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The Role of Energy Storage Technologies for the Integration of Renewable Electricity into the German Energy System

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Abbreviations

a	Years
AA-CAES	Advanced adiabatic compressed air energy storage
BEV	Battery electric vehicles
BNetzA	Bundesnetzagentur (Federal Network Agency)
CAES	Compressed air energy storage
CAPEX	Capital expenditures
CNG	Compressed natural gas
CO_2	Carbon dioxide
d	Days
DSO	Distribution system operator
€	Euro
EEG	Erneuerbare-Energien-Gesetz (Renewable Energy Act)
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energiewirtschaftsgesetz (Energy Industry Act)
EPEX	European Power Exchange
EU	European Union
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gases
GT	Gas turbine
GW	Gigawatt
GWh	Gigawatt hour
h	Hours
H_2	Hydrogen
HEV	Hybrid electric vehicle
ICE	Car with internal combustion engine

IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
KKT	Karush-Kahn-Tucker
km	Kilometer
kt	Kiloton
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LCOH	Levelized costs of hydrogen
Li-ion	Lithium-ion
LP	Linear programming
LPG	Liquefied petroleum gas
LPX	Leipzig Power Exchange
MCP	Mixed complementarity problem
MPEC	Mathematical problem with equilibrium constraints
M€	Million euros
ms	Millisecond
min.	Minute
MW	Megawatt
MWh	Megawatt hour
n/a	Not applicable
NaS	Sodium sulfur
NG	Natural gas
NPV	Net present value
OTC	Over the counter
Pb-acid	Lead-acid
PEM	Polymer electrolyte membrane
Phelix	Physical Electricity Index
PHEV	Plug-in hybrid electric vehicle
PHS	Pumped-hydro storage
PtG	Power-to-gas

PV	Photovoltaics
REEV	Range-extended electric vehicle
s	Second
SFE	Supply function equilibrium
SMES	Superconducting magnetic energy storage
t_{CO2}	Tonnes carbon dioxide
TJ	Terajoule
TSO	Transmission system operator
TWh	Terawatt hour
UNFCCC	United Nations Framework Convention on Climate Change
V2G	Vehicle-to-grid
VOLL	Value of lost load

1. Introduction

The power system in Germany is undergoing substantial change and is therefore challenged in many ways. This is due to a number of crucial developments, ranging from market liberalization to increasing renewable electricity generation. On the one hand, the restructuring of the power market from regulated monopolies to a competitive market place is intended to improve system efficiency and thus to reduce the corresponding costs. However, competitive market structures could give rise to an exertion of the market power of large suppliers and not necessarily provide sufficient investment incentives for new generation capacities. Both issues have been discussed extensively in the literature and have been taken into consideration by policymakers. On the other hand, intermittent electricity generation from renewable sources such as wind and solar power poses new challenges to the electricity system stability due to the limited predictability and seasonality of the weather-related feed-in, as well as to transmission congestion. This is further exacerbated by efforts to promote sustainable mobility and the corresponding additional energy demand of electric vehicles. Hence the German energy policy is based on three partially-concurrent objectives, including a cost-efficient, sustainable and reliable electricity supply.

The challenges outlined above can potentially be addressed by taking advantage of different flexibility options. In particular, electricity storage might provide valuable means to integrate renewable electricity into the existing energy system. More precisely, this flexibility option might help to cope with the problem of increasing intermittency by smoothing generation variability, i.e. storing surplus electricity when supply is higher than demand and providing energy when dispatchable generation is not able to meet the residual demand. In this way, this technology could make a substantial contribution towards system security on the one hand and towards system cost reduction by avoiding grid and renewable generation extensions on the other hand. Nevertheless, storing electricity is currently still expensive and requires

substantial investment outlays, typically due to high technology costs and poor round-trip efficiencies. In addition, the true economic value of different storage applications within the energy system is as yet not clear, and this issue receives increasing research interest. In the light of an expected decrease of technology costs, a promising application is represented by the production and storage of hydrogen as a universal energy carrier which can potentially be used in different areas including the electricity and mobility sectors. However, the impact of an additional electricity demand from the mobility sector on the power market, especially from the perspective of hydrogen technology, is not yet well understood.

The major objective of this work is to shed light on the role of electricity storage in the context of liberalized power markets and the increasing share of renewable electricity generation. The models developed for this study are used to analyze the value of electricity storage both from the business perspective of a single investor and from the perspective of the whole system under different technology ownership and market structures. The corresponding case studies provide an insight into the optimal sizing and operation as well as the resulting costs of different storage technologies in combination with intermittent electricity production. Thereby, special focus is placed on hydrogen technology as a link between the power and mobility sectors. All analyses are carried out in the context of the German electricity market.

The structure of this work is as follows: chapter 2 outlines the background of the German power market and electricity storage. First, it gives an overview of the value chain for electricity and current market design in Germany. Then, a more detailed discussion on major market trends and related challenges is provided. This is followed by a description of potential storage applications and technologies and by a review of possible modeling approaches.

The study in chapter 3 provides a comprehensive analysis of the value of electricity storage in combination with intermittent power generation from wind and photovoltaics (PV) in the context of seasonality. It is conducted from the perspective of a single profit maximizing investor interested in the relative performance of different alternatives either to meet a predetermined minimal demand or to avoid grid congestion in a selected grid node. In order

to achieve this, a simple deterministic linear programming (LP) model is developed to optimize storage sizing and operation and used to calculate the net present value (NPV) of a prototypical facility. These results are benchmarked against the outcomes simulated for electricity production by a gas turbine to provide dispatchable power and curtailment of renewable generation due to grid constraints. The selected storage technologies include sodium sulfur (NaS) battery, redox flow battery, pumped-hydro power plant, advanced adiabatic compressed air energy storage (AA-CAES) and hydrogen technology. All applications are mainly characterized by different specific investment outlays in power and energy capacities as well as round-trip efficiencies and are evaluated on an hourly basis within a prototypical year with corresponding electricity prices, renewable feed-in profiles and electricity demand patterns. A detailed scenario analysis identifies major influence factors on the overall value of storage.

Chapter 4 focuses on the specific costs of the production and storage of hydrogen used to meet a predefined demand in the power and mobility sectors. The analysis in this chapter is based on a modeling framework similar to the one in chapter 3 and is again carried out from the perspective of a single price taking player who decides on optimal capacity and utilization of a prototypical facility. The model is applied in a case study with different scenarios representing the expected technology and market developments such as falling technology costs, increasing electricity price and changing levels of price volatility. A detailed comparison of numerical results for different market and facility constellations identifies the value of renewable hydrogen production as well as synergy effects from co-utilization of the hydrogen plant in the power and mobility sectors.

The analysis in chapter 5 is conducted from the perspective of the overall electricity system with different market structures. The proposed game-theoretic equilibrium model à la Cournot covers both short-term storage operation and long-term capacity investment decisions of profit-maximizing firms acting strategically. The corresponding case study assumes a given renewable feed-in as expected for Germany in the long term and takes into account only two storage applications including pumped-hydro storage and hydrogen technology which is able to satisfy demand in both the power and

the mobility sector. The results for different degrees of competition and storage ownership structures are compared with regard to optimal technology sizing and operation, welfare and price effects and also overall greenhouse gas (GHG) emissions. The analysis further provides an insight into the influence of an additional energy demand from the mobility sector on the electricity market.

Finally, chapter 6 draws a comprehensive conclusion by summarizing the results and by outlining the implications for utilities, consumers and politics and the limitations of this work. Eventually, future research possibilities are briefly addressed.

2. Background on the German power market and electricity storage

2.1 Structure of the German power market

2.1.1 Value chain for electricity

The electricity sector can be subdivided into several parts according to different steps of the value chain for electrical energy including primary energy provision, electricity production, grid-based transmission and distribution as well as retail to final customers (Hunt 2002 and Ströbele et al. 2012). As indicated in Figure 2.1, the first part is represented by the sourcing of primary energy carriers such as fossil or nuclear fuels required for electricity generation by the corresponding power plants. This value chain step covers imports, trading and delivery of primary energy and is closely linked to other energy sectors and markets such as coal, oil or natural gas (NG) markets.[1]

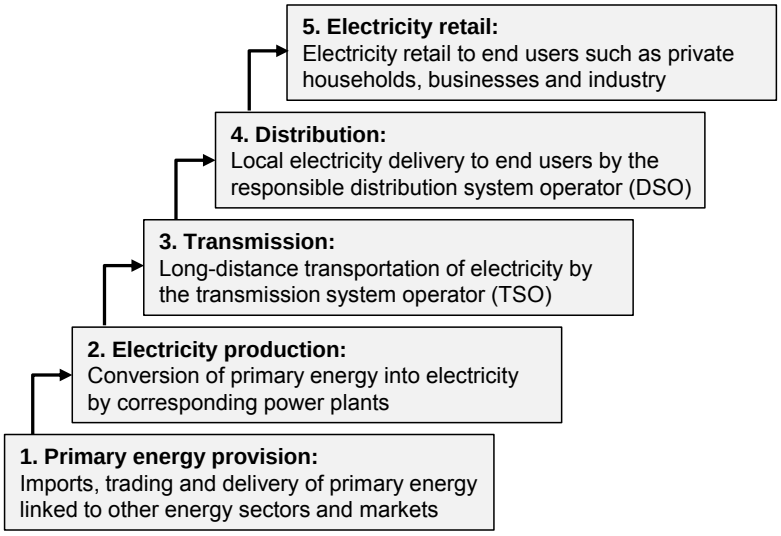


Figure 2.1: Five major steps of the value chain for electricity.

1 For an overview and introduction to the structure and functioning of primary energy markets see for example Ströbele et al. (2012).

The second value chain step contains actual electricity production by means of electric generators. Generally, power plants can be categorized in different ways according to the primary energy source, electricity generation process, production flexibility, and economic utilization (see Table 2.1).[2] Regarding the primary energy sources, one can distinguish between units powered by CO_2 intensive fossil fuels (such as lignite, coal, natural gas and oil), nuclear fuel, and renewable energy (wind, solar, bio, geothermal, hydro, wave and tidal energy). The categorization of the electricity generation process includes thermal power plants (steam turbines and engines, gas turbines, combined cycle gas turbines and internal combustion engines), hydro power plants (based on water turbines), wind generators (based on a wind turbines), and photovoltaics (based on photovoltaic cells). At this point, it is important to mention that the waste heat produced by thermal units can in principle be sold and thereby additional revenues be earned through adequate activities on the heat market, provided that the nearby heat demand is large enough and an adequate infrastructure for heat transport is in place. Therefore, the heat and power markets can be closely interrelated. For example, some generators such as combined heat and power plants optimize their operation mode based on the local heat demand.

The production flexibility distinction includes dispatchable power plants which can be turned on and off flexibly (such as fossil power plants) and intermittent power plants with generation dependent on weather conditions (wind and solar). Finally, regarding economic utilization there are typically base-load technologies (such as nuclear and lignite power plants) with low marginal generation costs, high specific investment outlays and high utilization (i.e. running most hours of the year) as well as peak-load technologies (such as gas turbines or oil power plants) with high marginal costs, lower specific investment outlays and comparatively low utilization (i.e. running only a few hours of the year with high electricity demand).

After the generation process, electricity is injected into a dedicated grid and transported over transmission and distribution networks to the end users. Accordingly, the next value chain steps include long-distance transportation

2 For more details on characteristics of different power plants see Ströbele et al. (2012, pp. 243 – 246) and Erdmann and Zweifel (2008).

Table 2.1: Power plant categorization and corresponding examples.

Category	Example
Primary energy source	
• Fossil fuel	Lignite, coal, natural gas, oil
• Nuclear fuel	Uranium
• Renewable energy	Wind, solar, bio, geothermal, hydro, wave, tidal
Electricity generation process	
• Thermal	Steam and gas turbines and engines
• Hydro	Water turbines
• Wind	Wind turbines
• Photovoltaics	Photovoltaic cell
Production flexibility	
• Dispatchable	Fossil fuel and some renewable (e.g. bioenergy) units
• Intermittent	Wind and solar
Economic utilization	
• Base-load	Nuclear and lignite power plants
• Peak-load	Gas turbines or oil power plants

by the transmission system operator (TSO) and local delivery to end users by the responsible distribution system operator (DSO).[3] Finally at the last value chain step, the electricity is sold by retail companies to end users such as private households, businesses and industry on the retail market.

Although technically the German electricity system has not altered substantially, economically the structure of the electricity sector has been undergoing large changes for the past two decades mainly due to market liberalization.[4] Prior to this process, all functions of the value chain were accomplished by vertically integrated local utilities which were responsible for a predefined region based on license agreements with local authorities and demarcated

3 In Germany, the electricity grid is operated as an alternating current network with a frequency of 50 Hertz at different voltage levels. The transmission system includes extra high (380 kV and 230 kV) and partially high voltage (110 kV) power lines whereas the distribution system is based on high, medium (1 – 35 kV) and low (below 1 kV) voltage lines. This distinction between TSO and DSO is also in line with the German Energy Industry Act (§3 EnWG).

4 Market liberalization process and its consequences are discussed in more detail in chapter 2.2.1.

from each other through contracts between the related parties (Hunt 2002 and Joskow 2008b). The major objective of market liberalization in Germany was to abolish such regulated natural monopolies and to introduce competitive markets in order to increase overall efficiency of the electricity value chain and thereby lowering the electricity prices for end customers (Lise et al. 2006). The consequence of this process was the development of an open and unified market for electricity.

2.1.2 Electricity market design in Germany

From the economic perspective, the electricity sector is organized in several market places according to their corresponding functions within the electricity system. As indicated in Figure 2.2, electricity markets can be classified according to trading and service time in comparison to the physical delivery of electricity including the wholesale market (derivatives and spot market) as well as the balancing market for tendering, use and settlement of control reserve and interruptible loads.[5]

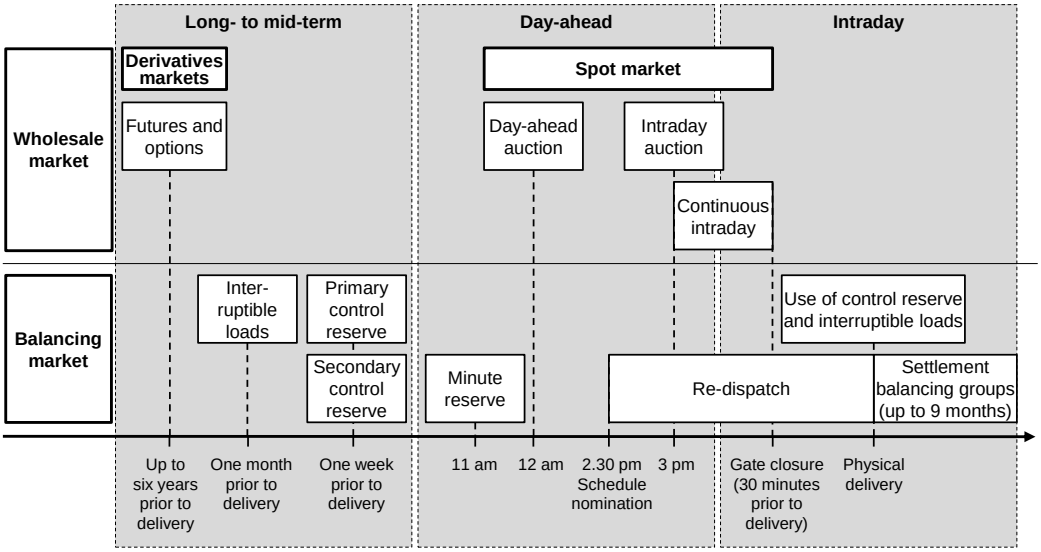


Figure 2.2: Overview of different markets for electricity trading in Germany.[6]

5 Note that this overview does not include the primary energy market (e.g. natural gas market etc.) and retail market for electricity as this is not the focus of this study. For more details on the remaining markets see for example Ströbele et al. (2012).

6 Own illustration based on Genoese (2013).

Wholesale market

The major trading platform for electricity providers is the wholesale market which can be subdivided into the derivatives and the spot markets. Both markets include standardized products being traded on the European Energy Exchange (EEX) in Leipzig and European Power Exchange (EPEX) SPOT in Paris[7] as well as individual bilateral contracts between related parties on the over-the-counter (OTC) basis. The standardized futures and options on the derivatives markets operated by EEX can be traded with a time of maturity of up to six years. In detail, for Phelix[8] Futures the underlying is represented by the German Phelix Day Base Index (electricity index calculated as an average of electricity prices for each hour of the day) and the German Phelix Day Peak Index (electricity index calculated as an average of electricity prices for the time between 8 am and 8 pm Monday to Friday regardless of holidays) provided by EPEX SPOT. In this case, market participants can choose between financial settlement and physical delivery. For Phelix Options, the underlying is represented by the corresponding Phelix Futures and allows only for financial settlement. In general, the products on the derivatives market can be utilized for hedging future trading positions and market risks.

According to the bidding period prior to delivery, the spot market operated by EPEX SPOT can be further subdivided into day-ahead auction, intraday auction and continuous intraday trading.[9] The day-ahead auction takes place each day at 12 am and allows for trading of 24 one-hour-contracts on electricity for the subsequent day (i.e. one contract for each hour of the day). The auction is carried out in a sealed-bid manner and provides a uniform market clearing price for all market participants. Although the trading volumes account for

7 EEX AG was founded in 2002 as a merger of the European Energy Exchange based in Frankfurt and the Leipzig Power Exchange (LPX). Through its subsidiaries, the company operates trading platforms among others for electricity derivatives, CO_2 emission certificates, and other primary energy carriers such as natural gas, coal, and oil. EPEX SPOT SE was established in 2008 through a merger of German and French spot trading activities by EEX AG and Paris-based Powernext SA. Today, EPEX SPOT SE is located in Paris and provides trading services for different electricity spot markets in Germany/Austria (with a common trading area for both countries), France, and Switzerland.

8 Phelix stands for 'Physical Electricity Index'.

9 Day-ahead auction is considered a part of the spot market although technically it allows for trading electricity with a future delivery date. This classification is in line with Ockenfels et al. (2008) and Schill (2011a).

less than 50 % of the total gross electricity consumption,[10] the day-ahead auction represents the most important market place for electricity in Germany and provides powerful reference price signals for all other market participants (Bundeskartellamt 2011 and Frontier Economics 2011).

After the nomination of the production schedule for the next day by all operators at 2:30 pm, the daily intraday auction takes place at 3 pm including the trading of 96 different contracts for each quarter-hour of the subsequent day. Finally, starting each day at 3 pm, the continuous intraday market allows for trading of electricity both on an hourly and quarter-hourly basis up to 30 minutes before the physical delivery (so-called gate closure).[11] The sealed-bid intraday auction sets a uniform market price for all bidders for each hour and quarter-hour of the next day, whereas for continuous intraday trading the price is determined in a pay-as-bid auction and may vary for each market participant depending on the underlying bids. However, both intraday markets allow for re-adjustments and fine-tuning of the trading portfolio in a similar way after the results of the day-ahead auction become available and therefore aim to improve the trading flexibility for all market participants.

Balancing market

In order to ensure system stability, the transmission system operators are responsible for maintaining and – in case of any unexpected events – restoring the grid balance between electricity production and consumption. This is achieved by means of control reserve which can be subdivided into primary control reserve, secondary control reserve, and minute reserve[12] according to activation time and tendering period. The different levels of control reserve are based on each other and are intended to be used successively.

10 According to EPEX (2015) and AGEB (2015), the trading volume at the day-ahead auction for the German market place in 2014 was approx. 262.9 TWh accounting for less than 46 % of the total electricity gross consumption of approx. 578.5 TWh (including power plant own consumption and electricity grid losses). The trading volume of the remaining intraday markets (auction and continuous) was in total approx. 26.4 TWh or less than 5 % of the gross consumption.

11 The continuous intraday trading starts each day at 3 pm for hourly contracts of the current and next day. For quarter-hourly contracts of the next day, the trading period begins at 4 pm, i.e. one hour after the intraday auction.

12 In the literature, 'tertiary control' reserve is sometimes used as a synonym for 'minute reserve'.

According to the decision of the Federal Network Agency,[13] TSOs are obliged to tender a pre-defined amount of control reserve for the whole transmission system[14] on a transparent and uniform market platform (BNetzA 2011a, BNetzA 2011b, BNetzA 2011c).

In this context, primary control reserve on the first level of the balancing services is characterized by the shortest activation time of less than 30 seconds and is intended to compensate unexpected short-term frequency imbalances. This type of control reserve with a minimal lot size of 1 MW is tendered one week in advance for the whole subsequent week. The secondary control reserve has an activation time of up to 5 minutes and a minimal lot size of 5 MW. In this case, tendering is carried out on a weekly basis for peak and off-peak periods[15] for each day of the subsequent week. Finally on the third level, the minute reserve with minimal lot size of 5 MW is expected to be activated within 15 minutes. The corresponding tender is conducted on a daily basis at 11 am (with bids being placed until 10 am) for six four-hour periods of the next day. For all three types of control reserve, one can distinguish between positive reserve needed when the actual production is lower than the demand and negative reserve when electricity supply is higher than consumption. Positive reserve can be provided by increasing power plant output or by load reduction, whereas for negative reserve it is the opposite.

Besides the control reserve, operators of large flexible and almost continuous electricity loads connected to high and extra high voltage lines have the opportunity to sell additional grid services by providing interruptible loads.[16] Based on the corresponding activation time, the so-called immediately interruptible

13 Federal Network Agency (German: Bundesnetzagentur; Abbr.: BNetzA) is the main regulatory authority under the Federal Ministry for Economic Affairs and Energy, being responsible among others for supervision and non-discriminatory access to the electricity network in Germany.

14 In Germany, the transmission system consists of four transmission zones which are operated by four separate companies: Amprion, Tennet TSO, 50Hertz Transmission and TransnetBW. Historically, the four zones and operators emerged from the four major utilities (RWE, E.ON, Vattenfall Europe and EnBW) during the unbundling process.

15 Peak period is considered from 8 am to 8 pm. Off-peak period includes the time from midnight to 8 am as well as from 8 pm to midnight.

16 This comparatively new balancing service has been introduced through a corresponding amendment of the Energy Industry Act and Ordinance on Interruptible Load Agreements by the German Federal Government in December 2012.

Table 2.2: Characteristics of different types of control reserve and interruptible loads.

Characteristics	Primary control reserve	Secondary control reserve	Minute reserve	Immediately interruptible loads	Quickly interruptible loads
Activation time	30 s	5 min.	15 min.	1 s	15 min.
Minimal lot size	1 MW	5 MW	5 MW	50 MW	50 MW
Tender prior to delivery	One week	One week	One day	One month	One month
Delivery period	Week	Week	4 hours	Month	Month

loads are expected to reduce electricity consumption automatically within a second as soon as the grid frequency drops below a pre-defined threshold, whereas the quickly interruptible loads are intended to respond within 15 minutes upon a remote control through the responsible TSO. The interruptible load of 3 GW in total is tendered commonly by the TSOs on a monthly basis for different load reduction patterns[17] within one month with a single lot size between 50 and 200 MW. Table 2.2 provides an overview of the different types of control reserves and interruptible loads and corresponding characteristics.

In general, the tendering for grid balancing services is organized as a pay-as-bid auction and includes two separate price components: capacity payments on per MW-basis[18] and energy payments on per MWh-basis. The capacity price can be considered as a reward for providing corresponding capacities to the market, whereas the energy price is paid only if the contracted electricity (or output/load reduction) is actually needed and called by the TSO as a compensation for potential costs (or loss of profit). Therefore, the capacity payments in the balancing market represent an important difference as compared to the wholesale market which is organized as an energy-only market.[19]

17 Possible load reduction patterns are: several times per day and at least four times per week for 15 to 60 minutes or at least four hours on a weekly basis or at least eight hours on a bi-weekly basis.

18 The only exception is represented by the primary control reserve which includes capacity payments only.

19 Typically, energy-only markets are defined as markets allowing merely for energy payments on per MWh-basis as the only investment remuneration possibility (Joskow 2008a). Chapter 2.2 provides a detailed discussion of the role of the energy-only market for investment decisions in generation capacities.

The costs of balancing services (i.e. capacity and energy payments for control reserve and interruptible loads) are allocated according to the costs-by-cause principle through so-called balancing groups, i.e. virtual accounts for electricity production and demand. The balancing group manager[20] is responsible for maintaining the balance between corresponding electricity provision and consumption for each quarter-hour of the year. In case of any imbalances, the responsible manager is charged the balancing fee which is calculated unitarily by the TSOs based on the overall imbalances in the entire grid after physical delivery.[21] Balancing group management and the corresponding fees is the major instrument to incentivize market participants to avoid unexpected deviations from the scheduled production and consumption, thus contributing to grid stability.

An additional mechanism to maintain the grid stability is the so-called redispatch. In case of any unexpected grid constraints or security concerns after the nomination of the operation schedule for the next day, TSOs are allowed to reschedule power plants despite any commitments on the wholesale market. The power plant operators receive adequate financial compensation for any schedule deviations which in turn are allocated among all end users through corresponding grid fees.

The subsequent analyses in chapters 3 to 5 will focus on electricity production (i.e. second value chain step) especially from renewable sources in combination with electricity storage as a flexibility option in the energy system. In addition, the forthcoming evaluations will be mainly limited to the interaction of market participants on the day-ahead market as a major energy exchange in Germany.

20 For example, a balancing group manager could be represented by an operator of a single power plant with electricity production on the one side of the account and electricity sales to the market on the other side of the account. Also, all end users of an individual retailer are usually summarized into one balancing group. The retailer as the group manager is then obliged to maintain the balance between total demand by his customers and electricity purchases from the wholesale market.

21 Note that balancing fees can be both positive and negative from the perspective of the balancing group manager. If the balancing group has the same type of imbalance as the entire grid (electricity provision higher than consumption in case of grid oversupply or vice versa), the fee is positive and the group manager has to pay the penalty to the market. However, if the balancing group has the opposite imbalance in comparison to the market (balancing group oversupply in case of grid undersupply and vice versa), the group manager receives a reward from the market as the concerned balancing group contributes to grid stability.

2.2 Power market trends and challenges

2.2.1 Market liberalization

As mentioned in chapter 2.1.1, one essential cornerstone for the modification of the German electricity system is market liberalization. It was initiated in 1996 by the Directive 96/92/EC of the European Union (EU)[22] and its transformation into German national law[23] (Meeus et al. 2005 and Erni 2012). After the introduction of competitive markets, the German electricity industry was characterized by extensive consolidation with a large number of mergers and acquisitions such that only four big companies became responsible for the major share of power generation (Lise et al. 2006). According to Weigt and Hirschhausen (2008) and Bundeskartellamt (2011), more than 80 % of the electricity generation market after 2006 was shared between RWE, E.ON, Vattenfall Europe, and EnBW. The liberalization process was accompanied by further European and national legal initiatives mainly in order to unbundle vertically integrated companies for a legal and economic separation of single value chain steps and to promote market transparency as well as the rights of individual end customers. Most important legal changes comprise the follow-up Directive 2003/54/EC repealing the original directive from 1996 and its integration into German Energy Industry Act in 2009 as well as the so-called European Union's Third Energy Package[24] and corresponding changes of the German national law.[25]

In this context, the price signals from the German energy-only wholesale market are intended to coordinate electricity production and consumption in the most efficient way and to provide adequate funds to remunerate investments in generation capacities (Finon and Roques 2013 and BMWi 2014). Typically on the day-ahead and intraday auction, electricity suppliers bid generation capacities for each power plant based on marginal costs which include mainly

22 Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity (Official Journal L 027).

23 The transformation of the Directive 96/92/EC was conducted by the revision of the Energy Industry Act (German: Energiewirtschaftsgesetz; Abbr.: EnWG) becoming effective in April 1998.

24 Including the Directive 2009/72/EC repealing the directive from 2003.

25 For more details on the liberalization process in Germany see for example Ströbele et al. (2012) and Genoese (2013).

fuel, CO_2 emission, and ramping costs[26] and depend on the unit's efficiency.[27] All bids are sorted by marginal costs representing the merit order of the generation portfolio available to the market and the corresponding supply curve (Ströbele et al. 2012, pp. 249 – 252). As illustrated in Figure 2.3, the intersection of the supply and demand curves determines the market equilibrium including the uniform clearing price P_1 and electricity quantity Q_1 provided to the market.[28] All generation units with marginal costs lower than the market clearing price are in a position to earn the infra-marginal rent which in energy-only markets allows for remuneration of fixed costs and capacity investment (Joskow 2007).

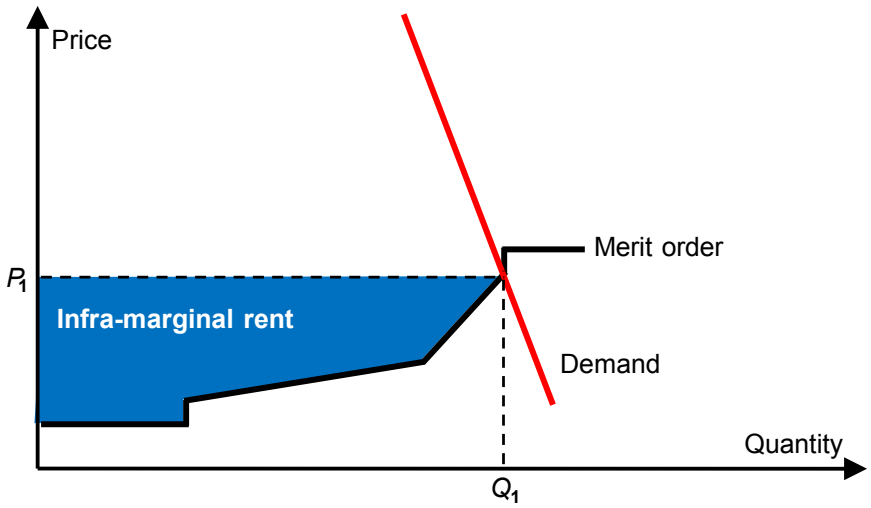


Figure 2.3: Market equilibrium determined by the intersection between the supply and demand curves.[29]

At this point, it is important to mention that electricity markets differ substantially from other commodity markets mainly due to three specific features

26 Ramping costs are referred to as operational costs occurring when production level varies over time due to inflexibility of some units. Such costs typically account for reduced efficiencies and thus rising fuel consumption, shorter lifetime, and opportunity costs in subsequent periods (Ströbele et al. 2012, p. 252 and Denny and O'Malleyb 2009)

27 Kahn et al. (2001) argue that in competitive markets suppliers have no incentives not to bid marginal opportunity costs which usually represent costs of providing one additional output unit. However, Kahn et al. (2001) also state that under some circumstances marginal opportunity costs might be based on the loss of profit from selling electricity to other markets or in subsequent hours (e.g. in case of electricity storage).

28 In this way, marginal costs of the most expensive power plant set the market price. According to Stoft (2002, pp. 67 – 68), in competitive markets this is true if at least one bidder on the supply side has a continuous marginal cost curve.

29 Own illustration based on Joskow (2007).

of electricity. First, from the technical perspective, electricity systems require continuous balancing between power production and consumption in order to ensure stability. Otherwise, if grid operators are not able to maintain the balance between generation and load at any given point in time, system breakdowns might occur with serious economic and social consequences (Kirschen and Strbac 2004 and Wolak 2014, p.213).[30] This problem is further exacerbated by the fact that currently the storing of electricity is expensive and requires substantial investments typically due to high technology costs and poor round-trip efficiency (Borenstein et al. 2008 and Sioshansi et al. 2012).[31] Thus, some authors consider electricity as practically non-storable (see for example Joskow 2006a or Ockenfels 2007). However, although electricity indeed cannot be stored directly in large amounts,[32] it can be transformed into other forms of energy (Dell and Rand 2001, p. 1 and Baker 2008).[33]

Second, electricity demand usually has only limited flexibility and is therefore characterized by low short-term price elasticity (Borenstein et al. 2002a).[34] According to Borenstein and Holland (2005), this is due to the fact that despite price variations on the wholesale market, electricity prices for end users in the retail market typically remain either at the same predefined level or the adjustment intervals are too long. Although already today some large industrial and commercial customers procure electricity based on time-varying tariffs and therefore behave flexibly with regard to the market prices, most consumers still enter fixed price contracts on the retail market (Borenstein

30 Joskow (2008a) argues that short-term costs of such system black-outs can be limited if system operators are able to schedule the imbalances in advance, for example through energy rationing in form of rolling black-outs affecting only a small number of market participants. However, unexpected grid collapses might interrupt power supply in large regions for a comparatively long time such that a market design potentially allowing for the threat of breakdowns of that kind is practically not acceptable in industrialized countries (Kirschen and Strbac 2004).

31 The economics of different storage technologies in combination with intermittent electricity feed-in are analyzed in more detail in chapter 3.

32 The only exception for direct electrostatic storage is represented by capacitors and superconductors which, however, suffer from significant technical and economic restrictions (Dell and Rand 2001, p. 1).

33 E.g. as potential energy in pumped-hydro storage facilities. See chapter 2.3.3 for an overview of different electricity storage technologies.

34 An overview of quantitative values for price elasticity and the corresponding literature can be found for example in Lijesen (2007) and Gillingham et al. (2009). More recent empirical studies on demand-side price elasticity in the power sector can be found in Ito (2014) and Jessoe and Rapson (2014). Low short-term elasticity is also one of the major assumptions in chapter 5.

and Bushnell 2015). Some authors, such as Holland and Mansur (2006) and Filippini (2011), advocate real-time pricing in retail markets[35] with corresponding demand metering in order to overcome the challenges related to demand inelasticity and thus to improve market efficiency. In fact, based on an empirical analysis of consumer behavior, Bushnell and Mansur (2005) and Reiss and White (2008) report significant demand changes due to interrelated price shocks in the retail and wholesale market in the San Diego region during California's energy crisis between 2000 and 2001.[36] Allcott (2011), however, argues that positive welfare effects from real-time pricing might be too small to compensate the costs incurred by adequate metering technology.[37] In addition, Borenstein and Holland (2005) state that in practice it is hardly possible to introduce real-time pricing for all customers.

Finally, electricity can be transported from the production to the consumption site only by means of transmission and distribution networks. In this context, utilization of the electricity grid can be considered as a natural monopoly as new capacities are costly and the establishment and operation of competing parallel power lines is extremely inefficient from the economic point of view (Stoft 2002 and Schill 2011a). For this reason, the electricity grid in Germany is supervised by the Federal Network Agency regulating the non-discriminatory access and homogenous prices for the use of the network to cover corresponding operation costs and investments expenditures.[38] In addition, power flows within the network are subject to physical constraints, specifically to Kirchhoff's current and voltage law which typically is a reason for the distribution of electricity among parallel lines based on the current load and electrical resistance of the concerned circuit (Schweppe et al. 1988 and Neuhoff et al. 2005). Thus, the

35 Real-time pricing is referred to as a pricing system which sets the consumer price on an hourly or half-hourly basis according to price variations on the wholesale market (Holland and Mansur 2006 and Borenstein 2007). A general overview over real-time pricing is provided for example by Borenstein et al. (2002b).

36 According to regulatory guidelines in force at this time, retail prices were related to price variations on the wholesale market (Reiss and White 2008). For a more detailed discussion on restructuring and energy crisis on the power market in California see for example Blumstein et al. (2002), Wilson (2002) or Wolak (2005).

37 Borenstein (2013) further supports this suggestion by finding only small reward for end users from smart metering and prise-responsive behaviour on the level of private households.

38 See for example Laffont and Tirole (1993), Vogelsang (2002), Viscusi et al. (2005) or Pedell (2006) for a literature overview and detailed discussion on price regulation for natural monopolies.

activities in a particular grid node might impose additional constraints on supply and demand in other grid nodes and in consequence both the electricity networks and the wholesale markets are interrelated (Joskow 2006b and Schill 2011a). However, since in Germany only one homogenous wholesale price is calculated for the entire transmission system, the prices on the day-ahead and intraday auctions do not take into account any grid congestion issues (Schill 2011a and Kirschen and Strbac 2004). On the one hand, as described by Turvey (2006), grid enhancements provide benefits to the electricity system through security improvements and cost savings from generation investment deferrals and exchange of cheap electricity and grid ancillary services. On the other hand, however, Bunn and Zachmann (2010) argue that market efficiency can be achieved through enhanced arbitrage between different trading areas, but it depends on the actual market design and coupling of auctions for electricity generation and transmission.

The above mentioned features of electricity pose specific challenges for the efficiency of electricity markets. Along with the concentration of production capacities on only a few market participants, also inelastic demand, expensive storability, and grid constraints are recognized as potential sources for the abuse of market power (Joskow 2006a and Twomey and Neuhoff 2010).[39] In general, market power can be exercised either by physical capacity withdrawing, i.e. corresponding capacities are not offered to the market, or by economic withholding, i.e. the bid price is above the marginal costs. In both cases, the supplier attempts to raise the market clearing price in order to increase his overall profit from electricity sales of the remaining power plants (Ockenfels 2007, p. 10 and Patton et al. 2014, p. 165). The research on the exploitation of market power in Germany provides ambiguous results (see for example Möst and Genoese 2009). Some studies, e.g. Müsgens (2006) and Weigt and Hirschhausen (2008), find a clear impact of market power on electricity prices in Germany, whereas other authors conclude that market power is rather limited and price increase is mainly due to other fundamentals[40] (Schwarz and Lang 2006, Ellersdorfer 2009, pp. 174 – 175 and Graf and

39 A more detailed discussion on market power and the corresponding behavior within an oligopolistic market structure in the context of electricity storage is provided in chapter 5.

40 According to Borenstein et al. (2002a), other fundamental factors might include fuel or CO_2 emission costs or might simply correspond to capacity scarcity.

Wozabal 2013) or that it is empirically not significant[41] (Bundeskartellamt 2011). According to Schill (2011a), proving the abuse of market power in particular under information asymmetries is rather difficult.[42] In principle, there are several strategies to mitigate market power ranging from increasing the number of competitors (e.g. through elimination of market entry barriers, enhancing the transmission system for a better market coupling, or reducing the size of the largest market participants) to structural market changes such as improving load responsiveness on the demand side, price caps limiting maximal electricity prices, or bidding restrictions (Hunt 2002, pp. 96 – 102).

However, some of the strategies on market power mitigation might give rise to other undesirable market inefficiencies. In particular, regulatory interventions such as price caps might reduce the potential revenue stream from sales on the energy-only market for peak-load technologies with comparatively high marginal costs (Joskow 2008a and Hogan 2013).[43] Consequently, market prices might be insufficient to remunerate investments in such power plants leading to the so-called "missing money" problem (Hogan 2005).[44]

As indicated in Figure 2.4, during peak-load hours the electricity demand might reach the maximal generation capacity K_{Max} available to the market. In theory, the electricity price P_2 is expected to increase beyond the marginal costs of the last and most expensive power plant. The difference between the market clearing price P_2 and the marginal costs of the last unit is referred to as value of lost load (VOLL) and represents the consumers' willingness to pay for electricity despite limited generation capacities (Stoft 2002 and Joskow 2008a). In this way peak-load technologies have the opportunity to earn the scarcity rent required to cover investment expenditures and costs of capital (Joskow 2007). However, price caps induced by market regulation[45] might reduce the

41 Note that the Bundeskartellamt (2011) also states that, although abuse of market power could not be found, the potential threat due to the actual market structure still exists.

42 Twomey et al. (2005) provide an overview of methodology for market power analysis with the corresponding advantages and drawbacks.

43 In chapter 5 one of the research questions focuses on the investment incentives in peak-load technologies under the day-ahead market framework without price caps.

44 In the literature, the "missing money" problem is also referred to as "resource adequacy" problem (Schill 2011a). The corresponding stream of literature analysing this problem in more detail is referred to as peak-load pricing literature.

45 In Germany, for example, the maximal electricity price on the day-ahead auction is limited to 3,000 €/MWh (Graf and Wozabal 2013).

scarcity rent with serious consequences for peak-load technologies. Although in the short run market equilibrium can be reached, in the long run the resource adequacy problem increases the threat of underinvestment in generation capacities needed for grid stability in peak-load hours (Cramton and Stoft 2006 and Joskow and Tirole 2006). In this context, Hogan (2014) argues that in practice an efficient distinction between price peaks due to market power abuse and due to capacity scarcity is rather difficult. Therefore according to the theory, the more competitive and efficient the market, the lower the threat of the "missing money" problem and hence the higher investment incentives and system reliability.

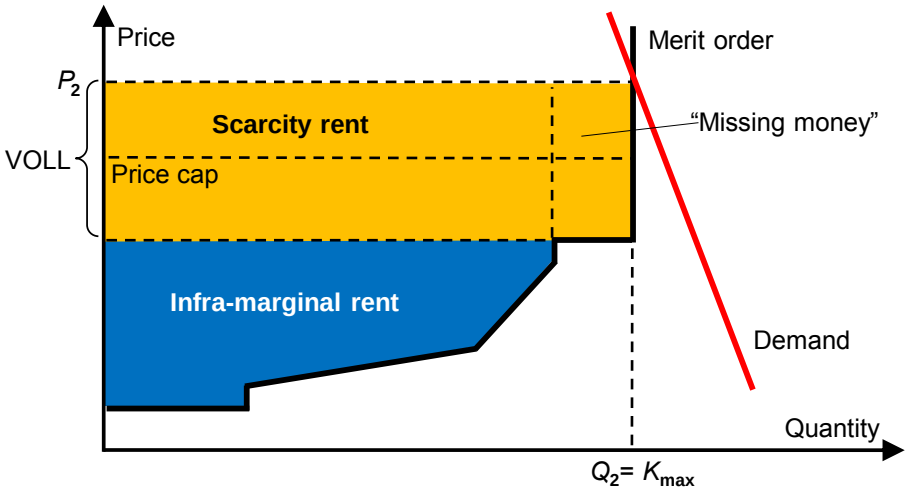


Figure 2.4: Value of lost load and the "missing money" problem due to price caps in energy-only markets.[46]

This issue is further exacerbated by the fact that currently grid stability can be viewed as a public good, since intentional power supply interruptions, if permissible at all, can practically occur only for specified areas and thus not for individual consumers (Joskow and Tirole 2006 and Finon and Pignon 2008). Consequently, the demand side can be considered as inelastic with regard to grid reliability (Joskow 2007). In addition, capacity investments in electricity markets are characterized by lumpiness, i.e. investors typically install large power plants with comparatively high capital expenditures (Schmalensee and Golub 1984 and Steggals et al. 2011) and long time lags for investments

46 Own illustration based on Joskow (2007).

(Kirschen and Strbac 2004 and Green 2008). Joskow (2008a) also states that investment decisions in electricity markets are exposed to regulatory risks, since in the ongoing liberalization process market design adjustments through responsible authorities might occur frequently. Finally, according to Bushnell and Ishii (2007) endogeneity of investment decisions of large generators on expected market outcomes and the uncertainty regarding the behavior of other market participants represent additional challenges for capacity expansion in electricity markets.

2.2.2 Sustainable energy supply

Environmental policy guidelines

Another important factor influencing the development of the German power sector is the environmental policy both on the European and national levels. The climate policy in the European Union is related to the Kyoto Protocol[47] which was the first convention introducing a binding target for the reduction of greenhouse gas emissions in the multinational context in order to mitigate anthropogenic global warming[48] (Hammer 2011). Based on the Treaty of Lisbon, the member states of the European Union committed themselves to a common energy policy in a spirit of solidarity and defined security of supply, competitiveness and sustainability as major cornerstones for further actions.[49]

With its "Energy 2020" strategy, the European Commission specifies the so-called 20 – 20 – 20 target until 2020, i.e. 20 % – 30 % GHG emissions reduction (in comparison to the 1990 baseline), 20 % share of renewable energies in the

47 Kyoto Protocol to the United Nations Framework Convention on Climate Change (UNFCCC) adapted in December 1997 and effective from February 2005.

48 A widely recognized goal is represented by limiting the increase of the global temperature up to 2 °C in comparison to the pre-industrial era until the end of the current century (Meinshausen et al. 2009). This goal was confirmed for example by the Lima Call for Climate Action adapted on the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP20) in Lima in December 2014 (UNFCCC 2015). According to the Intergovernmental Panel on Climate Change (IPCC) and its fifth assessment report, global warming above 2 °C is likely to change the global climate substantially and irreversibly with negative consequences for ecosystems, economies and human security (IPCC 2014).

49 See Article 194 of the Lisbon Treaty on the functioning of the European Union confirmed by the European Commission in a number of official documents (see for example EC 2010).

final energy consumption and 20 % improvement in energy efficiency (EC 2010). Further development until 2030 and 2050 is defined by the "Energy Framework 2030" (EC 2014) and "Energy Roadmap 2050" (EC 2011): 40 % GHG emission reduction, 27 % share of renewables and 30 % energy savings until 2030 on the way to cut GHG emissions by 80 % and to increase renewable energy generation at least up to 55 % (or 64 % – 97 % for the power sector) until 2050.

In order to accomplish these goals, the Directive 2009/28/EC [50] constitutes the renewables target for 2020,[51] whereas the Directive 2012/27/EU[52] introduces binding measures to achieve the energy savings objective. Additionally, in line with flexible mitigation measures, as proposed by the Kyoto Protocol the Directive 2003/78/EC [53] initiated in 2005 a European emission trading system in order to decrease CO_2 emissions in selected sectors in an efficient way (Kemfert et al. 2006 and Aatola et al. 2013). As a "cap-and-trade" mechanism the system sets an overall upper CO_2 emission limit for some industries and allows for the trading of CO_2 certificates in order to fulfill individual targets (Betz and Sato 2006). Some CO_2 emissions allowances are granted for free to participants, and there is a number of trading platforms for the exchange of certificates between the market participants (Hammer 2011). However, BMWi (2014) states that due to a large amount of excess certificates and consequently low prices, the current trading system design does not provide sufficient incentives for emission reduction and therefore should be adjusted correspondingly.

On the national level, the German long-term climate policy aims at a comprehensive transformation of the German energy system into an energy-efficient and environmentally friendly economy and is often referred to as "Energiewende" (BMU 2012b, p. 5 and Pregger et al. 2013). As a principal guideline for the future energy policy, the Energy Concept [54] of the German Federal Government

50 Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources (Official Journal L 140).

51 This target is further detailed for each member state according to Annex I of the directive. For Germany, the quantitative national overall target is 18 % for the share of renewable energy sources in gross final consumption of energy in 2020.

52 Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency (Official Journal L 315).

53 Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community (Official Journal L 275).

