FCEVs, PHEVs and ICEs – in terms of economics, sustainability and performance across the entire value chain (well-to-wheel) between 2010 and 2050 and develops different market penetration scenarios for Europe (EU27 plus Norway and Switzerland) up to 2050 for the different powertrains. The economic comparison of different powertrains is based on total cost of ownership (TCO). This approach considers the purchase price and running cost, including fuel and infrastructure cost for a hydrogen refueling and electric charging infrastructure, respectively.

Having developed a supply model in order to analyze the investment required for hydrogen production, distribution and a retail infrastructure, the study found that the specific cost for such an infrastructure is in the range of € 1,000-2,000 per vehicle (approximately 5 % of the overall cost of FCEVs). It is therefore assumed that the cost of the hydrogen infrastructure will not prohibit FCEV rollout [30]. Furthermore, it states that the costs of hydrogen infrastructure are comparable to those of a charging infrastructure for BEVs and PHEVs. The cost of an electric charging infrastructure is estimated to be in the range of € 1,500-2,500 per vehicle, depending on the share of charging types (home charging vs. public charging). Potential investment in the power distribution networks is not considered and stated to be highly dependent on the local situation. The scenario analyzes the development of hydrogen retail stations in quantitative terms along with the hydrogen distribution mix through to the year 2050 and shows the related investments for hydrogen and charging infrastructure build-up for the years 2010 to 2050. One limitation of this study is that the results are not very transparent. This is because background information, e.g., regarding the number and type of charging points or the extent of the hydrogen distribution system (e.g., pipeline system length) are not provided.

According to the study [30], an advantage of a hydrogen infrastructure is that once a comprehensive nationwide infrastructure is established, no further investment will be needed, regardless of the number of cars. In contrast, infrastructure build-up for BEVs and PHEVs is more closely related to the number of cars, especially due to home charging opportunities and longer refueling times.

### **BDEW, „Die zukünftige Elektromobilitätsinfrastruktur gestalten“ [45]**

This study by the BDEW and Kearney [45] presents three different scenarios for the development and economics of a demand-oriented electric charging infrastructure based on different market penetration scenarios for electric vehicles developed in [38]. Key parameters and results from [38] are considered in the scenario analysis. Additional assumptions regarding vehicle utilization with different charging options and charging locations are also made. The study analyzes the complete spectrum of charging points, locations and technologies for all three scenarios, but does not consider the charging infrastructure's spatial distribution. Again for the three scenarios, the study analyzes the distribution of vehicle users (private households, commercial and public fleets) and vehicle types (BEV, PHEV, REEV). Demand-oriented charging infrastructure is defined as the infrastructure required per electric vehicle to meet charging needs in line with daily vehicle utilization. Key assumptions determining charging infrastructure demand are that every electric vehicle

owner with a private parking space owns a wall box. Furthermore, it is assumed that PHEVs and REEVs with a private parking place do not require a public charging infrastructure and that fast charging infrastructure is only required for BEVs. The number of charging points required is determined on the basis of the ratio between charging points and electric vehicles. A matrix of values for this ratio is set for different use scenarios and vehicle types, independent of charging technologies and locations.

A key finding of the study is that the majority of the charging points required will be private charging points at home and at work. In the case of public charging infrastructure, it makes a further distinction between charging points for on-street parkers ("Laternenladen"), normal charging and fast charging stations. The number of public charging points amounts to 5-7 % in relation to the total charging points in the scenario for 2020. The investment required to build up the charging infrastructure is also quantified for the three scenarios based on detailed data for the different charging options. It is assumed that, in a mass market for electric mobility, the saturation point for public charging infrastructure will be reached after 2020. Key drivers in this context are increasing charging point utilization, a higher electric driving range and enhanced fast-charging compatibility of electric vehicles.

#### **UBA, Treibhausgasneutrales Deutschland im Jahr 2050 [46]**

The aim of this study [46] is to demonstrate the technical feasibility of a GHG-neutral society in Germany in 2050. Technical solutions that reach this goal and possible alternatives are described for the relevant energy sectors. As a result, a scenario is developed that describes a GHG-neutral Germany in 2050 from a completely national perspective without interactions with other countries. For further details regarding the basic assumptions and boundary conditions for the scenario, reference is made to the UBA study [46]. The results for the transport sector are based on [119]. To reach the GHG reduction goals in the transport sector, different measures are combined based on traffic reduction, traffic relocation and emission reductions. Furthermore, several concrete regulatory and economic instruments are discussed that are considered in the scenario for a GHG-neutral transport sector. As a result, the scenario shows a possible pathway to a transport sector that is based entirely on renewable electricity and renewable synthetic fuels. The scenario presents detailed results regarding yearly kilometers travelled, distinguished by propulsion type. An analysis of the infrastructure build-up required for the transition to higher shares of electric and hybrid vehicles does not form part of the analysis.

#### **UBA, Erarbeitung einer fachlichen Strategie zur Energieversorgung des Verkehrs bis zum Jahr 2050 [36]**

The objective of this study [36] is to compare four different scenarios for a GHG-neutral transport sector in Germany in 2050. The comparison includes energy supply costs, infrastructure costs and vehicle production costs. Furthermore, it is important to point out that freight traffic was also included in both scenarios [36, , P. 31]. The energy supply options discussed for the transport sector are direct electrification (battery-electric vehicles and vehicle overhead contact lines), PtG-CH<sub>4</sub> (with ICE vehicles), PtG-H<sub>2</sub> (with fuel cell-electric vehicles) and PtL (with ICE vehicles). All options are based entirely on renewable electricity. One key finding from the analysis is that the cost of energy supply and vehicle production dominates the total cost of transforming the transport sector. In comparison, the cost of

adapting the infrastructure is considered to be fairly small. There is no optimization model or models that interact with the energy system at all. All findings are driven by basic cost models. In the following, only the PtG-H<sub>2</sub> scenario in which hydrogen is the overall energy carrier for the transport sector ("Scenario H2+") and the direct electrification scenario ("Scenario E+") are considered.