54 The so-called "Energiekonzept" was published in September 2010 in BMWi (2010).

promotes a number of legislative actions to enhance sustainable and renewable energy use and production and sets more ambitious targets than the European Union. As summarized in Table 2.3, in order to reduce the GHG emissions by 40 % until 2020 in comparison to 1990, the overall share of renewable energy generation should increase up to 18 %[55] (or 35 % in the electricity sector only), and the energy demand should decrease by 20 % in comparison to 2008 (or 10 % in the electricity and 10 % in mobility sector). In the long run until 2050, Germany aims to reduce GHG emission by 80 % – 95 % with a renewables share of 60 % (or 80 % in the electricity sector) and energy savings of 50 % (or 25 % in the electricity and 40 % in the mobility sector).[56]

Table 2.3: Climate targets of the German energy policy.[57]

Item	2020	2030	2040	2050
Reduction of GHG emissions (1990 baseline)	−40%	−55%	−70%	−80 to −95 %
Share of renewable generation on gross final energy consumption	18 %	30 %	45 %	60 %
Share of renewable generation on gross electricity consumption	35 %	50 %	65 %	80 %
Reduction of primary energy consumption	−20 %			−50 %
Reduction of electricity consumption	−10 %			−25 %
Reduction on final energy demand in mobility sector	−10 %			−40 %

According to the National Inventory Report provided by UBA (2014), more than half of the total GHG emissions in Germany are caused by the public power and heat production[58] (more than 35 % of total GHG emissions) and

55 This figure is in line with the mandatory national target specified for Germany by Directive 2009/28/EC.

56 The concrete targets in BMWi (2010) have been confirmed in a number of documents, recently by the German Federal Ministry for Economic Affairs and Energy in its green paper on the electricity market for Germany's energy transition (BMWi 2014). An overview is also provided by Pregger et al. (2013).

57 Based on BMWi (2010) and BMWi (2014) and adapted from Pregger et al. (2013).

58 It is worth to mention that heat consumption has a large share on the overall final energy demand in Germany. However, in the public sector heat is produced in thermal units such that heat and electricity production are closely related to each other. Thus, as Schill (2011a) states, electricity generation is responsible for the largest amount of GHG emissions.

by road transportation (more than 15 % of total GHG emissions).[59] Therefore, major building blocks of the Energy Concept consist of an extensive development of renewable energy generation, energy efficiency improvements for households, the industry and the public sector, grid expansion for a better integration of renewables as well as decarbonization of the mobility sector. In addition to other measures such as energy research, promotion of international cooperation, or increasing acceptance and transparency for global warming mitigation, the German energy policy also includes phase-out of the nuclear power until 2022 (Lutz et al. 2014). Consequently, all operating nuclear power plants are planned to be decommissioned upon an individual predefined expiration date (BMU 2012a, p. 22 , BMWi 2013b, Table 24).[60]

Renewable electricity generation

One of the major legislative initiatives to promote the expansion of renewable power in Germany is the Erneuerbare-Energien-Gesetz (EEG)[61] which ensures priority electricity uptake at a predefined feed-in tariff by the grid operator for renewable power plants for 20 years after commissioning (Wüstenhagen and Bilharz 2006).[62] The mechanism was established already in 1991 and then revised several times mainly in order to adapt the level of the feed-in tariffs and to increase the efficiency of this mechanism (Sensfuß et al. 2008 and Erni 2012).[63] According to the latest EEG version, renewable generators are strongly incentivized to sell the intermittent electricity directly to the market. Any losses in comparison to fixed feed-in tariffs due to market price fluctuations are compensated by the so-called market premium. This additional payment

59 Percentage values are based on UBA (2014) and UBA (2015).

60 Although the contrary is specified in the Energy Concept, after the nuclear incident in Fukushima in March 2011 the German parliament decided in the 13th Amendment of the Atomic Energy Act (German: Atomgesetz) on the abandonment of nuclear power (Pregger et al. 2013).

61 German Renewable Energies Act.

62 According to Schill (2011a), beside CO_2 emission reduction the rationale behind the support of renewable electricity generation are also supply security improvements through independence from energy imports as well as employment effects and thus strengthening of the domestic economy. Zerta et al. (2008) also state that limited recourses of conventional primary energy sources are an important trigger for the transition from fossil-based to renewable energy systems.

63 Initial regulation was determined by the Feed-in Act (Stromeinspeisegesetz) introducing fixed feed-in tariffs for small renewable generators (Lauber and Mez 2004 and Erni 2012). A major revision was conducted in 2000 which was the foundation of the present act. Further revisions took place in 2004, 2009, 2012 and most recently in 2014 (Hast et al. 2015).

is based on a predefined reference price calculated as a monthly weighted average of wholesale spot prices provided by EPEX SPOT.[64] In addition, generators under the direct sales regime receive a small predefined bonus for any expenses associated with the trading procedure.[65] The overall costs for renewable generation are then shared between all consumers based on a uniform reallocation rate (Genoese 2013).[66]

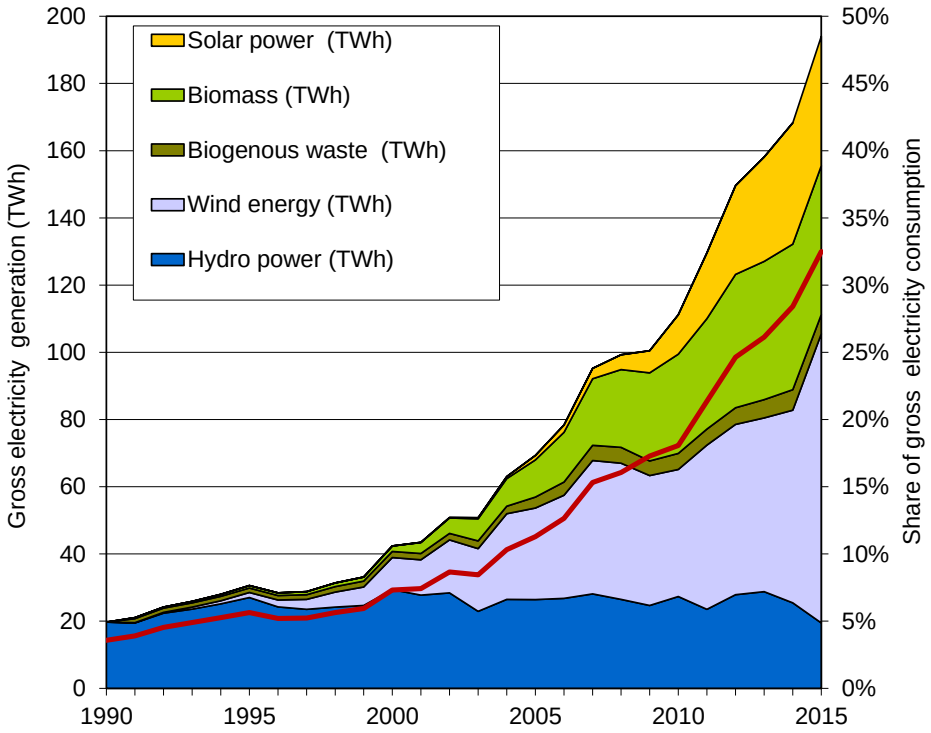


Figure 2.5: Annual renewable electricity generation and share on gross electricity consumption in Germany between 1990 and 2015.[67]

According to Blazejczak et al. (2014), the policy support was an important driver for the extensive development of renewable electricity in the past two

64 I.e. market premium is the difference between a predefined technology specific fixed feed-in tariff and the reference price.

65 Although in its latest version the EEG postulates direct sales as a standard feed-in tariff scheme (see §2 EEG), there are still some exceptions: owners of existing and small renewable generators (below 500 kW of installed capacity until 2015 and below 100 kW after 2015, see §37 EEG) can still choose between direct sales and fixed feed-in tariffs. All other generators can also deviate from this rule. In this case, however, the tariffs are reduced by 2 % (see §38 EEG) in order to provide more economic incentives for direct sales.

66 So-called "EEG Umlage" as specified by §60 EEG.

67 Data based on BMWi (2016).

decades. As indicated in Figure 2.5, the share of renewable electricity on the gross electricity consumption increased by a factor of 6 from approx. 5 % at the end of the 1990's up more than 30 % in 2015. While until 2000 almost all renewable electricity was provided by hydro power plants with a minor contribution of onshore wind, the generation portfolio changed drastically in recent years. Annual electricity supply provided by wind power plants grew up to 86 TWh in 2015 (almost 10 % of the gross electricity consumption) followed by biomass energy (50 TWh per year or almost 8 % of the gross electricity consumption) and solar power (39 TWh per year or 6 %). Currently, intermittent energy sources (wind and solar) account for more than 50 % of the renewable production (BMWi 2016), and according to the Federal Ministry for Environment both technologies will also play an important role in the future energy supply in Germany (BMU 2012a, pp. 28 – 32).

However, intermittent electricity generation through wind and photovoltaic power plants poses new challenges for the existing energy system. The fluctuating supply depending on weather conditions and thus uncorrelated with the demand requires new means to cope with system security by balancing electricity supply and consumption at any point in time (Joskow 2011). In fact, García–González et al. (2008) argue that due to the stochastic feed-in pattern forecasting renewable generation[68] is rather difficult, and this source of uncertainty has a considerable impact on the market prices (Giabardo et al. 2010, Jónsson et al. 2010 and Wozabal et al. 2013).

In addition, according to Castronuovo and Lopes (2004) and Denholm and Hand (2011), the seasonality of renewable energy is another important aspect. Typically, on an annual basis, electricity from PV in Germany is mainly available during the summer when solar irradiation is comparatively high, whereas only a small portion of PV feed-in occurs during the winter months (see Figure 2.6). Wind onshore generation, however, is distributed more equally over the year with a slightly higher availability in winter than in summer. This relationship is further exacerbated by the fact that electricity demand has a seasonal pattern which better fits the wind profile, i.e. in Germany the demand is higher in winter than in summer. Thus from a technical

68 On overview of different wind power forecasting methods is provided for example by Giebel et al. (2011).

perspective, an electricity system with a large amount of renewable electricity typically requires dedicated mechanism such as energy storage and flexibly dispatchable power plants in order to cope with intermittency and seasonality of renewable energy and to maintain system security (Schill 2014).[69]

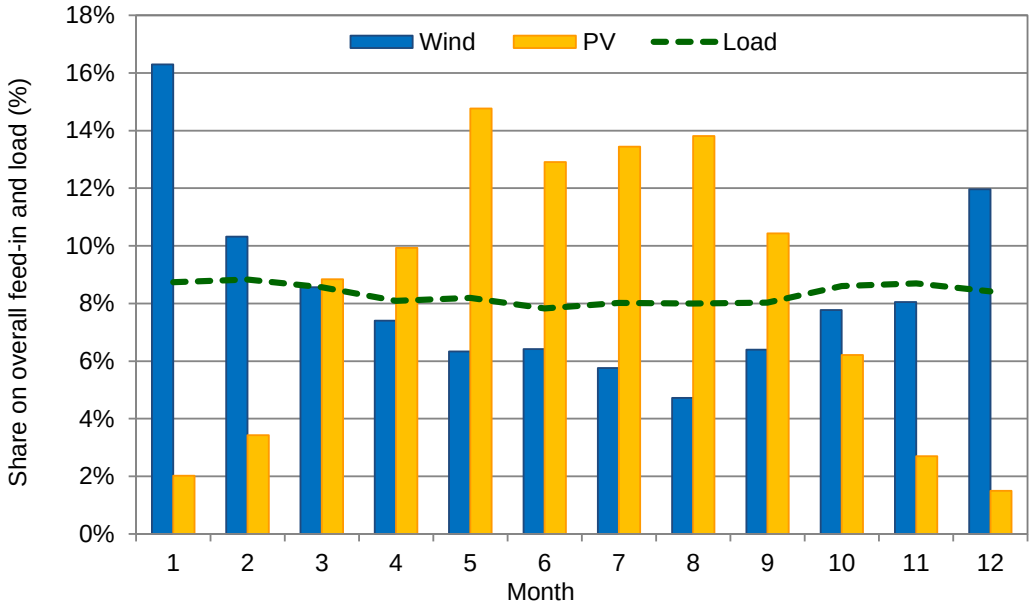


Figure 2.6: Annual distribution of load and wind onshore and PV feed-in in Germany in 2012.

Besides intermittency and seasonality, the sharp increase of renewable feed-in is also a potential challenge for the existing electricity transmission and distribution infrastructure. In particular, different renewable technologies are unevenly distributed across various regions in Germany (wind in Northern and PV in Southern Germany) necessitating adequate long-distance transmission to the end users BMWi (2013a). Also on the regional and local scale, renewable feed-in might cause serious grid congestion problems if the local network at medium and low voltage levels is insufficient to accommodate all renewable electricity provided by distributed units such as rooftop PV (Schill 2011a). For example in Northern Germany, where intermittent generation from wind has a disproportional share on the overall electricity

69 See chapter 2.3 for a more detailed discussion on this issue as well as chapter 3 to 5 for case studies in the context of electricity storage with intermittent electricity production from wind and solar sources.

production, already today wind curtailment based on the so-called "feed-in management"[70] is required to ensure transmission network stability (Loisel et al. 2010 and Stiller et al. 2011).[71]

From an economic perspective, renewable production has a considerable effect on the operation of conventional power plants (Ströbele et al. 2012). Since wind and PV generation is characterized by low marginal costs, additional renewable electricity feed-in might shift the merit order curve and the corresponding intersection between the supply and demand curves such that the new market clearing price P_2 is lower than the original price P_1 (see Figure 2.7). As a consequence, remaining power plants earn less profit required for investment remuneration in hours with a large amount of fluctuating electricity, and more expensive units, usually peak-load technologies, operate less frequently since they are not needed to satisfy the demand (Oswald et al. 2008 and Twomey and Neuhoff 2010). In this way, renewable feed-in might cause the so-called resource adequacy problem for dispatchable generation.

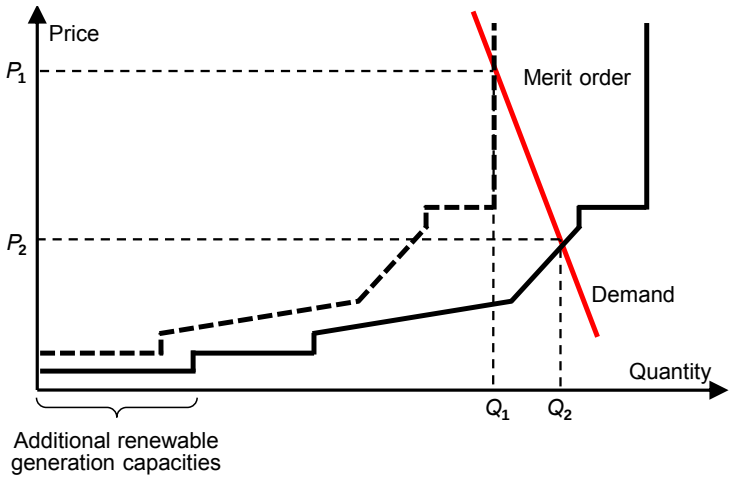


Figure 2.7: Merit order effect due to additional renewable generation capacities.

This price suppressing effect, often referred to as merit order effect, has also a negative impact on renewable generation itself. Typically, the market value

70 The so-called "Einspeisemanagement" as specified by §14 EEG.
71 Note that the case study in chapter 3 considers electricity storage as an option to avoid such network constraints in a given grid node.

of renewable generation is lower than the value of dispatchable power plants as there is a negative correlation between variable electricity feed-in and wholesale market prices (Sioshansi 2011). According to Twomey and Neuhoff (2010), this relationship is not a consequence of any market inefficiencies, but simply represents the fair value of renewable energy. In fact, as indicated in Figure 2.8, in Germany the day-ahead price in 2012 was lower in hours with high wind and PV utilization and low demand (i.e. with a high ratio of renewable utilization to load) than in peak-load hours with a small amount of intermittent electricity.[72] This observation is in line with the findings on the merit order effect provided in the literature.[73]

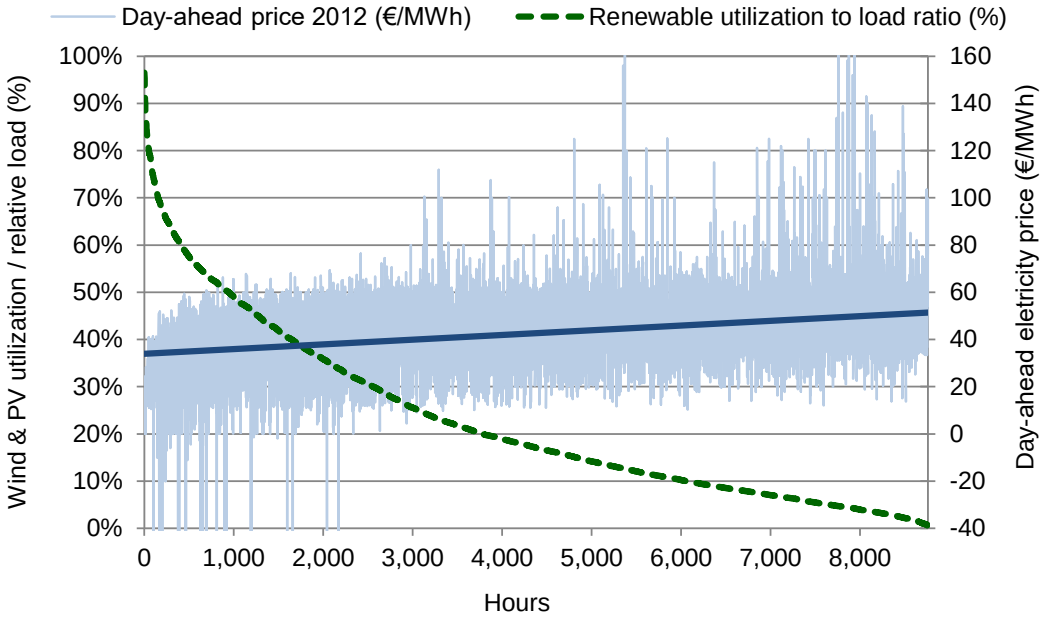


Figure 2.8: Merit order effect on the day-ahead auction in Germany in 2012.

Regarding market price volatility, the effect of intermittent feed-in is not fully clear and the literature provides ambiguous results. On the one hand, some

72 In 2012, the difference was approx. 18 €/MWh on average which is comparable to the findings in the literature. For example, Weigt (2009) reports slightly lower price effects for the time period between 2006 and 2008 but still in the same order of magnitude.

73 See for example Sensfuß et al. (2008) and Weigt (2009) for the German and Sáenz de Miera et al. (2008) for the Spanish market. A comprehensive overview over theoretical and empirical results can be found in Hirth (2013).

authors, such as Green and Vasilakos (2010) or Gatzen (2008, p. 40),[74] report increasing price variability due to renewable generation whereas on the other hand, Wozabal et al. (2015) argue that in the future the volatility might be at different levels according to the overall quantity of intermittent electricity and the slope of the supply curve.[75]

Sustainable mobility

In the context of sustainable energy supply, mobility has a large potential to contribute to climate change mitigation. Currently, fossil energy carriers play a key role in the transportation sector as the vast majority of propulsion systems depend on conventional oil-based fuels (Zerta et al. 2008). Hence, mobility is responsible for 20 % – 25 % of the worldwide CO_2 emissions (Avci et al. 2015), and in Germany road transportation produces most greenhouse gases in this sector (UBA 2015). Besides the environmental concerns, strong dependency on oil might also increase supply security risks due to geopolitical issues (Morrow et al. 2010). As a response to these challenges, some efforts have been made to utilize alternative energy carriers such as biofuels, compressed natural gas (CNG) or liquefied petroleum gas (LPG) and to substitute conventional gasoline or diesel cars with internal combustion engine (ICEs) by new propulsion technologies such as electric vehicles including hybrid, range extended and full electric vehicles.[76]

Correspondingly, the EU has undertaken several actions in order to promote sustainable mobility in Europe. Supplementing the goal of 20 % renewables, the Directive 2009/28/EC also specifies sustainability criteria for biofuels and claims that at least 10 % of final energy consumption in transport be

74 Other authors are for example Jacobsen and Zvingilaite (2010), Jónsson et al. (2010), Chao (2011), Milstein and Tishler (2011), Woo et al. (2011) or Ketterer (2012).

75 More specifically, large amounts of intermittent electricity might increase the volatility, whereas small amounts rather tend to decrease price variations in comparison to the case without renewable electricity generation.

76 A hybrid electric vehicle (HEV) is typically defined as a combination of ICE and electric vehicle, i.e. as a car with an internal combustion engine and an electric motor connected to a battery on board. A subcategory of an HEV is represented by a plug-in hybrid electric vehicle (PHEV). A PHEV has a similar design as an HEV, however, with the possibility to charge the battery from the grid. An REEV is an electric vehicle including an electric motor with a battery as major power-train and an additional internal combustion engine with a generator to extend the driving range of the car. For a more detailed definition and distinction between the different vehicle types see for example McKinsey (2010), JEC (2013) and JEC (2014).

covered from renewable sources. Further, the Directive 2009/30/EC[77] sets an objective of 10 % GHG emission reduction for road transportation, whereas Regulations 443/2009[78] and 510/2011[79] introduce binding average emissions targets of 95 g_{CO2}/km and 147 g_{CO2}/km for the new passenger car fleet and new light-duty vehicles, respectively, beginning from 2020. In Germany, as detailed by the Energy Concept, the Federal Government calls for one million electric vehicles until 2020 and six million until 2030 in order to achieve the GHG emission targets BMWi (2010).

However, biofuel potential is rather limited due to restricted agricultural area and biomass resources (Rostrup-Nielsen 2005). Other fuels based on hydrocarbons such as CNG and LPG still produce substantial amounts of CO_2 as a by-product, although the specific GHG emissions are lower than in the case of conventional ICEs (JEC 2014).[80] HEVs and PHEVs, however, allow for GHG emission reduction only in areas with sufficient availability of sustainable biofuels or for short-distance driving due to limited battery capacity (McKinsey 2010). In fact, only full electric vehicles which can be further subdivided into battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs),[81] allow for zero emission driving if renewable electricity

77 Directive 2009/30/EC of the European Parliament and of the Council amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amending Council Directive 1999/32/EC as regards the specification of fuel used by inland waterway vessels (Official Journal L 140).

78 Regulation (EC) No 443/2009 of the European Parliament and of the Council of 23 April 2009 setting emission performance standards for new passenger cars as part of the Community's integrated approach to reduce CO_2 emissions from light-duty vehicles.

79 Regulation (EU) No 510/2011 of the European Parliament and of the Council of 11 May 2011 setting emission performance standards for new light commercial vehicles as part of the Union's integrated approach to reduce CO_2 emissions from light-duty vehicles.

80 JEC (2014) provides detailed well-to-wheels analyses and corresponding specific CO_2 emissions values on per km-basis for a whole range of various production pathways for different fuel types and drive-train systems.

81 A BEV is a car with an electric motor and a battery charged by grid electricity. An FCEV has the same propulsion system as a BEV, but the electric energy is provided by a fuel cell which in turn is powered by hydrogen (usually as compressed gaseous hydrogen, although other aggregate states such as liquefied hydrogen are possible from the technical perspective). Since both concepts are very similar, a combination of both systems, e.g. as fuel cell range extender, is possible in order to exploit the strengths of both technologies. Moreover, hydrogen fuel can be also utilized directly in internal combustion engines, however, less efficiently in comparison to a fuel cell (Farrell et al. 2003). See also McKinsey (2010) and JEC (2014) for more details on the technical concept of BEVs and FCEVs.

is utilized.[82] However, on the one hand, the disadvantages of BEVs are the short driving-range due to battery costs, capacity constraints and the long charging times (Avci et al. 2015). On the other hand, the commercialization of FCEVs is a chicken-and-egg problem, since consumer acceptance requires satisfactory refueling station coverage, but at the same time infrastructure build-up depends on sufficient hydrogen demand (Michalski et al. 2011).[83]

From the perspective of the power markets, electric vehicles have two major effects on the energy system. First, although electric vehicles are characterized by higher energy efficiency than conventional cars, battery charging and hydrogen production through electrolysis technology[84] represent an additional load and might pose new problems for energy supply and transmission (Zerta et al. 2008 and Xi and Sioshansi 2014).[85] The costs of hydrogen production for the mobility sector will be analyzed in chapter 4 whereas the influence of the corresponding electricity demand on the energy system will be addressed in chapter 5. Second, however, as Sioshansi (2012) suggests, electric vehicles[86] can potentially provide grid services through balancing power demand and intermittent supply. Corresponding actions can be taken either directly by the system operator or by consumers based on flexible electricity price tariffs. Kempton and Tomić (2005a) argue that batteries in electric vehicles[87] are not utilized for most hours of the day and therefore, car owners could participate in the wholesale and balancing market.[88]

82 According to JEC (2014), BEVs and FCEVs do not produce any greenhouse gases from the tank-to-wheel perspective (i.e. during the actual driving activity), and the carbon footprint related to fuel supply and distribution is very low. In addition, according to Zerta et al. (2008), hydrogen production from renewable sources requires less land use, i.e. the yield per land used is substantially higher, in comparison to biofuels.

83 Comparatively high costs of the technology represent another obstacle for the introduction of electric vehicles (Struben and Sterman 2008).

84 Electrolysis technology uses electrical energy for hydrogen production. See also chapter 2.3.3 for a general description and more techno-economic details in the context of hydrogen storage.

85 Another additional electricity demand might stem from heat generation through heat pumps (Pregger et al. 2013).

86 More specifically plug-in electric vehicles, i.e. all vehicles utilizing electricity from the grid, such as BEVs or PHEVs.

87 A more detailed discussion on stationary electricity storage systems is provided in chapter 2.3.

88 Kempton and Tomić (2005a) refer to such a concept as vehicle-to-grid (V2G). In the literature, the V2G system is analyzed in various ways and from different perspectives in a number of studies. Besides the analyses mentioned above, see for example Kempton and Tomić (2005b), Denholm and Short (2006), Lemoine et al. (2008), Wang et al. (2010) or Schill (2011b).

2.3 Role of electricity storage

As discussed in the previous chapter, market liberalization and the claim for sustainable energy supply pose substantial challenges on the current and future power system in Germany. An important strategy to cope with these challenges, in particular in the light of increasing intermittent generation, is represented by the improvement of system flexibility (Loisel et al. 2010 and BMWi 2014). Therefore, this chapter first provides a brief overview of some common flexibility measures including supply side management, grid extension, feed-in curtailment of excess electricity as well as demand side management. Then, power market applications for electricity storage as another flexibility option and corresponding potential benefits are presented in more detail. This is followed by a description of different storage technologies.

2.3.1 Measures for system flexibility improvements

Supply side management represents grid stabilization through dedicated dispatchable units either based on fossil fuels such as gas turbines or on renewable sources such as biofuels or biomass[89] providing balancing power or back-up capacities for black start to the entire power system(Luickx et al. 2008 and Bünger et al. 2016 and Bünger et al. 2016). Typically, the corresponding technical requirements include frequent start-up and shutdown ability, quick response capability, higher ramp rates and efficient operation during part load (Landinger et al. 2013 and Bünger et al. 2016). In this context, inflexible base-load units such as lignite and nuclear power plants represent must-run capacities[90] rather incompatible with large amounts of intermittent electricity (Stiller et al. 2011 and Nikolakakis and Fthenakis 2011). In Germany, the balancing power is traded and acquired by TSOs through the balancing market,[91] whereas reserve capacity is based on additional power plants which can be activated to avoid regional supply shortages (BMWi 2014).

89 As noted by Schill (2008), fossil fuel power plants still produce greenhouse gases and thus might undermine the climate mitigation objective.

90 According to Denholm and Hand (2011), besides technical constraints, must-run capacities might be also due to economic considerations associated with the ramping costs.

91 See also chapter 2.1.2.

Electricity grid extension is recognized as an important measure for the integration of intermittent electricity into the energy system.[92] In the light of further increase of renewable production in Germany and Europe, several studies, such as dena (2010) and Pape et al. (2014), estimate network expansion requirements in the amount of many thousands of kilometers (Landinger et al. 2013 and Bünger et al. 2016).[93] Therefore, the German Federal Government considers the enhancement of existing and the build-up of new grid capacities as an important measure in its Energy Concept (BMWi 2010, p. 18, BMU 2012a, p. 38).[94] However, major challenges in this context are the high investment needs and a lack of public acceptance (Schill 2011a).

A simpler strategy to increase network stability is based on feed-in curtailment, i.e. supply reduction at times when local electricity production, particularly from intermittent sources, is higher than the corresponding load or grid capacity. Although in comparison to other flexibility measures this option does not require large upfront investments, curtailment is still associated with some losses as typically in this case renewable electricity with low marginal costs is wasted (Jacobsen and Schröder 2012).[95] In Germany, feed-in management under EEG is accompanied by financial compensation for renewable generators and the corresponding costs are distributed among end users (Loisel et al. 2010).[96] However, currently in Germany the overall amount of curtailed renewable electricity is still rather limited (BNetzA 2016).[97] In addition, curtailment does not solve all problems associated with variable feed-in as it does not help with energy provision when intermittent generation is lower than demand.

92 See also chapter 2.2.2.

93 For studies in the European context see for example SUSPLAN (2011) and TYNDP (2012).

94 More details on preliminary intentions on grid development in Germany are provided by the German Federal Network Agency (Bundesnetzagentur) and the four German TSOs (50Hertz Transmission, Amprion, TenneT and TransnetBW) in NEP (2014) and BNetzA (2013).

95 At this point, it is important to mention that Jacobsen and Schröder (2012) also argue that potential losses from curtailment should be carefully compared with costs of alternative network enhancements. They conclude that under some circumstances curtailment might be economically more efficient than overinvestment in grid capacities.

96 See §13 EEG.

97 According to BNetzA (2016) in 2014 the overall curtailed energy through feed-in management accounted for 555 GWh or only 0.8 % of the total renewable electricity production supported under EEG feed-in tariffs.

Alternatively, system flexibility can be increased by means of demand side management as active consumer behavior adequate to the current power supply situation in the system (Strbac 2008 and Gottwalt et al. 2011). Today, demand side management is mainly applied in industrial processes where electricity costs can be reduced accordingly. In the future, it might also occur in small commerce, services and the residential sector including electric vehicles (Bünger et al. 2016).[98] However, the possible time span for such load shifting will be still limited (Schill 2011a). According to Paulus and Borggrefe (2011), an important obstacle for the full utilization of demand side management in the industry sector stems from the comparatively high costs of production disruptions. Further challenges are the need to integrate information and communication technologies in the electricity system, the complexity of the solution, the unfavorable market structure and the missing clarity regarding the costs and benefits of the technology (Strbac 2008). In addition, demand shifting from one period to another typically occurs within a limited time span.

2.3.2 Electricity storage applications in power markets

Another important option for increasing system flexibility is energy storage. In the context of power markets, storage can be utilized for a number of different applications and thus can potentially provide a whole range of system benefits (Sioshansi et al. 2012). As summarized in Table 2.4, the respective services can be categorized along the value chain step for electricity including electricity generation, transmission and distribution as well as retail and end user applications.

Storage applications related to electricity production cover energy time-shift, substitution of peak-load capacities, load following as well as renewable capacity firming and feed-in curtailment avoidance. According to Sioshansi (2014), energy time shift refers to typical arbitrage activities, i.e. economic utilization of hourly price differences through cheap charging and expensive discharging, and is one of the most frequently analyzed applications for electricity storage.[99]

98 Klobasa (2007), Paulus and Borggrefe (2009), and Paulus and Borggrefe (2011) provide an overview over demand side management potential and expected future developments for different sectors in Germany.

99 Detailed analyses on time shifting effects can be found in many studies, for example in Graves et al. (1999), Figueiredo et al. (2006), Walawalkar et al. (2007), García–González et al. (2008), Sioshansi et al. (2009), Fertig and Apt (2011) and Sioshansi et al. (2011).

Table 2.4: Power market applications and benefits through electricity storage according to the concerned value chain step.

Category and application	Major benefits
Generation	
• Energy time-shift	Arbitrage profits for storage operator
• Peak-load capacity substitution	Payment deferral for generation capacity
• Load following	Avoiding fuel costs and emissions
• Renewable capacity firming	System integration for renewables
• Renewable curtailment avoidance	System integration for renewables
Transmission and distribution	
• Congestion reduction	Decreasing grid operation costs
• Grid extension avoidance	Payment deferral for grid capacity
• Balancing services	Increasing grid stability
Retail and end user	
• Energy cost management	Lowering end user energy costs
• Power quality improvement	Avoiding losses due to supply unreliability

In this context, storage in combination with renewable power production might also be a potential remedy to mitigate the merit order effect[100] of intermittent electricity feed-in (Eyer and Corey 2010).[101] Some authors, such as García–González et al. (2008) or Sioshansi (2011) suggest that this strategy can potentially increase the value of renewable electricity. In complete markets, however, opportunity costs related to intermittent electricity used for storage charging correspond to actual market prices and the additional arbitrage profits do not impact the value of intermittent electricity, but rather reflect the market value of the storage itself. Yet, in incomplete markets, where prices do not fully reflect the costs of intermittency, combined operation of renewable and storage units might be economically more favorable than separated operation. Such situations might occur, for example, when penalties for imbalances due to feed-in variability posed by the system operator on renewable generators are higher than the payments for balancing services

100 See chapter 2.2.2 for more details on the definition and consequences of the merit order effect.

101 The influence of the electricity storage on energy prices in markets with a large share of intermittent feed-in is analyzed in chapter 5.

provided by the storage within the balancing market.[102] Sioshansi et al. (2012) actually argue that incomplete markets and utilization of storage in different markets with varying and hardly comparable market environments (i.e. in liberalized and regulated markets) are important obstacles for a fair valuation and development of storage technologies. Notwithstanding the above, it is undoubted that electricity storage helps to integrate renewable generation into the energy system.

Moreover, substitution of peak-load capacities and corresponding load following[103] through electricity storage are closely interrelated and might help to defer payments for additional capacities to satisfy peak demand on the one hand and to avoid marginal production costs and CO_2 emissions associated with power plants based on fossil fuels on the other hand (Denholm et al. 2010).[104] In addition, another important benefit of energy storage related to the supply side is its ability to actively support the integration of renewable generation into the energy system. Besides time shifting of intermittent electricity and mitigation of the merit order effect, storage might be used to support renewable capacities, i.e. to provide power when variable feed-in is lower than the load, as well as to reduce curtailment, i.e. to avoid output regulation when intermittent generation is higher than the load or local grid capacities (Greenblatt et al. 2007 and Loisel et al. 2010). Both applications are similar to peak-load capacity substitution and grid extension avoidance, however, they apply exclusively to intermittent electricity generation. The analysis in chapter 3 focuses on the benefits from electricity storage in the context of system integration of renewable power feed-in.

Regarding transmission and distribution networks, storage applications include services intended to mitigate congestion issues and to improve system stability on different grid voltage levels. On the one hand, storage utilization might help

102 For example in Germany, as discussed in chapter 2.1.2, the system operators procure balancing services on the corresponding reserve control market in a pay-as-bid manner. However, any supply and consumption discrepancies within a balancing group are penalized based on the corresponding balancing fees.

103 Load following refers to hourly production adjustment in accordance with the actual load to ensure continuous balance between electricity demand and supply.

104 Additional costs might occur due to lower efficiencies and thus suboptimal operation of dispatchable power plants in part load (Denholm et al. 2010).

to defer payments for grid capacity extensions required to supply consumers in different areas (Vasconcelos et al. 2012). Typically, this can be achieved by avoiding upstream curtailment or by downstream load management, i.e. charging storage when the actual load is low and discharging when the load is high (Walawalkar 2008). On the other hand, if grid constraints exist, storage utilization might also decrease the overall system operation costs through reduction of congestion or utilization improvement of existing power lines (Denholm and Sioshansi 2009 and Johnson et al. 2014). In Germany, congestions costs are associated with re-dispatch activities carried out by the corresponding TSOs which are then distributed among the end users.[105] In addition, storage facilities can participate in the balancing market[106] and thus actively contribute to grid stability if the corresponding technical prequalification criteria for different services are met (Walawalkar et al. 2007).[107]

Finally, storage technology has the ability to provide some benefits directly to consumers typically through cost management and power quality improvement. In this context, consumers can utilize storage to minimize energy costs in particular if payments are based on flexible retail tariffs (Ahlert and Block 2010). In this way, storing electricity might increase price responsiveness of demand and thus help to avoid potential market power exertion. For some end users power quality may play an important role and any unpredicted power supply distortions might incur additional costs. This is typically true for large individual industrial and commercial consumers potentially suffering from production disruptions or downtimes (Eyer and Corey 2010).

At this point, it is important to mention that some storage technologies are capable of coupling different energy markets beyond the power sector

105 According to BNetzA (2016), in 2014 these costs in Germany amounted to approx. 190 M€ and affected approx. 1 % of the total electricity production (not under the EEG feed-in tariff regime) distributed over almost 8,000 hours.

106 These services include primary, secondary and minute control reserve as well as provision of interruptible loads. See chapter 2.1.2 for a detailed description of the balancing market in Germany.

107 In Germany, TSOs specify and test a number of technical requirements such as minimal ramping rates as well as frequency and voltage control prior to admission to the balancing market in order to ensure that the concerned unit will be able to provide corresponding grid services. The interested reader is referred to Rebours and Kirschen (2005) for the technical specification of the prequalification requirements in Germany in comparison to other market places.

representing an additional benefit of such devices. In particular, heat storage might help to satisfy fluctuating heat demand, for example in district heating networks, whereas hydrogen technology provides a universal energy carrier which can be used for heating and as fuel for hydrogen cars (Connolly 2010). The aforementioned benefits resulting from electricity storage utilization are interrelated to each other and might provide additional synergies when provided by the same facility (Eyer and Corey 2010). Such benefits of the hydrogen technology and potential synergies between the electricity and mobility sectors are evaluated in more detail in chapter 4. Moreover, He et al. (2011) argue that a comprehensive cost-benefit analysis should take different storage applications into account in order to determine the true value of electricity storage. This is rather difficult to accomplish, however, due to inefficient and in some cases nontransparent price signals as well as the complexity of storage operations and the corresponding modeling limitations (Sioshansi et al. 2012).

2.3.3 Energy storage technologies

Storage technologies can be classified according to the underlying form of energy including mechanical, chemical, direct electrical and thermal energy (Chen et al. 2009). Applications utilizing mechanical energy can be subdivided into devices that take advantage of potential energy such as pumped-hydro storage (PHS) and compressed air energy storage (CAES) on the one hand and units based on kinetic energy such as flywheels on the other hand. Moreover, electricity can be converted into chemical energy and stored either in batteries or as hydrogen in adequate facilities. As shown in Figure 2.9, the most important types of batteries[108] differ in materials used, and technical concepts include flow batteries, lead-acid (Pb-acid), lithium-ion (Li-ion), sodium sulfur (NaS) and flow batteries. Furthermore, there are only few applications capable of direct electricity storage like superconducting magnetic energy storage (SMES) and supercapacitors. Finally, energy can also be stored in thermal devices consisting of high or low-temperature units. All storage types have different characteristics regarding energy rating, efficiency, self-discharge,

108 In general, according to Vieira Da Rosa (2013, p. 821), batteries can be subdivided into primary batteries for one-way use and rechargeable secondary batteries. For energy storage in the context of power markets only secondary batteries are of major interest.

lifetime and the corresponding specific investment outlays influencing typical plant sizing and market application. Table 2.5 summarizes major techno-economic parameters for selected storage technologies.

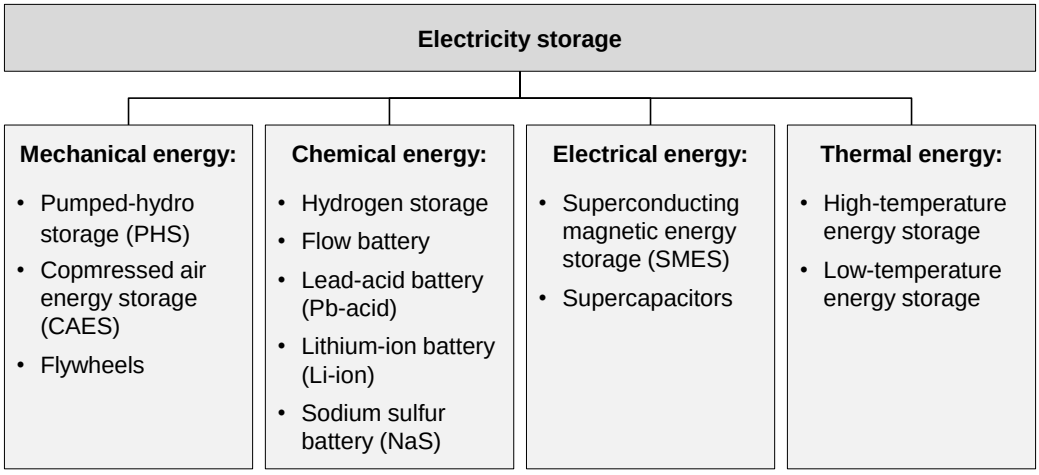


Figure 2.9: Electricity storage classification according to underlying energy form.

Pumped-hydro storage is a well-established technology, as the first facilities were constructed in the Alps more than one hundred years ago (Rehman et al. 2015). In principle, this storage type utilizes the potential energy of water between reservoirs at two different elevations. Electricity is stored by pumping water from the lower to the upper reservoir and released in the opposite way by passing it through a dedicated water turbine and generator. In this context, it is important to distinguish between pure pumped-hydro facilities and other hydro power plants which typically can produce but are not able to consume and store electricity (e.g. run-of-river units) or are connected to a water reservoir with a natural inflow (Deane et al. 2010).

Pumped-hydro storage is a long-living technology with more than fifty years of expected lifetime characterized by high round-trip efficiencies between 70 % – 85 % without self-discharge.[109] Typical facility size is strongly dependent on the topographical conditions in the selected region[110] and ranges between 10 MW

109 Self-discharge of a pumped-hydro storage might occur for example through water evaporation from one of the two reservoirs. However, this might be compensated through natural water inflow due to precipitation.

110 In particular in regard to the size of the two reservoirs.

Table 2.5: Techno-economic data for selected storage technologies.

Technology	Power rating[a] MW	Energy rating[a]	Suitable storage duration[b]	Round-trip efficiency[a] %	Self-discharge[a] %/day	Life-time[a] a	Investment power capacity[a),c)] €/kW	Investment energy capacity[a),c)] €/kWh
Pumped-hydro unit	10 – 5,000	1 – 24 h +	Hours – months	70 – 85	0	> 50	500 – 3,600	60 – 150
CAES	100 – 300	1 – 24 h	Hours – months	40 – 70	0	25 – 40	400 – 1,155	10 – 120
Hydrogen technology	< 1	s – days	Hours – months	20 – 40	0	5 – 20	550 – 1,600	1 – 15
Flow battery	< 10	s – 10 h	Hours – months	70 – 80	0 – 10	5 – 20	900 – 1,500	150 – 850
Lead acid (Pb-acid)	< 50	s – h	Minutes – days	60 – 95	< 1	3 – 15	200 – 650	50 – 300
Lithium ion (Li-ion)	< 50	s – h	Minutes – days	85 – 100	< 1	5 – 20	700 – 3,000	200 – 1,800
Sodium sulfur (NaS)	< 50	s – 6 h	Seconds – hours	75 – 90	< 20	10 – 15	700 – 2,000	200 – 900
Flywheels	< 20	15s – 15 min.	Seconds – minutes	85 – 95	20 – 100	> 20	100 – 300	1,000 – 3,500
SMES	< 10	ms – 5 min.	Minutes – hours	> 95	10 – 15	∼ 20	100 – 400	700 – 7,000
Super-capacitors	< 1	ms – 1 h	Seconds – hours	85 – 98	2 – 40	> 20	100 – 400	300 – 4,000
High-temperature unit[b]	< 60	1 – 24 h +	Minutes – months	30 – 60	< 1	5 – 15	200 – 300[d]	30 – 60
Low-temperature unit[b]	< 300	1 – 8 h	Minutes – days	30 – 60	< 1	10 – 40	200 – 300	3 – 50

a) Derived from JRC (2011) and Landinger et al. (2013) except for high- and low-temperature units.
b) Derived from Chen et al. (2009).
c) Specific power- and energy-related investment outlays represent specific costs of the whole storage system and are therefore not additive.
d) Same specific power-related investment outlays as for low-temperature unit.

and 5 GW, allowing for a full discharge between one and more than 24 hours.[111] Specific investment outlays vary within a comparatively wide range between 60 €/kWh and 150 €/kWh (or 500 €/kW and 3,600 €/kW) as the actual construction costs are determined by the local topology (Genoese 2013). In Europe, pumped-hydro power stations exist predominantly in mountainous regions (e.g. in the Alps or Pyrenees) with a total installed capacity of more than 50 GW[112] and new projects accounting for additional 6 GW[113] (EC 2013 and Landinger et al. 2013). In Germany, currently the total capacity amounts to approx. 8 GW or 50 GWh, and further potential is rather limited due to topological constraints and public acceptance issues (VDE 2008) and (VDE 2010).[114]

Another technology based on potential energy is compressed air energy storage.[115] In case of diabatic CAES, the storage is charged by compressing air into underground formations such as caverns or aquifers and discharged by expanding the air and co-firing with natural gas in adequate turbines (Mauch et al. 2012).[116] The round-trip efficiency of such a system is 40 % – 55 %, but it can be improved up to 70 % in so-called adiabatic CAES, where natural gas combustion is replaced by stored thermal energy originating from the compression process (Bullough et al. 2004 and JRC 2011, p. 136). So far, only two diabatic CAES facilities with installed capacity between 100 MW and 300 MW are in service,[117] whereas adiabatic CAES technology is still under

111 This value is referred to as energy rating indicating the time required for a full release of the energy at rated power. It can be considered as the ratio between actual energy-related storage capacity on per MWh-basis and installed power-related output capacity on per MW-basis.

112 This accounts for approx. 40 % of worldwide pumped-hydro capacities (Landinger et al. 2013 and Rehman et al. 2015).

113 Most projects are located in Switzerland, Austria, Portugal, Germany and Spain. Further potential of approx. 10 – 25 GW is estimated for Norway (JRC 2011).

114 However, Germany could potentially use jointly storage facilities in neighbouring countries, in particular in Austria with capacities of approx. 4 GW and 92 GWh and in Switzerland with approx. 4 GW and 91 GWh (Prognos 2012, BfE 2014).

115 According to Hadjipaschalis et al. (2009), CAES can also be classified as pneumatic storage technology. Another application belonging to this group is represented by liquid-piston storage based on compression of other gases such as nitrogen into vessels filled with adequate fluids.

116 According to Crotogino (2010), the compressed air must be cooled prior to injection into the cavern as otherwise the temperature would be too high for the subsequent equipment. However, when discharging the storage, the air must be heated again prior to processing by the gas turbine as otherwise the turbine would freeze over.

117 One facility is located in Huntorf in Germany with an installed capacity of 320 MW and another one in McIntosh in Alabama, USA, with a capacity of 110 MW (JRC 2011, p. 136).

development (Crotogino 2010, p.282). Major advantages of CAES are comparatively high storage capacities with energy rating of up to 24 hours, long lifetime between 25 and 40 years and no self-discharge (JRC 2011, p. 136). However, in case of diabatic CAES, additional energy from natural gas is needed which causes corresponding CO_2 emissions. The specific investment outlays range between 10 €/kWh and 120 €/kWh (or 400 €/kW and 1,150 €/kW) and are comparatively moderate.

Generally, hydrogen can be considered as a universal energy carrier. In the context of the power markets, it can be produced by electrolysis utilizing electricity to split water into its elements oxygen and hydrogen. Technically, this can be achieved by a positive and negative electrode separated either by an aqueous alkaline electrolyte in an alkaline electrolysis or by a polymer electrolyte membrane in a PEM electrolysis or by ceramics in a high-temperature electrolysis (Ball et al. 2009a).[118] Whereas oxygen is typically a by-product,[119] hydrogen can be stored for later use in different facilities including aboveground compressed tanks, buried storage tubes and underground salt caverns (Barbier 2010, pp. 125–134). For re-electrification, hydrogen can be converted back to water either in fuel cells or bruned in gas turbines analogously to natural gas combustion (Wietschel et al. 2009).

The round-trip efficiency of the hydrogen system is between 20 % and 40 % and in comparison to other storage technologies rather low.[120] However, since hydrogen is a chemical energy carrier, the storage has no self-discharge and can be easily scaled such that the energy rating can in principle range between seconds (for small applications) and up to several days (for large applications, theoretically up to several hundred MW). The overall lifetime ranges between

118 Note that there are also other technologies for hydrogen production such as steam methane reforming or biomass or coal gasification. However, from the perspective of the electricity market, only electrolysis allows for conversion of electricity into chemical energy. For more details see for example Ball et al. (2009a) or Sørensen (2012).

119 Nevertheless, oxygen might have an economic value as it could be used for a number of other applications (e.g. in sewage plants).

120 Since single facility components can be easily separated from each other, the overall efficiency of the hydrogen technology strongly depends on the corresponding values for each system element: electrolysis 40 % – 70 %, stationary fuel cells 40 % – 50 % and gas turbines 40 % – 60 % (Bertuccioli et al. 2014 , Marscheider-Weidemann et al. 2009, p. 359 and Nitsch et al. 2010b).

5 and 20 years[121] and specific investment outlays between 1 €/kWh and 15 €/kWh (or 550 €/kW and 1,600 €/kW). Although currently hydrogen storage is an expensive technology, some cost reductions are expected in the future as the electrolysis and fuel cell as major system components are still under research and development. Currently, there are no large-scale hydrogen facilities in the context of electricity storage as this technology is utilized only in demonstration projects (Landinger et al. 2013).

Besides hydrogen technology, electricity can be stored as chemical energy also in batteries. In fact, their functional principle is similar to hydrogen storage as this technology is also based on two separate electrodes and an electrolyte allowing for an electrochemical reaction (Hadjipaschalis et al. 2009). There are several technical concepts which mainly differ in the engaged material and the corresponding chemical characteristics. In addition, one major distinction can be made on the one hand for conventional batteries where electrodes and electrolyte are within the same structure and on the other hand for flow batteries consisting of a separate power cell and electrolyte containers (JRC 2011). Therefore, for conventional batteries the ratio between power and energy capacity is typically in a limited range, whereas for flow batteries this figure may vary according to the selected system design (Baker 2008 and Chen et al. 2009).[122] Among conventional batteries the best established ones are the lead-acid battery, which is considered as a mature technology, whereas the sodium sulfur and lithium-ion batteries are rather advanced technologies with further development and cost reduction potential (Hadjipaschalis et al. 2009).[123] Flow batteries are mainly based on vanadium-, zinc-bromine and polysulphide bromide (Hall and Bain 2008).

121 Note that also the lifetime can vary substantially for different system elements.

122 In principle, also conventional batteries can be scaled differently in regard to the power and energy capacity (e.g. in a parallel circuit). However, as Genoese (2013) argues, battery design is rather triggered by energy capacity with a predetermined ratio between power and energy, since the corresponding specific energy-related investment outlays are comparatively high.

123 These battery types can be considered as major electrochemical technologies. Other battery types include, for example, different nickel combinations (e.g. with iron, cadmium or metal hydride), lithium-air and other lithium combinations (e.g. with titanate or sulfur) as well as other combinations such as sodium nickel chloride, metal-air, zinc-bromine, polysulphide bromide and sodium metal chloride (also referred to as ZEBRA). See for example Dell and Rand (2001) for a comprehensive overview of other battery technologies.

All batteries are characterized by high round-trip efficiency between 60 % and 100 %, but a limited lifetime between 3 and 20 years depending on the number of charge cycles. In addition, some devices such as NaS batteries are prone to self-discharge of up to 20 % per day.[124] Due to comparatively high specific investment outlays on per kWh-basis of 50 €/kWh – 1,800 €/kWh (or 200 €/kW – 3,000 €/kW), stationary batteries with up to 50 MW installed capacity are used for relatively short storage periods between a few seconds up to a few hours. According to Landinger et al. (2013), overall installed capacity for stationary batteries in Europe accounts to approx. 50 MW, out of which only 1 MW can be attributed to flow batteries.

Similarly to batteries, energy rating is comparatively low also for another group of storage devices including flywheels (few seconds up to few minutes), SMES (milliseconds up to minutes) and supercapacitors (milliseconds up to an hour). Whereas flywheels transform electricity into kinetic energy through mass rotation, SMES and supercapacitors are capable of direct electricity storage through electrostatic or magnetic field (Hall and Bain 2008 and Ibrahim et al. 2008). All three technologies have in common high round-trip efficiencies above 85 % and a long lifetime of more than 20 years but also comparatively high self-discharge rates (e.g. up to 100 % per day for flywheels). Specific investment outlays on per kW-basis between 100 €/kW and 400 €/kW are rather moderate, however, the figures on per kWh-basis are comparatively high 300 €/kWh – 7,000 €/kWh. Worldwide SMES capacities are estimated at more than 100 MW[125] while for flywheels and supercapacitors first commercial applications are already available (JRC 2011).

According to Chen et al. (2009), thermal devices can be subdivided into high-temperature technologies such as steam or hot water accumulators and low-temperature units such as cryogenic energy storage[126] depending on the

124 The NaS battery is a high temperature technology such that self-discharging usually stems from heat losses and is strongly dependent on the actual battery isolation and potential use of heat for further purposes.

125 According to EERA (2012), in Germany the installed capacity amounts to approx. 25 MW. Other countries with some SMES devices are Italy, France, USA, Japan, Korea and China.

126 According to Morganand et al. (2015), this technology based on liquid air can be referred to as liquid air energy storage.

relationship between operating and room temperature.[127] Both storage types are based on insulated substances which are capable of keeping the heat or cold for comparatively long times. In principle, thermal storage can potentially provide both electrical energy for the power system and heat or cold which can be directly used for corresponding purposes, i.e. for heating or cooling in households or industrial processes (Baker 2008 and Ibrahim et al. 2008).

The round-trip efficiency between 30 % and 60 % is comparatively low, but at the same time the small daily self-discharge rate of less than 1 % allows for storage periods of several hours. High-temperature units are characterized by a short lifetime of up to 15 years, whereas low-temperature units have a long lifetime of up to 40 years. Specific investment outlays are between 3 €/kWh and 60 €/kWh (or 200 €/kW and 300 €/kW).

As illustrated in Figure 2.10, various technical characteristics and the corresponding costs determine the typical storage design and thus adequate field of application for different technologies (Hall and Bain 2008).[128] Schoenung and Hassenzahl (2003), Ibrahim et al. (2008) and EFZN (2013) provide a comprehensive comparison of the availability of different storage technologies for various applications from a technical perspective.

For example, pumped-hydro storage is usually a large utility-scale device which can store large amounts of electricity. Although in theory this technology is able to store energy even for months, in practice existing implementations are operated on a shorter time basis between a few hours and a few days (Landinger et al. 2013).[129] In combination with a low self-discharge rate and high number of cycles, pumped-hydro storage can provide a number of generation- and transmission-related services ranging from energy time-shift to balancing services (Chen et al. 2009 and JRC 2011). Likewise, CAES can be considered as a large-scale technology with an energy capacity in a multi-MWh category and similar benefits. Thanks to fast response and short ramping time,

127 Typically, low-temperature units operate at temperatures between −18 °C and 12 °C whereas high-temperature devices between 25 °C and 50 °C and above 175 °C (Chen et al. 2009).

128 Note that the ranges presented in Figure 2.10 refer to typical applications and have an indicative character.

129 For example, in Germany the energy rating of pumped-hydro facilities is approx. 6 hours.

CAES is not only capable of load following and grid congestion reduction but also of balancing intermittent power generation (Crotogino 2010, p. 283).

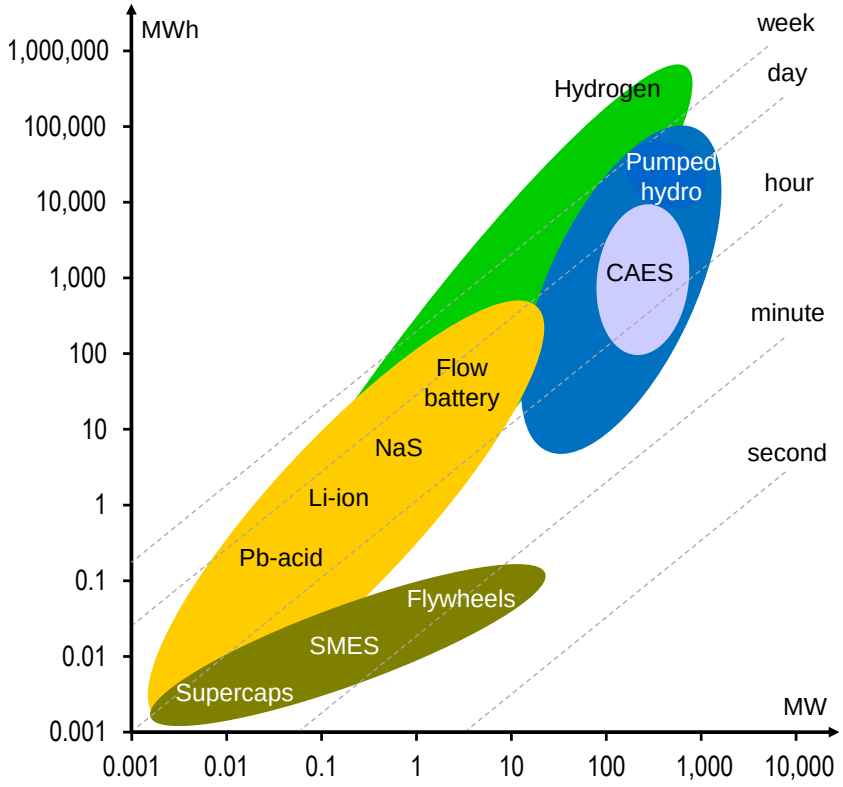


Figure 2.10: Relation between power and energy capacity and energy rating (dashed lines) for different technologies in typical applications.[130]

Hydrogen has a comparatively high energy density and is practically the only technology allowing for storage of large quantities of electricity for a very long time (i.e. for several weeks or months). Moreover, the corresponding storage facility is easily scalable and therefore can be used both in large utility and small end user applications (Chen et al. 2009). In fact, electrolysis, fuel cells or turbines can be located at sites next to generation units, grid bottlenecks and consumption sites (Ibrahim et al. 2008). When combined with underground salt caverns, hydrogen technology can be utilized as a multi-MW seasonal storage mainly due to very low energy capacity costs on per MWh-basis (Crotogino 2010, p. 282). Needless to say, hydrogen as a chemical energy carrier can be easily transported over long distances avoiding grid extension on the one hand and enabling cross-sectoral

130 Own illustration based on Ibrahim et al. (2008) and Landinger et al. (2013).

coupling with mobility and other markets[131] with corresponding synergies and additional stream of revenues on the other hand (Ball et al. 2009b and Stiller et al. 2011). Therefore, hydrogen technology is often referred to as power-to-gas (PtG) technology indicating the capability of converting electricity into a gaseous energy carrier regardless of its actual application.

Due to comparatively high energy-related investment outlays and low energy density, batteries are suitable rather for storing electricity at a shorter, i.e. hourly or daily time scale. In addition, with a typical power capacity of up to 50 MW, batteries are used in small to medium scale applications including local grid stabilization and end user applications. Yet, flow batteries with independent power and energy capacity can be easily scaled for a longer energy rating up to several days (JRC 2011). Flywheels, SMES and supercapacitors are characterized by fast discharge cycles, but high energy-related investment outlays being less suitable for long-term electricity storage. Consequently, these solutions can be typically used to provide large power capacity in a very short time between seconds and a few hours in particular for grid services and short-term balancing of intermittent electricity supply (Schainker 2004 and Hadjipaschalis et al. 2009).

Due to the expected increase of intermittent electricity generation and corresponding technical and economic challenges, the analyses in chapters 3 to 5 are mainly conducted for large-scale technologies such as pumped-hydro storage, CAES and hydrogen technology which are capable of storing a large amount of energy over a considerable time scale.

2.4 Modeling electricity storage

In general, energy storage utilization in a power system can be modeled in various ways. The adequate approach depends on the actual objective and focus of the underlying analysis characterized by a number of specific features. As summarized in Table 2.6, electricity storage models can be categorized according to modeling scope, mathematical structure, degree of competition,

131 For example, for direct use as feed stock in the chemical and process industries (Stiller et al. 2011).

uncertainty of input parameters, electricity price representation, and grid constraint considerations (Ventosa et al. 2005 and Grünewald et al. 2012).

Regarding the modeling scope, Grünewald et al. (2012) distinguish between engineering and system models. On the one hand, engineering models are used to conduct detailed techno-economic analyses of selected storage technologies under given boundary conditions. On the other hand, system models focus on the behavior and relationship between different players and technologies in power markets subject to system-specific constraints (Zucker et al. 2013).

Table 2.6: Categorization of electricity storage models.

Category	Characteristics
Modeling scope	• Engineering models • System models
Mathematical structure	• Single-firm optimization • Equilibrium models • Simulation models
Degree of competition	• Perfect competition • Monopoly • Oligopoly
Input parameters	• Deterministic • Stochastic
Electricity price representation	• Exogenous input parameter • Endogenous variable
Electricity grid	• Single-node representation • Explicit network modeling

According to Ventosa et al. (2005), energy models can be further subdivided based on their mathematical structure into single-firm optimization, equilibrium models and simulation models.[132] Single-firm optimization includes only one objective function of a single player under selected technical constraints. Although this approach can be used to focus on technical details of the energy

132 This categorization also corresponds to the classification of different computational tools for energy system analyses provided by Connolly (2010), including among others simulation, equilibrium, top-down, and bottom-up tools. Note that bottom-up tools typically correspond to engineering or single-firm models whereas top-down tools correspond to system models.

system controlled by the concerned firm the major drawback of this approach is represented by the lack of interactions between different market participants (Schill 2011a).

In contrast, in equilibrium models objective functions of multiple players are linked together by specific market clearing conditions. With regard to the strategic behavior of market participants, Day et al. (2002) differentiate between Bertrand models with decision variables represented by price offers, Cournot models where players decide on bidding quantities, as well as supply function equilibrium (SFE) models where decision making is based on bid functions.[133] Although SFE models allow for a more realistic representation of market behavior, they are typically difficult to solve in comparison to other equilibrium models (Ventosa et al. 2005). In addition, applying the SFE approach to analyze storage utilization requires additional assumptions on the intertemporal relationship between generation decisions of various players (Sioshansi 2011). From the empirical perspective, Cournot modeling tends to be well suitable to represent strategic market behavior, in particular for long-term capacity decisions (Day et al. 2002 and Puller 2007). Moreover, as argued by Day et al. (2002), Cournot competition became a popular modeling approach for strategic decision making due to its good solvability and numerical tractability.

All equilibrium approaches can be further extended by Stackelberg-type competition with interrelated behavior of a leader and followers as well as conjectural variations representing different assumptions on the strategic reaction of various market participants. In this context, an issue related to the choice of mathematical structure is represented by the degree of competition. Energy markets can be modeled either in a perfectly competitive framework where single participants have no market power, as an oligopoly with a small number of large generators, or as a monopoly with only one energy provider typically operating under different regulatory rules. Equilibrium models are typically used to analyze markets with a limited degree of competition either within an oligopolistic or a monopolistic framework.

133 In detail, in SFE models decision making of strategic firms is represented by the functional relationship between bid prices and quantities offered to the market. This approach was developed by Klemperer and Meyer (1989).

Similarly, simulation models also intend to analyze strategic behavior of different market participants. However, the optimization problem is not expressed within a set of formal equations, but is rather solved heuristically based on a predefined sequence of iterative rules. Therefore, this approach is very flexible and can be applied to problems which otherwise would be too difficult to be addressed within a formal framework (Ventosa et al. 2005 and Schill 2011a). Simulation models can either be based on formal equilibrium problems and be used to search for optimal solutions, or they explicitly account for adaptive behavior of single market agents within the so-called agent-based simulation framework (Ventosa et al. 2005). As argued by LeBaron and Tesfatsion (2008), a major advantage of agent-based simulation over equilibrium models is represented by the fact that the agent-based approach allows to find market results through dynamic interaction of different agents according to predefined real-world rules without the need for simplifying assumptions on equilibrium conditions.[134]

Besides the scope, mathematical structure and degree of competition uncertainty also play an important role in energy modeling as typically a number of input parameters such as prices, demand, intermittent feed-in, or capacity outages are unpredictable (Zucker et al. 2013). Therefore, probabilistic models explicitly take into account the stochastic nature of such input parameters, whereas deterministic models neglect parameter randomness and use expected values instead (Wallace and Fleten 2003 and Ventosa et al. 2005). According to Möst and Keles (2010), energy models can be subdivided into four major categories based on the approach for energy price prediction including fundamental models which take into account a full range of technical system characteristics, financial mathematical models such as real option models,[135] econometric time-series models applying statistical methods[136] as well as game-theoretic models as described above. Foley et al. (2010) distinguish

134 A more detailed description and survey on agent-based models and tools is provided by Zhou et al. (2007), Weidlich and Veit (2008) and Weidlich (2008). Corresponding literature reviews can be found in Sensfuß et al. (2007) and Sensfuß et al. (2008).

135 See for example Bøckman et al. (2008), Siddiqui and Fleten (2010), Fuss and Szolgayovà (2010), or Gaudard (2015).

136 According to Aggarwal et al. (2009), time-series models can be further subdivided into parsimonious stochastic models, regression models and artificial intelligence models such as neuronal network or data-mining models.

between two major methods for solving stochastic problems consisting of dynamic programming through decomposition of the underlying problem into several sub-problems and stochastic optimization by applying adequate algorithms.

Furthermore, the electricity price can be viewed either as an exogenous input parameter or as an endogenous variable. In the former case, a profit maximizing firm is a price taker assuming the market price as given, when solving the corresponding optimization problem, whereas in the latter case, the player takes the impact of his own decisions on the market price into account. Finally, another important modeling feature is represented by electricity grid considerations. On the one hand, energy models can either include an explicit representation of the transmission and distribution network by taking into account corresponding technical constraints on energy flows within the grid.[137] On the other hand, for the sake of simplicity, many system models neglect grid constraints assuming the power system as a single node where electricity can be transported between different market participants without any restrictions. Note that in some cases in engineering models grid constrains can be still included without the need of explicit network modeling by applying an additional upper bound on energy output of the selected unit.

Table 2.7: Model categorization in subsequent chapters.

Category	**Chapter 3 and 4**	**Chapter 5**
Modeling scope	Engineering	System
Mathematical structure	Single-firm	Equilibrium
Input parameters	Deterministic	Deterministic
Electricity price representation	Exogenous	Endogenous
Degree of competition	Perfect competition	Oligopoly
Electricity grid	Single-node	Single-node

Table 2.7 provides an overview of the main characteristics of the models proposed in the subsequent chapters. The models in chapters 3 and 4 are based

137 See for example Joskow and Tirole (2000), Hobbs (2001), Day et al. (2002), Neuhoff et al. (2005), Wilson (2008), or Downward et al. (2010).

on the same methodology focusing on engineering aspects of single technologies. Therefore, both analyses are conducted from the perspective of a single firm as a price taker (exogenous market price representation) under perfect competition. In contrast, the system model in chapter 5 is developed in order to analyze market equilibrium under oligopolistic competition. Consequently, the market price is considered as an endogenous variable. All models have in common the deterministic nature of all input parameters as well as the single-node representation of the electricity grid.

3. Economics of electricity storage for intermittent power generation

3.1 Introduction

The structural changes in the German power sector due to market liberalization and increasing intermittent generation create new challenges for profit maximizing firms in comparison to regulated natural monopolies. Uncertainty of electricity prices and increasing system complexity through variable generation carry new risks for market participants when making investment and production decisions. Therefore, investors who are interested in provision and operation of new generation capacities, in particular in combination with intermittent technologies, need a good understanding of system economics and adequate support tools for careful decision making (Castronuovo and Lopes 2004 and Vespucci et al. 2012). The attractiveness of renewable generation and electricity storage should be evaluated not only in terms of system cost minimization or social welfare maximization but also through an economic comparison of different investment opportunities from the point of view of a single profit maximizing player. Typically, the analyses from the single-firm perspective allow for a better representation of the selected technology and its boundary conditions and thus provide more detailed results on the economic value of the underlying investment project. Moreover, as argued by Ventosa et al. (2005) such models are characterized by a better computational tractability and might be used to solve difficult mathematical problems related to complex operational strategies of individual market players. According to Brunetto and Tina (2007), the comprehensive valuation of different investment opportunities should be based on a well-founded techno-economic analysis of corresponding storage costs and benefits.

The major objective of this chapter is therefore to evaluate the economics of different electricity storage technologies connected to variable renewable generation in the context of a single investor in a given grid node. In our analysis, we are interested in the role of the storage to support operators

of intermittent power plants to meet a specified minimal demand or to use excess electricity due to limited grid capacities. We calculate the NPV associated with different wind, PV and storage combinations and benchmark the results with two simple conventional alternatives: on the one hand electricity supply by a dispatchable thermal peak-load power plant when intermittent generation is not sufficient to balance the load, and on the other hand curtailing excess renewable electricity in a selected grid node. In this context we focus on the value of storage for integration of intermittent generation through renewable capacity firming and curtailment avoidance.[138] In order to allow for a fair comparison of storage technologies with conventional alternatives, we develop two models for optimal sizing and hourly operation of a corresponding facility under minimal load and maximal grid constraints.

This chapter is organized as follows. Chapter 3.2 includes a literature review on storage value in the context of intermittent electricity generation. In chapter 3.3, detailed information is provided on two models which are used to analyze the value of storing renewable electricity in comparison to corresponding conventional alternatives. First, an overview of major assumptions and the general model structure is given. This is followed by the mathematical formulation of both models for the reference and storage case. Chapter 3.4 presents numerical results of a case study for different wind, PV and storage technology combinations in the context of the German electricity market. For the sake of transparency, we subdivide our assessment into a case with minimal demand requirement and maximal grid capacity. In addition, we test the robustness of the results from both cases in respect to main input parameters. Finally, chapter 3.5 summarizes our findings and draws a comprehensive conclusion.

3.2 Literature on storage value for intermittent electricity

The existing literature on the value of energy storage includes a large number of studies assessing the potential benefits and corresponding costs of storage

138 Note that in the context of this study renewable capacity firming can also be viewed as peak-load capacity substitution and load following on the one hand and curtailment avoidance as congestion reduction on the other hand. See chapter 2.3.2 for a comprehensive discussion on different storage applications in the power markets.

for intermittent electricity. Following the categorization proposed by Grünewald et al. (2012),[139] the engineering studies are more detailed but calculate the value of storage usually only for a single technology and market participant, whereas the system studies provide a more comprehensive analysis of storage sizing and utilization[140] but often under simplifying assumptions on the technical representation of the storage unit.In this context, most engineering studies conclude that storage costs are high in comparison to potential revenues based on the wholesale electricity prices, and receiving benefits from multiple storage applications is rather difficult (Loisel et al. 2010). However, the analysis results vary within a broad range and strongly depend on the underlying market and techno-economic assumptions.

Pumped-hydro storage can be considered as a well-established technology, and its utilization in combination with intermittent wind feed-in has been analyzed in a number of studies, for example in Castronuovo and Lopes (2004), Brown et al. (2008), García–González et al. (2008), Angarita et al. (2009) or Vespucci et al. (2012). Other authors, such as Denholm and Sioshansi (2009), Mauch et al. (2012) or Lamy et al. (2014), focus on the value of compressed air energy storage often in comparison to pumped-hydro technology (e.g. Loisel et al. 2010, Hessami and Bowly 2011, Sioshansi et al. 2011). Some of these authors find positive business cases for CAES under specific boundary conditions, however, the storage value varies again within a wide range, typically being lower than for the pumped-hydro technology.

Studies providing a valuation of battery storage can be found for example in Walawalkar et al. (2007), Dufo–López et al. (2009) or Johnson et al. (2014), whereas for hydrogen corresponding analyses were conducted for example by Korpås and Holen (2006), Brunetto and Tina (2007) or Loisel et al. (2015). More comprehensive studies which value several storage technologies in different application areas were provided by Sullivan et al. (2008), Kaldellis et al. (2009) or Eyer and Corey (2010). In addition to technology-specific studies, some authors such as Löhndorf and Minner (2010) or Kim and Powell (2011) develop generic storage models, typically in order to find optimal

139 See chapter 2.4 for more details on possibilities for energy storage modeling.

140 The objective of the system analysis is typically defined as minimization of total system costs or maximization of the social welfare.

trading strategies for storage in combination with intermittent generation, explicitly taking uncertainty into account.

The contribution of this chapter to the existing literature is three-fold. First, our study provides a detailed and comprehensive analysis of sizing and operations of a number of possible storage technologies in combination with different patterns of intermittent generation. In this way, the suitability of different technologies for the given boundary conditions of an energy system can be compared. Second, our analysis is conducted for the entire year on an hourly basis providing insights into the role of seasonal effects on the value of electricity storage. Many studies on detailed storage operations from an investor's perspective are carried out for a limited number of hours in a year, such as typical day, week or month, and do not take into account the seasonality of the intermittent electricity generation. Third, we model the sizing and operation of storage as simultaneous decision-making. Therefore, the outcomes of our analysis represent the optimal setting of the facility and do not depend on any exogenous assumption on storage dimensioning. Many studies on the value of electricity storage consider energy capacity as an input parameter when calculating the detailed operation of the facility. In this way, our analysis provides more adequate results as the actual storage size is co-optimized for different technologies and renewable profiles.

3.3 Modeling storage sizing and operation

3.3.1 Major assumptions and general model structure

The analysis in this paper is carried out from the perspective of a single firm making a decision on optimal sizing and operation of storage for intermittent electricity generation. It is sufficiently small and its behavior does not impact the market prices represented by an exogenous input parameter. This simplification is in line with the approach adopted by many other studies on energy storage in combination with intermittent electricity supply, (e.g. Löhndorf and Minner 2010, Mauch et al. 2012 or Vespucci et al. 2012). In practice, this assumption might be true for isolated analysis of small generation units without the ability to observe any substantial impact of the corresponding

bidding behavior on the market price. For large capacities, however, energy arbitrage has an adverse impact on the value of storage as charging in off-peak periods increases the low electricity prices, and releasing electricity decreases the peak prices until the profitable price spread diminishes (Sioshansi 2010). This price-smoothing effect of storage on electricity prices is reported by some studies such as Sioshansi et al. (2009), Schill and Kemfert (2011) or Schill (2011a, p. 66). In our study, however, we refrain from this model complication.

The firm is located in a specific grid node with a minimal load requirement and a maximal transmission capacity. The minimal load requirement corresponds to a given electricity demand which must be met by the firm at each point in time. The maximal transmission capacity is a physical upper bound for electricity injection into the electricity network. In this way, we take into account the dynamics of electricity demand and actual grid constraints and are interested in economics of the system to cope with electricity deficit and surplus.[141] It is worth to mention that the selected firm is the only electricity provider and there are no other means for load regulation in the given node. Thus load and grid constraint directly apply to the selected firm. The characteristics of both constraints within an exemplary month are illustrated in Figure 3.1.

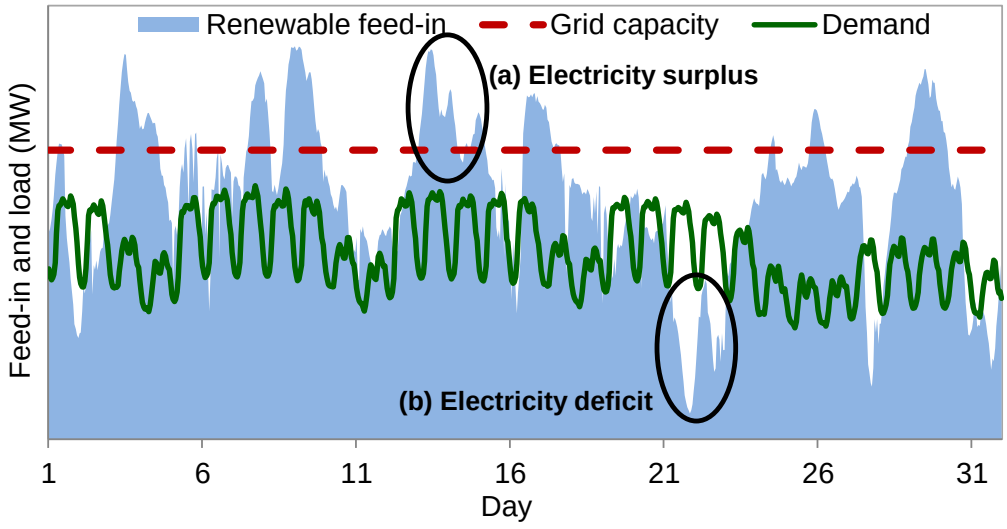


Figure 3.1: Demand and grid constraints: electricity surplus when renewable generation exceeds grid capacity (a) and electricity deficit when minimal demand has to be met by the facility operator (b).

141 A similar approach is also taken by Castronuovo and Lopes (2004).

Further, the only source of revenues is represented by electricity sales on the day-ahead spot market for electricity. Following Bathurst and Strbac (2003) and Kim and Powell (2011), we assume that the spot market is sufficiently deep and there are no trading costs and limitations except for the physical transmission capacity in the selected grid node. No other markets are taken into account in our analysis. In reality, electricity storage can be utilized for different applications, and operators may bid on multiple markets in order to increase the revenues. In particular, flexible units can provide balancing services for electricity grid stabilization and benefit from the additional stream of revenues when remuneration for such services is higher than the spot market price (Graves et al. 1999, Schill 2013).[142] Consequently, as pointed out by some authors such as He et al. (2011), Sioshansi (2011) and Strbac et al. (2012), considering revenues only from one market understates the overall value of electricity storage.

However, Sioshansi et al. (2012) argue that the ability to quantify the exact benefits and thus revenues from some storage applications and in particular their combinations is rather limited, since many co-optimization problems are potentially hard to solve and the quality of some input data is not satisfactory for a comprehensive and unambiguous analysis. Moreover, for many market applications all selected storage technologies can provide identical services with similar revenues. Thus explicit modeling of additional markets would rather complicate our analysis without any additional insights.[143] Therefore, for the sake of clarity, we refrain from the explicit modeling of multiple storage use, as we are interested in the relative performance of different technologies from the perspective of a single firm when coping with fluctuating electricity generation. In this context, we consider the spot-market price as a fair estimate for the value of renewable electricity at a given point in time and selected grid node. Further, we exclude explicit

142 See chapter 2.1.2 for more details on the design of the power market in Germany.

143 There are few exceptions in this context. For example, small batteries can be reused flexibly in different areas with large renewable generation and limited grid capacities whereas siting large-scale storage technologies such as pumped-hydro is rather limited to few predefined locations. Hence in this way, system aspects might play an important role when estimating the total value of storage. Yet the focus of our analysis is not on co-optimization of such system benefits which remains an interesting field for further research.

energy arbitrage[144] from our analysis such that the storage unit has no possibility to purchase electricity from the market, and the only source for charging the storage is represented by the intermittent generation.[145] In this way the results of our analysis represent a lower bound for the value of storage.

We formulate two related models within the linear programming framework. The first model, referred to as reference model, represents the case without storage where electricity can be supplied either by renewable generation or a dispatchable unit such as a gas turbine (GT). In case that the renewable generation exceeds the predefined grid capacity, we allow for curtailment of the intermittent feed-in. The second model, referred to as storage model, combines intermittent electricity production with different storage technologies which are subdivided into an input unit (e.g. pumps of the pumped-hydro storage or electrolysis of the hydrogen technology), actual storage unit (e.g. upper and lower reservoir or underground salt cavern for hydrogen) and output unit (e.g. generators of a pumped-hydro storage or GT for re-electrification in case of hydrogen). The size of the input and output unit can be considered as power capacity whereas the volume size as energy capacity of the corresponding storage. The structure of both models is schematically illustrated in Figure 3.2.

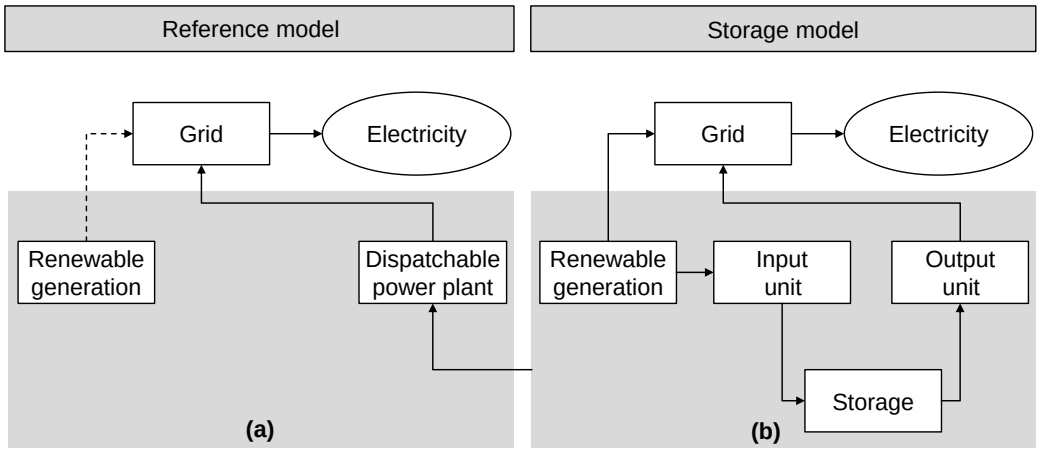


Figure 3.2: Structure of the reference (a) and storage (b) model.

144 I.e., buying electricity in low-price periods (usually off-peak load with high intermittent feed-in) and selling in high-price periods (usually peak-load with low intermittent feed-in).

145 Similar model restriction is also imposed by other studies on storage value, e.g. by Mauch et al. (2012).

Both models implicitly assume simultaneous decision making on short-term electricity generation quantities for each hour of a prototypical year and long-term investments into the capacity of the corresponding facility. The operation of the facility is simulated for each hour of a year under a perfect foresight assumption. In particular, the electricity prices and the availability of renewable electricity are known a priori for all hours of the year. In reality, storage operators face substantial uncertainties regarding future market prices and availability of intermittent electricity generation. Thus, our model underestimates the potential market risks and overestimates the value of storage operation under realistic conditions when taking uncertainty into account (Nyamdash et al. 2010 and Sioshansi et al. 2012).[146] However, we refrain from this model complication as all technologies examined in our analysis would potentially face similar market risks.[147]

We follow Walawalkar et al. (2007) and calculate NPV of the underlying facility as it is a typical basis for decision making by investors interested in alternative projects. Potential revenues and costs of the hourly operation in both models determine an overall cash flow from operations for a prototypical year. This annual cash flow is then assumed to be identical for all periods within a detailed planning horizon and is considered for initial investment remuneration. After the planning horizon, the remaining facility is evaluated at salvage value assuming linear depreciation for each of the facility's components.

3.3.2 Mathematical representation of the reference model

The optimal facility sizing and hourly operation of the renewable generator and dispatchable thermal unit within the reference model is obtained from solving the following NPV maximization problem:[148]

146 Note that on the one hand our analysis understates the value of storage as we consider only benefits from integration of renewable generation into the energy system, and on the other hand we overstate the value of storage as we do not take any risk issues into account. The real overall value of the storage remains an interesting research area.

147 A number of studies analyze the impact of uncertainty on the value of storage and compare the results of deterministic and stochastic modeling. See for example Mokrian and Stephen (2006), Lund et al. (2009), Drury et al. (2011), Vespucci et al. (2012) or Löhndorf et al. (2013).

148 A full list of all indices, decision variables and input parameters for both models can be found in Appendix A.

$$\max NPV = \left\{ AF \cdot \left[\sum_{t \in T} \left(p_t \cdot q_t^{Ren} + p_t \cdot q_t^{Th} - c^{Th} \cdot q_t^{Th} \right) - f^{Th} \right] - e^{Th} \cdot I^{Th} + V^{Th} \right\} \quad (3.1)$$

subject to constraints

$$q_t^{Ren} \leq \bar{k}_t^{Ren} \quad \forall t \in T \quad (3.2)$$

$$\underline{d}_t \leq q_t^{Ren} + q_t^{Th} \quad \forall t \in T \quad (3.3)$$

$$q_t^{Ren} + q_t^{Th} \leq \bar{g}_t \quad \forall t \in T \quad (3.4)$$

$$q_t^{Th} \leq K^{Th} + I^{Th} \quad \forall t \in T \quad (3.5)$$

$$I^{Th} \leq \bar{I}^{Th} \quad (3.6)$$

$$AF = \frac{(1+r)^n - 1}{r \cdot (1+r)^n} \quad (3.7)$$

$$c^{Th} = \frac{p^{Th}}{\eta^{Th}} + \frac{p^{CO_2} \cdot \varepsilon^{Th}}{\eta^{Th}} + v^{Th} \quad (3.8)$$

$$f^{Th} = \varphi^{Th} \cdot e^{Th} \cdot (I^{Th} + K^{Th}) \quad (3.9)$$

$$V^{Th} = \frac{1}{(1+r)^n} \cdot I^{Th} \cdot e^{Th} \cdot \frac{l^{Th} - n}{l^{Th}} \quad (3.10)$$

and non-negativity constraints for the decision variables

$$q_t^{Ren} \geq 0 \quad \forall t \in T \; ; \quad q_t^{Th} \geq 0 \quad \forall t \in T \; ; \quad I^{Th} \geq 0 \qquad (3.11)\ (3.12)\ (3.13)$$

Equation (3.1) represents the objective function of the model maximizing the net present value of the facility taking into account the discounted value of constant annual cash flows from operations, corresponding investment outlays in dispatchable capacity at the beginning of the planning horizon and discounted salvage value of the dispatchable technology V^{Th}. The definition of the annual cash flow from operations corresponds to the first part of the objective function. It includes the revenues from market sales by the intermittent and dispatchable power plant in each hourly period $t \in T$ as well as hourly variable and annual fixed costs of the thermal unit. In order to obtain the discounted value of the operating cash flows for the whole planning horizon, the annual cash flows are multiplied by annuity factor AF based on interest rate r and number of years within the planning horizon n as formulated in equation (3.7).

Hourly revenues are based on exogenous electricity price p_t, sales quantities of the renewable generator q_t^{Ren} and sales quantities of the dispatchable thermal power plant q_t^{Th}.[149] The hourly variable costs of the dispatchable power plant depend on specific variable costs c^{Th}.[150] As formulated in equation (3.8), these costs include fuel costs (average fuel price p^{Th} divided by the corresponding efficiency v^{Th}), costs for CO_2 emissions (average price for a CO_2 certificate p^{CO2} multiplied by a specific emission factor ε^{Th} and divided by the corresponding efficiency) and other variable costs ν^{Th}.[151] Equation (3.9) defines the fixed costs f^{Th} calculated as a share φ^{Th} of the specific investment expenditures e^{Th} for new and existing generation capacity, I^{Th} and K^{Th} respectively. Note that in this way we underestimate the fixed costs as we use the same factor φ^{Th} and specific investment outlays for new and existing capacities without taking into account any cost reductions due to technological progress.

149 Note that for both units the sales quantity equals the respective production quantity. Thus in contrast to the storage model, produced electricity must be sold to the market in the same hour.

150 We assume that production of intermittent electricity by wind turbines or PV systems has no variable and fixed costs. Although they could be easily incorporated in our model, we do not expect that such model extension would change the nature of our results as the variable costs for renewable electricity would arise in the same way in the reference and storage case and for all applications.

151 Variable costs must by adjusted by the corresponding efficiency as they apply to the primary energy needed for electricity production whereas the production decision variables refer to energy provided to the market. This is in line with the approach adopted by a number of studies e.g., Traber and Kemfert (2011) or Schill and Kemfert (2011).

For the sake of simplicity, however, we refrain from explicit modeling of separate fixed costs for new and existing capacities as we expect this error to remain sufficiently small.

The corresponding initial investment outlays represent the second part of the objective function and are calculated by multiplying the specific investment expenditures by the new dispatchable capacity. At this point it is worth to mention that we assume predefined and fixed capacities for renewable generation. This is because we are interested in estimation of storage benefits and costs from integrating intermittent electricity into the energy system rather than in any incentives to build-up renewable capacities themselves. Equation (3.10) defines the salvage value of the thermal unit at the end of the planning horizon as the third part of the objective function. This value is calculated as a discounted fraction of the initial investment outlays for new thermal capacities taking into account the corresponding lifetime l^{Th} and total number of years within the planning horizon.[152] In this way, the salvage value is based solely on linear deprecation of new dispatchable capacities. Any previous investments in initial capacities prior to the horizon of our analysis are considered as sunk costs and have no impact on the facility's value. Moreover, we implicitly assume that the residual value at the end of the planning horizon can be fully captured by the investor. In some cases this might not be true and other approaches for terminal value estimation such as re-placement costs or perpetuity approach might be more appropriate.

The technical constraints are summarized in equations (3.2) – (3.6). As formulated in equation (3.2), renewable electricity generation is restricted by the corresponding availability $\bar{k}_t^{Ren}$ in each hour of the year. In equations (3.3) and (3.4), we define hourly lower and upper bounds $\underline{d}_t$ and $\bar{g}_t$, respectively, for the overall electricity sales to the market. In this way, we can impose minimal electricity demand in the selected grid node on the one hand and limit electricity sales due to grid capacity constraints on the other hand. Equation (3.5) represents the capacity constraints for dispatchable production which must be lower than the total capacity consisting of initial capacity K^{Th} and new capacity investments I^{Th}. In equation (3.6) we include an upper

152 Note that in this case the length of the planning horizon n must be lower than the lifetime of the thermal unit.

bound $\bar{I}^{Th}$ for the expansion on the dispatchable power plant. This constraint can be considered as natural limitation of the facility capacity such as available space.[153] Finally, equations (3.11) – (3.13) contain the non-negativity constraints for the decision variables q_t^{Ren}, q_t^{Th} and I^{Th}.

3.3.3 Mathematical representation of the storage model

The mathematical structure of the storage model is similar to the framework of the reference model. The optimal dimensioning of all storage components and facility operation is again derived from the results of the following *NPV* maximization problem:

$$\max NPV = AF \cdot \Big[\sum_{t \in T} \left(p_t \cdot q_t^{Ren} + p_t \cdot q_t^{Out} \right) - \left(f^{In} + f^{St} + f^{Out} \right) \Big] - \left(e^{In} \cdot I^{In} + e^{St} \cdot I^{St} + e^{Out} \cdot I^{Out} \right) + \left(V^{In} + V^{St} + V^{Out} \right) \quad (3.14)$$

subject to the constraints

$$q_t^{Ren} + q_t^{In} \leq \bar{k}_t^{Ren} \quad \forall t \in T \quad (3.15)$$

$$\underline{k_t}^{Ren} \leq q_t^{Ren} + q_t^{In} \quad \forall t \in T \quad (3.16)$$

$$\underline{d_t} \leq q_t^{Ren} + q_t^{Out} \quad \forall t \in T \quad (3.17)$$

$$q_t^{Ren} + q_t^{Out} \leq \bar{g}_t \quad \forall t \in T \quad (3.18)$$

153 Note that the optimization problem is already bounded by equations (3.3) and (3.4). However, as discussed later in chapter 3.4.1 we define scenarios analyzing the minimal demand requirement without grid capacity constraints. In this case equation (3.6) is required to assure that the maximization problem has a definite solution. Otherwise, if investments in thermal production are profitable, one additional unit of capacity will always provide higher net present value than not investing. Therefore the optimal solution would lead to an infinite size of the facility. Equation (3.6) is also needed to explicitly exclude thermal production in order to analyze the effect of curtailment of renewable electricity.

$$q_t^{Out} \leq \bar{k}_t^{Out} \quad \forall t \in T \tag{3.19}$$

$$q_t^{In} \leq K^{In} + I^{In} \quad \forall t \in T \tag{3.20}$$

$$q_t^{Out} \leq K^{Out} + I^{Out} \quad \forall t \in T \tag{3.21}$$

$$I^{Out} \leq \bar{I}^{Out} \tag{3.22}$$

$$s_t = s_{t-1} + q_t^{In} \cdot \eta^{In} - q_t^{Out} \cdot \frac{1}{\eta^{Out}} \quad \forall t > 1 \tag{3.23}$$

$$\underline{K}^{St} \leq s_t \leq K^{St} + I^{St} \quad \forall t \in T \tag{3.24}$$

$$s_t = q_t^{In} \cdot \eta^{In} - q_t^{Out} \cdot \frac{1}{\eta^{Out}} + s^i, \ t = 1 \tag{3.25}$$

$$s_t = s^i, \quad t = 8760 \tag{3.26}$$

$$AF = \frac{(1+r)^n - 1}{r \cdot (1+r)^n} \tag{3.27}$$

$$f^{In} = \varphi^{In} \cdot e^{In} \cdot (K^{In} + I^{In}) \tag{3.28}$$

$$f^{St} = \varphi^{St} \cdot e^{St} \cdot (K^{St} + I^{St}) \tag{3.29}$$

$$f^{Out} = \varphi^{Out} \cdot e^{Out} \cdot (K^{Out} + I^{Out}) \tag{3.30}$$

$$V^{In} = \frac{1}{(1+r)^n} \cdot e^{In} \cdot I^{In} \cdot \frac{l^{In} - n}{l^{In}} \tag{3.31}$$

$$V^{St} = \frac{1}{(1+r)^n} \cdot e^{St} \cdot I^{St} \cdot \frac{l^{St} - n}{l^{St}} \tag{3.32}$$

$$V^{Out} = \frac{1}{(1+r)^n} \cdot e^{Out} \cdot I^{Out} \cdot \frac{l^{Out} - n}{l^{Out}} \tag{3.33}$$

and non-negativity constraints for the decision variables

$$q_t^{Ren} \geq 0 \quad \forall t \in T; \; q_t^{In} \geq 0 \quad \forall t \in T; \; q_t^{Out} \geq 0 \quad \forall t \in T \quad (3.34)\ (3.35)\ (3.36)$$

$$I^{In} \geq 0\,; \quad I^{Out} \geq 0\,; \quad I^{St} \geq 0\,; \qquad s^i \geq 0 \qquad (3.37)\ (3.38)\ (3.39)\ (3.40)$$

The first line of the objective function in equation (3.14) represents the annual cash flow of the prototypical year multiplied by the annuity factor AF defined in equation (3.27).[154] The hourly revenues come from electricity sales both directly through renewable generation q_t^{Ren} and storage output q_t^{Out}. Market sales q_t^{Out} refer to storage discharging, and there is no other use of electricity from the storage than spot market sales. Since the storage facility is subdivided into several components, the overall fixed costs include the corresponding values for the input unit f^{In}, storage unit f^{St} and output unit f^{Out}. Moreover, in our model we neglect any variable costs associated with storage input and output. In reality some technologies such as diabatic CAES require additional energy for adequate operation and thus additional variable costs might occur. Hence, explicit modeling of the variable costs for storage charging and discharging represent a potential extension of our model. Analogously to the reference model, equations (3.28) – (3.30) define the fixed costs for each component of the storage based on the initial capacity, K^{In} for the input unit, $\overline{K}^{St}$ for the storage unit, K^{Out} for the output unit, additional capacity investments I^{In}, I^{St}, I^{Out}, specific investment expenditures e^{In}, e^{St}, e^{Out} and the fixed costs fraction on the investment outlays φ^{In}, φ^{St}, φ^{Out}, respectively.