Two types of power ratings are considered for the public charging infrastructure of BEVs: normal charging points with a power rating of up to 22 kW and fast-charging systems with a rating  $\geq 50$  kW. Furthermore, it is assumed that 70 % of the BEV owners in 2050 charge their car at home with a wall box (until 2020: 99 %). For local commercial transport, it is further assumed that 85 % of the vehicles have a charging opportunity at the depot ("Scenario E+"). The demand for a public charging infrastructure (normal charging) is determined by the number of cars that do not have a private charging capacity. A simple approach based on the ratio of vehicles per charging point for different vehicle types is used to determine charging infrastructure demand. The detailed assumptions for the charging infrastructure and the related number of charging points can be found in [36, , P. 50-52]. The costs assumptions for the implementation of the new charging points are given in [36, , P. 59-60]. Key drawbacks include the fact that the report does not include information about vehicle stock development and the related investments required for charging infrastructure build-up. Furthermore, no electrical grid model was used to simulate the new loads in the distribution grid. Therefore, no consideration is given to the potential expansion of the distribution or transmission grid. For fast charging stations, the study considers the additional installation of a transformer for the grid connection of stations located on freeways (50 % from total fast charging points). For all other charging stations, it is assumed that a grid connection without an additional transformer is possible.

With regard to the hydrogen pathway ("Scenario H2+"), it is assumed that in the year 2030 Germany will not have high surplus power and that energy production costs will be significantly lower in Great Britain (on and offshore wind), Turkey (PV) and Egypt (CSP), resulting in hydrogen being produced in these countries. They will then ship the hydrogen in liquefied form to Germany. It is assumed that the hydrogen will also be transported in liquid form in Germany and distributed by truck and ship. Furthermore, liquid hydrogen is also stored at the filling stations. The study does not consider a dedicated hydrogen pipeline grid, but instead deems long-distance trailer transport of liquefied hydrogen to be more cost efficient [36, , P. 46]. It is stated that even under these assumptions (production of H<sub>2</sub> outside Germany), different infrastructure systems, such as transporting electricity to Germany and producing hydrogen on-site, are possible. The study also mentions the fact that a heterogeneous hydrogen supply and distribution system would be the most likely option in practice. Nevertheless, in order to make the results comparable and to reduce the potential supply pathways in the analysis, the described pathway was considered [36, , P. 46].

The analysis resulted in the calculation of the number of public and private (for commercial transport and buses) hydrogen filling points. It is assumed that the total number of filling stations (excluding filling stations on freeways) will drop from approx. 14,000 (2014) to 9,000 in 2050, whereby the number of filling stations on freeways is assumed to remain constant. The study also analyzed the number of hydrogen filling points per filling station, producing detailed cost assumptions for the filling stations, including cost regressions for the retrofitting of existing stations and learning curve effects [36]. The costs of hydrogen transport, distribution and storage in Germany are also considered in the analysis. Costs for long-

distance transport from the producing countries to Germany are neglected though. Assumptions regarding the investments required for liquefied hydrogen transport trucks, for instance, are provided however.

### **Grube, T. Kosten von Ladeinfrastrukturen für Batteriefahrzeuge in Deutschland [47]**

This study [47] quantifies the demand for an electric charging infrastructure for scenarios with high shares of electric vehicles (up to 30 million BEVs in Germany) and the related investment for infrastructure build-up. Demand for charging infrastructure is analyzed for three different scenarios with 1 million, 6 million and 30 million BEVs in Germany. The study assumes a homogenous fleet consisting of BEVs only. PHEVs and REEVs are not considered. Different BEV shares and related vehicle utilizations are also considered for four different settlement types. A comparison to the investment required for a hydrogen infrastructure for FCEVs is also included.

A simple approach based on the ratio of vehicles per charging point is used to determine demand for normal charging infrastructure. This differentiates between private charging points, semi-public charging points for on-street parking, commercial charging points and public charging points. The scenarios make different assumptions regarding the ratio of vehicles per charging type. For private charging at home or for on-street parking, it is assumed that a charging point will be available for every BEV. The public and semipublic charging infrastructure is quantified independently of assumptions regarding the degree of infrastructure development (moderate, strong).

To quantify the level of investment required for charging infrastructure build-up, basic data including charging power, investment, operating costs and lifetime for four different charging types are presented. In addition to investments directly related to the construction of charging stations, the study also assesses grid-related investment for grid extension due to the additional load for EV charging, making cost assumptions for grid components (cables, transformers and IT systems) in the process. The investment required for infrastructure build-up for the three scenarios is mentioned in [47]. A Monte Carlo simulation was conducted owing to the uncertainties regarding input parameters and assumptions. The calculations concerning requirements for a fast charging infrastructure on freeways are based on a maximum charging power of 150-300 kW DC (depending on the scenario). It is assumed that charging points are installed at existing service stations. Due to the high charging power, a direct grid connection to the medium voltage grid is considered and the related investments for grid connection and grid extension on the low and medium voltage level (including transformers and cables) are quantified. The number of fast-charging points is calculated in keeping with the Instruction chapter for the author team.

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