154 The annuity factor plays the same role as in the reference model. For the sake of comparability, we also assign the same interest rate r and the same number of periods n.

The second line of the objective function formulates the investment outlays for each component of the storage based on the specific investment expenditures and actual capacity increase. The investment outlays are further adjusted by the discounted salvage value of the entire facility. According to equations (3.31) – (3.33), the corresponding discounted salvage values are again based on investment outlays and frictions of the remaining lifetime of each component l^{In}, l^{St} and l^{Out}, respectively.

In equations (3.15) and (3.16), the total output of the renewable generation consisting of direct sales to the market and electricity used for charging the storage q_t^{In} is constrained by the overall availability $\bar{k}_t^{Ren}$ and a minimal uptake $\underline{k}_t^{Ren}$ of renewable energy in every hourly period t. Equations (3.17) and (3.18) represent the lower and upper bounds for the market sales directly from intermittent production and storage release as a minimal load requirement and maximal grid capacity, respectively.

In equation (3.19) we introduce an additional constraint on the storage output quantity to ensure that the storage can be either charged or discharged but not both during the same hourly period. In order to keep our model simple, we include an upper bound $\bar{k}_t^{Out}$ for storage output as a predefined parameter. According to equation (3.41), $\bar{k}_t^{Out}$ is equal to zero and storage output is not possible if the minimal renewable uptake is higher than the grid capacity $\bar{g}_t$ as in such period intermittent electricity must be stored by the facility and storage discharging is not allowed. Otherwise $\bar{k}_t^{Out}$ corresponds to the grid constraint reduced by the actual renewable feed-in.[155] We assume that storing electricity is always prone to efficiency losses, and the round-trip efficiency is always lower than 100 %, i.e., $\eta^{In} \cdot \eta^{Out} < 1$.[156]

$$\bar{k}^{Out} = \begin{cases} 0 & \text{if } \bar{g}_t \leq \underline{k}_t^{Ren} \quad \forall t \in T \\ \bar{g}_t - \underline{k}_t^{Ren} & \text{otherwise} \end{cases} \tag{3.41}$$

155 In this context, we also assume positive sales price in the last period of the prototypical year, i.e. $p_t > 0$ for $t = 8760$, ensuring that there is always an incentive to sell electricity exceeding the minimal storage level in the last period as defined by constraints in equations (3.23) and (3.25). See Appendix B for a proof of exclusive storage charging or discharging when applying equation (3.41) in our model.

156 Note that one of the efficiency parameters might be equal to 100 % but not both of them.

Equations (3.20) and (3.21) formulate the capacity constraint for storage charging and discharging, respectively, dependent on the corresponding initial and new capacities. Analogously to the reference model, in equation (3.22) we also introduce an upper bound $\bar{I}^{Out}$ for investments in the storage output unit.[157] Moreover, in the case of batteries, we further extend our model by a constraint on the relationship between input and output capacities such that $I^{In} = I^{Out}$.

The constraints for the storage operation are described in equations (3.23) – (3.26). In equation (3.23) the storage level s_t corresponds to the storage level from the previous period $t-1$ increased by the storage charging q_t^{In} and decreased by storage discharging q_t^{Out} in the given period t. Both storage input and output are adjusted by the corresponding efficiencies η^{In} and η^{Out}.[158] According to equation (3.24), the storage level is constrained by a lower bound $\underline{K}^{St}$ as the minimal allowable storage content and an upper bound based on the initial storage capacity and additional investments in energy-related storage capacity. Equations (3.25) and (3.26) define the initial and final storage levels in the first and last periods of the prototypical year, respectively. The initial level corresponds to storage input and output in the first period plus initial storage content s^i. In order to ensure an accurate valuation of the facility, the storage content in the last hour of the year is identical to the initial content at the beginning of the year. In this way, the initial storage content is an additional decision variable which allows for optimizing storage operation independent from the actual starting point of the simulation.[159] Equations (3.34) – (3.40) include non-negativity constraints for decision variables on facility operations (q_t^{Ren}, q_t^{In} and q_t^{Out}), sizing (I^{In}, I^{Out}, I^{St}) and initial storage content s^i.

157 This constraint can again be interpreted as size limitation of the facility in a given grid node and has the same function as the investment constraint for the dispatchable unit in the reference model. It is worth to mention that the constraint for the output unit also limits the investments in all other storage components as capacity extension is typically costly and there is no incentive to oversize any of the storage elements (since all units are directly linked to each other).

158 Note that the storage output must be divided by the output efficiency as the output quantity corresponds to actual market sales. Thus the actual amount of electricity released from the storage is typically higher than the market sales if corresponding efficiency is lower than 100 %.

159 For example in Germany, if the starting point of the simulation is set to the beginning of a calendar year, then in some cases the aggregated PV feed-in in the first weeks of the year might be too low to meet the predefined demand due to comparatively low PV availability in the winter months. Hence, setting the initial storage content s^i to zero would provide infeasible solution in our model.

3.4 Case study

In this chapter we apply the reference and storage model for a realistic case study in the context of the German electricity market. We are interested in an optimal operational and investment strategy for different storage technologies based on real input parameters for the intermittent feed-in and electricity prices within a prototypical year. In this way we obtain realistic results on the actual value of storage taking into account the seasonality of renewable electricity generation. However, for an hourly representation of the entire year the model consists of several tens of thousands of decision variables and therefore can be solved only in a numerical case study.

First, in chapters 3.4.1 and 3.4.2 we give an overview over the selected cases, technologies and input data. Chapters 3.4.3 and 3.4.4 provide numerical results of two main case studies (case A for minimal demand requirement and case B for maximal grid capacity), whereas chapter 3.4.5 includes a scenario analysis on the influence of major input parameters on the calculated outcomes. Finally, in chapter 3.4.6 we further examine the relationship between the renewable feed-in, demand level and grid capacity as one of the crucial assumptions in our analysis.

3.4.1 Overview of selected cases and technologies

In the first step in case A, we assume a given minimal demand to be met by the facility without grid constraints. In this way, we analyze the value of storage when the electricity producer is obliged to provide a certain level of electricity, and all renewable electricity can be sold to the market in a given grid node. The corresponding conventional alternative to meet this obligation is represented by operation of a gas turbine as a dispatchable power plant. In the second step in case B, we omit the minimal electricity demand but introduce an explicit maximal transmission capacity preventing the intermittent generator from electricity sales in particular hours. All excess electricity is used to charge storage for sales in later periods, and the conventional alternative is based on curtailment of intermittent production. In both cases we compare five different storage technologies in combination with

an onshore wind park and a photovoltaic system. The selected technologies include pumped-hydro, advanced adiabatic compressed air energy storage (AA-CAES) and hydrogen power-to-gas technology as large-scale technologies as well as two battery applications containing sodium sulfur and vanadium-redox flow batteries.[160] Figure 3.3 provides an overview of the cases selected for further analysis.

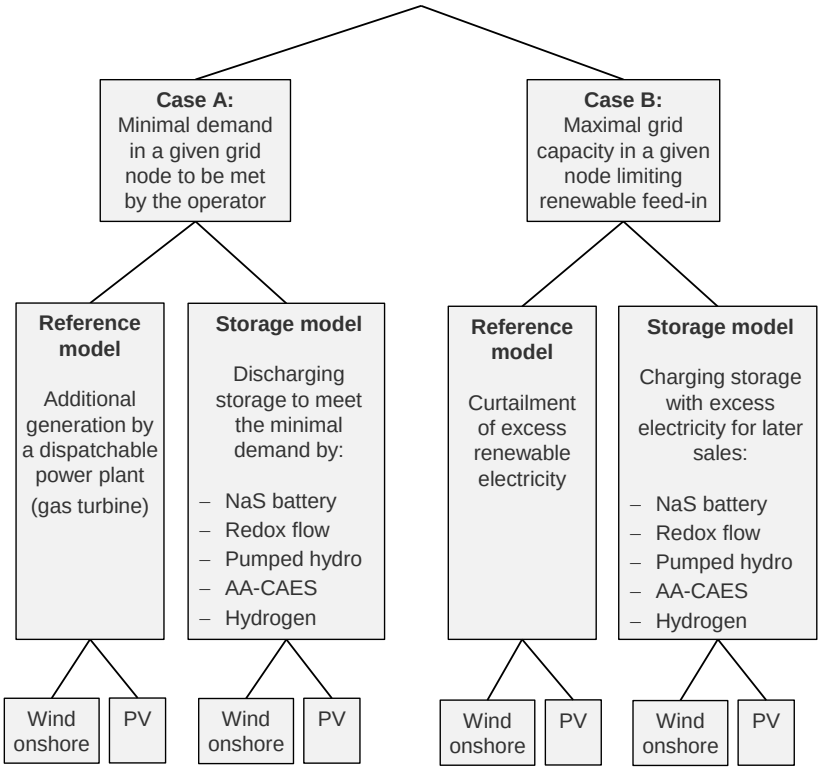


Figure 3.3: Overview of selected cases for further analysis.

As indicated in Figure 3.4, in both cases we calculate the costs of integrating intermittent feed-in into the energy system as the difference between the NPV of renewable generation without any constraints and conventional alternatives or storage operations. In our model these costs are paid by the facility operator, but they could potentially be reimbursed by the grid operator (TSO or DSO) and the end users based on corresponding grid fees. Further, we define the value of storage as a difference in NPV between storage operation

160 See chapter 2.3.3 for a comprehensive description and characterization of different storage technologies.

and the conventional alternative indicating the economic advantageousness of each option. Note that the costs for integrating renewable generation might still occur even for a positive value of storage if the NPV of storage is higher than for the conventional alternative but lower than for unconstrained renewable sales.

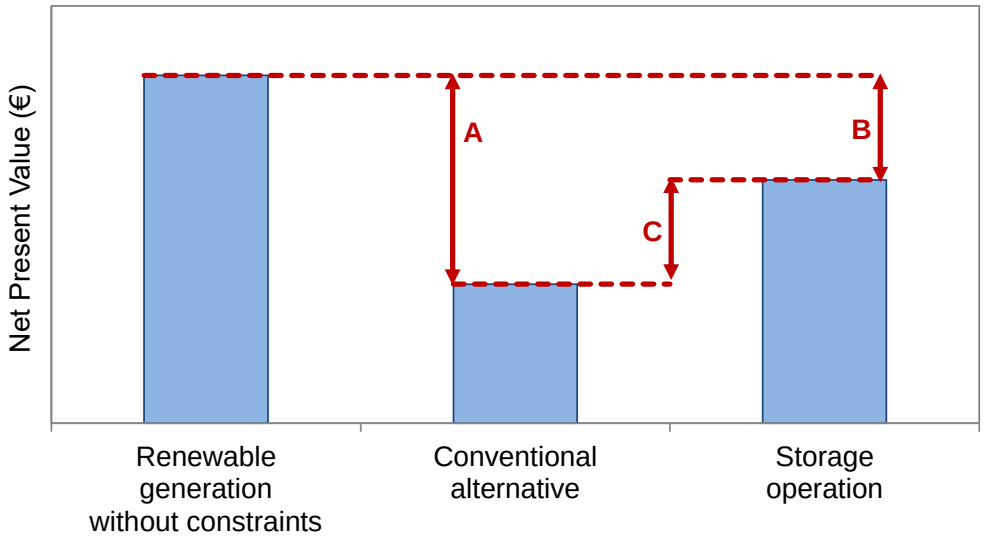


Figure 3.4: Costs of integrating intermittent feed-in (A and B) in comparison to value of storage (C).

Moreover, in order to compare the optimal operation and sizing of the selected options in the reference and storage model, we introduce two additional metrics within a prototypical year: utilization rate of the gas turbine and input and output units as well as number of full cycle equivalents of the storage. The utilization rate is defined as number of full load hours[161] divided by the total number of hours in a year. The higher the utilization rate, the lower the impact of the corresponding investment outlays on the overall results, as only a relatively small capacity is used for a given energy turnover and vice versa.

The number of cycle equivalents is formulated as $CE = \frac{\sum_{t=1}^{8760} |s_t - s_{t-1}|}{K^{St} + I^{St}} \cdot 50\,\%$. It is calculated as total change in storage level between the given and previous hour divided by the total storage energy capacity (consisting of initial and

161 The number of full load hours represents the number of hour equivalents when the unit is operated at full capacity. It is calculated by dividing total energy processed by the corresponding unit in MWh by the installed capacity in MW.

additional investment capacity) and multiplied by a factor of 50 %. This metric indicates the role of the storage size. For a given energy turnover, the higher the number of full cycle equivalents, the smaller the storage size and hence the better its utilization. Alternatively, storage size can also be indicated by the number of storage days, i.e. the total number of days within a year divided by the number of full cycle equivalents.

3.4.2 Input data

In our analysis, we assume a large wind park consisting of 100 wind turbines with a total nameplate capacity of 126 MW providing approx. 194 GWh of intermittent electricity during one year.[162] For the sake of comparability, we assume that the PV power plant provides the same amount of renewable electricity. However, due to a lower number of operating hours (approx. 800 hours per year in Germany), the total nameplate capacity of the PV system amounts to approx. 243 MW.[163] The hourly wind and PV feed-in patterns are obtained from publicly available data on renewable generation in 2012 provided by German TSOs.[164] The electricity prices are historical day-ahead prices from 2012 for the German marketplace at EPEX SPOT in Paris,[165] whereas the hourly demand pattern corresponds to typical German electricity consumption of the same year.[166] Table 3.1 provides an overview of the statistics on intermittent feed-in, electricity demand and prices.

162 Nitsch et al. (2012b, p. 1, Table 1 – 2) report an average installed capacity for wind onshore in Germany of 1.2 MW. Total electricity generation is then calculated by multiplying the total installed capacity with a typical number of full load hours of 1,550 hours. This number corresponds to a capacity factor of approx. 18 % and is derived from BMWi (2013b, Table 20) as a five years average between 2008 and 2012 in order to account for different wind years.

163 See Nitsch et al. (2012b, p. 1, Table 1 – 2) for the status-quo and possible future development of a representative PV system in Germany.

164 In Germany, the electricity grid is operated by four independent TSOs: 50Hertz, Amprion, Tennet and TransnetBW. Each TSO reports forecasted and actual wind and PV feed-in in its own control area on at least hourly basis. The actual data usually represents an online projection of intermittent generation at selected typical sites within the corresponding area.

165 The data on spot market prices is publically available at EPEX (2015).

166 The electricity consumption data is obtained from European Network of Transmission System Operators for Electricity (ENTSO-E). See ENTSO-E (2013).

The minimal demand in a given grid node to be met by the facility operator in case A is approx. 39 GWh or 20 % of the total intermittent production.[167] We also assume that the same electricity amount cannot be sold to the market due to grid constraints in case B. For wind onshore this corresponds to a grid capacity of approx. 31 MW and for PV of approx. 62 MW. In case B we further assume that all electricity subject to the grid constraint has to be stored by the facility operator in the storage model representing the minimal renewable uptake requirement.

Table 3.1: Statistics on intermittent feed-in, electricity demand and prices for the selected case study.

Item	Unit	Min	Max	Mean	Standard deviation	Total (GWh)
Wind feed-in	MW	1	114	22	19	194
PV feed-in	MW	0	153	22	34	194
Minimal load	MW	2	6	5	1	39
Electricity price	€/MWh	−222	210	43	19	—

At this point it is important to mention that the hourly renewable feed-in used in our analysis is based on the aggregated data for all of Germany and to some extent is different in comparison to a generation profile of a stand-alone power plant. This is due to the fact that geographically distributed plants can balance out each other according to varying weather conditions in different areas. Therefore, the maximal feed-in for wind and PV is lower than the nameplate capacity,[168] and the minimal wind availability is higher than zero. However, as argued by Ernst et al. (2007) and Nyamdash et al. (2010), the advantage of the aggregated data is a minor forecast error.

The gas turbine for dispatchable generation in our analysis is characterized on the one hand by comparatively low specific investment expenditures

167 This figure is somehow arbitrary and in reality it depends on the actual location of the facility within the transmission network. Therefore, we will test the impact of this crucial assumption on the overall results in more detail in chapter 3.4.6.

168 This is also due to efficiency losses of the power plants' control subsystems and, in particular for PV, due to potential suboptimal orientation of the system in a given location.

of 400,000 €/MW but on the other hand also by a low electrical efficiency of 40 %.[169] According to the default value provided by IPCC (2006),[170] we calculate with a specific emission factor for natural gas of 0.205 tons CO_2 per MWh. The total variable costs amount to approx. 70 €/MWh under the assumption of an average primary energy price for natural gas of 25 €/MWh, a comparatively low average price for CO_2 certificates of 5 €/t_{CO2} and other variable costs of 5 €/MWh.[171] Table 3.2 summarizes the techno-economic input data for the dispatchable thermal power plant with regard to electricity production.

Table 3.2: Techno-economic data for the dispatchable thermal power plant.

Item	Unit	Value
Maximal capacity	MW	400
Efficiency	%	40
Lifetime	a	25
Specific emissions	t_{CO2}/MWh	0.205
Primary energy prices	€/MWh	25
CO_2 price	€/t_{CO2}	5
Other variable costs	€/MWh	5
Total variable costs	€/MWh	70
Investment expenditures	€/MW	400,000
Fixed costs	% of investment	2

169 The assumptions on specific investment expenditures, efficiency, lifetime and fixed costs are in line with Nitsch et al. (2010a) and Nitsch et al. (2010b). Moreover, we expect constant specific investment outlays for large power plants of several MW as predicted by our analysis. This assumption is also made in other studies such as Nitsch et al. (2010a) and Nitsch et al. (2012a).

170 The Intergovernmental Panel on Climate Change proposes in IPCC (2006, p. 2.18, Table 2.3) a range between 54,300 and 58,300 kg of greenhouse gases per TJ with a default value of 56,100 kg/TJ as a specific emission factor for stationary combustion of natural gas in energy industries.

171 The average primary energy price for natural gas corresponds to NG spot price in the gaspool market area at EEX and the price for CO_2 certificates to the EU Emission Allowances on the spot market (EEX 2013). The assumption on other variable costs is in line with Dienhart et al. (1999).

Table 3.3: Techno-economic input parameters for selected storage technologies.

Parameter	Unit	NaS Battery[a)]	Vanadium Redox Flow[a)]	Pumped hydro[b)]	Adiabatic CAES[b)]	Hydrogen[b),c)]
Investment expenditures for input unit	€/kW	230	582	320	325	1,485
Investment expenditures for output unit	€/kW	230	582	320	325	400
Investment expenditures for total power	€/kW	460	1,164	640	650	1,885
Investment expenditures for energy-related capacity	€/kWh	274	535	10	40	0.2
Fixed costs for input unit	%	0.2	0.2	3	3	3
Fixed costs for output unit	%	0.2	0.2	3	3	2
Fixed costs for for energy-related capacity	%	0.2	0.2	3	3	3
Lifetime input unit	a	10	13	20	40	15
Lifetime output unit	a	10	13	20	40	25
Lifetime for energy-related capacity	a	10	13	60	40	30
Input efficiency	%	78	75	89	81	70
Output efficiency	%	100	100	90	86	40
Round-trip efficiency	%	78	75	80	70	28

$a)$ Input values for investment outlays, lifetime and efficiencies are calculated as average of data provided by Connolly (2010, pp.42-43) and Akhil (2013 p.B-31, Table B-14 and p.B-33, Table B-16), whereas figures for fixed costs are derived from Akhil (2013).

$b)$ Data derived from Nitsch (2010b, p. 16, Table 1-31 and pp.28-30, Table 1-45 - Table 1-50).

$c)$ The output unit of hydrogen technology has the same characteristics as the thermal power plant.

The techno-economic data for different storage technologies is taken from Connolly (2010), Nitsch et al. (2010b) and Akhil et al. (2013). As presented in Table 3.3, batteries are characterized by rather low specific power-related investment expenditures for the input and output unit but high investment expenditures for energy capacity. The opposite is true for the large-scale storage technologies including pumped-hydro, AA-CEAS and hydrogen technology. Also, the lifetime of NaS and redox flow batteries of 10 and 13 years, respectively, is rather low in comparison to the large-scale technologies with up to 60 years for the reservoirs of the pumped-hydro storage. The highest round-trip efficiency is assumed for pumped-hydro storage (80 %) and the lowest for hydrogen technology (28 %).[172] In each case the maximal facility size is 400 MW, and there are no initial capacities in both the reference and storage models, and the minimal storage level is zero. Further, we assume a detailed planning horizon of 10 years and an annual interest rate of 8 %.

3.4.3 Storage value in case A

In the absence of any technical constraints, the present value of intermittent electricity sales from wind is approx. 50 M€ and is considerably lower than for PV amounting to approx. 57 M€. This is due to the fact that PV feed-in matches the electricity demand during daytime better than wind and therefore is more likely to occur at hours with high market prices. In contrast, wind is mostly available at those hours of the day when the demand and market prices are comparatively low (Joskow 2011 and Borenstein 2012). Accordingly, the average sales price for wind onshore is approx. 39 €/MWh, whereas for PV it is higher by 12 % at approx. 44 €/MWh. In addition, as in our model the renewable generator has no incentive to sell intermittent electricity at a negative price, a small fraction of renewable is curtailed and not provided to the market (approx. 4 GWh or 2 % in case of wind and almost all electricity from PV can be sold to the market).[173]

172 Note that we do not take self-discharging of NaS battery into account as we assume that the corresponding losses can be limited through adequate insulation or compensated through heat usage for other applications.

173 Since the direct sales of intermittent electricity are defined as a separate decision variable in our model the producer is always better off when curtailing renewable generation rather than paying negative market price for electricity delivery.

Introducing the minimal demand constraint has a negative impact on the economic value of the facility in both the reference and storage models.[174] Since investment and operation of a gas turbine and electricity storage are costly, the corresponding net present value is lower in comparison to renewable generation without any technical constraints for both intermittent sources. In addition, under the given techno-economic assumptions the NPV of electricity storage is always lower than the NPV of the conventional alternative and therefore, as indicated in Figure 3.5, the value of storage is negative for all applications. We find that for each technology the storage value is 10–25 times lower in combination with PV than with wind. The best results (least negative value) are achieved by pumped-hydro storage (−1 M€ for wind and −18 M€ for PV) and the worst results (most negative value) by redox flow battery (−67 M€ for wind and −781 M€ for PV). Surprisingly, hydrogen technology has the second highest value despite its comparatively low round-trip efficiency and high investment expenditures for the electrolysis as an input unit. Generally, large-scale storage technologies including pumped-hydro, AA-CEAS and hydrogen are economically better off than batteries.

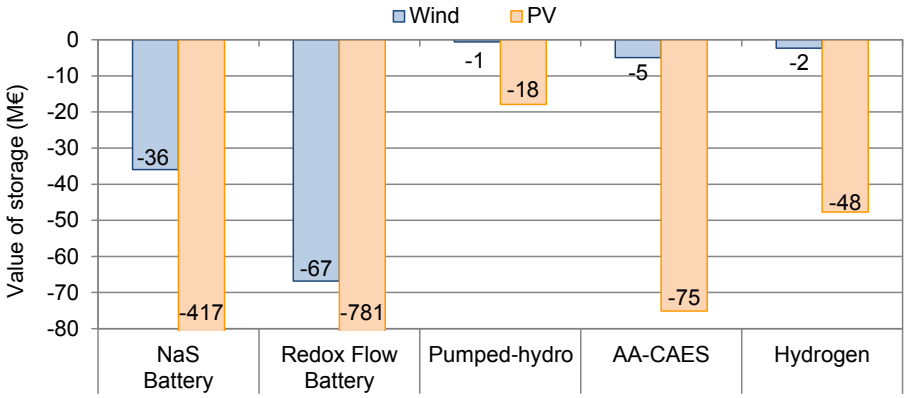


Figure 3.5: Value of storage for different technologies in combination with wind and PV in case A.

In this context, the relationship between the feed-in pattern of intermittent generation and the demand profile represents one major technical factor influencing the optimal sizing and operation of a storage facility. In particular as depicted in Figure 3.6 and 3.7, wind requires low and PV very high storage input capacities due to rather equal distribution of wind feed-in over the year

174 Detailed analysis results for case A are also summarized in Appendix A.3.

in comparison to PV with production peaks during daytime mainly in the summer (approx. 1 MW – 5 MW for wind corresponding to approx. 1 % – 4 % of the installed renewable capacity and approx. 20 MW – 40 MW for PV corresponding to approx. 8 % – 16 % of the installed capacity). This relationship also leads to a better utilization of the input unit in combination with wind (39 % – 86 %) than with PV (11 % – 35 %). Based on intermittent feed-in pattern and minimal demand profile, the electricity deficit within a prototypical year amounts to approx. 1.7 GWh for wind and to approx. 19 GWh for PV. Consequently, wind requires comparatively low energy-related storage capacities (0.1 GWh – 0.8 GWh) and low initial levels (0.1 GWh – 0.2 GWh) in comparison to PV (1.5 GWh – 15.5 GWh capacity and 0.4 GWh – 7.4 GWh for initial level). Therefore, storing wind electricity is characterized by a higher number of full cycle equivalents and a better storage utilization than for PV. In fact, except for hydrogen technology, storage is used on a weekly basis for wind (53 – 92 cycle equivalents or 4 – 7 days) and on a monthly basis for PV (15 – 19 cycle equivalents or 19 – 24 days). Only hydrogen is a typical seasonal storage in both cases (5 cycles or 73 days for wind and 3 cycles or 122 days for PV). Moreover, the efficiency of the output unit has an adverse impact on the energy capacity: the lower the efficiency, the higher the energy-related capacity needs to be to meet a predefined minimal power demand.

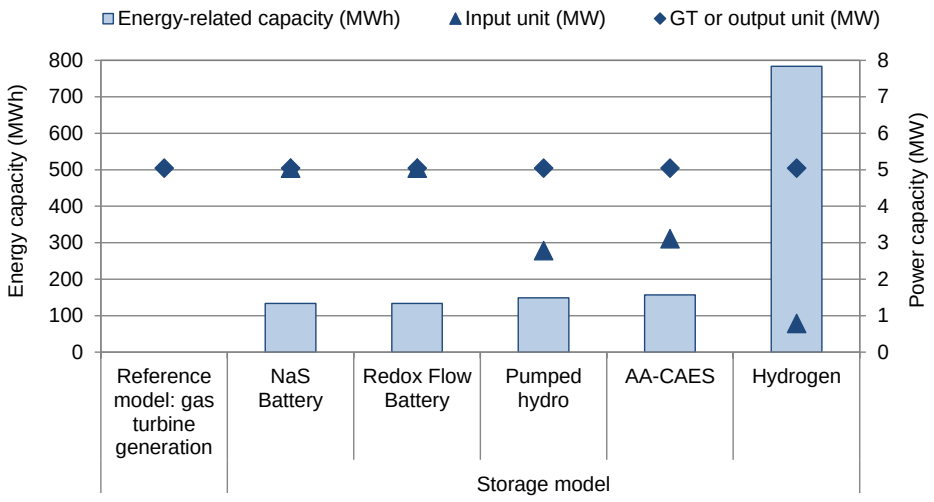


Figure 3.6: Optimal sizing of gas turbine and different storage technologies in combination with wind in case A.

Except for batteries, the power-related output capacity for most applications remains at the same level despite varying specific investment expenditures (approx. 5 MW in case of wind and approx. 6 MW in case of PV).[175] This is due to the fact that the optimal output capacity corresponds to the difference between the peak demand and the lowest feed-in value and there is no economic incentive to provide any higher capacity. We also find that the output unit has a lower utilization rate for wind (4 % – 28 %) than for PV (12 % – 51 %) as only a small amount of electricity is provided to the market in case of wind.[176]

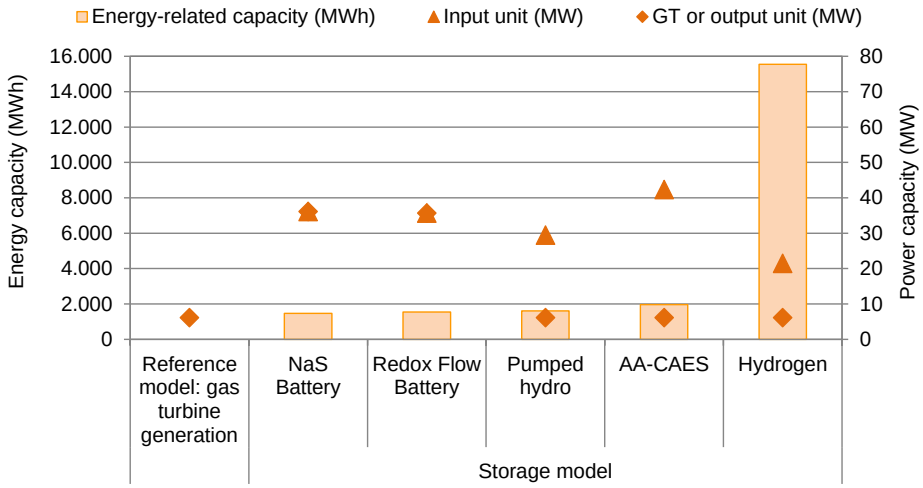


Figure 3.7: Optimal sizing of the gas turbine and different storage technologies in combination with PV in case A.

From the economic perspective, the optimal facility sizing and operation is also based on a trade-off between investment outlays for energy-related capacity and opportunity costs through storage charging.[177] Given a predetermined output profile, the lower the specific outlays, the more energy is shifted between different periods potentially lowering the opportunity costs. In addition, in most cases storage output is higher than electricity deficit[178] and the installed capacities are co-utilized to benefit from renewable capacity firming and energy time-shifting. Our findings in this regard are in line with observations

175 Note that as defined in the storage model, batteries must have the same input and output capacity.

176 This is valid for large-scale storage technologies where the power-related input and output capacities are identical. For batteries the opposite is true.

177 Note that energy stored for later use could otherwise be sold directly to the market at a corresponding market price.

178 In case A, the energy deficit is the lower bound for storage output.

made by Eyer and Corey (2010, p. 47) who state that storage applications for renewable capacity firming in many cases occur in combination with energy time-shifting effects. Similarly, the electricity amount provided by the gas turbine is also higher than the actual energy deficit, as in some hours the market price is higher than the variable production costs and the technology is able to earn some profits from additional market sales. Only for hydrogen the time-shifting benefit does not come into effect due to low round-trip efficiency and high specific power-related investment expenditures.

Table 3.4: Composition of net investment outlays in case A*.

Parameter	Unit	Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
Net investment outlays in case of wind onshore							
Storage input unit	M€	0.0	1.2	2.6	0.7	0.7	1.0
Energy-related capacity	M€	0.0	36.6	63.8	0.9	4.1	0.1
GT or storage output unit	M€	1.5	1.2	2.6	1.2	1.1	1.5
Total	M€	1.5	38.9	69.1	2.8	5.8	2.6
Net investment outlays in case of photovoltaics							
Storage input unit	M€	0.0	8.3	18.5	7.3	9.0	27.0
Energy-related capacity	M€	0.0	402.2	738.9	9.9	51.3	2.1
GT or storage output unit	M€	1.8	8.3	18.5	1.5	1.3	1.8
Total	M€	1.8	419.0	776.3	18.7	61.6	30.9

* All values are calculated as actual investment outlays less discounted salvage value of the corresponding investment at the end of the detailed planning horizon.

When comparing the financial results of different technologies we find that total revenues are typically higher for PV than for wind[179] but are in the same order of magnitude for all technologies for the same intermittent feed-in pattern. The only exception is again represented by hydrogen technology where in the PV case efficiency losses and corresponding opportunity costs over-compensate the higher market value of direct electricity sales from PV in comparison to the wind case. Moreover, for all storage technologies expensive

179 This is mainly due to higher market value of direct PV sales, different overall storage and GT output due to the seasonality effects as well as higher storage time-shifting effects in case of PV.

investments in new capacities are the major reason for the low NPV in comparison to the conventional alternative and consequently for the negative storage value. As indicated in Table 3.4, net investment outlays[180] for energy capacity have substantial impact on the overall level of capital expenditures. Especially technologies with high specific investment expenditures for energy capacity, such as batteries or AA-CAES, have the highest overall outlays. This effect is further exacerbated by the seasonality of PV. Contrary, although hydrogen has high specific power-related expenditures for the input unit, this technology benefits from notably low costs for energy-related storage capacities. Hence it is a comparatively cheap technology for seasonal storage of intermittent electricity and it has the second best storage value behind pumped-hydro.

3.4.4 Storage value in case B

In this chapter, we present the results of our analysis of the value of storage in the context of transmission congestion by relaxing the constraint on the minimal demand but introducing maximal grid capacity as a limitation for market sales together with the requirement for an uptake of all excess electricity. Similar to case A, storing intermittent electricity in case B is economically less favorable than the conventional alternative.[181] In comparison to curtailment all storage technologies have lower NPV and hence negative value of storage. As depicted in Figure 3.8, the technology with the best economic results (least negative value) is again represented by pumped-hydro (value of storage of −122 M€ for wind and −27 M€ for PV), and the technology with the lowest value (most negative) is redox flow battery (−5,208 M€ for wind and −287 M€ for PV). Except for hydrogen, all technologies are economically better off when avoiding curtailment of excess PV rather than wind feed-in.

When comparing cases A and B, we find that for wind the storage value is generally lower in case B than in case A, indicating that electricity storage is economically better suitable to meet minimal demand rather than to cope with transmission congestion in the context of seasonality. In case of PV, however,

180 Net investment outlays are calculated as total investment outlays less discounted salvage value.

181 Detailed analysis results for case B are summarized in Appendix A.4.

our analysis provides partially contrary results. Except for pumped-hydro and hydrogen technology the value of storage in case B is higher than in case A, and we conclude that electricity storage with expensive energy-related capacities in combination with PV is typically more useful for avoiding transmission congestion rather than for satisfying the minimal demand. Surprisingly, we find relatively high NPV of the NaS battery being comparable to the value of hydrogen. However, large-scale technologies again tend to have an economic advantage over batteries.

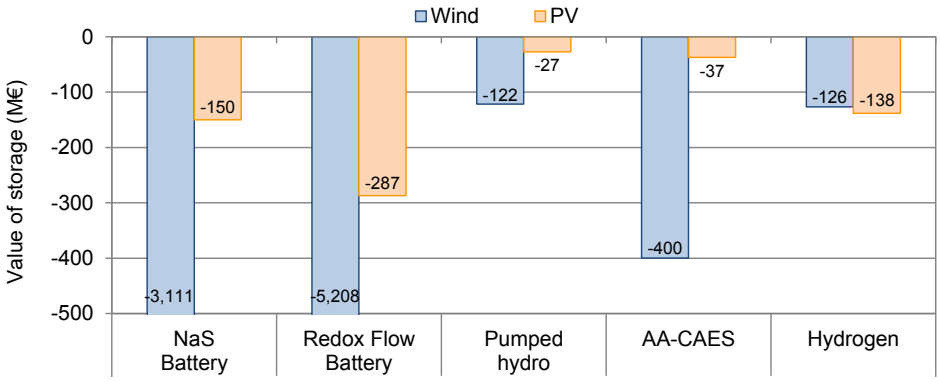


Figure 3.8: Value of storage for different technologies in combination with wind and PV in case B.

The results on the optimal facility sizing are illustrated in Figure 3.9 for wind and in Figure 3.10 for PV. The power-related capacities of the input unit are determined by the maximal difference between the feed-in and the corresponding grid capacity (82 MW for wind and 90 MW for PV for all technologies). For each intermittent source the input capacity remains at a constant level for all technologies as there is no economic incentive to oversize the input unit. The corresponding utilization of the input unit (6 % – 11 % for wind and 5 % – 10 % for PV) is comparatively low, indicating that excess electricity occurs at relatively few hours but at high power capacity.

The optimal energy-related storage capacity varies substantially between the different sources of intermittent electricity, again due to different seasonal feed-in patterns. Excess electricity from onshore wind occurs predominantly in the winter months in large quantities and within comparatively long time steps such that large energy-related capacities are required to store electricity above the

grid capacity.[182] In case of PV, excess electricity in Germany is available typically between March and October and only for a few hours during daytime.[183] This allows for operation of a smaller storage on a daily basis with charging during the day and discharging at night. Consequently, the optimal energy-related capacity and initial storage level in combination with wind are large, amounting to approx. 11 GWh – 13 GWh and approx. 3 GWh – 4 GWh, respectively, whereas for PV these figures are notably lower between 0.4 GWh – 1.7 GWh and 0.4 GWh – 1.2 GWh, respectively. At this point it is also worth to mention that due to efficiency losses of the input unit, the actual storage input is typically lower than the excess electricity in a particular period. In case of wind, the storage is generally operated on a seasonal basis with only 3 – 6 cycle equivalents per year (corresponding to a storage size of 61 – 122 days). In case of PV, only hydrogen technology has large energy-related storage capacity characterized by a low number of cycle equivalents (16 cycles or 23 days) due to low specific investment outlays for the corresponding capacity. For all other technologies we find better utilization of the storage with 90 – 133 cycle equivalents (approx. 3 – 4 days).

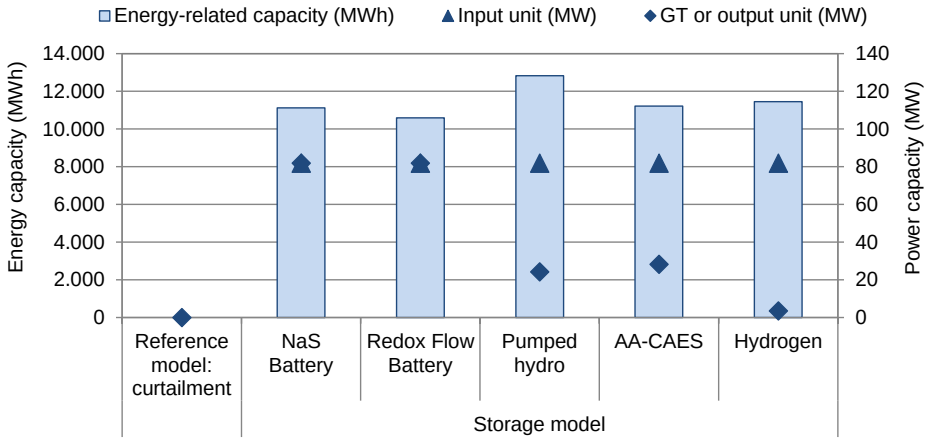


Figure 3.9: Optimal sizing of the facility in combination with wind in case B.

In addition, we find only a small difference in optimal output capacity between wind and PV for all technologies. This is due to the fact that each storage

182 For example, the longest uninterrupted period with grid congestion in case of wind lasts for 147 hours between January 1st and January 7th with total excess electricity of approx. 7 GWh. The subsequent period without grid congestion lasts for only 21 hours and the storage cannot be fully released during this time.

183 For example, the largest amount of excess electricity from PV (approx. 0.6 GWh) occurs continuously for 9 hours between 8 am and 5 pm on May 25th.

application faces the same market prices both in case of wind and PV and can sell excess electricity in the same way. In comparison to the input unit the utilization of the output unit is higher, ranging between 9 % – 37 % for wind and 7 % – 32 % for PV. In this context, the optimal size and utilization of the output unit is a trade-off between the investment outlays and maximization of revenues based on the frequency and actual level of peak prices.

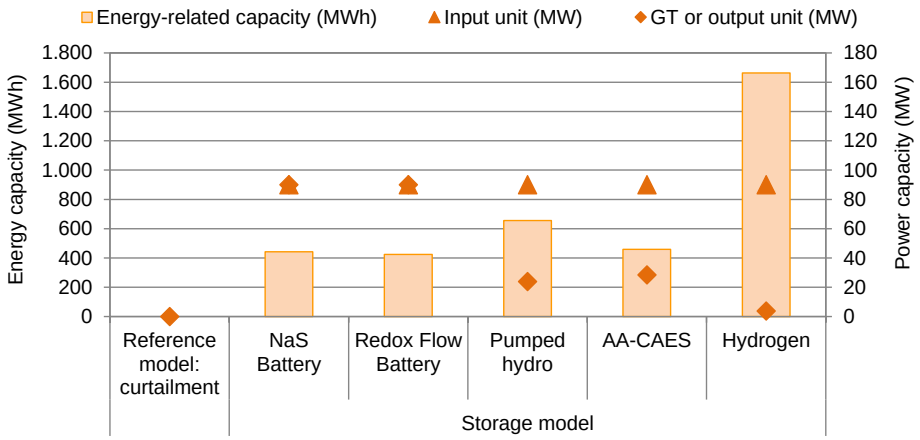


Figure 3.10: Optimal sizing of the facility in combination with PV in case B.

From the economic perspective, curtailment of excess electricity does not require any investment, and the NPV of the conventional alternative in case B is equal to discounted total revenues from direct market sales. This value is lower for wind than for PV (approx. 42 M€ versus approx. 47 M€), again due to different average market prices in hours when the renewable electricity is available. Introducing electricity storage in case B increases the overall revenues of the facility as it allows for sales of excess electricity which otherwise would be subject to curtailment. This effect directly depends on the round-trip efficiency and is higher for technologies with lower efficiency losses. In addition, all technologies benefit from additional time-shifting of intermittent electricity, as the overall storage input is always higher than the excess electricity. Since storage capacities are built anyway to cope with grid congestion, they are also co-utilized to sell renewable electricity in a later period at a higher price. This effect is proportional to the round-trip efficiency of each technology and is slightly higher for PV than for wind. This difference again stems from various distributions of the corresponding feed-in patterns between daytime and night. In comparison to conventional alternatives,

on the one hand the revenues from direct sales by the renewable plant decrease, but on the other hand sales of the storage output unit and hence overall facility revenues increase.

However, costly capacity investments are the major drawback of the storage technology. Comparatively high capital expenditures over-compensate the storage benefits in case B such that the value of storage is negative in all cases. In this context, the net investment outlays for storage input and energy capacities are major drivers for the value of storage in both the wind and PV cases. Table 3.5 presents the composition of net investment outlays in case B.

Table 3.5: Composition of net investment outlays in case B*.

Parameter	Unit	Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
Net investment outlays in case of wind onshore							
Storage input unit	M€	0.0	18.8	42.6	20.1	17.4	102.9
Energy-related capacity	M€	0.0	3,047.7	5,060.3	78.8	292.7	1.6
GT or storage output unit	M€	0.0	18.8	42.6	6.0	6.0	1.0
Total	M€	0.0	3,085.4	5,145.4	104.9	316.1	105.5
Net investment outlays in case of photovoltaics							
Storage input unit	M€	0.0	20.7	46.8	22.2	19.1	113.1
Energy-related capacity	M€	0.0	121.0	202.9	4.0	12.0	0.2
GT or storage output unit	M€	0.0	20.7	46.8	5.9	6.0	1.1
Total	M€	0.0	162.5	296.6	32.1	37.1	114.5

* All values are calculated as actual investment outlays less discounted salvage value of the corresponding investment at the end of the detailed planning horizon.

Except for hydrogen technology, investment outlays for energy-related capacity have a share of more than 65 % of the overall expenditures in the wind case. This is due to the need for large energy capacities in the context of seasonality and comparatively high specific investment outlays. According to the optimal storage sizing, the net investment outlays in energy capacities for PV are notably lower by a factor of 7 – 25 than for wind. For large-scale applications including pumped-hydro, AA-CAES and hydrogen, net investment outlays in energy capacities are lower than for the input and output capacities, whereas

for batteries the opposite is true. However, for hydrogen technology, high capital expenditures for electrolysis as storage input unit make this technology comparatively expensive for avoiding PV curtailment. Therefore, hydrogen has a lower storage value for PV in comparison to wind and almost the same value as NaS battery in PV case.

3.4.5 Scenario analysis for case A and case B

The objective of this chapter is to analyze the impact of selected input parameters on the value of storage. We intend to examine under which boundary conditions electricity storage becomes an attractive option to cope with intermittent electricity. The key parameters identified for the analysis are specific investment expenditures for storage technology, variable production costs of the thermal power plant represented by average prices for natural gas and CO_2 certificates as well as electricity price volatility. We first define the scenarios and then present our findings for cases A and B.

Scenario definition

As described in chapter 2.3.3 the actual investment outlays for different storage technologies typically vary within a broad range. For example as argued by Deane et al. (2010), the costs for a pumped-hydro storage depend on the specific facility location and might be very high for sites with unfavorable topological conditions. Moreover, according to Brunetto and Tina (2007), the hydrogen technology costs might decrease in the future thanks to further research activities. We examine the impact of technology costs by multiplying the specific investment expenditures by factors of 150 %, 50 % and 25 %.[184]

Moreover, since in case A the storage value is defined as the NPV difference between thermal power plant and storage technology, the development of variable production costs of the gas turbine has a direct impact on the relative

184 Note that we use the same factors to adapt the specific investment expenditures for all components of the storage including input and output unit as well as energy-related storage capacity. In reality, for some technologies applying various factors for different storage components might be a more adequate approach. For example, for the hydrogen technology the electrolysis costs might decrease in the future whereas the GT as an output unit can be considered as a mature technology without cost reduction potential. However, for the sake of traceability we refrain from the separate variation of investment outlays of single storage components.

performance of both alternatives. The main drivers for the variable production costs are represented by uncertain prices for primary energy and CO_2 certificates. In our analysis we follow Nitsch et al. (2012a) and Pregger et al. (2013) on the expected energy and carbon price pathways and expect the prices to increase up to 36 €/MWh for natural gas and 35 €/t_{CO2} for CO_2 certificates in the mid-term and up to 56 €/MWh and 75 €/t_{CO2}, respectively, in the long-term.[185] Taking other variable costs of 5 €/MWh into account, this corresponds to an increase of overall variable production costs from 70 €/MWh in the short-term up to 113 €/MWh in the mid-term and 192 €/MWh in the long-term.

Electricity price volatility is an important factor influencing the value of storage shifting electricity from low-price periods (usually off-peak load with high intermittent feed-in) to high-price periods (usually peak-load with low intermittent feed-in). To assess the impact of this parameter, the electricity price volatility is doubled from approx. 19 €/MWh to approx. 37 €/MWh. This adjustment is conducted by multiplying the difference between each hourly price value and the average price by a factor of 2. This corresponds to a clockwise rotation of the price duration curve. In a given hour t the adjusted price $p_t^* = \left(p_t - \frac{\sum_{t=1}^{8760} p_t}{8760}\right) \cdot 2 + \frac{\sum_{t=1}^{8760} p_t}{8760}$.

For the sake of clarity, we conduct our analysis by combining specific values of the considered parameters in predefined scenarios rather than calculating the sensitivity of each factor separately. In this way, we examine under which circumstances electricity storage is a valuable option for integrating renewable electricity into the energy system. The scenarios can be classified into short-, mid- and long-term categories according to the expected market trends and technology development. As summarized in Table 3.6 we define the following scenarios:

- **Reference scenario:** This scenario represents the original outcomes for cases A and B as described in chapters 3.4.3 and 3.4.4. It is based on the input data from chapter 3.4.2 and used for comparison with other scenarios.

185 The values in our analysis correspond to the figures in price path A ("Preispfad A: Deutlich") from Nitsch et al. (2012a, p. 51, Table 2–3). Since original numbers are expressed as real prices for 2009, we adapt the figures for natural gas for 2012 assuming an annual inflation rate of 2.5 %.

- **Scenario 1:** In order to account for higher investment outlays for the storage technology, we increase the specific investment expenditures by a factor of 150 %. All other parameters remain unchanged. We expect this scenario rather in the short-term and it can be viewed as a worst case from the storage perspective.

- **Scenario 2:** This scenario is considered as a mid-term case. The storage investment expenditures are expected to decrease by 50 % and the variable costs of the thermal power plant increase moderately up to approx. 113 €/MWh. Electricity price volatility remains unchanged.

- **Scenario 3:** This is a long-term scenario with a further increase of market prices for natural gas and CO_2 certificates. The average marginal costs of the thermal power plant are approx. 192 €/MWh. Moreover, we also assume the same storage investment expenditures as in scenario 2 but a double electricity price volatility due to increased overall renewable feed-in.

- **Scenario 4:** This scenario can be viewed as a best case from the storage perspective. We assume very low storage investment expenditures going down to 25 % of the original values from the reference scenario. Prices for natural gas and CO_2 certificates as well as electricity prices volatility are at the same high level as in scenario 3.

Table 3.6: Major characteristics of the selected scenarios.

Scenario	Expected time horizon	Investment expenditures for storage technology in % of initial values	Average NG price €/MWh	Average price for CO_2 certificates €/t_{CO2}	Electricity price volatility €/MWh
Refrence	Short-term	100	25	5	19
1	Short-term	150	25	5	19
2	Medium-term	50	36	35	19
3	Long-term	50	58	81	37
4	Long-term	25	58	81	37

Scenario analysis for case A

The results of the scenario analysis in case A are illustrated in Figure 3.11. As expected, scenario 1 represents the lower bound and scenario 4 the upper bound for the storage value for all selected technologies. In scenario 2 all storage applications are economically better off than in the reference scenario but they are less beneficial than in scenario 3. This order in storage value among the selected scenarios remains unchanged for all technologies in both the wind and PV cases.

According to the observations in the reference scenario, storing renewable electricity is more attractive with wind rather than with PV. In combination with wind, large-scale technologies including pumped-hydro, AA-CAES and hydrogen break even with the conventional alternative in scenarios 2, 3 and 4 as the corresponding storage value is positive or close to zero. Surprisingly, we also find a positive value for NaS battery under the assumptions of scenario 4 thanks to low investment outlays and the comparatively high efficiency of this technology. For PV positive storage values are achieved only by pumped-hydro in the optimistic scenarios 3 and 4. In general, large-scale storage technologies tend to be economically more attractive than batteries in almost all cases.

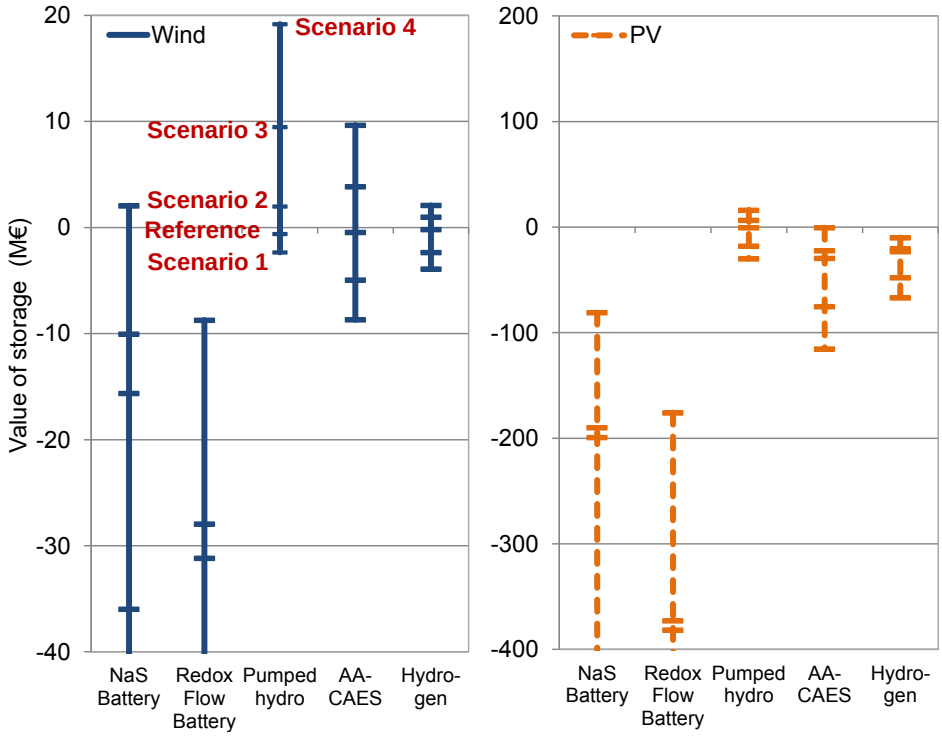


Figure 3.11: Results of the scenario analysis on value of storage in case A.

In order to better understand the results of the scenario analysis we provide an overview of the net present value of each option in Table 3.7. The overall level of investment outlays in energy capacity has a comparatively large impact on the NPV of storage. Therefore, the storage value of hydrogen technology varies within a comparatively small range as this application has relatively low corresponding capital expenditures. In contrast, battery technologies are characterized by high energy-related investment outlays and hence have a substantial risk of loss. Moreover, thanks to low specific investment expenditures in scenarios 3 and 4 almost all storage technologies take advantage of additional time-shifting benefits and utilize higher input and output capacities than in the reference scenario. Consequently, revenues from market sales through electricity storage and the overall NPV increase in comparison to the reference scenario. This effect is more significant for technologies with high round-trip efficiencies such as NaS battery and pumped-hydro.

Table 3.7: NPV for the gas turbine and storage technologies in case A for the selected scenarios.

Scenario	Unit	Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
NPV in combination with wind							
Reference	M€	49	13	−18	48	44	46
1	M€	49	−7	−53	46	40	45
2	M€	48	32	17	50	47	48
3	M€	45	35	17	55	49	46
4	M€	45	47	37	64	55	47
NPV in combination with PV							
Reference	M€	52	−365	−729	34	−23	4
1	M€	52	−577	−1,123	22	−63	−15
2	M€	47	−153	−335	46	17	23
3	M€	39	−145	−328	52	23	25
4	M€	39	−36	−131	61	45	35

As expected, higher primary energy and CO_2 certificate prices lead to higher variable costs of the gas turbine and ceteris paribus reduce the corresponding

annual profits. This is the main reason for the difference in NPV of the thermal power plant between the selected scenarios. Consequently, storage appears more attractive when the NPV of the gas turbine is lower, since the NPV of the conventional alternative is used as a basis to calculate storage value. For this reason, storage is more beneficial in scenario 3 rather than in scenario 2 although we assume the same investment expenditures in both scenarios.

In order to understand the impact of price volatility on the overall results, it is important to distinguish between two major effects on the storage NPV. On the one hand larger volatility typically changes the market value of direct renewable sales which might decrease according to the actual distribution of intermittent production over time, but on the other hand it also increases the profits from additional energy time-shifting (beyond the requirement to satisfy the minimal demand). The overall change in total revenues and hence the NPV under minimal demand constraint depends on the actual market value of renewable generation and whether one effect is stronger than the other. In particular, today wind has lower market value with increasing price volatility as the corresponding feed-in occurs comparatively often during night time. However, the additional time-shifting effect over-compensates these losses and for most applications the overall revenues and the NPV increase. Contrary, for hydrogen technology with low round-trip efficiency and hence high opportunity costs the opposite is true and therefore its NPV is lower in scenarios 3 and 4 than in scenario 2 despite the reduction of specific investment expenditures. In case of PV the price volatility has a positive effect on the value of intermittent electricity due to a better correlation of PV availability with current electricity prices and overall revenues and corresponding NPV increase.

Scenario analysis for case B

In case B the value of storage for all technologies and both intermittent sources follows the same order as in case A. The smallest value occurs again in scenario 1 being lower than in the reference scenario, and the highest value is achieved in scenario 4 with very cheap storage technology. Scenario 3 provides better boundary conditions for electricity storage than the reference scenario but is only slightly better than scenario 2. In addition, again

as in the reference scenario, electricity storage is economically better off in combination with PV rather than with wind for all applications except for hydrogen technology. In the reference case and in scenarios 1 and 2, hydrogen storage has a higher value with wind than with PV. Moreover, as in the reference scenario storage technologies with expensive energy-related capacities, such as batteries, are always better suitable to avoid transmission congestion from PV rather than to meet the minimal demand. The opposite is true for hydrogen (in all scenarios) and partially for pumped-hydro storage (in the reference case and in scenario 1 and 2). Under the given assumptions, positive storage values can only be achieved by pumped-hydro and AA-CAES in combination with PV in scenario 2 and 3.

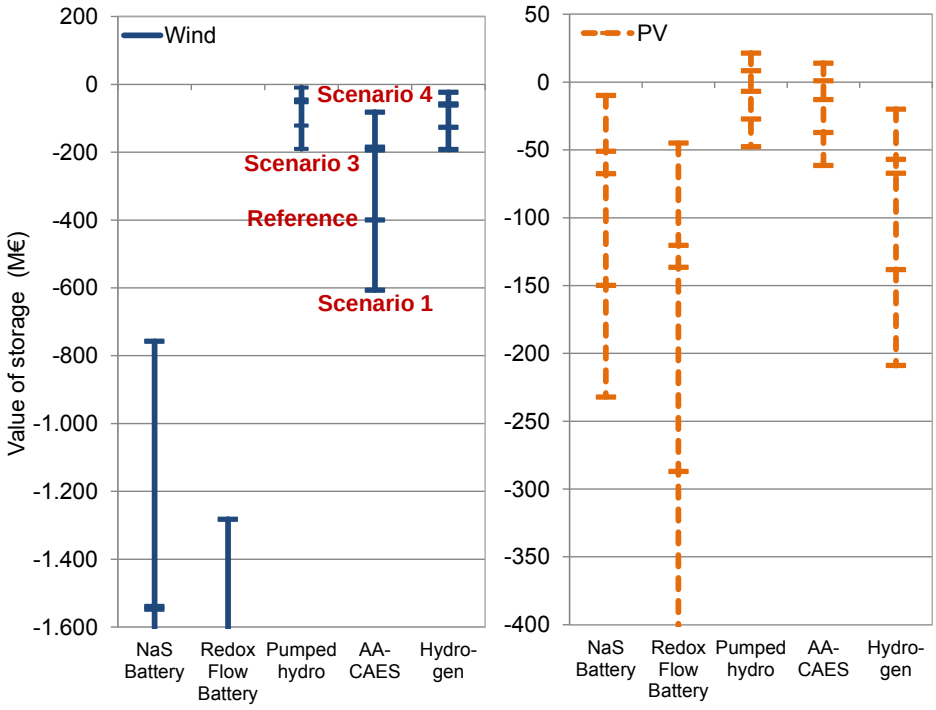


Figure 3.12: Results of the scenario analysis on value of storage in case B.

Table 3.8 contains a comparison of the NPV from curtailment and storage investment and operation. Similar to case A, the reduction of technology costs has a great impact on the storage value for all applications and this effect is proportional to the actual net investment outlays: the higher the outlays, the larger the range between scenarios 1 and 4. Moreover, as expected the change

of natural gas and CO_2 certificate prices has no influence on the results of the conventional alternative since the thermal power plant is not considered in the reference model in case B.

Table 3.8: NPV for curtailment and storage technologies in case B in selected scenarios.

Scenario	Unit	Curtail-ment	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
NPV in combination with wind							
Reference	M€	42	−3,069	−5,165	−79	−358	−84
1	M€	42	−4,632	−7,777	−148	−564	−149
2	M€	42	−1,505	−2,554	−10	−151	−19
3	M€	42	−1,497	−2,546	−3	−143	−15
4	M€	42	−715	−1,240	33	−40	19
NPV in combination with PV							
Reference	M€	47	−103	−240	20	10	−91
1	M€	47	−185	−390	−1	−14	−162
2	M€	47	−20	−89	40	34	−20
3	M€	50	−9	−78	50	43	−15
4	M€	50	32	−3	63	56	22

Rising volatility has again a negative effect on the value of wind on the one hand but a positive effect on the value of renewable generation from PV on the other hand. Nevertheless, the NPV of the conventional alternative in combination with wind remains almost unchanged, as in the reference model in hours with negative prices renewable electricity is curtailed and not sold to the market. In contrast, the corresponding figure for PV increases by 6 % from approx. 47 M€ in reference scenario to approx. 50 M€ in scenarios 3 and 4. For storage technologies, higher price volatility again allows for additional time-shifting of renewable electricity and therefore the NPV of all storage applications increases. This effect is stronger for PV than wind and for technologies with better round-trip efficiencies such as pumped-hydro or NaS battery. In general, however, the impact of volatility is smaller than the impact of decreasing technology costs. This is one reason why the results of scenarios 2 and 3 are rather similar.

3.4.6 Relationship between renewable feed-in, demand level and grid capacity

The level of minimal demand and maximal grid capacity can be viewed as an arbitrary assumption which might change considerably depending on the actual situation in a given grid node. Therefore, in this chapter we vary these parameters and calculate the corresponding NPVs for each scenario as defined in the previous chapter. For the sake of transparency the amount of intermittent electricity remains unchanged in both cases.

In case A, a rising level of minimal demand increases the electricity deficit which has to be compensated by the gas turbine or storage. Therefore, due to greater investments in costly capacities and higher production costs, the NPV of the conventional alternative and all storage technologies drops. At this point it is important to mention that the maximal amount of deficit electricity which can be sufficiently provided by the storage strongly depends on the corresponding round-trip efficiency. Low efficiency means high energy losses and therefore some applications are not able to meet the predefined level of minimal demand.[186] In addition, we find that growing demand leads to a larger range of the storage value among the selected scenarios and hence to a greater uncertainty regarding the profitability of the storage. This again stems from the increasing role of the capacity investment outlays. In most scenarios and for most applications in combination with both intermittent sources we report falling storage value over all levels of the minimal demand.[187] This means that higher demand makes storage usually less attractive to cope with intermittent electricity in case A. Positive storage values can typically only be found for comparatively cheap technologies and very low levels of minimal demand of 20 % and less. In such cases, storage costs are smaller than the costs of the thermal power plant.

186 For example, hydrogen storage has a comparatively low round-trip efficiency of 28 %. Therefore this technology is not able to meet minimal demand which is higher than 60 % of the intermittent feed-in from wind (i. e. more than approx. 116 GWh). Note that the share of minimal demand in renewable feed-in can be higher than the round-trip efficiency as some electricity is still provided directly by the renewable plant without any losses.

187 In combination with PV: all technologies in all scenarios. In combination with wind: both batteries in all scenarios, hydrogen and AA-CAES in the reference scenario as well as in scenario 1 and 2; pumped-hydro storage only in the reference scenario and scenario 1.

Surprisingly, we find a somehow different behavior of the storage value for large-scale technologies in combination with wind in scenarios 3 and 4 and partially in scenario 2. As presented in Figures 3.13 – 3.15, the storage value is positive for cheap large-scale applications and it rises up to a technology-specific maximum followed by a rapid drop once a certain level of minimum demand is reached. Highest storage values are achieved for a demand share of between 50 % and 80 % (scenarios 2 and 4, respectively) for pumped-hydro and between 30 % and 50 % (scenarios 3 and 4, respectively) for AA-CEAS and hydrogen technology.

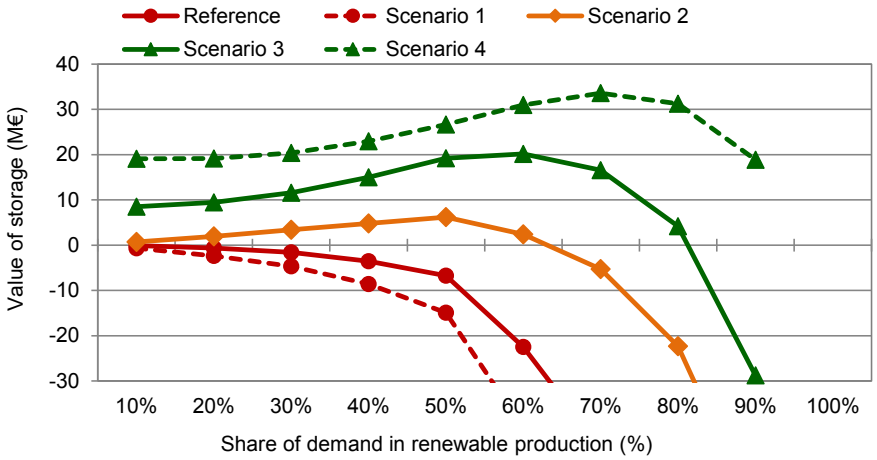


Figure 3.13: Value of storage for pumped-hydro as a function of share of minimal demand in wind availability in case A.

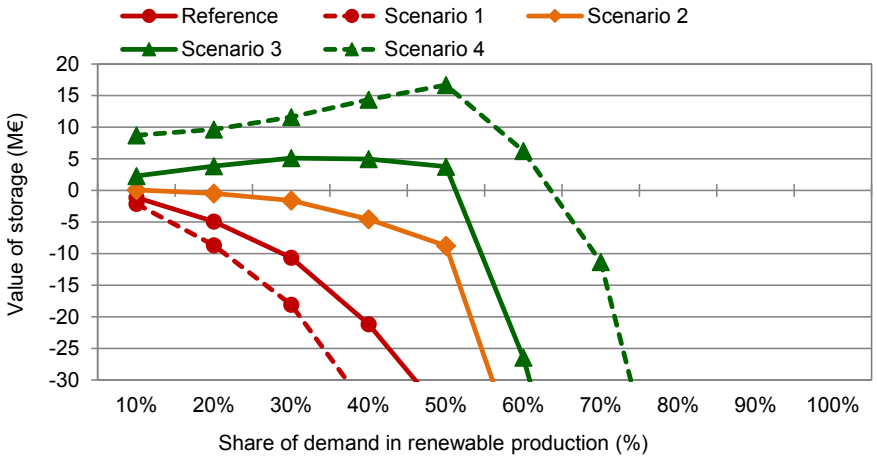


Figure 3.14: Value of storage for AA-CAES as a function of share of minimal demand in wind availability in case A.

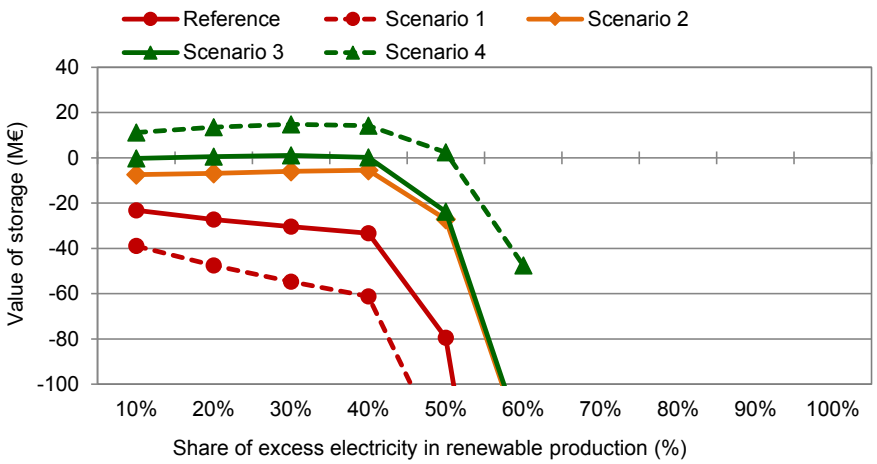


Figure 3.15: Value of storage for hydrogen technology as a function of share of minimal demand in wind availability in case A.

For cheap storage technologies and high electricity price volatility, the production costs of conventional alternative increase faster than the overall gains from energy time-shifting of the storage unit decrease. Hence until a certain demand level is reached, the NPV of storage is higher and decreases at a slower pace than the NPV of the thermal power plant. Based on these effects, the optimal storage NPV is a result of a trade-off between net investment outlays for power and energy capacity by taking into account the distribution of electricity prices as well as demand and feed-in profiles. In this context, under some circumstances an optimal choice regarding minimal demand level might help to maximize the value of storage.

As expected, falling grid capacity in case B has a negative effect on the NPV of the facility in both the reference and storage models. For the conventional alternative, stricter grid constraint increases curtailment of intermittent generation and reduces the revenues of the renewable power plant. For the electricity storage, smaller gird size requires larger investment outlays in corresponding storage capacities since all excess electricity must be utilized by the storage. The round-trip efficiency is again a limiting factor for the ability of storage applications to cope with excess intermittent electricity. In fact, for a given grid capacity, the lower the efficiency, the more electricity can be sold to the market in periods when transmission constraint is not binding

as more electricity is lost through storage charging and discharging. This is a somewhat counterintuitive outcome but is due to the fact that in the storage model the facility is forced to store all excess electricity for later sales. Therefore, for some unfavorable constellations not all excess electricity can be re-injected into the grid. In such cases the model provides an infeasible solution which is interpreted as the inability of the storage to avoid grid congestion. Of course, relaxing the minimal uptake constraint would change our results, however, this particular analysis is not in the scope of our study. In this context, hydrogen technology with the lowest efficiency is capable of operating under stricter grid constraints than other applications.[188] In addition, due to differing distribution of the intermittent electricity over the year, storage in combination with PV is able to process more excess electricity than in combination with wind onshore.[189]

Similar to case A, smaller grid capacity increases the range between the highest and lowest NPV in scenario 1 and scenario 4. This is again due to rising investment outlays for storage capacities and the large difference in technology costs between the various scenarios. In most circumstances the value of storage decreases with the rising share of excess electricity in renewable production. Due to large investments in storage capacities, the NPV of the storage typically drops more than the corresponding NPV of the conventional alternative.

However, as indicated in Figures 3.16 and 3.17, the opposite is true in scenario 4 for pumped-hydro and AA-CEAS in combination with PV up to a level of excess electricity of approx. 30 % – 40 %. In this case, thanks to a favorable trade-off between energy time-shifting effect as well as relatively low power-related and energy-related capacitiy outlays, the storage NPV changes at a slower pace than the present value of direct market sales of the conventional alternative. The rapid drop in storage value beyond this threshold is mainly due to the fact that the excess electricity during the daytime is too large and

188 However, this does not mean that hydrogen has a higher storage value. This figure depends on the trade-off between the actual investment outlays and the additional benefits from market sales.

189 The maximal share of excess electricity on renewable generation amounts to 30 % – 40 % for wind and to 60 % – 80 % for PV. The higher percentage values correspond to hydrogen technology with the lowest efficiency whereas the lower values correspond to all other storage types.

the grid capacity at night is too small to empty the storage prior to the next day and a costly seasonal capacity is required to uptake the aggregated excess electricity. For hydrogen, however, this relationship has a limited impact on the value of storage thanks to comparatively low specific investment expenditures for energy capacity (see Figure 3.18).

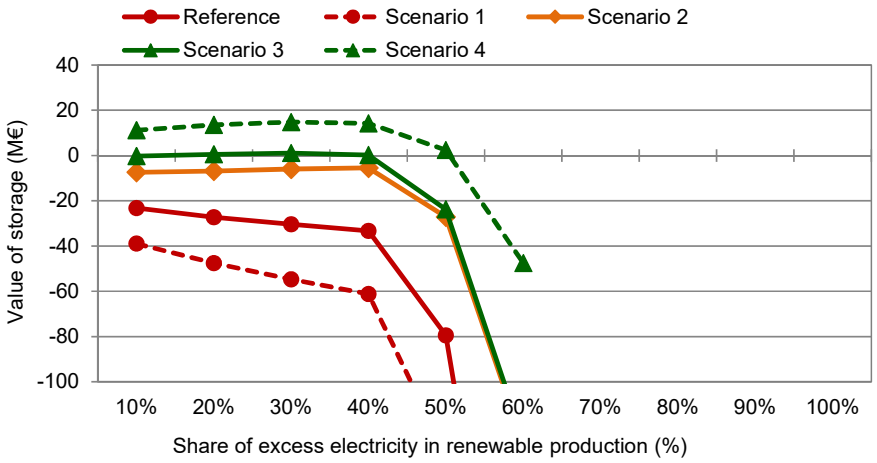


Figure 3.16: Value of storage for pumped-hydro as a function of share of excess electricity in PV availability in case B.

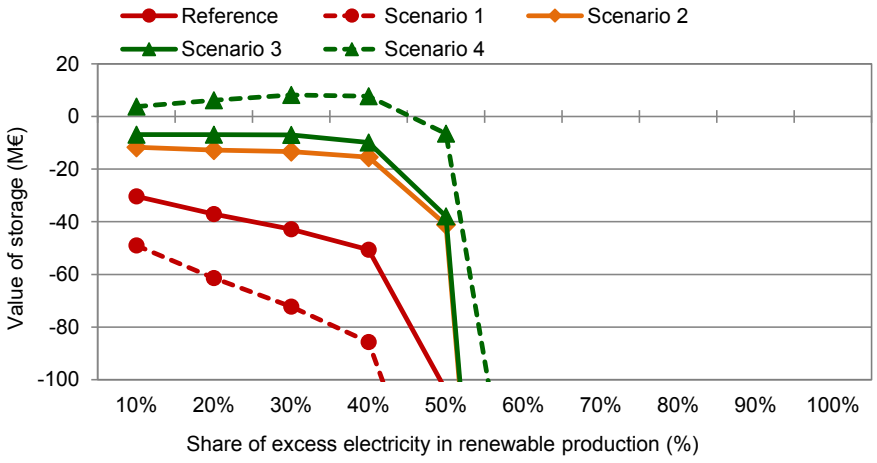


Figure 3.17: Value of storage for AA-CAES as a function of share of excess electricity in PV availability in case B.

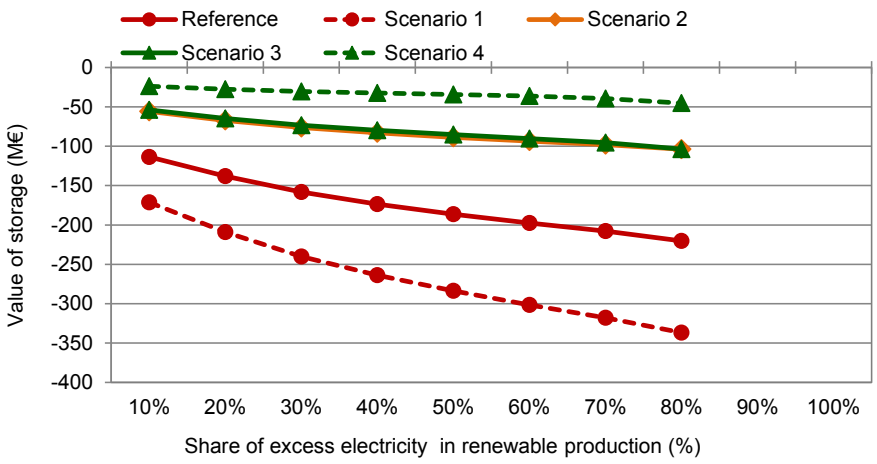


Figure 3.18: Value of storage for hydrogen technology as a function of share of excess electricity in PV availability in case B.

3.5 Conclusion

Under the current conditions including relatively high technology costs, low CO_2 prices and limited electricity price volatility, conventional alternatives, i.e. investment and operation of a thermal power plant to meet minimal demand and curtailment of excess electricity in case of limited grid capacity, have a higher NPV than storage technologies and thus the value of storage is negative. In the context of seasonality we find that large-scale technologies such as pumped-hydro, AA-CEAS and hydrogen are economically more favorable to cope with challenges of intermittent electricity generation from a single investor's perspective. In fact, in some cases large-scale technologies have a positive NPV which is only slightly lower than the corresponding value of the conventional alternative. Moreover, all storage applications provide better results in combination with wind rather than with PV when minimal demand constraint holds. Typically, the opposite is true when avoiding curtailment of electricity surplus above limited transmission capacity. In this case, except for hydrogen all storage applications are better off in combination with PV rather than with wind. Further, we find that for wind storage is economically more suitable to meet minimal demand rather than to avoid grid congestion. For PV our analysis shows that storage applications with high specific energy-related investment outlays such as batteries provide better results for curtailment avoidance rather than for renewable capacity firming.

These outcomes are mainly due to different seasonal patterns of both intermittent sources as a major technical constraint for facility sizing and operation. Electricity from PV typically occurs in summer with production peaks at noon, whereas wind generation is more equally distributed over the year with a bias towards the winter months. Therefore, wind requires limited energy-related capacities and small size of the output unit to meet minimal demand, but usually large energy capacities are needed to uptake all excess electricity when grid constraint is binding. For PV the opposite is true (e.g. large energy-related capacity to meet minimal demand and small energy-related capacity to uptake excess electricity), as on the one hand minimal demand requires large seasonal energy compensation between summer and winter, and on the other hand excess electricity can be stored on a shorter basis with charging at day time and discharging at night. In case of minimal demand the capacity of the gas turbine and storage output device is determined by the maximal difference between demand and renewable feed-in. We find that for the data used in our analysis this capacity is at a similar level for both wind and PV, and there are no economic incentives to install larger capacities. Analogously, storage input capacity is related to the maximal difference between variable generation and grid capacity. Also in this case, the input capacities are similar for both intermittent sources without any incentive for oversizing. Low utilization rates of the input unit indicate that in this context excess electricity is available at high power rates within a limited number of hours.

For almost all technologies and constellations, energy-related investment outlays have a significant influence on the overall value of storage. Although applications with expensive energy capacity such as batteries are characterized by high storage utilization (i.e. a large number of full cycle equivalents or a small number of storage days), the corresponding overall storage value is lower than for large-scale technologies with cheap energy capacity such as hydrogen. This is due to the need of shifting comparatively large amounts of energy in the seasonal context. An important exception is represented by curtailment of PV electricity where large input capacities are required but energy capacity needs are limited. In this case, batteries might provide similar economic results as hydrogen technology. In addition, we find that storage utilizes a larger electricity amount than is needed

to fulfill corresponding technical constraints, i.e. storage output is higher than electricity deficit and storage input is larger than electricity surplus. This is due to the fact that in both cases storage is co-utilized to earn profits from additional energy time-shifting. In this way, the facility's NPV can be improved and it has a clear advantage over the inflexible conventional alternatives.

We conclude that positive value of storage can be achieved only under substantial changes of the boundary conditions. In particular, the specific investment expenditures must decrease notably to make storage economically attractive. Also in the short-term, providing back-up electricity through thermal power plants is a better alternative unless the marginal costs of conventional electricity generation increase dramatically or environmental targets are prohibitive to fossil fuel use. However, if all advantageous circumstances arise then electricity storage will become more profitable than the conventional alternative and from the economic perspective it should be favored over conventional generation. In general, increasing the share of renewable generation and thus changing the ratio between installed renewable capacity and minimal demand or maximal grid capacity has some impact on the overall results. In this context, we find that under some circumstances choosing the optimal level of renewable feed-in in comparison to actual demand or grid capacity might increase the value of storage.

In this context, the results of our case study confirm the findings in the literature stating that storage costs are high in comparison to potential revenues from the wholesale power market. Moreover, we also conclude that among different storage alternatives pumped-hydro turns out to be an established technology with comparatively high storage value. However, as mentioned above, our results emphasize the advantage of large-scale storage technologies with cheap energy-related investment outlays over other storage types when seasonality of intermittent power generation is taken into account. In particular, batteries cannot be considered as a good choice for shifting large amounts of PV power between summer and winter months. This is in contrast to the results of some other studies which examine battery operation on a daily basis and conclude that batteries are a suitable solution to complement electricity production from PV

in small scale applications. This is mainly due to the fact that on the daily basis the energy-related storage capacities required to balance electricity demand and intermittent PV power are rather low whereas in the context of seasonality the opposite is true.

Furthermore, we prove that the methodology developed in this chapter allows for a comprehensive evaluation of different storage technologies in the context of intermittent power feed-in. The models can be used to support decision making on investment projects form a single player perspective. Our analysis reveals which technology is most suitable for different applications under varying boundary conditions. In particular, we provide useful insights into the optimal sizing of different storage components under some operational constraints.

Nevertheless, there are several limitations of our analysis. First, it is conducted from the perspective of a single investor who assumes power prices as exogenous input parameters. Hence, we do not take into account the price-smoothing effect of electricity storage on the power prices and might overestimate the value of storage when operated under real market conditions. Second, we use only deterministic input parameters and exclude uncertainty from our analysis. In particular, we presume perfect foresight of the electricity prices and intermittent feed-in. In the context of seasonality this is a strong assumption as we have to predict the corresponding values for each hour of a prototypical year. Third, we consider electricity sales on the day-ahead spot market as the only source of revenues and neglect potential storage benefits from other market applications. As mentioned in chapter 3.3.1, in this way the true value of electricity storage is not fully reflected in our results. Finally, we simplify our model in regard to some technology characteristics such as variable costs for storage input or energy losses due to self-discharge. Thus an analysis based on an extended model might provide more realistic results.

4. Green hydrogen supply for the power and mobility sectors[190]

4.1 Introduction

In previous chapter we studied the value of storage in the context of integrating intermittent electricity in the power sector by renewable capacity firming and avoiding curtailment of excess generation. Our results show that among the different applications, hydrogen is a promising technology to cope with variable power production as it is characterized by comparatively low specific energy-related investment outlays allowing for inexpensive shifting of large electricity amounts on a seasonal basis (weeks to months). Another important advantage of hydrogen is represented by the fact that it can be used directly as a fuel by FCEVs establishing a connection between the mobility and power sectors. As described in chapter 2.2.2 hydrogen cars can overcome some of the shortcomings of pure battery electric vehicles such as short driving range and long charging times and allow for zero emission driving when combined with electrolytic hydrogen production from renewable sources. Therefore an important advantage of hydrogen technology over other storage applications is represented by additional revenues from the mobility sector and potential synergies when utilized in different markets simultaneously.

From today's perspective, however, electrolysis as a key component of hydrogen technology is still expensive although some cost reductions are expected in the future. Moreover, hydrogen production via electrolysis can be viewed

190 This chapter is partially based on a common publication with Dr. Ulrich Bünger, Fritz Crotogino and Dr. Olaf Kruck in Bünger et al. (2016). Being in charge of the economic valuation of the hydrogen technology I have developed the model, collected the input data, run the techno-economic analysis and written the corresponding parts of the contribution. Some parts of the model description in this chapter are identical with the text published in Bünger et al. (2016). The methodology developed in this chapter was also used in publicly funded projects presented in DLR (2015) and Albrecht et al. (2016).

as a new consumer who purchases electricity from the market and thus imposes new challenges for the power system. In addition, depending on the actual source of electricity, hydrogen production is not necessarily fully renewable.

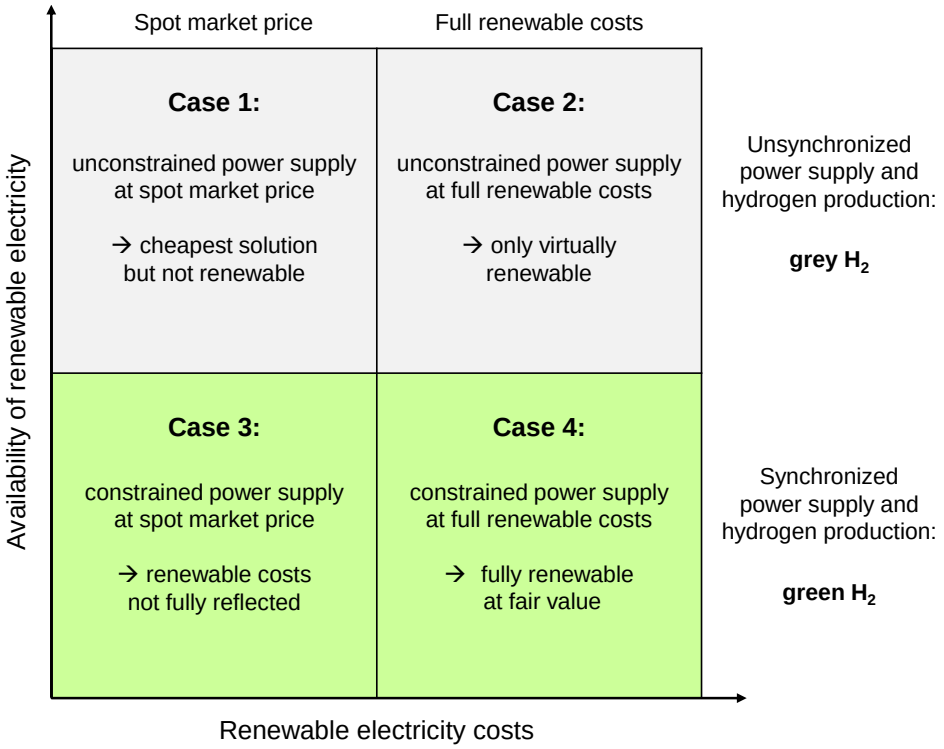


Figure 4.1: Hydrogen supply classification.

In fact, based on the current market structure, hydrogen supply both for power and mobility applications can be subdivided into grey and green hydrogen production according to the underlying assumptions on the availability of renewable electricity (see Figure 4.1). Green hydrogen is provided when power supply and electrolysis operation are fully synchronized, i.e. electrolysis is run only if renewable and usually intermittent electricity is available, whereas for grey hydrogen this restriction is not binding. In addition, hydrogen supply can be categorized according to the underlying electricity costs based either on spot market prices or full renewable costs. Unconstrained electrolysis operation valued at spot market prices usually represents the cheapest solution which, however, cannot be considered as fully renewable (case 1). Hence, the value of such a unconstrained production regime can be further adjusted

by taking into account additional payments for corresponding grid fees, CO_2 allowances or certificates of origin in order capture full renewable costs (case 2). This solution can be viewed only as virtually renewable as from the system perspective additional electricity demand through electrolysis and intermittent power generation are still not aligned.

In contrast, synchronized green hydrogen production ensures that electrolysis is operated in such way that it supports system stability in the context of variable power generation. However, when valued at spot market prices it might not reflect full renewable costs (case 3).[191] Therefore hydrogen supply can be viewed as fully renewable at fair value only if synchronized production takes into account all investment outlays associated with corresponding renewable capacities (case 4).

The major objective of this paper is to evaluate the overall costs of the aforementioned hydrogen categories for different market applications. In detail, we are interested in the cost difference between green and grey hydrogen production under varying boundary conditions represented by falling technology costs and changing electricity prices. We assume that this difference indicates the value of green hydrogen as a universal energy carrier in the context of the integration of renewable electricity into the future energy system. In addition, we analyze potential synergy effects from the co-utilization of the hydrogen facility in the power and mobility sectors. Our study is carried out from the perspective of a single profit maximizing firm which optimizes capacities and hourly operations of a prototypical production plant. The remainder of this chapter is structured as follows: chapter 4.2 includes a literature review on costs and value of hydrogen technology. In chapter 4.3 we propose a linear programming model to analyze the optimal sizing and operation of a prototypical hydrogen facility. This is followed by the application of the model in chapter 4.4 within a case study for Germany under different boundary conditions. In chapter 4.5 we conclude.

191 For example as described in chapter 2.2.2, in Germany under the current market structure renewable generation is remunerated based on additional feed-in tariffs which are not reflected in the spot market price.

4.2 Selected literature on hydrogen technology in the power and mobility sectors

In general, the economic literature[192] on hydrogen technology can be subdivided into different streams according to the categorization presented in chapter 2.4. Regarding the modeling scope, system studies[193] typically explicitly take into account potential demand for hydrogen in different markets such as the mobility or heat sector. The overall objective of such analyzes is the minimization of total costs or maximization of social welfare of an integrated energy system including power, heat and mobility markets where hydrogen is considered as a universal energy carrier. In contrast, engineering studies focus on techno-economic analyzes of a single facility producing hydrogen for different applications. Such contributions allow for a more detailed representation of the technical constraints of the selected hydrogen technology distinguishing between different production processes,[194] hydrogen storage types[195] and interfaces to the surrounding system. Usually, system studies employ simulation or equilibrium models with or without explicit representation of a power transmission network whereas engineering models minimize the costs or maximize the profits of a single hydrogen production plant. In our review, we focus on engineering studies for single-firm optimization of a facility in a single grid node providing hydrogen via water electrolysis. Moreover, we limit our survey to contributions estimating the costs and the value of hydrogen in the power or mobility sectors.

Korpås and Holen (2006) develop a dynamic programming algorithm for optimization of a power plant operation consisting of electrolysis, compressed hydrogen storage and fuel cell in combination with wind generation. The facility provides back-up power in the electricity system as well as hydrogen fuel for mobility applications. In the context of Norwegian island system,

192 Typically, the economic literature on hydrogen technology focuses on the costs and market value of hydrogen in different applications. Besides such business-related contributions there is also a broad range of technology-related studies addressing purely technical issues of hydrogen, which, however, are not in the scope of our review.

193 See for example Nitsch et al. (2010a), Nitsch et al. (2010b), Nitsch et al. (2012a), Pregger et al. (2013) or Stolzenburg (2014).

194 The production technology analyzed in this chapter is water electrolysis. However as mentioned in chapter 2.3.3, there are also other techniques such as steam methane reforming or biomass gasification

195 For example underground salt-caverns or pressurized vessels.

they find that hydrogen production is mainly based on the predefined demand in the mobility sector and the fuel cell is utilized for re-electrification only in the case of high electricity price volatility due to the low storage round-trip efficiency. The studies in Greiner et al. (2007) and Korpås and Greiner (2008) are carried out within a similar modeling framework, however, in the context of a Norwegian distribution grid with limited capacity. The authors conclude that the additional hydrogen demand in the mobility sector as a flexible load might be an effective means to improve the utilization of intermittent electricity generation and to defer grid capacity extensions. However, the corresponding investment decision should take the seasonal effect of variable electricity generation into account.

Linnemann and Steinberger-Wilckens (2007) calculate the costs of hydrogen for the mobility sector provided by a small pilot facility and a large-scale production plant. Based on fixed electricity prices for off-shore wind in Germany and a given utilization of the electrolysis they report hydrogen costs excluding tax between 10 €/kg_{H2} and 23 €/kg_{H2} (or 300 €/MWh and 700 €/MWh).[196] The authors also find that on per km basis, hydrogen fuel is more expensive than conventional fuels by a factor of 3. They conclude that hydrogen costs can be reduced through maturing of electrolysis technology, cheaper renewable electricity as well as improved operation strategies and suggest taking into account the external costs of GHG emissions[197] when comparing hydrogen with conventional fuels.

Brunetto and Tina (2007) analyze the optimal operation and sizing of a hydrogen storage for wind generation in the Italian power market by applying both a linear and dynamic programming approach. Assuming current technology costs and Italian electricity market prices, hydrogen storage has a negative net present value and is therefore economically unfavorable when utilized solely in the power sector in combination with intermittent electricity. In addition, LP modeling framework tends to underestimate storage revenues in comparison with the dynamic programming approach.

196 Lower value refers to the large-scale facility whereas the higher value to the pilot facility.

197 Typically external costs are expanses which cannot be directly allocated to a certain polluter, such as additional health or global warming costs.

An interesting study is provided by Jørgensen and Ropenus (2008) who calculate the costs for electrolytic hydrogen production when electricity is purchased from the power market under different wind penetration levels. Based on Danish electricity prices and moderate specific technology investment outlays, hydrogen costs in this study vary between 4.5 €/kg_{H2} and 5.0 €/kg_{H2} (or 135 €/MWh and 150 €/MWh) and the optimal facility utilization strongly depends on the trade-off between capital expenditures and electricity price volatility. The analysis results indicate that optimal utilization and hydrogen costs are lower for a higher share of renewable electricity in the power system due to positive correlation between intermittent generation and price volatility. However, the specific hydrogen costs associated with peak shaving, i.e. balancing excess electricity production in a limited number of hours, are comparatively high due to the large impact of the capital expenditures.

Similar outcomes are obtained by Wietschel et al. (2009) who estimate the costs of hydrogen production from surplus renewable electricity in the German power market. Due to low overall utilization of the facility the hydrogen costs range between 8 €/kg_{H2} and 13 €/kg_{H2} (or 250 €/MWh and 400 €/MWh) but could decrease based on the reduction of specific investment outlays down to 6 €/kg_{H2} – 8 €/kg_{H2} (or 180 €/MWh – 240 €/MWh). They also find that producing hydrogen to satisfy the demand in the mobility sector without dedicated hydrogen storage is cheaper than the application in the power market with specific costs amounting to approx. 3 €/kg_{H2} (or 95 €/MWh). Also according to Stiller et al. (2011), the costs for the production and distribution of hydrogen from wind energy in the context of the German market are between approximately 5 €/kg_{H2} and 8 €/kg_{H2} (or 140 €/MWh and 240 €/MWh) based on a simple electricity price threshold strategy for electrolysis operation. Simón et al. (2014) and Albes et al. (2014) assess the potential and business cases of hydrogen underground storage for renewable electricity in Europe. The hydrogen costs in this comprehensive study are in the same range (4 €/kg_{H2} – 7 €/kg_{H2} or 120 €/MWh – 210 €/MWh) and the only application with a positive margin in Germany is represented by hydrogen sales in the mobility sector.

Kroniger and Madlener (2014) use a real option approach and Monte Carlo simulations to estimate the economic value of a system consisting of an electrolyzer, hydrogen storage device and a fuel cell. The facility is connected

to a wind park as well as to the transmission grid and provides services related to renewable curtailment avoidance, energy balancing in the market for minute reserve, energy time-shifting and hydrogen fuel production. The authors report that based on comparatively high technology costs as well as the uncertainty of wind feed-in, spot market prices and trading volumes in the balancing market, the only valuable application is represented by direct sales of hydrogen as a fuel. This is mainly due to lower investment requirements through the omission of the fuel cell unit, higher system efficiency and better electrolysis utilization. According to the case study, a hydrogen sales price of at least 4 €/kg_{H2} (or 120 €/MWh) is needed to reach the break-even point.

Loisel et al. (2015) analyze the economic value of a hydrogen storage system in combination with a wind off-shore power plant earning revenues from different markets including the power, mobility and natural gas markets. Specific hydrogen costs vary between 4 €/kg_{H2} and 47 €/kg_{H2} (or 120 €/MWh and 1,400 €/MWh) depending on the number of considered storage applications and required infrastructure scope and costs. The authors find that under the given conditions of the underlying case study, the profits are negative due to limited hydrogen sales prices. However, although the analysis is based on the net present value maximization, the major drawback of this study is exogenously predefined facility size.

The analysis in this chapter uses the same methodology as similar case studies on hydrogen technology presented in Bünger et al. (2016), DLR (2015) and Albrecht et al. (2016). Although our case study also determines the optimal sizing and operation of the hydrogen storage and production plant on an annual basis including seasonal effects, one important contribution of this work is represented by a detailed comparison of the value of different hydrogen categories as described in chapter 4.1 for various market applications. On the one hand we simultaneously dimension the electrolysis and wind turbines within an integrated facility and examine the effect of direct electricity provision from a wind park on the overall hydrogen costs. Most contributions in the literature do not give a comprehensive overview of the differences between the various hydrogen applications and categories in combination with intermittent electricity generation. On the other hand, the estimation of potential synergy effects provides interesting insight into the role of

hydrogen as a universal energy carrier in different markets in the context of integration of renewable energy into the German energy system. Therefore in contrast to the aforementioned contributions, our analysis combines both the effect of intermittent power supply and synergetic use of the hydrogen technology.

In DLR (2015) the hydrogen storage facility is connected to the electricity grid and does not take into account the variability of the renewable feed-in. Based on predicted spot market prices, the study analyzes the optimal operational strategy and estimates the hydrogen costs for different electrolysis technologies and market applications. Albrecht et al. (2016) examine the economic potentials for the commercialization of hydrogen technology in the region of Baden-Wuerttemberg in Germany. Although the authors define different scenarios for synergetic hydrogen use and energy provision from intermittent sources, none of them take into account both effects simultaneously. Moreover, due to geological conditions of the selected region, the storage technology in Albrecht et al. (2016) is represented by pressurized tube storage with different techno-economic characteristics than the underground salt caverns as assumed in this chapter. The hydrogen production in the analysis presented by Bünger et al. (2016) is based on the intermittent power supply but only for single applications without any synergy effects. Furthermore, both Albrecht et al. (2016) and Bünger et al. (2016) do not include the optimal sizing of the wind power plant needed to provide intermittent electricity for green hydrogen production. Also they calculate the value of green hydrogen only for the mobility sector without a comparison with other sectors.

In this context, DLR (2015) focusses on the value of hydrogen for re-electrification in the power sector, refueling FCEVs in the mobility sector, injection into natural gas grid and industrial hydrogen utilization. The authors report hydrogen costs in a range between 3 and 7 €/kg_{H2} (or 90 and 210 €/MWh) with positive profits only in the mobility sector. In addition, the study indicates potential synergy effects when utilizing the facility to satisfy the demand both in the power and mobility sectors. This effect is stronger for technologies with higher specific investment outlays due to the potential co-utilization of the same electrolysis capacities.

Albrecht et al. (2016) also analyze the hydrogen costs for the same applications, however, limited to the region of Baden-Wuerttemberg. Based on different spot market prices and hydrogen demand pattern the hydrogen costs are between 2 €/kg_{H2} and 6 €/kg_{H2} (or 60 €/MWh and 180 €/MWh). Interestingly, the lowest costs are reported for the power sector where a large amount of electricity can be directly sold to the market without converting it into hydrogen and the highest costs occur for the injection of hydrogen into the natural gas grid due to strong seasonal demand differences and thus low utilization of electrolysis. The variability of renewable feed-in has a large impact on hydrogen costs which increase by 10 % – 80 % depending on the size of the wind park and electrolysis. The synergy effects arise mainly from the co-utilization of electrolysis in the mobility and natural gas markets as both demand patterns complement each other.[198] However, the specific hydrogen costs decrease only slightly by less than 10 % based on the synergy effects.

The case study in Bünger et al. (2016) focuses on a techno-economic analysis of a hydrogen facility consisting of an alkaline electrolysis and an underground salt cavern as a large hydrogen storage. The authors calculate again specific costs of hydrogen for the use in the power, mobility, industry and natural gas sectors based on exogenous prices for electricity and natural gas. Moreover, the electrolysis operation is constrained by the intermittent feed-in from a dedicated wind park corresponding to case 3 as defined in chapter 4.1 (synchronized wind and hydrogen production at spot market price). Depending on the predefined scenarios the hydrogen costs range between 4 €/kg_{H2} or 120 €/MWh in the natural gas market and 10 €/kg_{H2} or 300 €/MWh in the power sector. These results are contrary to the outcomes from Albrecht et al. (2016) due to two effects. First, Bünger et al. (2016) neglect the seasonality of the heating demand in Germany and assume constant injection of hydrogen into the natural gas grid. Second, there are no direct electricity sales to the power market and the entire energy is provided through a re-electrification unit with low round-trip efficiency. Nevertheless, based on the expected hydrogen sales price, the facility is profitable only

198 According to Albrecht et al. (2016) due to the heating needs the demand for natural gas in Germany is high in the winter but low in the summer. For the mobility sector the opposite is true as there is more driving in the summer (e.g. for holidays) than in the winter due to the weather conditions.

when hydrogen is sold as a fuel in the mobility sector. The authors also report increasing hydrogen costs over time despite rising electricity price volatility and declining technology costs due to disproportional increase of average spot market prices.

4.3 Modeling hydrogen supply for the power and mobility sectors

4.3.1 Model overview

Similar to chapter 3, the analysis in this chapter is carried out from the perspective of a single firm interested in the investment and operation of a hydrogen production plant. As indicated in Figure 4.2, the facility can serve both power and mobility markets and consists of several interrelated processes. The major component is represented by the electrolysis which converts electricity and water into hydrogen and oxygen. The electricity is either purchased from the market provided by the grid or produced directly by a dedicated renewable power plant. Hydrogen can be either stored in a separate unit or immediately sold as a fuel in the mobility sector whereas oxygen is viewed as a by-product without any additional revenues and therefore released into the atmosphere. The storage unit consists of a compressor as an input device, large underground salt cavern or similar large-scale storage device and drying unit as an output device.[199] When operated as electricity storage, hydrogen can be converted back to electricity in a gas turbine and subsequently injected into the grid. At this point, it is important to mention that electricity for power applications can be also provided directly by the renewable power plant or transmitted through the grid to end users if available at the given point in time.[200]

199 When using a salt cavern as a storage unit, a drying device is needed to purify hydrogen for further processing to eliminate water and other impurities.

200 Note that of course purchasing or producing electricity, converting it into hydrogen and then immediately using for re-electrification in a gas turbine is economically not reasonable due to efficiency losses. Therefore direct electricity transmission to end users is explicitly included in our model. However, we assume an electricity network as given and do not model any investments in grid capacity.

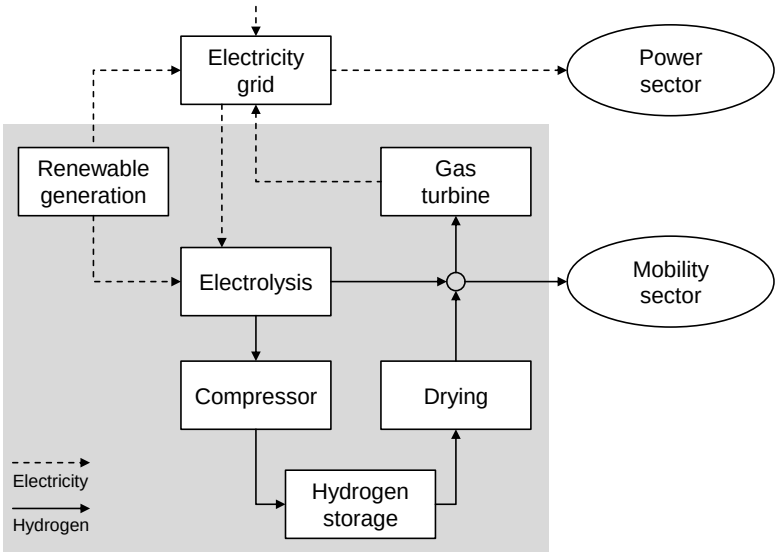


Figure 4.2: Structure of the model for hydrogen production plant.

We make the same assumptions as in chapter 3 regarding the price taking behavior of the firm, perfect foresight of prices, demand and feed-in patterns as well as storage use solely related to the spot market (i.e. additional services on the balancing market are not considered).[201] We propose again a simple linear programming model with simultaneous decisions on optimal facility sizing and operation. Since the mathematical representation of our model is analogous to the one presented in chapter 3, we refrain from an explicit discussion on all parts of the model but focus on the extensions in comparison to the previous chapter instead. Appendix B.1 and B.2 provide an overview over all indices, parameters and variables as well as full model formulation, respectively.

4.3.2 Mathematical representation of the model[202]

In our model, the underlying optimization problem is again represented by NPV maximization of the hydrogen production facility from a perspective of a single price taking firm. The investment outlays required to build-up

201 See chapter 3.3.1 for a detailed discussion in this regard.

202 The model description in the first two paragraphs of this chapter is identical with the text published in Bünger et al. (2016).

the facility are compensated by a stream of constant annual cash flows from facility operations in a prototypical year over a given number of periods within a detailed planning horizon. At the end of the planning horizon, we assume additional cash inflows from the sales of each component of the facility represented by the corresponding residual value under linear depreciation.

$$\max NPV = AF \cdot \left[\left(\sum_{h \in H} TR_h - TEC_h - SC_h - TOC_h \right) - TFC \right] - TI + \frac{1}{(1+r)^T} \cdot TRV \tag{4.1}$$

The first part of the objective function in equation (4.1) represents the constant annual cash flow from operations multiplied by an annuity factor $AF = \frac{(1+r)^T - 1}{r(1+r)^T}$ for a given number of periods T of the planning horizon and the interest rate r. In this way, we account for the time value of money of prototypical annual cash flows which are assumed to remain constant over the entire planning horizon. The constant annual cash flow consists of total revenues TR_h from sales in all markets in each hour $h \in H$ of the prototypical year and takes into account the corresponding costs consisting of total electricity costs TEC_h, standby costs of the electrolysis SC_h, total other variable costs TOC_h as well as the annual total fixed costs TFC. The second and third term of the objective function stand for the total investment outlays TI and discounted total residual value TRV of each component of the facility, respectively.

$$TR_h = p_h^e \cdot \left(q_h^r + q_h^g + q_h^d \right) + p_h^m \cdot (q_h^m + q_h^s) \quad \forall h \in H \tag{4.2}$$

As defined in equation (4.2), total revenues in each hour h stem from hourly hydrogen or electricity sales in each market where p_h^e and p_h^m stand for the electricity price in the power sector and hydrogen fuel sales price in the mobility sector, respectively. On the one hand, the corresponding decision variables are q_h^r, q_h^g, q_h^d for electricity sales quantities provided by the renewable power plant, through re-electrification of hydrogen in a gas turbine and directly from the grid, respectively. On the other hand,

the operator can decide to sell hydrogen as a fuel either directly after production or by releasing it from the storage where the corresponding quantities are q_h^m and q_h^s, respectively.

$$TEC_h = p_h^e \cdot \left[q_h^d + x_h^p + \gamma^c \cdot x_h^e + \frac{\gamma^d}{\eta^d} \cdot \left(\frac{q_h^g}{\eta^g} + q_h^s \right) \right] \quad \forall h \in H \tag{4.3}$$

The total electricity costs in equation (4.3) are calculated by multiplying the electricity price by the adequate energy consumption of each component of the facility. For the sake of simplicity, we assume that the electricity required to run all components of the equipment other than the electrolysis is purchased on the spot market. In reality, the facility might also use electricity directly from the renewable generation to operate the entire topside equipment. However, since the exogenous hydrogen demand has to be met in each point of time and demand is independent from production, this would require explicit modeling of electricity sourcing for each component of the facility. In our analysis we refrain from this complication of the model as we are interested mainly in optimal sizing and operation of electrolysis and hydrogen storage and expect this error to remain sufficiently small. In this context, the first and second part of the corresponding consumption quantities are represented by q_h^d and x_h^p as the amount of direct energy sales and electricity purchased from the market to run the electrolysis, respectively. The third term defines the electricity consumption of the compressor prior to the storage unit which is calculated by multiplying storage input quantity x_h^e by specific electricity consumption of the compressor γ^c. The fourth term of the electricity consumption refers to the drying unit based on the specific electricity consumption γ^d and the overall hydrogen output from the storage. The total amount of hydrogen being released from the storage is determined by hydrogen sales quantities to different markets (q_h^g and q_h^s) taking into account the efficiency of the drying unit η^d and the corresponding efficiencies of the gas turbine η^g in order to adjust for efficiency losses associated with re-electrification.

$$SC_h = p_h^e \cdot \sigma^e \cdot \left(K^e + I^e - x_h^r - x_h^p \right) \quad \forall h \in H \tag{4.4}$$

As represented by equation (4.4), the hourly stand-by electricity costs of the electrolysis, i.e. costs for energy required to keep the electrolysis in a warm stand-by when hydrogen is not produced, are also dependent on the spot market electricity price p_h^e. The stand-by energy is calculated as a fraction σ^e of the unused electrolysis capacity consisting of initial capacity K^e at the beginning of the planning horizon and additional investment I^e. This capacity is further adjusted by the actual hydrogen production from renewable and spot market electricity in order to account for hours when the electrolysis is in operation (e.g. by hydrogen productin basd on electricity from renewable power plant and the grid x_h^r and x_h^p, respectively).[203]

$$TOC_h = \nu^e \cdot (q_h^m + x_h^e) \quad \forall h \in H \tag{4.5}$$

Total other variable costs formulated in equation (4.5) arise from water consumption of the electrolysis multiplied by specific variable costs ν^e. The respective hydrogen quantity includes storage input and direct sales within the mobility market.

Total fixed costs TFC in the objective function are modeled as fixed fraction of the overall value of installed capacity consisting of the initial capacity and additional investments. Finally, total investment outlays TI and total residual value TRV are calculated analogously to the modeling approach in chapter 3 by taking into account corresponding specific investment outlays, lifetime and new installed capacities of each element of the facility.[204]

$$x_h^r + x_h^p = \frac{1}{\eta^e} \cdot (q_h^m + x_h^e) \quad \forall h \in H \tag{4.6}$$

In equation (4.6) we formulate the technical constraint on electrolysis operation. The overall electricity provided by a renewable power plant x_h^r and

203 Note that in this way, stand-by costs are proportional to the actual amount of unused capacity also in hours in which electrolysis produces hydrogen but not at full capacity. However, this is in line with the fact that electrolysis is usually a modular technology such that a given part of the electrolysis capacity can be utilized to produce hydrogen while the remaining part is kept in warm stand-by.

204 Note that again for consistency of the underlying problem the number of periods T within the planning horizon must be lower than the shortest lifetime of any of facility elements.

obtained from the market x_h^p for hydrogen production corresponds to hydrogen output including direct sales in the mobility sector q_h^m and the storage input x_h^e adjusted by the electrolysis efficiency.

$$\underline{X}_h^p \leq x_h^p + q_h^d \leq \overline{X}_h^p \quad \forall h \in H \tag{4.7}$$

For the decision variables on electricity purchase from the spot market x_h^p and direct transmission to the end user q_h^d the lower and upper bounds $\underline{X}_h^p$ and $\overline{X}_h^p$ in equation (4.7) represent the minimal and maximal electricity supply. While the lower bound enforces electricity uptake in a given hour, the upper bound can be interpreted as available electricity in the facility's grid node.

$$\underline{d}_h^e \leq q_h^r + q_h^g + q_h^d \leq \bar{d}_h^e \quad \forall h \in H \tag{4.8}$$

$$\underline{d}_h^m \leq q_h^m + q_h^s \leq \bar{d}_h^m \quad \forall h \in H \tag{4.9}$$

In equation (4.8), the lower and upper bounds $\underline{d}_h^e$ and $\bar{d}_h^e$ for electricity production by renewable generator, gas turbine and direct transmission to the end user define on the one hand facility's minimal power supply and on the other hand the maximal network capacity. Analogously, for the hydrogen sales in the mobility sector the corresponding bounds in equation (4.9) represent the minimal hydrogen delivery requirement $\underline{d}_h^m$ and maximal hydrogen demand $\bar{d}_h^m$.

$$q_h^r + x_h^r \leq \rho_h \cdot (K^r + I^r) \quad \forall h \in H \tag{4.10}$$

Similar to chapter 3, the capacity constraints provide the upper bound for electricity and hydrogen production for the given renewable power plant, electrolysis, compressor, drying unit and gas turbine. For all components the maximal production is limited by their initial capacity and new investments. Note that for the renewable power plant we have adjusted the overall capacity by the hourly availability factor ρ_h to account for intermittent electricity supply as described in equation (4.10).

Further, the storage level in each hour of the prototypical year is an additional auxiliary decision variable based on the storage level in the previous hour and storage inflow and outflows in a given hour. In this context, the storage level must be always non-negative but lower than the overall capacity consisting of initial energy-related capacity and corresponding investments. We also assume that the storage is empty at the beginning of the first hour and at the end of the last hour of the year. Moreover, we limit investments for the renewable power plant and electrolysis by an upper bound which again can be interpreted as available facility space. In order to allow for a better comparability of analysis results in different cases and scenarios, we also calculate levelized costs of hydrogen (LCOH) as facility's NPV less discounted total revenues[205] divided by discounted annual hydrogen sales in both sectors as specified in equation (4.11).[206] These costs can be expressed either in €/MWh or in €/kg_{H2} depending on how the energy output is measured.

$$LCOH = \frac{NPV - AF \cdot \sum\limits_{h \in H} TR_h}{AF \cdot \sum\limits_{h \in H} \left(q_h^r + q_h^d + q_h^g + q_h^m + q_h^s \right)} \tag{4.11}$$

4.4 Case study

4.4.1 Scenario definition and input data

The described model is applied to analyze the value of green hydrogen supply in the power and mobility sectors. In detail, we compare the costs of the four hydrogen production cases as defined in chapter 4.1 and test our results for varying boundary conditions within the following scenarios:

- short-term scenario based on current technology costs and historical electricity prices from 2012 as reference for further calculations,

205 Note that the NPV includes the present value of total revenues as well as discounted net expenditures. Therefore, since LCOH are based on the present value of total expenditures, we deduct discounted total revenues from the NPV.

206 The concept of LCOH is analogous to the common approach of levelized costs of electricity. See for example Reichelstein and Yorston (2013) for a more detailed definition and explanation of this approach.

- mid-term scenario with decreasing specific investment outlays for electrolysis and renewable power plant as well as moderate average electricity prices combined with low volatility due to a moderate penetration of renewable generation in the power sector and

- long-term scenario with low overall specific investment outlays as well as high average level and volatility of electricity prices due to high share of intermittent electricity production and expensive peak-load technologies in the energy system.

The analysis is carried out for a prototypical hydrogen production plant with an obligation to satisfy a predefined energy demand in the power and mobility sectors. For the sake of comparability, we assume the same annual energy need of $30\,\mathrm{kt_{H2}}$ or approx. 1 TWh for both applications corresponding to an electricity consumption of approx. 300,000 average households or 250,000 FCEVs.[207] For the mobility sector, we assume a constant hydrogen sales price of $5.5\,€/\mathrm{kg_{H2}}$ (or 165 €/MWh) in all scenarios (see DLR 2015 and Albrecht et al. 2016). Moreover, since we are also interested in potential synergies from a co-utilization of the facility, we analyze a combined operation to meet an aggregated demand of $60\,\mathrm{kt_{H2}}$ or approx. 2 TWh simultaneously in the power and mobility sectors. In this way and as indicated in Figure 4.3, we calculate the value of three different applications including power and mobility related as well as synergetic hydrogen production for each scenario and electricity supply cases.

For electricity demand, we again use typical electricity consumption data for 2012 obtained from ENTSO-E (2013). For the mobility sector, the demand profile is derived from monthly, weekly and daily fuel consumption patterns of a typical conventional refueling station available from DOE (2008) and MWV (2012) under the assumption of one day hydrogen storage at the refueling station. For a better comparison of results, both demand profiles are used as an upper and lower bound for the energy uptake in corresponding markets.

207 Assuming an average annual consumption of 3,200 kWh per household and $1\,\mathrm{kg_{H2}}/100\,\mathrm{km}$ in combination with an average annual driving range of 12,000 km for a FCEV.

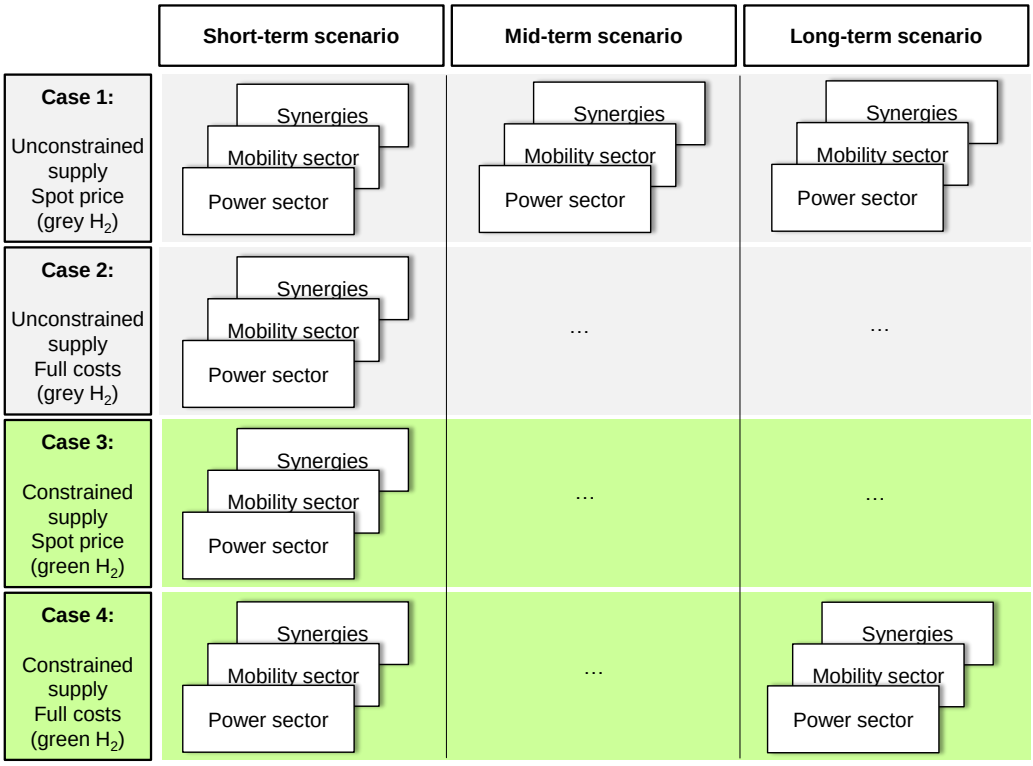


Figure 4.3: Selected combinations for further analysis on green hydrogen supply.

Hence in our analysis the revenues are predetermined in each scenario and have no impact on facility sizing and operation. Moreover, renewable energy production and electricity purchase profiles in the constrained case are again based on an hourly wind onshore feed-in from 2012 as provided by German TSOs. The electricity available for market purchases in case 3 takes the overall facility efficiency into account and amounts to approx. 2 TWh in each market or to 4 TWh if both markets are served. In order to adjust electricity prices, we follow DLR (2015) and increase historical day-ahead prices from 2012 at the German marketplace of EPEX SPOT in the mid-term by approx. 60 % on average but decrease the volatility by approx. 60 % Due to the expected rise of intermittent electricity production in Germany in the long run, the corresponding volatility is assumed to increase by approx. 90 % in comparison to historical prices.[208] Table 4.1 provides statistical characterization of the aforementioned data.

208 For volatility adjustment we use the same approach of clockwise rotation of the price duration curve as described as in chapter 3.4.5.

Table 4.1: Statistical characterization of supply, demand and price profiles.

Item	Unit	Min	Max	Mean	Standard deviation	Total (GWh)
Electricity demand	MWh	62	159	114	22	1,000
Hydrogen fuel demand	MWh_{H2}	82	137	114	13	1,000
Wind feed-in	%	1	100	19	17	n/a
Short-term electricity price	€/MWh	−222	210	43	19	n/a
Mid-term electricity price	€/MWh	−49	141	68	8	n/a
Long-term electricity price	€/MWh	−432	382	67	35	n/a

The techno-economic input parameters for all individual processes of the facility are summarized in Table 4.2. Following Nitsch et al. (2012b), we assume a slight decrease of specific investment outlays for the wind power plant from 1,100 €/kW in the short-term down to 1,000 €/kW in the long-term.Moreover, we assume PEM electrolysis technology in our analysis and derive the corresponding input data from DLR (2015). Accordingly, specific expenditures for electrolysis are expected to fall substantially from 1,850 €/kW today to 350 €/kW in the future due to further research and development activities. The corresponding lifetime of 30 years is comparatively long but it is compensated by high fixed costs of 7 % in the short- and mid-term. At the same time, the anticipated efficiency rises from 58 % to 70 % and the hourly stand-by electricity consumption ranges between 1 % – 1.5 % of the installed capacity. Other variable costs include water costs based on a constant consumption of 9 kg/kg_{H2} and water price of 0.0015 €/kg. The compressor unit as storage input device is comparatively cheap and efficient with specific investment outlays falling from 300 €/kW to 160 €/kW and electricity consumption going down from 1 kWh_{el}/kg_{H2} to 0.5 kWh_{el}/kg_{H2} over time. Further, we assume constant drying losses of 5 % and an improvement of the gas turbine efficiency from 40 % up to 47 %. The interest rate amounts to 8 % and the planning horizon is 10 years.

Table 4.2: Techno-economic input parameters of the hydrogen production facility.

Technology	Unit	Short–term	Mid–term	Long–term
Renewable generation				
Investment outlays	€/kW_{el}	1,100	1,000	1,000
Fixed costs	% of investment	4	4	4
Lifetime	a	18	18	18
Electrolysis				
Investment outlays	€/kW_{el}	1,850	950	350
Fixed costs	% of investment	7	7	2
Other variable costs	€/MWh_{H2}	0.41	0.41	0.41
Efficiency	%	58	70	70
Stand-by consumption	%	1	1.5	1.5
Lifetime	a	30	30	30
Compressor				
Investment outlays	€/kW_{In}	300	300	160
Fixed costs	% of investment	4	4	4
Electricity consumption	kWh_{el}/kg_{H2}	1.0	1.0	0.5
Lifetime	a	15	15	15
Hydrogen storage				
Investment outlays	€/MWh_{H2}	200	200	200
Fixed costs	% of investment	3	3	3
Lifetime	a	30	30	30
Drying unit				
Investment outlays	€/kW_{Out}	6	6	6
Fixed costs	% of investment	4	4	4
Electricity consumption	kWh_{el}/MWh_{H2}	0.02	0.02	0.02
Efficiency	%	95	95	95
Lifetime	a	15	15	15
Gas turbine				
Investment outlays	€/kW_{el}	400	400	400
Fixed costs	% of investment	2	2	2
Efficiency	%	40	45	47
Lifetime	a	25	25	25

4.4.2 Levelized costs of grey hydrogen in case 1 and 2

For an unconstrained power supply and in absence of additional payments for renewable generation in case 1 the levelized costs of hydrogen in the mobility sector are at a comparatively low level ranging between approx. 5 €/kg_{H2} in the short-term and approx. 3 €/kg_{H2} in the long-term scenario. As depicted in Figure 4.4, electricity costs in all scenarios account for the major share of the overall costs (accruing approx. 50 % in the short-term and approx. 75 % in the mid- and long-term) followed by capital expenditures (CAPEX) for all components of the facility (approx. 30 % in the short-term, 15 % in the mid-term and 20 % in the long-term). All other costs including feed water costs and fixed costs are rather low. Generally, the overall economic results are mainly determined by optimal sizing and utilization of electrolysis as a major component of the facility. For a relatively low electricity price volatility in the short- and mid-term scenario we find rather low electrolysis capacities (between 170 MW and 200 MW) operating at very high utilization (more than 95 % or 8,400 full load hours per year) whereas for the long-term scenario with high electricity price volatility the installed electrolysis capacity is higher (approx. 370 MW) and its utilization is lower (less than 50 % or 4,300 full load hours).[209] In fact, for given hydrogen demand the optimal dimensioning and utilization is determined by a trade-off between investment outlays and electricity costs.

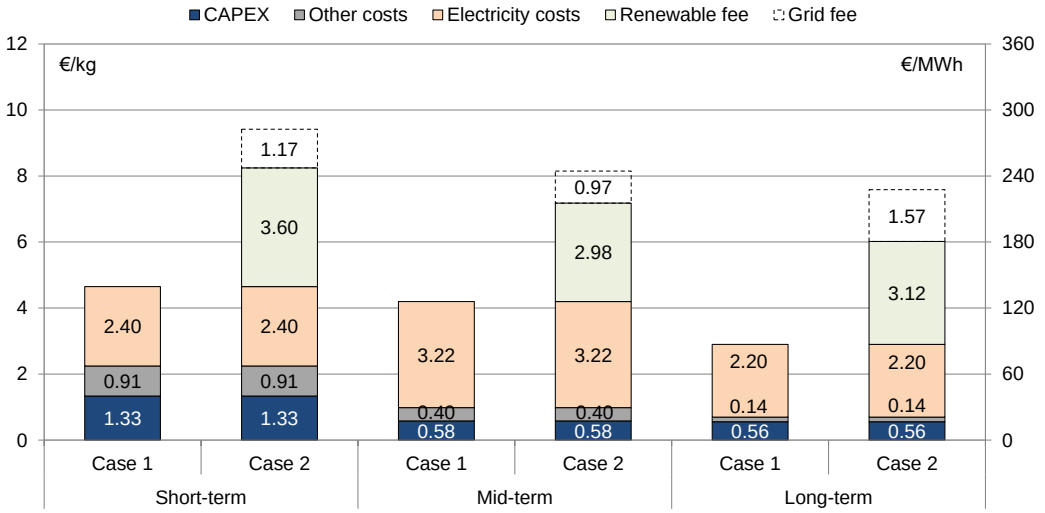
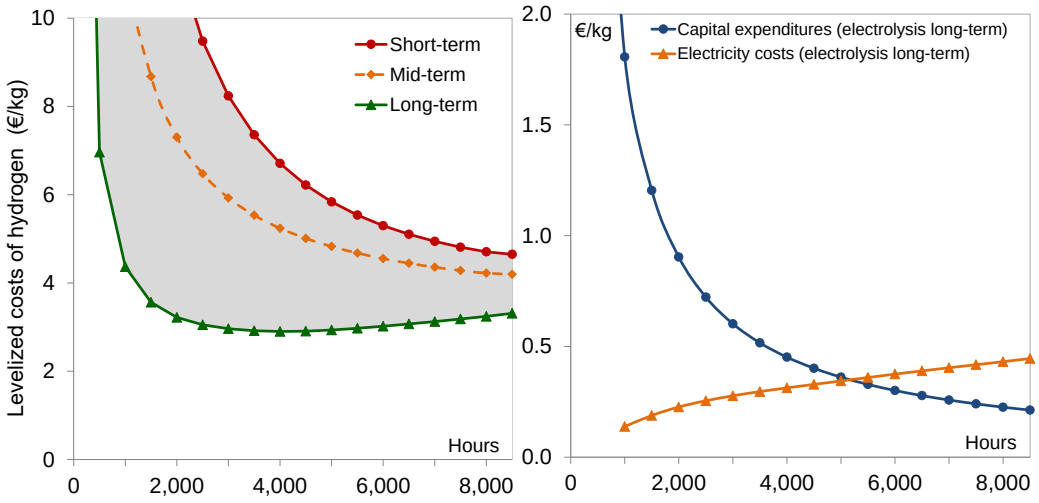


Figure 4.4: Levelized costs of hydrogen in mobility sector in case 1 and 2.

209 Detailed overview over facility sizing and utilization in case 1 and 2 is provided in Appendix B.3.

As indicated in Figure 4.5a, for predetermined hydrogen output the overall costs change substantially depending on the actual facility utilization. In the short- and mid-term, low capacities and high utilization rate minimize overall costs for hydrogen production due to comparatively high specific investment outlays and low price volatility. In the long-term on the one hand, annualized capital expenditures decrease with rising utilization as only small electrolysis capacities are needed to provide the same amount of hydrogen (see Figure 4.5b). On the other hand however, increasing electrolysis utilization also leads to higher electricity costs since energy must be purchased at almost all hours of the year and the facility is not able to take advantage of volatile prices. Therefore an optimal electrolysis size and utilization is determined by minimizing aggregated costs incurred by both effects. In this context, the storage sizing is calculated to be between approx. 14 GWh and 20 GWh. In the short- and mid-term, it is characterized by a very low number of full cycle equivalents whereas in the long-term it is operated almost on a bi-weekly basis (approx. 30 cycles per year). Generally, decreasing specific investment outlays for electrolysis, improved efficiency and increasing electricity price volatility are responsible for falling costs of grey hydrogen production in the mobility sector in different scenarios.



a) LCOH depending on electrolysis utilization

b) Trade-off between capital expenditures and electricity costs

Figure 4.5: Minimal LCOH as a trade-off between electrolysis size and utilization.

At this point it is also important to mention that by definition unconstrained electricity provision in case 1 allows for direct electricity supply in the power sector and additional investment in costly electrolysis and storage capacities can be avoided. Hence, in this case, overall supply costs correspond solely to an average electricity purchase price. In addition, in such constellations there are no specific synergies from combined electrolysis operation for the power and mobility sectors.

As defined in chapter 4.4.1, in case 2 we also assume unconstrained electricity availability but we take into account additional fees to capture full costs of intermittent power in a real market. Facility sizing and operation in the mobility sector are identical as compared to case 1 as for the sake of comparability the fees are not considered explicitly within the model optimization but added on top of the results of case 1 instead. The additional payments include grid fees (based on an energy-related share of 10 €/MWh and a power-related share of approx. 90 €/kW)[210] as well as a renewable electricity fee (62.4 €/MWh).[211] Both fees have a substantial impact on the LCOH being higher by a factor of 2 – 3 in comparison with case 1 and ranging between 7.5 €/kg_{H2} (long-term) and 9.5 €/kg_{H2} (short-term). In the mid-term, both fees have the lowest value since in this case electricity consumption is lower than in other scenarios due to a higher electrolysis efficiency and limited electricity consumption of the compressor as storage input device. In the long-term scenario, power-related grid fees are higher due to larger capacity investments. Similar to case 1, energy supply in the power sector does not require any investments in new capacities and there are no additional synergy effects.

4.4.3 Levelized costs of green hydrogen in case 3

In contrast to case 1 and 2, electricity supply in case 3 is limited by intermittent wind feed-in. Therefore in order to satisfy the demand in the power sector 17 % of the overall energy is provided from the storage whereas 83 % is still directly transmitted to the end users through the grid. As indicated

210 This assumption is based on typical tariffs for consumers connected to high voltage lines in German power networks.

211 The renewable fee corresponds to the reallocation rate of German fixed feed-in tariffs for 2014 under EEG (see chapter 2.2.2).

in Figure 4.6 the corresponding LCOH amounts to approx. 6 €/kg_{H2} (or approx. 180 €/MWh) in the short-term decreasing to approx. 3.5 €/kg_{H2} (or approx. 105 €/MWh) in the long run due to falling technology costs and a rising electricity price volatility.

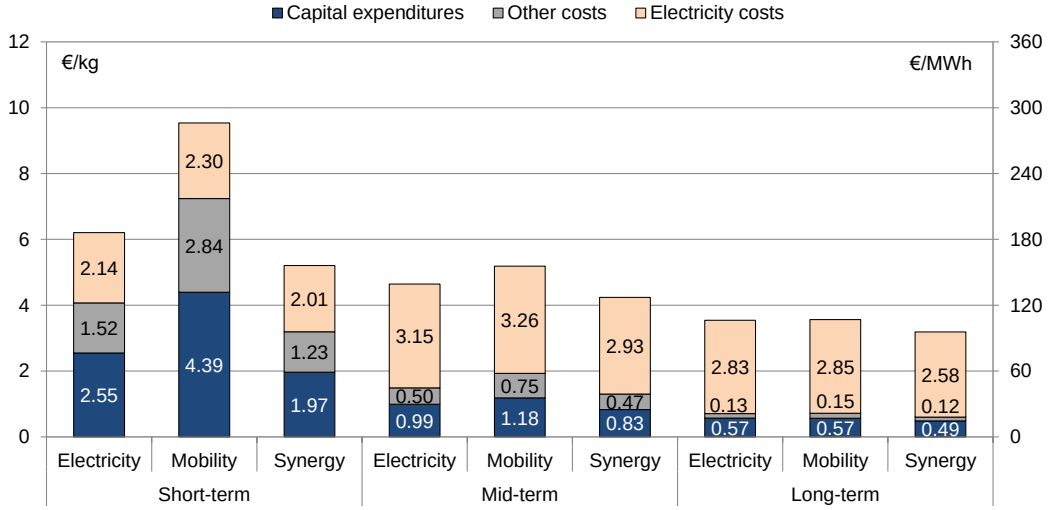


Figure 4.6: Levelized costs of hydrogen in case 3.

These results are again based on the trade-off between investment outlays in electrolysis and storage capacities as well as electricity costs. In fact, in the short-term capital expenditures account for 40 % of the overall LCOH followed by electricity costs with 35 % whereas in the long-term scenario this relationship changes substantially (only 16 % is related to capital expenditures and 80 % to electricity costs). At the same time, the optimal electrolysis size first decreases from approx. 319 MW (with an average utilization of approx. 1,500 full load hours) in the short-term down to 174 MW (approx. 3,200 full load hours) in the mid-term but then increases again up to 185 MW (approx. 3,000 full load hours) in the long run.[212] This is mainly due to two effects. First, higher electrolysis efficiency in the mid- and long-term allows for smaller electrolysis capacities required to satisfy a predefined demand. Second, based on a rising electricity price volatility, higher electrolysis capacity (and lower utilization) helps to reduce electricity costs and hence overall facility costs in the long run. Interestingly, optimal

212 Detailed data is provided in Appendix B.3.

storage size and utilization are in the same order of magnitude for all scenarios between 70 GWh – 100 GWh and 5 – 6 full cycle equivalents, respectively. Similarly to outcomes in chapter 3.4.3 the capacity of a re-electrification unit is determined by a maximal difference between electricity demand and intermittent wind feed-in. Hence, the utilization of the gas turbine remains at the same level of approx. 1,200 full load hours in all scenarios. Moreover, due to a relatively low storage round-trip efficiency, large energy amounts must be purchased from the market for hydrogen re-electrification in the power sector (approx. 800 GWh in the short-term scenario and approx. 550 GWh in the remaining scenarios).

In the mobility sector we find similar effects for an optimal facility sizing and operation. However, due to the fact that all energy must be converted to hydrogen as a fuel under adequate efficiency losses and as there is no possibility for direct electricity use the overall LCOH are higher than for the power sector (between 9.5 €/kg_{H2} in the short-term and 3.5 €/kg_{H2} in the long-term). Accordingly, the installed electrolysis capacity (approx. 300 MW – 600 MW), the corresponding utilization (2,800 – 4,900 full load hours) and the electricity purchased from the market (approx. 1.5 TWh – 1.8 TWh) are rather high in comparison to the power sector. The impact of capital expenditures on the overall LCOH is again rather high in comparison to electricity costs in the short-term whereas the opposite is true for the long-term scenario. In addition, we report some differences in optimal storage sizing between selected scenarios. The energy-related storage capacity is again higher than for the power sector decreasing from approx. 140 GWh in the short-term to 80 GWh in the long-term. The storage is again used on a seasonal basis with 3 – 4 full cycle equivalents per year. In all scenarios, approx. 70 % of the hydrogen produced is directly used for the sale as fuel to the mobility sector and approx. 30 % is stored for later use due to intermittent electricity availability.

The analysis reveals that a combined use of the facility for hydrogen production in the power and mobility sectors allows taking advantage of substantial synergy effects. As depicted in Figure 4.7, the aggregated facility costs for both individual applications are higher than for the case of synergetic hydrogen supply in all scenarios. The potential cost reduction ranges between more than 33 % in the short-term scenario (discounted net expenditures

amounting to approx. 3,200 M€ in total from separate and 2,100 M€ from synergetic use) and approx. 10 % in the long-term scenario (approx. 1,400 M€ and 1,300 M€, respectively).[213] Accordingly, the LCOH are lower for the synergetic application (between 3.2 €/kg_{H2} and 5.2 €/kg_{H2}) than for both sectors separately.

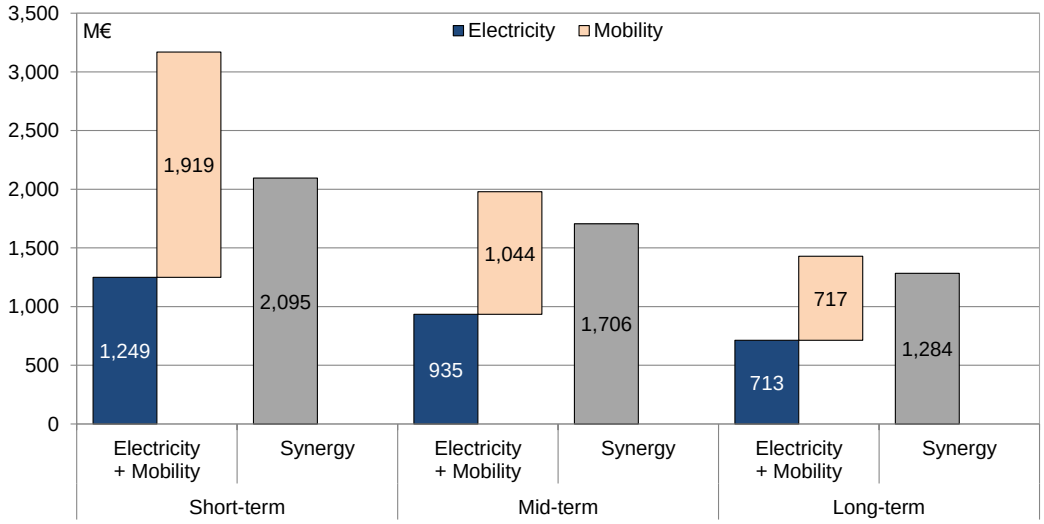


Figure 4.7: Discounted net expenditures of separate and synergetic facility use in case 3.

The synergy benefit is mainly related to two effects. First, co-utilization requires clearly lower electrolysis and storage capacities than separate hydrogen production for each application alone. Second, since more intermittent electricity is available in the synergetic case it can be used more efficiently. In this context, more electricity is used directly in the power sector (approx. 93 % of demand in this sector) and overall electricity purchase and corresponding efficiency losses are lower although slightly more hydrogen must be stored to satisfy the additional demand in the mobility sector. The size of the gas turbine (135 MW in all scenarios) is similar to the installed capacity from separate operation and the corresponding utilization is very low (only about 500 full load hours). However, this has only little impact on the overall hydrogen costs.

213 Discounted net expenditures correspond to investment outlays and total discounted production costs adjusted by discounted residual value. Note that in the context of our analysis revenues have no impact on facility sizing and operation since we use a predefined demand profile in both sectors.

4.4.4 Levelized costs of green hydrogen in case 4

In case 4, electricity for hydrogen production is provided by a dedicated wind power plant. Therefore, the LCOH are mainly determined by capital expenditures and corresponding fixed costs (see Figure 4.8). The electricity costs are due to the fact that some electricity from the market is still required to operate the compressor and the drying unit. However, this effect is very small representing only 1 % – 2 % of the facility's total electricity needs and can be neglected for further analysis. As in previous cases, we identify also decreasing LCOH between the short- and long-term for both sectors due to falling wind and electrolysis technology costs. In the power sector, specific hydrogen costs decline from 9 €/kg_{H2} (or approx. 270 €/MWh) to 5.6 €/kg_{H2} (or approx. 170 €/MWh) and in mobility sector from 11 €/kg_{H2} (330 €/MWh) to 5.5 €/kg_{H2} (170 €/MWh).

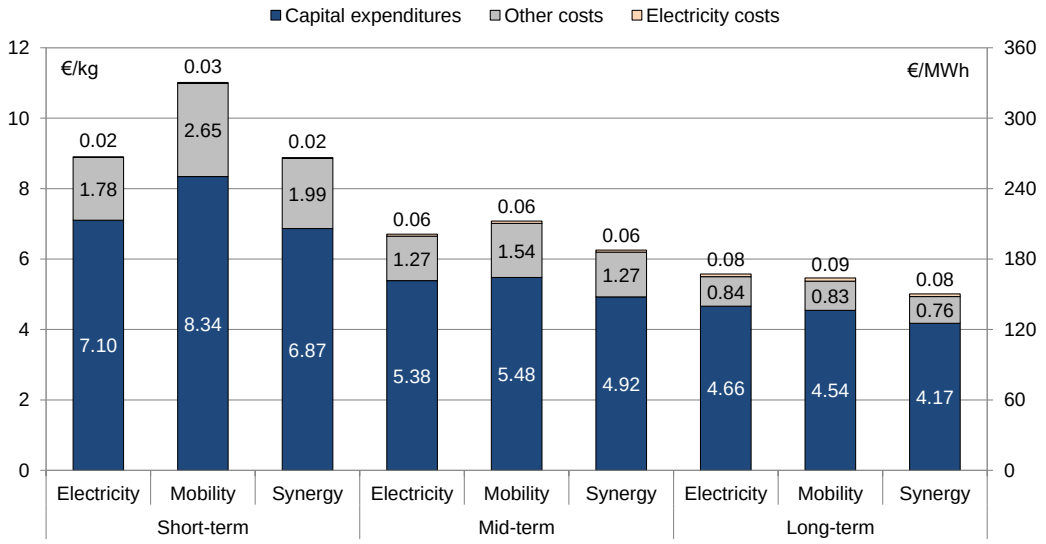


Figure 4.8: Levelized costs of hydrogen in case 4.

In this context, in all scenarios and for all applications major net investment outlays[214] are associated with the wind power plant (70 % – 85 % of total net investment outlays) and electrolysis (5 % – 28 %) whereas storage and other parts of the equipment (compressor, drying unit and gas turbine)

214 Net investment outlays are calculated as investment outlays less discounted residual value.

are responsible for only a very small share of overall capital expenditures. Generally, optimal sizing of different facility elements is based on the trade-off between corresponding investment outlays. For a predetermined hydrogen demand, the higher the capacity of the intermittent power plant, the more energy can be directly provided to the respective market and thus the lower the required electrolysis and storage capacity can be.

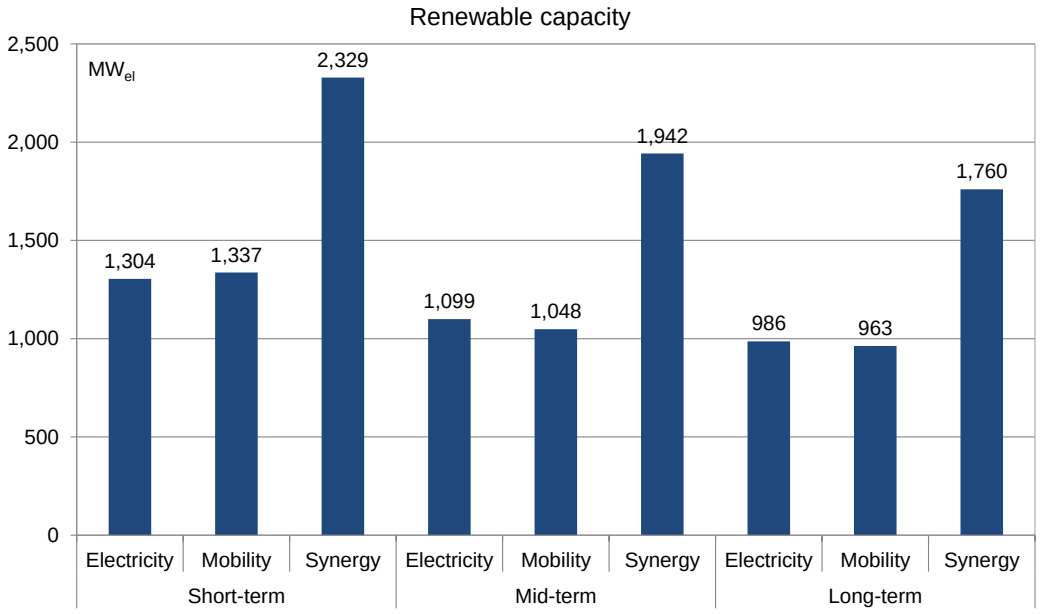


Figure 4.9: Optimal intermittent generation capacity in case 4.

When comparing different scenarios we find on the one hand that the size of the wind power plant decreases from the short- to long-term scenario (from approx. 1.3 GW to 1 GW in both sectors) but on the other hand the electrolysis capacity (from approx. 170 MW to 290 MW in the power and from 360 MW to 430 MW in the mobility sector) and storage capacity increase (from approx. 70 GWh to 100 GWh in the power sector and from approx. 90 GWh to 120 GWh in the mobility sector). Accordingly, optimal electrolysis utilization is reduced substantially (from 3,800 to 2,300 full load hours in the power sector and from 4,800 to 3,400 full load hours in the mobility sector). Interestingly, in the mid- and long-term scenario, the installed wind capacity required to satisfy the demand in the power sector is slightly larger than in the mobility sector. Therefore, in the long-term scenario the LCOH in the power sector are higher than in the mobility

sector as in this scenario the electrolysis is comparatively cheap and the investment outlays in wind power plant have a major impact on the all over costs. Nevertheless, in all scenarios and applications, storage is used on a seasonal basis with 3 – 5 full cycle equivalents per year. Figure 4.9 depicts the optimal capacity of the renewable power plant while detailed data on electrolysis and storage sizing and operation can be found in Appendix B.3.

In the power sector approx. 80 % – 86 % of the electricity demand is directly satisfied by intermittent power plant whereas the remaining share comes from energy storage and hydrogen re-electrification. According to the changing intermittent capacity the gas turbine's size is in a similar order of magnitude (approx. 144 – 146 MW) for all scenarios but the corresponding utilization increases (from 960 full load hours in the short-term to 1,400 full load hours in the long-term). In the mobility sector approx. 70 % – 75 % of the produced fuel is directly delivered to the market without any storage needs. Interestingly, the overall intermittent electricity production is slightly higher for the mobility sector (approx. 1.5 GWh – 1.7 GWh) than in the power sector (approx. 1.4 GWh – 1.5 GWh) although for re-electrification the round-trip efficiency is much lower than for hydrogen production as a fuel.[215]

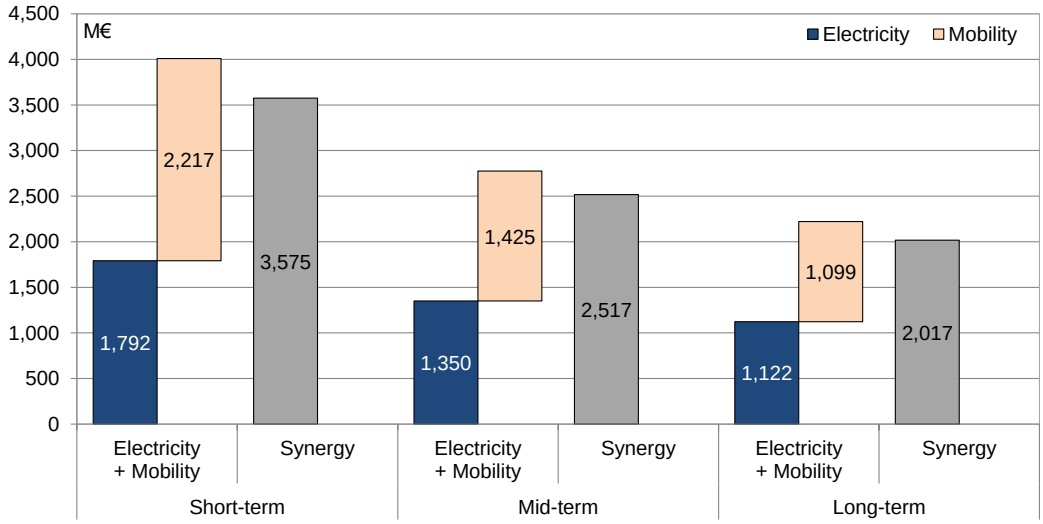


Figure 4.10: Discounted net expenditures of separate and synergetic facility use in case 4.

215 Note that the overall electricity produced by the renewable power plant and thus its optimal capacity also depends on facility's round-trip efficiency which increases between short-term and long-term scenario.

Similarly to case 3 we also find synergy effects from joint energy supply to both sectors. As indicated in Figure 4.10, the overall discounted expenditures of separate facility use are always higher by approx. 10 % than for the synergetic application. This again is due to the fact that total facility size including installed capacity of wind power plant, electrolysis and storage are lower when the demand from both sectors is satisfied simultaneously. In addition, intermittent electricity can be used more efficiently such that the direct electricity sales in the power sector are higher and the corresponding efficiency losses from re-electrification of hydrogen are lower. Although in this way more hydrogen must be stored for the mobility sector (and less hydrogen is directly provided as a fuel to the respective market) the overall efficiency losses are lower and less renewable electricity is needed to satisfy the aggregated demand for both sectors.

4.4.5 Comparison of results and the value of hydrogen

As expected, the levelized costs of grey hydrogen are typically lower than the corresponding values for green hydrogen, since imposing additional constraints on intermittent electricity availability limits the facility's flexibility and necessitates investments in costly storage capacities. Accordingly and as illustrated in Figure 4.11, lowest costs are achieved in case 1 with an unconstrained electricity supply valued at a pure spot market price while highest costs are observed for case 4 with the need for investments in renewable energy production capacities. The LCOH for the grey hydrogen (case 1 and 2) range between 1.5 €/kg_{H2} and 8.5 €/kg_{H2} (45 €/MWh and 255 €/MWh), whereas for the green hydrogen (case 3 and 4) the corresponding values are between 3 €/kg_{H2} and 11 €/kg_{H2} (90 €/MWh and 330 €/MWh). Moreover, hydrogen supply in the power sector is typically cheaper than in the mobility sector since for this application a large share of electricity can be directly transmitted to the end user without efficiency losses and without the need for hydrogen storage.[216] In this regard the only exception is represented by the long-term scenario in case 4 where electrolysis is cheap and power sector requires larger wind capacities than the mobility sector.

216 Note that by definition in case 1 and 2 all electricity from the grid is directly transmitted to the end user in the power sector and no investments in any of the facility's element are required.

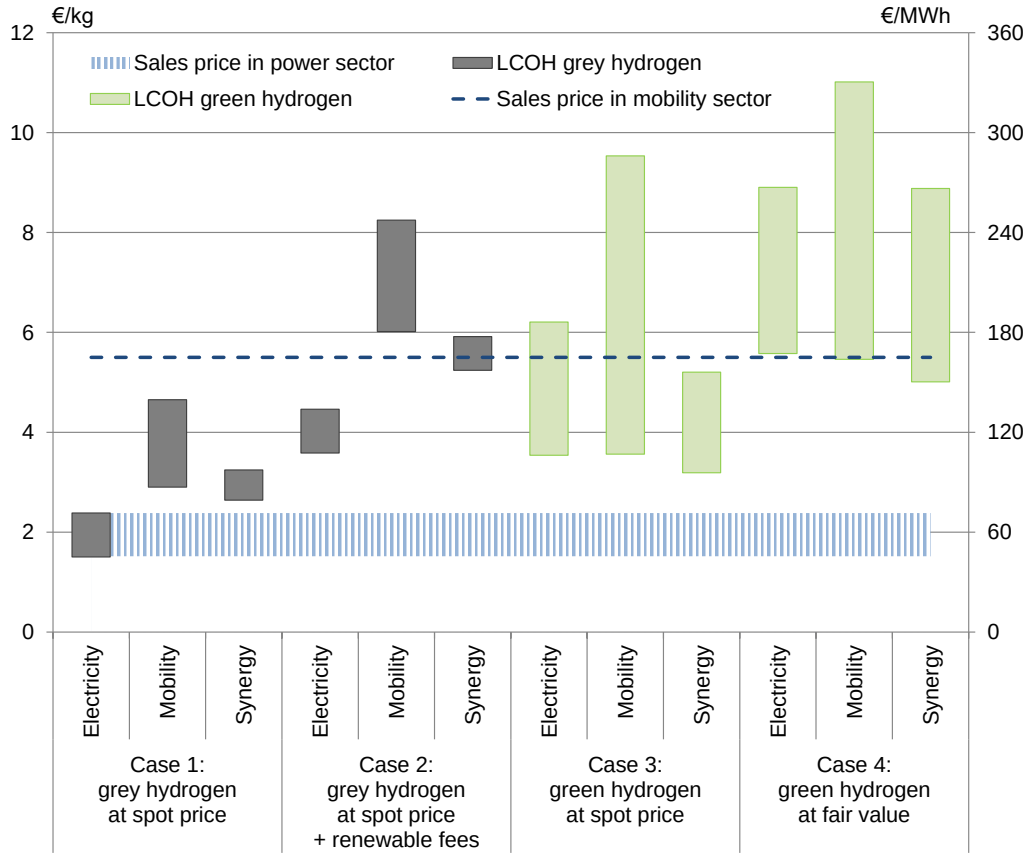


Figure 4.11: Sales price and levelized costs of hydrogen for selected cases and applications.[217]

The additional value of green hydrogen lies between 2 €/kg_{H2} and 4.5 €/kg_{H2} for the power sector (i.e. an increase of LCOH between both cases by approx. 100 % – 130 %), between 0.5 €/kg_{H2} and 3 €/kg_{H2} for the mobility sector (i.e. an increase of approx. 20 % – 30 %) and also between 0.5 €/kg_{H2} and 3 €/kg_{H2} for the synergetic facility utilization (i.e. an increase of approx. 20 % – 50 %). As mentioned in chapter 4.4.1, the average sales price and revenues in both sectors are predetermined in our analysis as the hourly facility output is explicitly defined by the identical lower and upper bound on energy demand. In the power sector, the average sales price ranges between 45 €/MWh in the short term and 71 €/MWh in the long term whereas in the mobility sector the sales price amounts to 5.5 €/kg_{H2} (165 €/MWh) for all scenarios. It is also worth mentioning that for the long-term scenario the LCOH in the mobility sector

217 Lower value within the LCOH range corresponds to the results from the long-term scenario whereas the upper value to the outcomes from the short-term scenario.

are lower in case 4 with a dedicated wind park than in case 3 with additional fees. This outcome indicates that in the context of hydrogen fuel production the additional costs of intermittent power generation are fully reflected by the grid and renewables fees if the technology costs decrease substantially.

Table 4.3: Calculated NPV in selected cases and scenarios.

Item	Unit	Short–term	Mid–term	Long–term
Case 1				
Power sector	M€	0	0	0
Mobility sector	M€	171	262	523
Synergy	M€	171	262	523
Case 2				
Power sector	M€	−486	−486	−486
Mobility sector	M€	−788	−534	−420
Synergy	M€	−1,274	−1,020	−906
Case 3				
Power sector	M€	−946	−473	−233
Mobility sector	M€	−812	63	390
Synergy	M€	−685	−137	303
Case 4				
Power sector	M€	−1,489	−889	−643
Mobility sector	M€	−1,110	−318	8
Synergy	M€	−2,165	−949	−430

The actual net present value of the hydrogen production plant in different cases and scenarios as summarized in Table 4.3 can be explained by the comparison of LCOH and corresponding sales prices. In case 1 where electricity storage is not needed to satisfy the demand the revenues in the power sector equal the purchase costs[218] and the corresponding NPV is zero. In the mobility sector we find a positive and increasing NPV between the short- and long-term scenarios as decreasing LCOH are lower than the hydrogen sales prices. Synergetic application results in the same facility

218 In this case electricity sales price equals electricity purchase price.

value as in the mobility sector since the electrolysis is used solely to provide hydrogen as a fuel. In case 2 the NPV for all applications and in all scenarios is considerably lower than in case 1 due to additional renewable and grid fee payments which are not included in the hydrogen sales price in both sectors. In this way, the LCOH are higher than the sales price and thus all NPVs are negative. Similar to case 1 there are no synergy effects and the aggregated NPV from both sectors corresponds to the NPV from the combined application.

For green hydrogen in case 3 and 4, the NPV in the power sector is still negative as the revenues from electricity sales are not sufficient to remunerate the investments in electrolysis, storage and gas turbine capacities. For the mobility sector however, we find a positive hydrogen value for selected cases and scenarios (mid-term and long-term scenario in case 3 as well as long-term scenario in case 4) since the hydrogen sales prices are higher than the corresponding LCOH. In addition as reported in chapter 4.4.3 and 4.4.4, thanks to synergy effects the NPV from a combined facility utilization is always higher (or less negative) than the aggregate value for both cases. Nevertheless, a positive NPV for synergetic application can be obtained only in case 3 in the long-term with comparatively cheap spot market electricity and electrolysis technology.

4.5 Conclusion

The levelized costs of hydrogen in all applications are mainly determined by investment outlays in electrolysis as major component of the facility and corresponding electricity costs. Similar to Jørgensen and Ropenus (2008) and DLR (2015), we find that for predetermined hydrogen demand and cases where electricity is purchased directly from the market (case 1 to 3) an optimal investment and operation strategy is based on a trade-off between electrolysis size and utilization. For a given hydrogen demand the higher the electrolysis capacity, the lower its utilization on the one hand, but also the lower the average energy purchase price and corresponding electricity costs on the other hand. Hence, when comparing different scenarios, we observe that declining specific investment outlays and improving efficiency are responsible

for decreasing LCOH and in this way they have substantial impact on the overall profitability of the facility. Unfortunately, additional grid and renewable fee payments as well as investment outlays in renewable power plant capacities lower the profitability of the hydrogen supply such that for most applications and scenarios in case 2 and 4 we report negative NPVs.

In this context, the results of our study indicate that the costs of hydrogen supply are strongly influenced by the assumption of synchronization between hydrogen production and intermittent electricity generation. As expected we find higher levelized costs for green hydrogen (synchronized power supply and hydrogen generation) than for grey hydrogen (unconstrained electricity provision). The corresponding cost ranges calculated in our analysis are similar to the values reported in the literature. As predicted by Albrecht et al. (2016), the costs associated with an energy supply in the power sector are typically lower than in the mobility sector due to an overall more efficient use of energy in the power sector when electricity is purchased from the spot market. However, in the long-term scenario in case 4 with investments in a dedicated wind park and cheap electrolysis the opposite is true. In this particular case, we confirm the findings reported by DLR (2015) and Bünger et al. (2016) who assume that the entire power demand is satisfied through re-electrification of hydrogen from the corresponding storage.

In fact, the largest cost difference between grey and green hydrogen is observed for the electricity sector with a clear increase by approx. 100 % – 130 % since in the best case electricity can be directly transmitted to end users without any investments in hydrogen technology but in the worst case costly investments in renewable generation and storage capacities are needed. Similar to the figures reported by Bünger et al. (2016), the costs in the mobility sector rise by only approx. 20 % – 50 % as for both hydrogen categories electrolysis is required to produce hydrogen fuel at corresponding efficiency losses. Albrecht et al. (2016) report a slightly higher value of green hydrogen in the mobility sector due to more expensive energy capacity of the pressurized tubes as the selected storage technology. At this point it is worth mentioning that Bünger et al. (2016) and Albrecht et al. (2016) analyze the impact of constrained electricity supply only on hydrogen fuel production and do not provide a comparison between the different sectors. In this way, our analysis sheds light on the

somehow ambiguous results from the literature on the differences in hydrogen costs between various markets. We conclude that a comparison of the green hydrogen value should take into account not only the various technology costs and electricity sources[219] but also the corresponding demand patterns in different markets.

In the future, hydrogen technology might benefit substantially from providing hydrogen as a fuel in the mobility sector. In fact, the expected hydrogen sales price in this sector can be comparatively high and under some assumptions larger than the calculated levelized costs of hydrogen allowing for a positive NPV. This is mainly true for cases with cheap electricity from the spot market (case 1 and 3) and low specific investment outlays for electrolysis capacity (mid- and long-term scenario). In contrast, the average sales price in the power sector is not sufficient to remunerate for capacity investments needed to satisfy the electricity demand based on a variable wind power supply. Hence the corresponding NPVs are non-positive for all cases and scenarios. These outcomes are in line with the findings reported in a number of studies such as Kroniger and Madlener (2014), Bünger et al. (2016) or Albrecht et al. (2016).

Interestingly, we also find substantial benefits from synergy effects when the facility is used to provide hydrogen simultaneously for the power and mobility sectors under the constraint of an intermittent electricity supply. Due to lower combined capacity investments, better facility utilization and a more efficient use of renewable electricity the NPV from the synergetic operation in case 3 and 4 is higher than the aggregate value of a separate hydrogen production in both sectors. Similar to DLR (2015), the synergy effect in case 3 is stronger when specific investment outlays for the electrolysis are higher (i.e. stronger in the short-term than in the long-term scenario). However, when electricity is provided by a dedicated wind turbine in case 4 the synergy effect is slightly lower than in case 3 and remains almost unchanged for all scenarios. Due to the additional investment outlays in wind capacity, the better utilization of electrolysis has only a limited impact on the facility's NPV in the synergetic case. There are no synergies when electricity supply

219 I.e. constrained or unconstrained power from the spot market or from a dedicated wind turbine.

is unconstrained (case 1 and 2). We conclude that hydrogen as a universal energy carrier can contribute to a sustainable energy supply in the power and mobility sectors in an efficient way and might be helpful to integrate intermittent electricity into the future energy system.

5. Investment decisions in imperfect power markets with energy storage and large share of intermittent electricity

5.1 Introduction

The analysis in chapter 3 and 4 was carried out from the perspective of a single player interested in maximizing the NPV from the investment, and operation of storage for renewable electricity. In both cases we studied a prototypical facility where intermittent electricity supply was combined with energy storage in order to meet a predefined demand in the power and mobility sectors in a selected node. One important drawback of both models is represented by the assumption of a sufficiently small firm which has no influence on the underlying electricity price. In reality, from the perspective of the power system, storage technology typically has a price-smoothing effect, as it increases low electricity prices through additional demand in off-peak periods and decreases high electricity prices through supply in peak-load periods.[220] In addition, due to the limited number of market participants, single firms might exercise market power and behave strategically when making investment and production decisions.[221] Consequently, under such circumstances, optimal storage sizing and operation might deviate from the results obtained in previous chapters.

In this chapter, we analyze the role of storage and peak-load power plants in an electricity system where market participants behave strategically. We develop a game-theoretic market model for capacity investment and electricity generation under an oligopolistic market structure á la Cournot, and apply it in the context of the German power market. We assume phase-out of nuclear power plants and a large amount of intermittent electricity feed-in according

220 See for example Sioshansi (2010) as well as chapter 3.3.1.

221 See chapter 2.2.1 for a more detailed discussion on the market power and corresponding challenges in electricity markets.

to the plan of the German Federal Government (BMWi 2015). In peak-load hours when renewable supply is not sufficient to meet the demand, electricity is provided either by the peak-load power plants or by discharging energy from the storage plants. In this context, we are interested in optimal sizing and operation of different peak-load and storage technologies by the various market participants and the corresponding effects on market prices, social welfare, and GHG emissions. As argued by Sioshansi (2014), comparing the results for different market and ownership constellations might help to develop important guidelines for policy decision in regard to the role of energy storage in the future energy system. Hence, the analysis is conducted for different market (perfect and imperfect competition) and storage ownership structures (storage owned by one player versus by all players). Moreover, we study the impact of additional demand from the mobility sector on the overall market results. In the next chapter we provide a literature review on storage utilization and capacity expansion in imperfect power markets. In chapter 5.3 we formulate a game-theoretic market model, which is then applied in chapter 5.4 in a case study in the context of the German market in a long-term perspective. Finally, chapter 5.5 concludes our study.

5.2 Literature on storage sizing and operation under a game-theoretic framework

The literature related to strategic utilization of electricity storage in the context of optimal sizing and operation can be subdivided into two major streams. On the one hand, the literature on storage operation typically analyzes optimal production decisions and their impact on market results under imperfect competition from the short-term perspective, such as a single week or month assuming given storage capacities. On the other hand, the capacity expansion literature focuses on investment games between strategic firms, from the long-term perspective (e.g. several years) and neglecting short-term intertemporal production constraints such as storage charging and discharging.

The analysis conducted in Sioshansi (2014) belongs to the first stream of literature. The author proposes a stylized two-period model á la Cournot

in order to investigate welfare effects of electricity storage under different market and ownership structures. He finds that stand-alone storage[222] increases social welfare under perfect competition between all other generators, but might have a negative welfare effect when other market participants behave strategically. Moreover, storage operated by market participants with other production capacities might also decrease social welfare, however, this effect depends on the overall storage capacity installed, in comparison to the market size.

Sioshansi (2011) calculates the value of storage and welfare changes when storage is utilized by a wind generator to mitigate price-suppressing effects of intermittent feed-in. The proposed approach is defined as a Stackelberg-type SFE model with two stages including wind storage optimization within a rolling two-day horizon in the first step, and generation response of all other market participants in the second step. In the context of the Texas power market, Sioshansi (2011) reports positive storage value, which, however, diminishes with rising wind capacity. In comparison to a case without storage, profits from wind generation increase on the one hand but the welfare of conventional generators and consumers decreases on the other. Since the latter effect is stronger than the former, the overall welfare is also lower when storage is in operation. The results are sensitive in respect to storage efficiency, level of market competition and storage ownership structure.

Schill and Kemfert (2011) develop a detailed model for storage operation under the Cournot oligopoly market structure. It is formulated as a mixed complementarity problem (MCP), which takes into account exact intertemporal relationship between storage input and output decisions as well as ramping constraints of conventional power plants. The model is applied to the German power market for two representative weeks assuming various ownership structures of given storage capacities. According to the analysis, pumped-hydro storage operation has a price-smoothing effect and increases overall social welfare. The authors find that strategic behavior leads to underutilization of storage capacities and lower welfare in comparison to the non-strategic case. Both effects are further exacerbated by an uneven distribution of storage capacities among different players. The analysis also shows that under the assumptions of the case study, consumers' rent increases but producers suffer

222 I.e., storage is owned by a firm that has no other generation capacities in the market.

from welfare losses for all market and ownership structures due to storage utilization. At this point it is worth mentioning that on the one hand the producer rent of the firm operating the storage increases due to additional arbitrage profits, but on the other hand all other conventional generation units are worse off due to the price-smoothing effect of the storage. Since the latter effect is stronger than the former, the overall producer rent decreases when storage is introduced to the market.

A similar methodology is also proposed by Bushnell (2003), who applies a Cournot oligopoly model to the electricity market in the western United States. However, the intertemporal representation of storage utilization in this analysis is rather limited as the model accounts only for releasing energy from a reservoir of a given hydro plant, but not for storage charging within a representative month. The author reports that strategic players might be motivated to shift hydro generation from peak-load to off-peak periods in order to increase corresponding peak-load prices and thus earn profits in comparison to perfect competition.

Rivier et al. (2001) develop a Cournot game-theoretic model which explicitly accounts for storage input and output as well as the levels of a hydro reservoir in each time period. In order to analyze long-term generation decision making, each time period is represented by a number of load levels with a predefined duration. The model is applied in a case study for a stylized power system, showing that hydro power plants and pumped-hydro storage technologies can substitute thermal power plants efficiently according to the value of water in comparison to marginal costs of thermal units.

Regarding the second stream of literature, capacity expansion models under the game-theoretic framework can be classified into two broad categories according to the informational structure and decision dynamics of the players concerned.[223] On the one hand in open-loop equilibrium models, market participants make simultaneous production and investment decision and thus commit to a predefined strategy at the beginning of the planning horizon (Fudenberg and Tirole 1991, p. 131). According to Murphy and Smeers (2005),

223 Detailed overview, definition and discussion on modeling possibilities under game-theoretic framework can be found, for example, in Başar and Olsder (1999) and Fudenberg and Tirole (1991).

such information and decision-making structure corresponds to markets with long-term contracts for electricity delivery. Typically, open-loop equilibrium models can be solved comparatively easily and are therefore characterized by a good numerical tractability (Fudenberg and Tirole 1991, p. 131 and Pineau et al. 2011).[224] This model class can be further extended by taking into account stochastic variables such as demand growth when selecting the optimal pathway of actions within the so-called S-adapted[225] models (Haurie et al. 1990). On the other hand closed-loop equilibrium modeling is a typical two-stage approach where investment decisions are made in the first step by taking into account optimal generation decisions in the second step.[226] In this way, the investment equilibrium is subject to equilibrium constraint from the game on electricity production, and the corresponding market structure can be represented by trading in a spot market (Murphy and Smeers 2005). In practice, closed-loop equilibrium problems are often solved using the concept of backward induction and have limited numerical tractability, especially for games with a large space of actions (Pineau and Murto 2003 and Haurie et al. 1990). In general, the literature does not provide unambiguous results on the relationship between the degree of competition and investment level.

One of the early capacity expansion models under the game-theoretic framework is proposed by Chuang et al. (2001). The model is based on a heuristic search algorithm at two levels, including separate profit maximization for each firm at the lower level and equilibrium detection at the upper level. Numerical results of a case study indicate that Cournot competition leads to higher investments and better system reliability than collusive behavior by market participants organized in a cartel.

Ventosa et al. (2002) extend the model introduced by Rivier et al. (2001) to include investment decisions within the mixed complementarity problem

224 Note that open-loop equilibrium models represent non-convex problems, which are still hard to solve in comparison to other mathematical problems such as linear programming.

225 In this case S-adapted stands for sample adapted.

226 In the literature, closed-loop information structure is sometimes also referred to as feedback information structure (Başar and Olsder 1999, p. 10). Although both structures are similar there are still some differences between the corresponding models. Feedback models consider only current system-state variables under Markov perfect equilibrium framework whereas pure closed-loop models take into account all possible state variables (Haurie et al. 1990).

under open-loop information structure. They compare case study results under the MCP framework with the corresponding outcomes of a Stackelberg-type approach formulated as a mathematical problem with equilibrium constraints (MPEC), and find that both models provide similar results. According to the authors, MCP should be favored over the MPEC approach from a computational viewpoint when applied to comprehensive system studies. Bushnell and Ishii (2007) propose a very flexible methodology for analyzing investment decisions under closed-loop information structure. The model first solves the generation problem within any given spot market structure and then uses the short-term results to find investment equilibrium by backward induction under Markov's perfect equilibrium framework. They apply the model to an exemplary case study for three firms, assuming a Cournot oligopolistic structure of the spot market. They find that, on the one hand, investment incentives might be higher for new entrants than for existing firms and, on the other, increased uncertainty might motivate market participants to postpone investments.

Pineau and Murto (2003) develop an S-adapted open-loop equilibrium model and apply it in a case study with a peak and base-load technology in the context of the Finnish power market within a ten-year horizon. They report that under oligopolistic market structure investment in a new generation, capacities are rather limited, potentially raising an issue with regard to expected system reliability. These results are further empirically tested by Pineau et al. (2011), indicating that investment levels are rather sensitive to deprecation rate and planning horizon in contrast to price elasticity.

Lise and Kruseman (2008) report that in comparison to perfect competition, an oligopolistic market structure in regard to investments and generation decisions increases electricity prices, GHG emissions and technology diversity on the one hand but decreases overall capacity investments on the other. A similar approach as in Pineau and Murto (2003) and Pineau et al. (2011) is also applied by Genc and Sen (2008) in the context of the Ontario wholesale market in Canada for a varying number of market participants. However, their analysis shows that a lower number of strategic firms increases both electricity prices and overall generation capacities. Thus, the authors conclude that higher capacities do not necessarily mitigate the threat of market power exertion. Centeno et al. (2011) confirm these findings by employing a bilevel

MPEC model under Cournot market structure. They show that the lower the degree of competition in an oligopolistic market the higher the investments and utilization of peak-load technologies.

Grimm and Zoettl (2013) distinguish in their analysis between different levels of competitiveness for both long-term investment and a short-term generation game. Their findings also indicate that the overall capacities are lower under the strategic framework for both investment and production decision rather than in markets with perfectly competitive participants. However, as also reported by Genc and Sen (2008) and Centeno et al. (2011), more competitive spot markets also do not lead to higher incentives for capacity expansion in the event of strategic investment behavior. Therefore, the authors conclude that the influence of the spot market competition on the investment behavior should be taken into consideration when designing and regulating the spot markets.

One contribution of the analysis in this chapter is to bridge the gap between the two streams of literature. As postulated by Sioshansi (2014) the investment outlays for new storage capacities might play an important role in investigating the impact of storage on the overall market results. Therefore on the one hand our model includes intertemporal decision making associated with storage operation in the short term, and on the other hand it also takes into account investment outlays based on optimal storage sizing in the long term.

Moreover, as in chapter 3 and 4, we also explicitly consider the seasonality of the renewable feed-in and electricity demand. Most contributions either analyze the storage operations in detail for a limited number of hours within a year (e.g. for a typical week as conducted by Schill and Kemfert 2011) or simply assume that storage input and output balance for a given number of time periods in an investment game, thus neglecting the actual filling level of the storage (see for example Ventosa et al. 2002). In our study, however, we take into account the actual annual patterns of energy demand and renewable generation on the one hand, and the intertemporal relationship between storage charging and discharging on the other. This allows us to better understand the optimal operation strategy for storage capacities in the market based on the actual development of the storage filling level within the entire year.

As argued by Genc and Thille (2011), many analyses related to the capacity expansion literature are based on symmetric technologies, i.e. on a limited number of technology types[227] with identical characteristics for all market participants. In contrast, in our contribution we include two different storage technologies (pumped-hydro and hydrogen) and examine how both technologies can interact and complement each other in an environment under different ownership and market structures. In this way, we can take into account the different advantages of both storage types and might obtain more realistic results regarding the market behavior of predefined players. In addition, we also analyze the role of hydrogen as a universal energy carrier in the context of sector coupling between the electricity supply and sustainable mobility. As stated by BMWi (2015), the explicit linkage between the power and mobility sectors will be an important pillar for the future development of the energy system in Germany, and thus should be examined in more detail. Therefore, in our study, we provide some insights into the impact of hydrogen demand on the development of the future electricity market.

In this context, our findings can be used in politics, as well as by regulatory bodies, potential investors and other stakeholders to better understand the relationship between investment incentives for peak-load and storage technologies, anticipated electricity prices and welfare effects in the future power market. In particular, the comparison of the results for market structures with and without different types of electricity storage, as well as explicit market power might be helpful in estimating future needs for energy storage in a market with a large share of intermittent power. Hence our findings may be useful in determining the requirements for future policy support in order to satisfy such needs. In addition, regulatory bodies may better understand the role of storage in the context of avoiding potential market power abuse. Since our analysis also provides detailed insights into each player's individual production and capacity levels, investors may gain some insight into optimal behavior in the future electricity market. They might use the outcome of this analysis to adapt their strategies with respect to their future participation in the power market.

227 For example, some authors, such as Pineau et al. (2011), consider only one type of peak and base-load power plant without further distinction between various primary energy sources.

5.3 Game-theoretic market model

In this chapter we propose a game-theoretic model for long-term investment and short-term production decisions under the framework of Cournot oligopoly competition. We assume profit maximizing investors who can potentially invest and operate various dispatchable power plants as well as energy storage technologies. The total electricity amount provided by the firm in time period t to the market is represented by $q_{f,t} = \sum_{d \in D} q^d_{f,d,t} + \sum_{s \in S} q^o_{f,s,t} - \sum_{s \in S} q^i_{f,s,t}$ including dispatchable output $q^d_{f,d,t}$ by the technology d and storage output $q^o_{f,s,t}$ from technology s reduced by corresponding storage input $q^i_{f,s,t}$.[228] If applicable, the investor can also sell an amount of energy $q^m_{f,s,t}$ directly in the mobility sector (e.g. in the form of hydrogen fuel). Moreover, at the beginning of the planning horizon each firm decides on the investments in dispatchable and storage capacities $I^d_{f,d}$ and $I^s_{f,s}$, respectively.[229] Both investment and generation decisions are made simultaneously, as for the sake of numerical tractability we assume an open-loop information structure in our model. In this context, we define the following NPV maximization problem for each firm:[230]

$$\max NPV = AF \cdot \left[\sum_{t \in T} D_t \cdot \left(p^e_t (Q_t) \cdot q_t + p^m \cdot \sum_{s \in S} \mu_s \cdot q^m_{s,t} - \sum_{d \in D} c_d \cdot q^d_{d,t} \right) - FC \right] - NI \tag{5.1}$$

subject to constraints

$$q^d_{d,t} - K_d - I_d \leq 0 \quad \forall d \in D, t \in T \tag{5.2}$$

$$q^i_{s,t} - K_s - I_s \leq 0 \quad \forall s \in S, t \in T \tag{5.3}$$

$$q^o_{s,t} - K_s - I_s \leq 0 \quad \forall s \in S, t \in T \tag{5.4}$$

228 A full list of indices, variables and parameters is provided in Appendix C.1.

229 In reality, investment decisions can be made continuously and under some circumstances market participants might be interested in postponing their investments to subsequent years. In fact, such market behavior is explicitly considered in some studies, e.g. by Genc and Sen (2008) or Pineau et al. (2011). However, in our analysis we are interested in the impact of the storage operation on the overall market results. Taking into account a number of time periods during a year as well as several years would increase the overall number of time steps with negative effects on the numerical tractability of the model. Therefore for the sake of simplicity, we refrain from such model complication and assume investment decisions at the beginning of the planning horizon.

230 For the sake of better readability we omit the firm's index *f*.

$$\frac{1}{\eta_s^o} \cdot \sum_{\tau=1}^{t} D_\tau \cdot q_{s,\tau}^o + \mu_s \sum_{\tau=1}^{t} D_\tau \cdot q_{s,\tau}^m - \eta_s^i \sum_{\tau=1}^{t} D_\tau \cdot q_{s,\tau}^i \leq 0 \quad \forall s \in S, t \in T \quad (5.5)$$

$$\eta_s^i \cdot \sum_{\tau=1}^{t} D_\tau \cdot q_{s,\tau}^i - \frac{1}{\eta_s^o} \sum_{\tau=1}^{t-1} D_\tau \cdot q_{s,\tau}^o - \mu_s \sum_{\tau=1}^{t-1} D_\tau \cdot q_{s,\tau}^m - \overline{K}_s - \upsilon_s \cdot I_s \leq 0$$

$$\forall s \in S, t \in T \quad (5.6)$$

$$I_d - \bar{I}_d \leq 0 \quad \forall s \in S \quad (5.7)$$

$$I_s - \bar{I}_s \leq 0 \quad \forall s \in S \quad (5.8)$$

$$q_{d,t}^d \geq 0 \quad \forall d \in D, t \in T \quad (5.9)$$

$$q_{s,t}^i,\ q_{s,t}^o,\ q_{s,t}^m \ \geq 0 \quad \forall s \in S, t \in T \quad (5.10)$$

$$I_d \geq 0 \quad \forall d \in D \quad (5.11)$$

$$I_s \geq 0 \quad \forall s \in S \quad (5.12)$$

where

$$AF = \frac{(1+r)^n - 1}{r \cdot (1+r)^n} \quad (5.13)$$

$$q_t = \sum_{d \in D} q_{d,t}^d + \sum_{s \in S} q_{s,t}^o - \sum_{s \in S} q_{s,t}^i \quad \forall t \in T \quad (5.14)$$

$$FC = \sum_{d \in D} \left[\varphi_d \cdot \varepsilon_d \cdot (K_d + I_d) \right] + \sum_{s \in S} \left[\varphi_s \cdot \varepsilon_s \cdot (K_s + I_s) \right] \quad (5.15)$$

$$NI = \sum_{d \in D} \left[\varepsilon_d \cdot I_d \cdot \left(1 - \frac{\lambda_d - n}{\lambda_d \cdot (1+r)^n} \right) \right] + \sum_{s \in S} \left[\varepsilon_s \cdot I_s \cdot \left(1 - \frac{\lambda_s - n}{\lambda_s \cdot (1+r)^n} \right) \right] \quad (5.16)$$

Similar to the approach in Bushnell and Ishii (2007), each investor's NPV in equation (5.1) includes discounted annual cash flows from operations within a detailed planning horizon as remuneration of the initial net investment

outlays NI.[231] We assume a constant annual cash flow,[232] which is multiplied by the annuity factor AF based on the number of periods n within the planning horizon and the interest rate r as defined in equation (5.13). The annual revenues stem from total electricity sales q_t in the power market, as formulated in equation (5.14) at electricity price $p_t^e(Q_t)$ and from additional energy supply $q_{s,t}^m$ in the mobility sector at constant price p^m. Note that the electricity price depends on the total energy supply of all market participants as defined in equations (5.18) and (5.19). In order to distinguish between the storage technologies with the potential for sales in the mobility sector (e.g. electrolysis technology[233] providing hydrogen as a fuel) the additional energy supply $q_{s,t}^m$ is multiplied by the factor μ_s, which can be 0 or 1 to avoid or allow the additional sales, respectively. Moreover, in each time period t we account for variable production costs c_d associated with electricity generation by all dispatchable power plants of the firm. The corresponding contribution margin calculated as revenues less variable costs is further multiplied by the load duration D_t. In this way, we can summarize several hours of a year to one time period in our model.[234]

In addition, as represented in equation (5.15), the annual fixed costs for all dispatchable power plants and storage technologies of the selected firm are calculated by multiplying the total capacity installed, consisting of the initial capacities K_d and K_s, as well as investments in new capacities I_d and I_s, by the corresponding specific capital expenditures per capacity unit ε_d and ε_s and fixed costs fraction φ_d and φ_s. Equation (5.16) defines net investment outlays as actual payments for new dispatchable and storage capacities (i.e. investment I_d or I_s multiplied by the respective capital expenditures ε_d or ε_s) reduced by the discounted residual value of each technology. Under the assumption of linear deprecation, the residual value is calculated as a fraction of the initial expenditures based on the corresponding lifetime λ_d or λ_s and the total number of periods within the detailed planning horizon.

231 As in previous chapters, net investment outlays are defined as actual capital expenditures at the beginning of the planning horizon, less the discounted salvage value of each technology.

232 This means that there is no change in demand within the whole detailed planning horizon.

233 See chapter 2.3.3 for more details on this technology.

234 This approach is also employed by some other authors, e.g. Rivier et al. (2001) or Ventosa et al. (2002).

The technical constraints are formulated in equation (5.2) – (5.8). In equation (5.2) we define the maximum capacity consisting of initial capacity and additional investments for production quantity $q^d_{d,t}$ by the dispatchable power plant. Likewise, in equation (5.3) storage input is constrained by the total capacity of the storage input device (e.g. pumps of the pumped-hydro storage). At this point it is important to mention that we assume the same input and output capacity and a fixed technology-specific ratio υ_s between energy and power-related capacity. Hence, in equation (5.4) we use the same upper bound for hydrogen output as in equation (5.3).[235] Further, as formulated in equation (5.5), the aggregated storage output for the power and mobility markets up to the selected time period t must be lower or equal to the total storage input until that period adjusted by the corresponding efficiencies η^o_s and η^i_s.[236] In this context, we assume that the storage is empty at the beginning of the first time period and minimal storage level is zero.[237] According to equation (5.6), the upper bound for storage operation is represented by the initial capacity $\overline{K}_s$ and investments in new capacity $\upsilon_s \cdot I_s$ reduced by the current storage level calculated as aggregated input from past periods less total output for the power and mobility sectors up to the selected time period.[238] Equations (5.7) and (5.8) restrict investments in dispatchable power plant and storage up to the limit $\bar{I}_d$ and $\bar{I}_s$, respectively. Both constraints can be interpreted as the inability of the selected firm to invest in additional capacities above the predefined upper bound. Finally, equations (5.9) – (5.12) include non-negativity constraints for all production and investment decision variables.

In order to ensure that total energy sales in the mobility sector do not exceed a predefined level, we introduce the maximum demand M_t for all firms in equation (5.17). Further, we define the market clearing condition

235 Note that for the sake of consistency the specific capital expenditures ε_s should include all technology costs associated with input, output and energy-related capacities.

236 For mobility-related storage release we refrain from explicit modeling of efficiency losses as we assume that this value is sufficiently small. However, the corresponding quantity is again multiplied by the factor μ_s to account for the ability of energy sales in mobility market.

237 Note that equations (5.5) and (5.6) apply to each time period t such that the chronological order of storage input and output plays an important role in production decisions for the selected player.

238 Note that we assume a fixed ratio υ_s between energy and power-related storage capacity.

in the power sector as a linear inverse demand function as formulated in equation (5.18) where A_t and B_t represent demand scaling parameters. The overall electricity demand Q_t depends on total energy provision by all firms and intermittent feed-in q_t^r of all renewable power plants as represented in equation (5.19).[239] Similar to the approach in Traber and Kemfert (2011), we account only for the residual load, i.e. actual electricity demand net of intermittent feed-in. Although in reality, in an energy system with a large share of intermittent electricity the actual behavior of renewable generators will play an important role, we refrain from explicit modeling of the respective investment and production decisions. In this regard, we assume that intermittent electricity either will be provided to the market at marginal costs close to zero within the energy-only market structure, or it will be traded in a separate market such that the remaining demand will be satisfied by other generators in the wholesale market as defined in our model. Note that we also assume perfect foresight regarding the future demand and renewable feed-in profiles as well as symmetric information structure among all market participants.

$$\sum_{f \in F} \sum_{s \in S} q_{f,s,t}^m \leq M_t \quad \forall t \in T \tag{5.17}$$

$$p_t^e\left(Q_t\right) = A_t - B_t \cdot Q_t \quad \forall t \in T \tag{5.18}$$

$$Q_t = \sum_{f \in F} q_{f,t} + q_t^r \quad \forall t \in T \tag{5.19}$$

The NPV maximization problem as described in equations (5.1) – (5.16) applies simultaneously to all market participants interrelated with each other by the market-clearing conditions in equations (5.17) – (5.19). In order to find the optimal solution for all players, we derive Karush-Kuhn-Tucker (KKT) optimality conditions with respect to the corresponding decision variables and constraints. Together with the constraints and the market-clearing conditions, the KKT conditions form a mixed complementarity problem comprising

239 Note that for the selected firm f, the electricity provision $q_{f,t}$ can be also negative if storage charging exceeds storage releases and production by dispatchable power plants.

a square system of equations, which is solved numerically with the PATH solver.[240] The solution to MCP provides a valid solution for all market participants and represents Cournot-Nash equilibrium to the production and investment game. The formulation of the corresponding MCP can be found in Appendix C.2. At this point it is important to mention that the market power of each firm can easily be excluded by assuming an appropriate value for the market power parameters γ_f in the corresponding optimality conditions.[241] In this case, the firm f does not take into account its own impact on the market price and offers energy to the market based only on the marginal costs (Bushnell 2003). This approach can be used to model price-taking behavior either of the competitive fringe in an imperfect market (i.e. where all other players behave strategically) or of all market participants under perfect competition.[242]

In order to compare the results of our analysis, we also calculate social welfare including producer and consumer rent as defined in equation (5.20) – (5.22). Producer rent *PR* corresponds to the NPV of all firms and the profits from renewable electricity sales neglecting any costs of intermittent production.[243] Consumer rent *CR* is calculated as the integral of the inverse demand function up to the total electricity supply reduced by actual consumer payments (i.e. market clearing price multiplied by total demand). Note that consumer rent is also adjusted by the annuity factor and corresponding load duration. For better tractability, consumer rent in equation (5.21) can be further rearranged to the form presented in equation (5.22).

240 For more details on the underlying algorithm and application possibilities of the PATH solver see for example Dirkse and Ferris (1995) or Ferris and Munson (2000).

241 See also Appendix C.2 for more details.

242 Note that perfect competition typically occurs only in a market with a sufficiently large number of players (in contrast to oligopolistic markets with a limited number of players). However, this approach allows for modeling of the non-strategic behavior under the proposed game-theoretic framework. It is in line with methodology used by Bushnell (2003) and Schill and Kemfert (2011).

243 Recall that in our model we assume renewable electricity generation as a given input parameter with marginal costs close to zero. In this way the overall producer rent might be overestimated as it does not take into account the actual costs of renewable electricity production. However, the actual welfare effects of renewable generation itself are not in the scope of this study and this issue is an interesting field for further analyses. Instead as mentioned above, we assume that renewable electricity might be traded in a separate market where production costs will play an important role.

$$PR = \sum_{f \in F} NPV_f + AF \cdot \sum_{t \in T} \left[D_t \cdot p_t^e \left(Q_t \right) \cdot q_t^r \right] \tag{5.20}$$

$$CR = AF \cdot \sum_{t \in T} \left[D_t \cdot \int_0^{Q_t} p_t^e(x)\, dx - p_t^e \left(Q_t \right) \cdot Q_t \right] \tag{5.21}$$

$$= AF \cdot \sum_{t \in T} \left[\frac{D_t}{2} \cdot \left[A_t - p_t^e \left(Q_t \right) \right] \cdot Q_t \right] = AF \cdot \sum_{t \in T} \left(\frac{D_t}{2} \cdot B_t \cdot Q_t^2 \right) \tag{5.22}$$

5.4 Case study

5.4.1 Scenario definition and input data

As mentioned in chapter 5.1, we apply the game-theoretic market model to analyze the role of storage in an energy system with large share of intermittent electricity. The case study is carried out in the context of the German electricity market in the long-term, assuming a reduction of 25 % in electricity consumption in comparison to the 2008 baseline, and a share of renewable generation of 80 %.[244] Therefore the aggregated electricity demand amounts to 460 TWh and the intermittent power supply from wind and PV accounts for approximately 350 TWh.

The remaining energy is provided either by the base-load technologies represented by existing hydro run-of-river power plants or by flexible gas turbines as a peak-load technology. Due to climate policy requirements, there are no other dispatchable units such as nuclear, lignite or hard coal power plants. We consider two storage types, namely existing pumped-hydro power plants as well as hydrogen technology. The mobility sector is represented by the long-term demand for hydrogen fuel amounting to a maximum of 67 TWh in line with the assumptions in Pregger et al. (2013). Similarly to DLR (2015), the constant average hydrogen sales price in the mobility sector is 5.5 €/kg_{H2}

244 These figures correspond to the climate policy targets of the German Federal Government for 2050. See also chapter 2.2.2 for more details.

(or 165 €/MWh). For the sake of comparability, we allow only for investments in peak-load units and hydrogen storage, whereas all other capacities including base-load power plants, intermittent generators and pumped-hydro storage are given. This is mainly due to the fact that, on the one hand, we are interested in optimal sizing and operation of technologies required to cope with the intermittent energy supply such as peak-load or storage, and on the other hand, the potential for further expansion of run-of-river and pumped-hydro power plants in Germany is rather limited. Moreover, we assume current market structure consisting of four strategic firms (firm 1 – 4) and a competitive price-taking fringe. Only strategic firms make investment decisions whereas competitive fringe utilizes only predetermined initial capacities of selected technologies.

Table 5.1: Selected scenarios for the market analysis.

Scenario	Comepetition	Storage technology	Storage investments	Mobility sector
A1	Perfect	No storage	None	n/a
A2	Perfect	PHS	None	n/a
A3	Perfect	PHS and H_2	All firms	No demand
A4	Perfect	PHS and H_2	Firm 1	No demand
B1	Imperfect	No storage	None	n/a
B2	Imperfect	PHS	None	n/a
B3	Imperfect	PHS and H_2	All firms	No demand
B4	Imperfect	PHS and H_2	Firm 1	No demand
C1	Perfect	PHS and H_2	All firms	Max. demand
C2	Perfect	PHS and H_2	Firm 1	Max. demand
C3	Imperfect	PHS and H_2	All firms	Max. demand
C4	Imperfect	PHS and H_2	Firm 1	Max. demand

As summarized in Table 5.1, our analysis includes in total 12 different scenarios, which are grouped into three categories according to the degree of competition, storage technology use and investments, as well as fuel demand in the mobility sector. In scenarios A1 – A4, we assume perfect competition between all

market participants[245] but exclude energy supply in the mobility sector. The difference between these scenarios is based on various constellations regarding storage availability (no storage in scenario A1, only PHS in scenario A2 and PHS and hydrogen technology in scenario A3 and A4) and the possibility of investments in hydrogen storage capacities (all firms in scenario A3 and only firm 1 in scenario A4). Scenarios B1 – B4 have the same structure as scenario A1 – A4 regarding storage utilization and investment, however, under imperfect competition. In scenario C1 – C4 we analyze the impact of additional energy demand in the mobility sector on the power system containing both storage technologies (PHS and hydrogen technology). In these scenarios we distinguish again between perfect (scenario C1 and C2) and imperfect (scenario C3 and C4) competition as well as different ownership structures of hydrogen technology (all firms in scenario C1 and C3 and firm 1 only in scenario C2 and C4).

For the sake of numerical tractability, we follow the approach presented by Bushnell (2003) and construct a step function with 10 segments for each month as an approximation of the actual load duration curve. In this way, we are able to reduce the total number of time periods within one prototypical year from 8,760 hours to 120 time periods each representing an average of 73 hours (see Figure 5.1 for an example).[246] In addition, we calculate the corresponding average renewable feed-in, demand in mobility sector and the historical electricity price for each time step. Note that in this context we dissolve the load and renewable generation chronology within one month and thus underestimate the spread between maximum and minimum demand level and between load and intermittent feed-in. However, recall that we are interested in the role of the storage and peak-load technology in an energy system with a large share of intermittent electricity in the long-term. On the one hand, the proposed approach still accounts for the seasonal pattern of demand and intermittent electricity supply, but on the other hand it helps to reduce the computational time of the case study. In this way, each segment of the step function corresponds to one time period in our model. The model is calibrated with time-series data for 2012 where

245 As discussed in the previous chapter, we exclude the market power for all participants by assuming a value of 0 for the market power parameters γ_f for each firm. Such market behavior is considered perfect competition in the context of our case study.

246 This means that the load duration D_t is 73 hours for all time periods in our model.

historical electricity prices for the German market place are obtained from EPEX SPOT (EPEX 2015) and demand data from ENTSO-E (2013).[247]

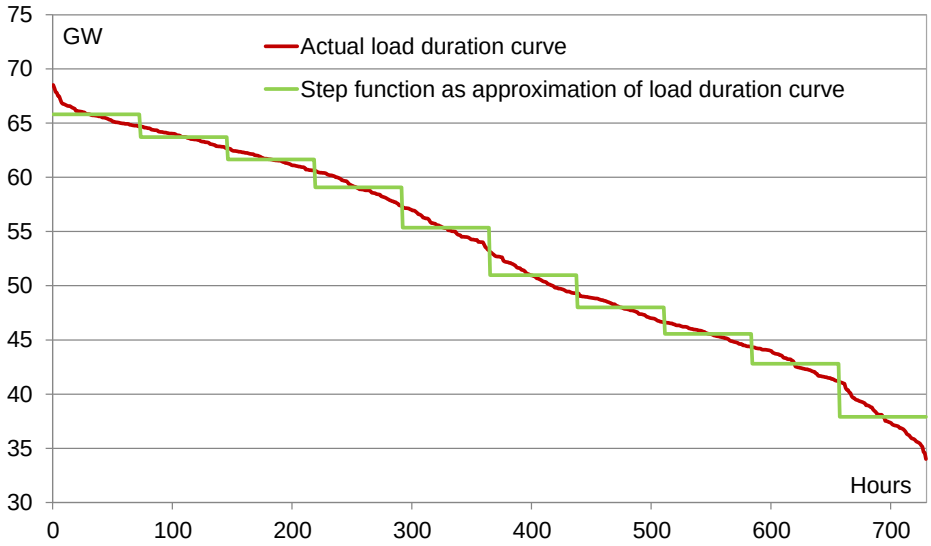


Figure 5.1: Actual load duration curve and its approximation with a step function.

Regarding renewable generation, we assume a wind to PV ratio of 80 % to 20 % (i.e., approx. 280 TWh come from wind and 70 TWh from PV generation)[248] and construct a corresponding feed-in pattern based on intermittent profiles provided by German TSOs.[249] At this point, it is important to mention that in scenario C1 – C4 the overall intermittent generation is higher, amounting to approx. 420 TWh (336 TWh wind and 84 TWh feed-in) in order to account for the additional energy need and efficiency losses of hydrogen production. The demand pattern in the mobility sector is again based on data provided by DOE (2008) and MWV (2012). The corresponding average renewable generation as well as the demand

247 The model calibration is conducted by choosing the demand scaling parameters A_t and B_t for each time period in such a way that for the historical demand data the inverse demand function provides corresponding historical electricity prices. The same approach is also chosen by Green and Newbery (1992) or Traber and Kemfert (2011), for example.

248 The same ratio is reported in Nitsch et al. (2012a) for intermittent supply in 2050.

249 The feed-in pattern for each technology is constructed by multiplying the overall annual wind or PV generation by the corresponding generic intermittent profile. Such a profile is obtained by dividing the historical feed-in in each hour of the year by the overall supply in that year.

in the power and mobility sectors in each time period of a prototypical year are illustrated in Figure 5.2. The monthly pattern of the demand in the power sector is due to load approximation with the step function,[250] however, still showing some seasonal differences between summer and winter months (i.e. slightly higher peak demand in winter than in summer).[251] In addition, we observe a good correlation between electricity load and renewable generation in spring and summer months (time periods 30 to 90, i.e. April to September) due to large PV feed-in but only poor correlation in winter and fall months (time periods 1 to 30 and 90 to 120, i.e. January to March and October to December) due to predominant wind feed-in. We assume a demand elasticity of −0.05 which is rather low in comparison to corresponding figures in the literature.[252] However, recall that the demand and price values in one time period of our case study correspond to an average of 73 hours and other flexibility options for electricity consumption (such as demand side management) typically occur within a small number of hours. Hence, we expect only limited potential for other flexibility options within one time step. The demand in the mobility sector is inelastic and rather constant, however, with a slight decrease between December and February due to limited driving in the winter time.

The initial capacities of the base-load technology and pumped-hydro storage for different market participants are derived from Traber and Kemfert (2011) and Schill and Kemfert (2011), respectively. As indicated in Table 5.2, the largest run-of-river capacity is assigned to firm 2 (approx. 1.5 GW) followed by the competitive fringe (approx. 0.9 GW).[253] Regarding pumped-hydro storage firm 2 controls largest capacity (approx. 2.9 GW power-related capacity and

250 As mentioned above, for each month of the year we make a stepwise approximation of the load duration curve from the highest to the lowest demand. The annual demand curve is then constructed by stringing together the monthly demand curves. A similar approach is employed by Rivier et al. (2001)Reivier et al. (2001).

251 For example, in February (time period 11 to 20) the peak demand accounts for approximately 72 GW, which is 13 % higher than in August (time period 71 to 80) at 64 GW.

252 For example Schill and Kemfert (2011) assume demand elasticity of −0.35 whereas in Bushnell (2003) this value is slightly lower amounting to −0.1.

253 Note that run-of-river capacity reported in Traber and Kemfert (2011) account for an average availability of 75 %. Thus considered capacities operated at full load (i.e., 8760 hours per year) are able to provide approx. 30 TWh per year corresponding to approx. 6 % of the expected annual demand.

approx. 17.1 GWh energy-related capacity) whereas all other strategic firms have similar storage size (approx. 1 GW power-related capacity and approx. 6.8 – 7.2 GWh energy-related capacity).

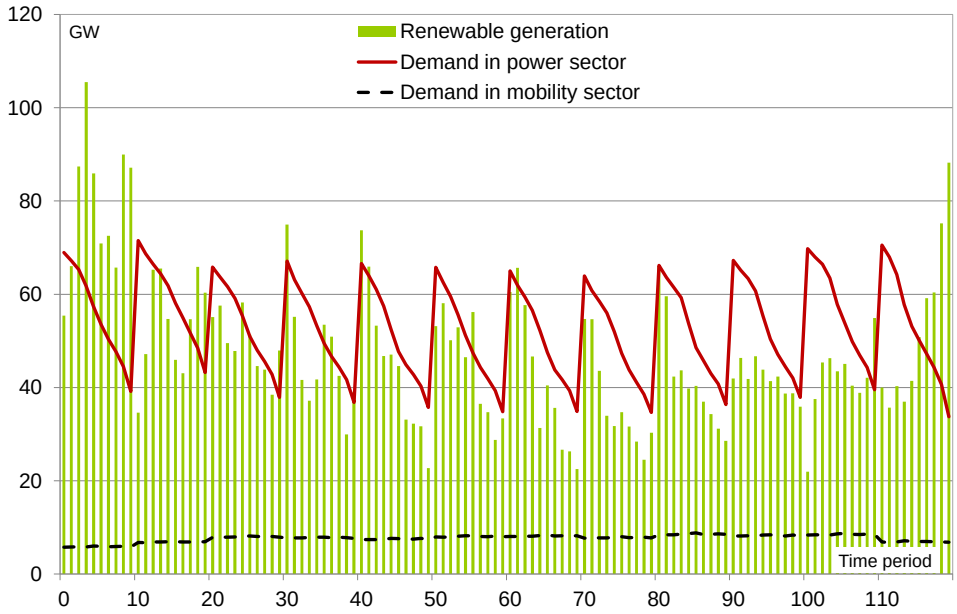


Figure 5.2: Renewable generation as well as demand in the power and mobility sectors in each time period within a prototypical year.

Table 5.3 summarizes techno-economic data of selected generation and storage technologies. For the peak-load generation and re-electrification unit of the hydrogen storage, we employ the data of a gas turbine with investment outlays of 400 €/kW and an efficiency of 47 % as stated by Nitsch et al. (2010b). Comparatively high variable costs of peak-load technology of 119 €/MWh are mainly due to a high natural gas price of 41 €/MWh and CO_2 certificate price of 60 €/t_{CO2}.[254] For electrolysis and hydrogen storage we follow DLR (2015) and assume cheap and efficient PEM electrolyzers in the long term with specific investment expenditures of 330 €/kW and efficiency of 70 %.[255] The round-trip efficiency of hydrogen storage, consisting of electrolysis and gas turbines, as re-electrification units is comparatively low at 33 %.

254 These figures correspond to the market assumptions of Path A in Nitsch et al. (2012a).

255 The optimistic figures for specific investment outlays of electrolysis technology are due to economies of scale as well as technological learning in the long-term.

Table 5.2: Initial capacities of the base-load technology and pumped-hydro storage.

Technology	Base-load capacity MW	Pumped-hydro storage	
		Power capacity MW	Energy capacity MWh
Firm 1	427	1,006	7,200
Firm 2	1,507	1,017	6,790
Firm 3	638	1,023	6,959
Firm 4	0	2,893	17,141
Competitive fringe	893	456	2,202
Total	**3,465**	**6,395**	**40,292**

The hydrogen storage is an underground salt cavern with cheap energy-related capacity valued at 240 €/MWh. Similarly to Schill (2014), we assume a fixed ratio of 500 between energy and power capacity for the hydrogen technology (i.e. $\upsilon_s = 500$). For the sake of simplicity, we omit fixed costs for base-load technology and pumped-hydro storage which has a round-trip efficiency of 81 % (i.e. $\eta_s^i = \eta_s^o = 90\,\%$). The interest rate is 8 %[256] and detailed planning horizon 10 years.

Table 5.3: Techno-economic parameters of selected generation and storage technologies.

Technology	Investment outlays €/kW	Fixed costs %	Variable costs €/MWh	Efficiency %	Lifetime a
Base-load generation	n/a	0	5	100	30
Peak-load generation	400	2	119	47	25
Pumped-hydro storage	n/a	0	n/a	81	20
Electrolysis	330	1.5	n/a	70	30
Hydrogen storage	240*	4	n/a	100	25
Re-electrification unit	400	2	n/a	47	30

∗ Energy-related capacity is expressed in €/MWh.

256 This figure is line with some other studies on the role of electricity storage in the future German electricity market, such as DLR (2015) or Schill (2014).

5.4.2 Optimal investment and production strategy

Under perfect competition in scenario A1 – A4, overall dispatchable and power-related storage capacity ranges between 33 GW and 44 GW. The maximum peak-load capacity is achieved in scenario A1 with more than 29 GW decreasing to 21 GW when further storage capacities are added (see Figure 5.3). Nevertheless as summarized in Table 5.4, the total electricity supply of gas turbines is only slightly lower, such that the corresponding utilization increases from 2,500 full load hours in scenario A1 to 3,200 hours in scenario A3 and A4. Note that in this case, ownership structure of hydrogen technology (i.e. all firms in scenario A3 and firm 1 only in scenario A4) has no influence on the sizing and operation of peak-load technology. This is due to the fact that under perfect competition, optimal decision making does not take into account its impact on electricity price and is based only on the relationship between given sales prices and the corresponding costs. Although by definition base-load capacity remains unchanged, both production and utilization of this technology increase by 10 % in scenarios with storage operation (from 26 TWh or 7,600 full load hours in scenario A1 to 29 TWh or 8,400 hours in scenario A3).

Interestingly, we observe the largest aggregated capacity in scenario A3 and A4 since the additional electricity demand from storage charging still provides sufficient incentives for investment in new gas turbines. In this way, the slight decrease in dispatchable capacity is overcompensated by the strong increase in power-related storage capacity. The corresponding input capacities are 6.4 GW for pumped-hydro and 12.9 GW for hydrogen storage.[257] Both technologies are operated for only a few hours within the prototypical year when the residual load[258] is very low (for charging) or very high (for discharging), providing less than 1 % of total electricity supply to the market. Due to efficiency losses, electricity consumption of both storage technologies is higher than the corresponding output such that the utilization of the input power capacity is considerably higher (approx. 110 full

257 Recall that pumped-hydro storage capacity remains at the same level in all scenarios as by definition we do not allow for further capacity investments in this type of storage.

258 Residual load is defined as total electricity demand in the market less intermittent feed-in.

load hours for PHS and approx. 1,000 full load hours for hydrogen) than the utilization of the output capacity (80 – 85 hours for PHS and 290 – 300 hours for hydrogen). At this point it is also worth mentioning that the overall electricity supply ranges between 436 TWh (scenario A3 and A4) and 447 TWh (scenario A1) being lower by 4 % – 6 % than the predefined demand of 464 TWh. On the one hand, this is due to storage efficiency losses, and on the other, to the fact that consumers still respond to electricity price changes despite rather inelastic demand.

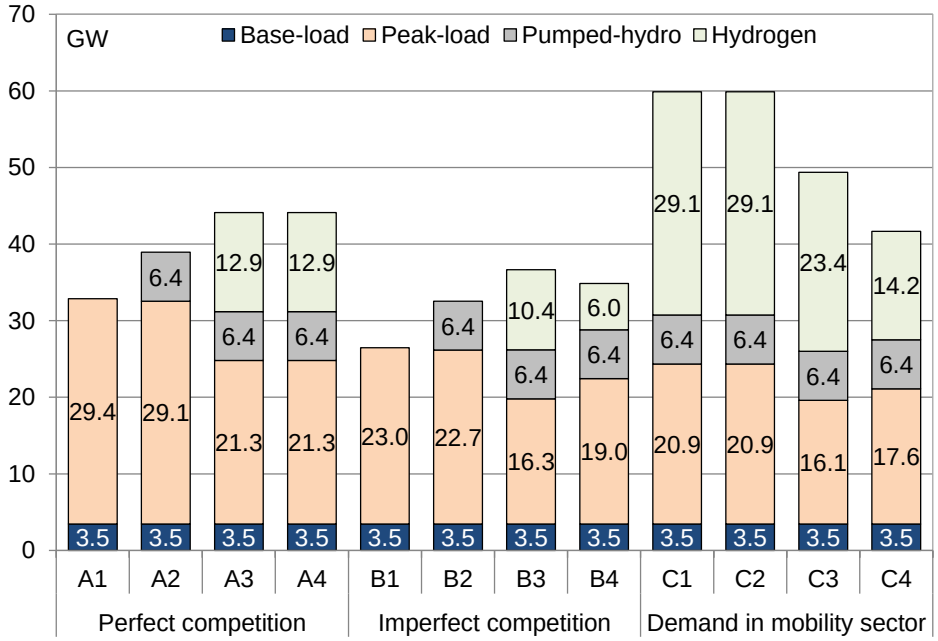


Figure 5.3: Installed dispatchable and power-related storage capacities.

Introducing imperfect competition in scenario B1 – B4 decreases the overall generation capacity and electricity supply, as market participants who behave strategically influence the market price in order to increase their profits. The aggregated dispatchable and power-related storage capacity ranges between 27 GW (scenario B1) and 37 GW (scenario B3) and the overall electricity supply between 420 TWh (scenario B3) and 429 TWh (scenario B1). Nevertheless, we find that the influence of storage is similar on optimal decision making as in the case with perfect competition. With increasing storage size, the peak-load capacity falls from 23 GW to 16 GW but its utilization rises from 2,400 to 3,200 full load hours, due to a comparatively constant output.

In comparison to scenarios under perfect competition, we find that output and utilization of the base-load technology and pumped-hydro storage are similar, indicating that market power is mainly exercised through reduction of peak-load supply and hydrogen storage use. Interestingly, the ownership structure of hydrogen storage has a substantial impact on optimal sizing and operation of this technology. In scenario B3 with storage operated by all firms, the corresponding capacity and output is higher than in scenario B4, where hydrogen technology is available only for firm 1. The aggregated hydrogen storage size and output of all firms in scenario B3 accounts for more than 10 GW and 3 TWh, respectively, whereas in scenario B4 these figures amount to 6 GW and less than 2 TWh, respectively.[259] This difference is due to the fact that in scenario B4, firm 1 exploits its monopolistic position regarding hydrogen storage in order to increase its overall profits. Since all other firms are not able to benefit from utilization of the hydrogen storage they invest in new capacities only to a limited extent.

As expected, additional demand for hydrogen fuel in scenarios C1 – C4 provides substantial incentives for investment in hydrogen technology. We find that the input and output capacity of hydrogen storage ranges between 14 GW (scenario C4) and 29 GW (scenario C1 and C2), being higher by a factor of 2 than the optimal capacity in corresponding scenarios without the demand in the mobility sector.[260] In contrast, the installed capacity of the peak-load technology is lower (between 16 GW and 21 GW) but the overall production higher (between 57 TWh and 84 TWh) than in the power sector case. Consequently, we observe improved utilization of the gas turbines, ranging from 3,300 full load hours in scenario C4 to 5,000 hours in scenario C3. For the base-load technology the optimal production strategy remains unchanged (supply of approx. 27 TWh to 29 TWh and utilization of more than 7,500 hours) whereas for pumped-hydro storage the overall energy output and the utilization of given capacities are lower. The only exception is observed under imperfect competition in scenario C4, where only firm 1 has access to hydrogen technology. In this scenario pumped-hydro storage is characterized

259 Note that in both scenarios the utilization of the hydrogen technology remains at a similar level.

260 Recall that in our model we use the same capacity for storage input and output. Thus our case study might overestimate the optimal size of the re-electrification unit, which corresponds to electrolysis size needed to satisfy the demand in mobility sector.

by a larger output and utilization. Moreover, firm 1 produces less hydrogen as a fuel (40 TWh) than the aggregated output in the mobility sector of all firms in the remaining scenarios (67 TWh corresponding to the maximum demand in this sector).

The rationale behind these findings is as follows. On the one hand, the additional demand in the mobility sector requires a larger electricity supply from both intermittent and dispatchable power plants. Among dispatchable power plants, only peak-load technology is able to provide the required energy since we do not allow for investments in base-load units that operate anyway at full capacity in all scenarios. On the other hand, in times of high demand in the power sector and low renewable feed-in hydrogen technology can be utilized in both sectors substituting peak-load capacities. Nevertheless, energy sales in the mobility sector are more attractive than in the power sector, meaning that the overall re-electrification of hydrogen and the utilization of the output unit are lower in scenario C1 – C4 (less than 1 TWh and less than 50 full load hors, respectively) than in the corresponding scenarios without the mobility demand. The strategic behavior of the market participants in scenario C4 is based on a trade-off between profits from the power and mobility markets. Since in this scenario, only firm 1 can benefit from additional hydrogen sales in the mobility sector it has a disproportional incentive to invest in new generation capacities and to provide electricity for hydrogen fuel production. In consequence, in the Nash equilibrium no other firms are willing to utilize their peak-load load capacities in the same way as in scenario C3 in order to keep electricity prices at a high level. Such behavior reduces the aggregated electricity generation, limiting the ability of firm 1 to satisfy maximum hydrogen demand in the mobility sector.

In general, we observe that pumped-hydro and hydrogen storage complement each other in all scenarios. Although both technologies compete for electricity purchase in off-peak hours and for power sales in peak-load hours, additional hydrogen storage capacities do not affect the operation of the pumped-hydro power plants. In this context, the amount of energy and the number of operating hours related to the pumped-hydro facilities remain almost unchanged under the corresponding market structure. The different advantages of both storage types, namely high round-trip efficiency of pumped-hydro storage and

cheap energy-related capacity of the hydrogen technology, allow for adequate arbitrage profits for both technologies.

5.4.3 Electricity price and welfare effects

From the system perspective, utilization of electricity storage has a positive impact on social welfare. As depicted in Figure 5.4, overall welfare is typically higher in scenarios with storage than without.

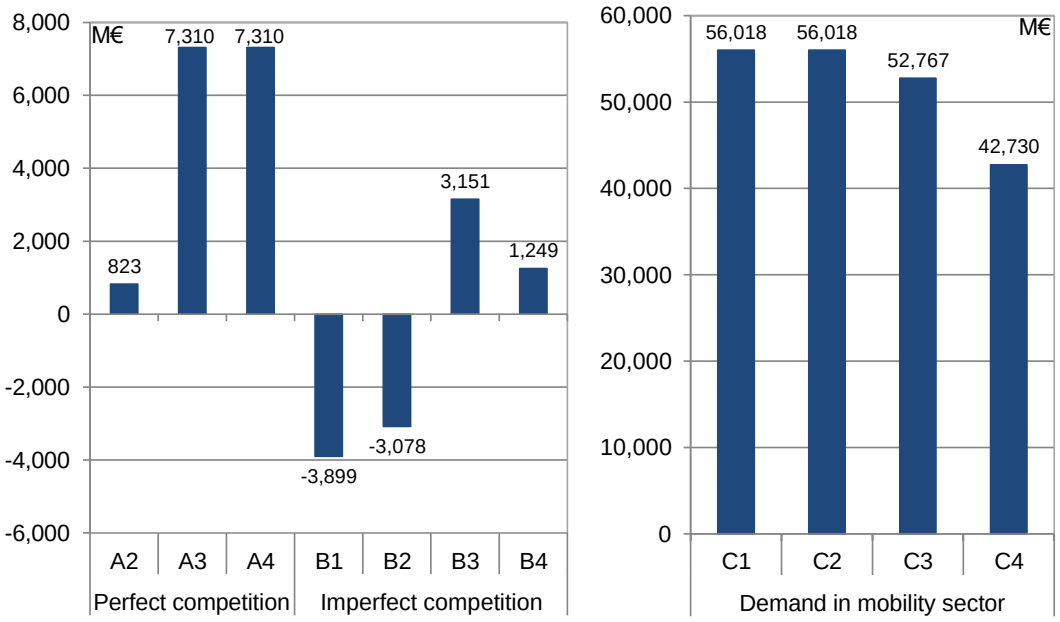


Figure 5.4: Social welfare change in comparison to scenario A1.

Under perfect competition, welfare change in comparison to scenario A1 is proportional to storage output ranging between 800 M€ (scenario A2 with pumped-hydro only) and 7,300 M€ (scenario A3 and A4 with both storage technologies). In all scenarios we observe a drop in consumer rent but an increase of producer rent, indicating that generators benefit more from storage utilization than end users (see Figure 5.5). On the one hand, storage utilization raises low prices in off-peak hours through charging activities, but on the other hand, it also reduces high prices in peak-load hours through additional supply. Although such price-smoothing behavior limits price volatility, the former effect is stronger than the latter, with the result that, on average, the market

Table 5.4: Annual electricity generation by technology and demand in the power and mobility sectors in TWh.

Technology	Perfect competition				Imperfect competition				Demand in mobility sector			
	A1	**A2**	**A3**	**A4**	**B1**	**B2**	**B3**	**B4**	**C1**	**C2**	**C3**	**C4**
Intermittent	347.8	347.8	347.8	347.8	347.8	347.8	347.8	347.8	419.9	419.9	419.9	419.9
Base-load	26.3	26.4	29.0	28.8	26.3	26.4	28.9	27.1	28.9	28.6	28.9	26.5
Peak-load	73.1	72.8	69.1	69.1	55.3	55.0	51.9	53.4	84.0	84.0	81.7	57.4
PSH output		0.5	0.5	0.5		0.5	0.5	0.5	0.3	0.3	0.3	0.7
H_2 output			3.8	3.7			3.2	1.6	0.9	0.8	0.7	0.2
PSH input		−0.7	−0.7	−0.7		−0.7	−0.7	−0.7	−0.4	−0.4	−0.4	−0.9
H_2 input			−13.5	−13.2			−11.2	−5.7	−102.1	−101.8	−100.4	−58.5
Total	**447.2**	**446.8**	**436.0**	**436.0**	**429.3**	**428.9**	**420.3**	**423.9**	**431.5**	**431.5**	**430.6**	**445.3**
Demand in power sector	463.7	463.7	463.7	463.7	463.7	463.7	463.7	463.7	463.7	463.7	463.7	463.7
Sales in mobility sector									67.3	67.3	67.3	40.0

price increases in comparison to scenario A1, ranging between 80 €/MWh and 96 €/MWh[261] (see Figure 5.6 and Appendix C.3). Nevertheless, similar to Schill and Kemfert (2011) and Sioshansi (2011), we observe decreasing profits in conventional power plants since the corresponding margins defined as the difference between the market price and generation costs are lower in base-load than in peak-load hours. Consequently, the profit increase in base-load hours when conventional power plants produce additional electricity to charge the storage is overcompensated by the profit reduction in peak-load hours, when conventional power generation is substituted by the storage.[262] This effect occurs despite the fact that due to efficiency losses the energy input in base-load hours is higher than the energy output in peak-load hours. However, the bottom line is that the additional profits from storage operation are higher than the losses of conventional power plants, so that the overall producer rent increases by 2 % – 47 % and the consumer rent declines by 0.2 % – 5 %.

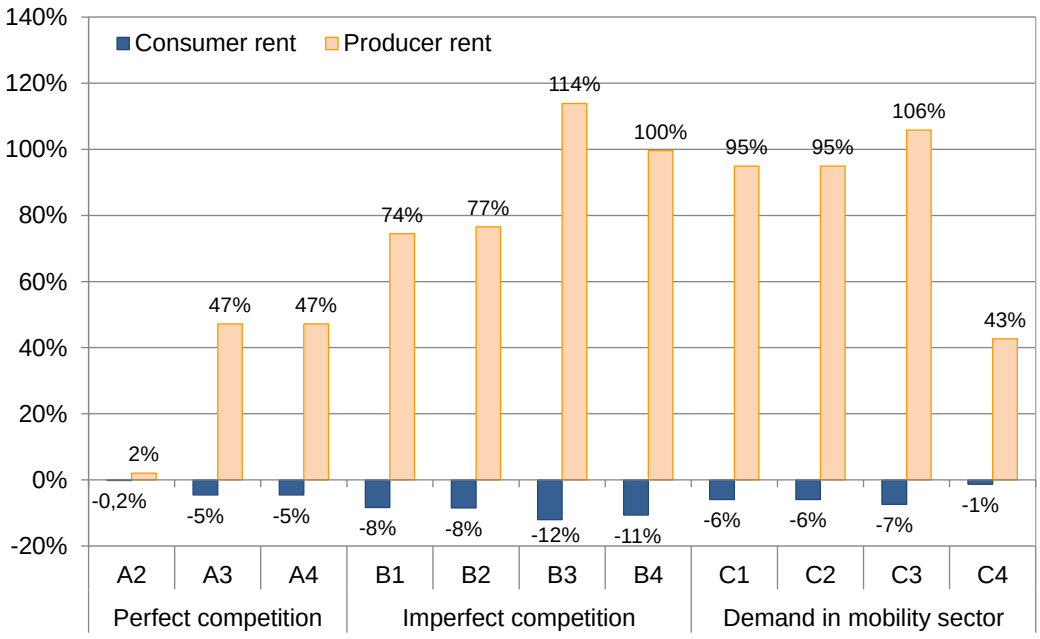


Figure 5.5: Change in consumer and producer rent in comparison to scenario A1.

261 Note that in our case study both average electricity price and its volatility are higher than the corresponding values of historical day-ahead prices in Germany, due to expensive peak-load generation in hours with low renewable feed-in.

262 Note that this relationship is further exacerbated by the low round-trip efficiency of hydrogen technology.

At this point it is important to mention that the hydrogen technology is characterized by cheap energy-related capacity, which is typically required to cope with the seasonal pattern of intermittent power production.[263] In this context, hydrogen storage is able to shift large amounts of renewable electricity from low-price to high-price periods and thus make large arbitrage profits. In fact, hydrogen storage is predominantly charged in the winter months during periods with low demand but large wind feed-in (January to March, i.e. time periods 1 to 30) and discharged in the fall months during periods with high demand and low feed-in from wind and PV (October to December, i.e. time periods 90 to 120). In the spring and summer months (April to September, i.e. time periods 30 to 90) the storage filling levels remains almost unchanged and the corresponding number of cycle equivalents[264] is rather low. In comparison, pumped-hydro storage is also in operation in the same time steps as the hydrogen technology. However, there are more charging and discharging activities throughout the whole year. Consequently, the storage filling level changes more often and the number of cycle equivalents is higher than in the case of hydrogen storage. This is mainly due to the fact that based on its high round-trip efficiency pumped-hydro storage can take advantage of lower price differences to earn arbitrage profits.

As expected, the oligopolistic market structure in scenario B1 to B4 has a negative impact on the consumer rent. Strategic firms exploit their market power in order to raise the average electricity price by 45 % to 62 % in comparison to scenario A1. In this way, producer profits go up by 74 % to 114 % despite costly investments in new generation capacities. In scenario B1 and B2 the negative change in consumer rent is larger than the producer gains, such that the overall welfare declines by 3,000 M€ to 3,900 M€. Moreover, in both cases price volatility grows by approx. 15 % as strategic firms exercise market power predominantly by capacity withholding in peak-load hours. In contrast, in scenario B3 and B4 we find an increase of overall welfare between 1,250 M€ and 3,150 M€ as producer gains are larger than consumer losses. Similar to scenarios with perfect competition, utilization of additional hydrogen storage capacities also has a price-smoothing effect on the market clearing price, reducing the corresponding volatility. Nevertheless, the average

263 See chapter 2.2.2 for a more detailed discussion on the seasonality of renewable feed-in.
264 See chapter 3.4.1 for a detailed definition of cycle equivalents.

market price rises by more than 50 % in comparison to scenario A1 and consumers are harmed by the oligopolistic market structure more than in all other scenarios (i.e. consumer rent decreases by approx. 11 % – 12 %). As in scenarios A1 to A4 the additional profits from storage utilization outweigh the losses incurred by the conventional power plants leading to positive change in the overall producer rent. Note that generally the ownership structure of hydrogen technology in scenario B4 mitigates the aforementioned negative effects of market power on electricity price and social welfare. This is mainly due to the fact that in this scenario, the hydrogen storage is operated only by one firm with a limited impact on the market prices.

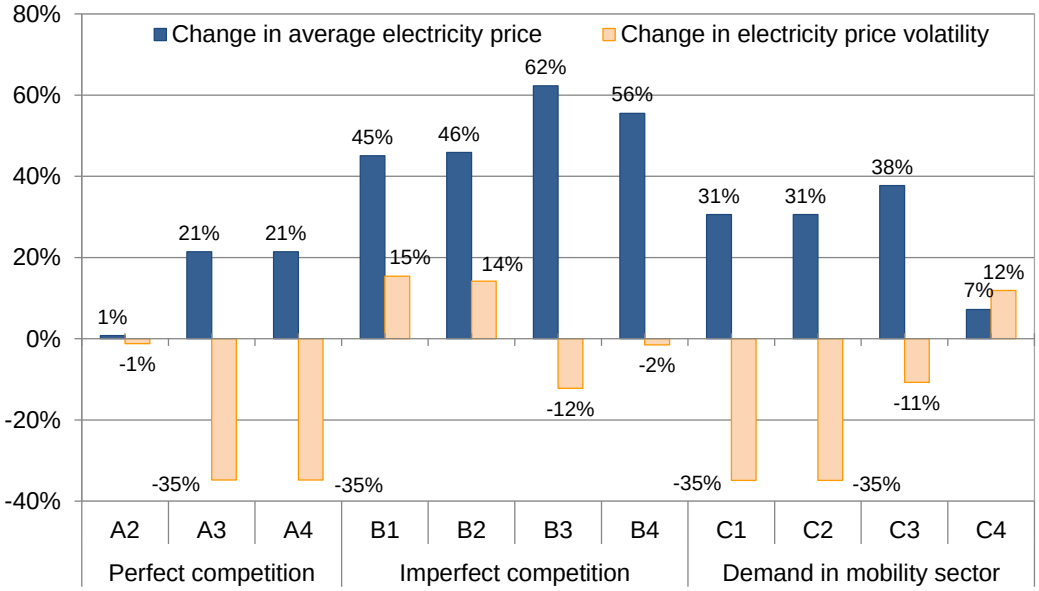


Figure 5.6: Change in electricity price average and volatility in comparison to scenario A1.

In scenario C1 and C4, we observe a large influence of additional energy demand in the mobility sector on the overall market results. Our analysis shows that social welfare increases between 42,000 M€ and 56,000 M€ mainly due to additional producer gains from the sales of hydrogen fuel. Accordingly, producer rent raises by more than 40 % in comparison to scenario A1. Although the aggregate energy demand from both markets is higher than in scenarios without the mobility sector, the average electricity price goes up moderately by 7 % – 38 % and consumer rent declines between 1 % in scenario C1 and 7 % in scenario C3. This comparatively small change in consumer

rent is based on additional electricity generation compensating the energy demand in mobility. In fact, as mentioned in the previous chapter, a high hydrogen fuel price motivates investment and operation of new generation capacities such that the overall impact on the power consumption is limited. Interestingly, we find a similar price-smoothing effect (i.e. similar decrease in electricity price volatility) as in corresponding scenarios without the mobility sector. Similar to scenario B3 and B4, oligopolistic behavior in scenario C3 allows for disproportional production gains at the costs of consumer rent. However, in scenario C4 we observe only limited market power exertion by firm 1, limiting the increase in market clearing price and producer profits. This is also the reason for higher market price volatility than in scenario A1 and B4.

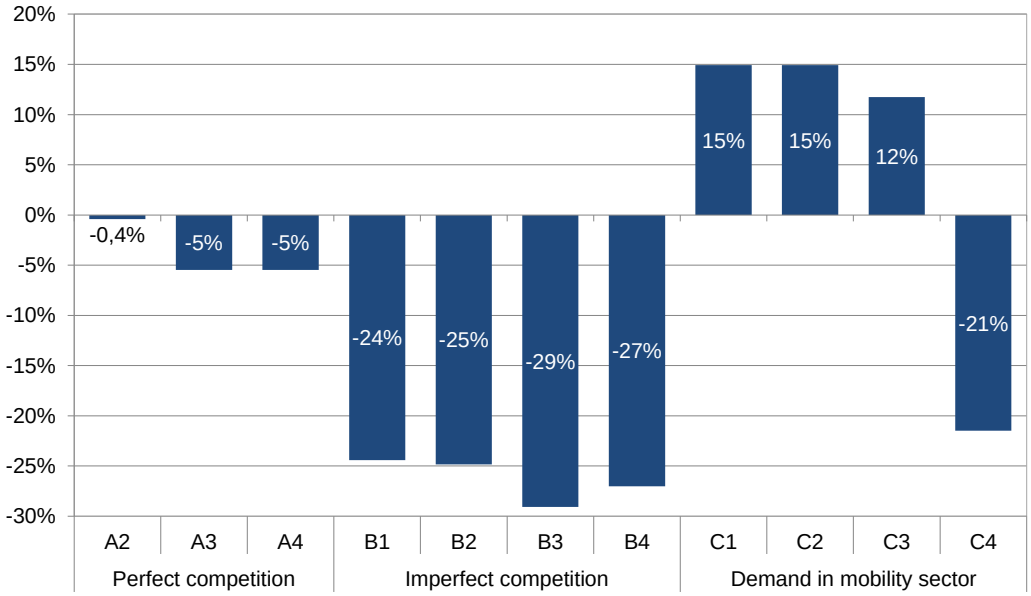


Figure 5.7: Change in CO_2 emissions in comparison to scenario A1.

Figure 5.7 shows the change in CO_2 emissions in comparison to scenario A1. In our analysis, we assume GHG production only by peak-load technology with a specific factor of 0.205 t_{CO2}/MWh. Therefore the overall emissions correspond to actual peak-load electricity generation ranging between 22 kt_{CO2} in scenario B3 and 37 kt_{CO2} in scenario C1 and C2. In this way storage utilization helps to reduce electricity generation by gas turbines and thus the overall CO_2 emissions. Moreover, under imperfect competition in scenario B1 to B4 we find the lowest emission values, whereas energy demand in mobility sector

potentially increases GHG production in comparison to scenario A1. In this case the additional CO_2 amount in power sector should be carefully compared with emission decrease associated with the substitution of conventional diesel and gasoline vehicles through FCEVs.

5.5 Conclusion

The major purpose of this chapter was to examine the role of electricity storage in an energy system where market participants can make simultaneous production and investment decisions under different market and ownership structures. In order to achieve this, we propose a game-theoretic market model assuming a Cournot oligopoly and open-loop information structure. The corresponding case study is carried out in the context of the German power market assuming reduction of gross electricity demand, phase-out of nuclear power, large increase in renewable supply and additional demand from the mobility sector. The numerical results of our analysis indicate that utilization of energy storage has a positive effect on energy systems with large amount of intermittent electricity production and rather inelastic demand. We find that additional storage capacities improve system reliability, increase overall welfare and decrease GHG emissions.

In general, we confirm that storage substitutes flexible peak-load technology in terms of both quantities and capacities and enhances the utilization of inflexible base-load power plants.[265] However, we also find that under the boundary conditions of our analysis, the aggregated dispatchable and storage output capacities are higher in scenarios with storage than without due to additional electricity consumption through charging activities. This effect is observed regardless of the market and ownership structure. In this way, energy storage can play an important role in future electricity markets with large share of intermittent generation as it can make a substantial contribution to system stability. Nevertheless, electricity storage reduces overall power supply due to efficiency losses and thus increases average spot market price. This effect is further exacerbated by the low round-trip efficiency of hydrogen technology.

265 Similar observations are also reported by Rivier et al. (2001).

Consequently, on the one hand producer profits rise but on the other hand consumer rent decreases. Interestingly, this finding is contradictory to the observations made by Schill and Kemfert (2011) but it is in line with the results provided by Sioshansi (2011), who reports aggregated producer gains when storage is used in combination with wind generation. As mentioned in the previous chapter, on the one hand storage utilization allows for additional arbitrage gains but on the other hand it also reduces the profits from the operation of conventional power plants. Since Schill and Kemfert (2011) study the role of pumped hydro storage in a market with comparatively low intermittent feed-in, the latter effect is stronger than the former one and the overall producer rent decreases. In this case, consumers can buy electricity at a lower price causing consumer rent to increase. In our case study however, we assume a large amount of intermittent electricity and the arbitrage profits are higher than the losses of the conventional generation. The profitability of the hydrogen technology is also based mainly on the low costs of the energy-related capacity which is needed to balance large amounts of electricity in the context of seasonality of the renewable feed-in. Therefore, we conclude that electricity storage can help to increase producer profits at the costs of consumer surplus when generators can choose optimal storage size in a market with a large amount of renewable energy. Yet, in regard to the whole market, the overall welfare change is positive since producer gains are greater than consumer losses.[266] Our analysis also confirms that storage has a price-smoothing effect and decreases spot market price volatility. In this context, as argued by Sioshansi (2011) storage utilization counteracts the merit order effect of intermittent generation. Moreover, hydrogen storage does not change the operation of pumped-hydro power plants as both technologies complement each other.

As predicted by the peak-load pricing literature,[267] strategic behavior in our case study leads to lower investments and production quantities for both

266 Note that in Schill and Kemfert (2011), overall social welfare also increases as consumers gain more than producers lose. In contrast, Sioshansi (2011) reports a reduction in overall social welfare as the decrease in consumer rent is higher than the increase in producer rent. This is mainly due to the fact that under the given assumptions of this particular case study, off-peak power plants are characterized by high variable costs and low margins. Therefore the reduction in profits of the conventional generation is disproportionately large and almost as high as additional arbitrage profits from storage utilization.

267 See chapter 2.2.1 for more details.

peak-load and storage technology, and thus to higher spot market prices than in scenarios under perfect competition. Although we also find that the lower degree of competition under an oligopolistic market structure with regard to storage operation (i.e. storage investments by only one firm in scenario B4 or C4 versus by all firms in scenario B3 or C3) increases peak-load capacities, we observe the opposite effect in regard to re-electrification capacities of the hydrogen storage. In this context, a monopolistic storage operator has lower investment incentives than all firms together in scenario B3 or C3 such that the aggregated dispatchable and storage output capacities are lower in scenario B4 or C4. Therefore we conclude that increasing the degree of competition also improves system reliability.

This result is in line with the peak-load pricing literature on resource adequacy but in contrast to the findings within the existing literature on capacity expansion (e.g., Genc and Thille 2011 or Grimm and Zoettl 2013).The authors argue that strategic investors anticipate lower prices in a more competitive spot market and decide to under-invest in dispatchable capacities in order to maximize their profits. In our analysis, however, the degree of competition refers to the ownership structure of the hydrogen storage. In the more competitive case (scenario B3 or C3), all firms foresee arbitrage profits from storage operation and are therefore willing to invest in substantial capacities until the Cournot-Nash equilibrium is reached. In the less competitive case (scenario B4 or C4), only one firm benefits from storage utilization whereas all other investors anticipate lower peak-load prices through the price-smoothing effect of the storage affecting the profitability of all peak-load power plants. In consequence, investments in peak-load capacities are slightly higher in the less competitive scenarios[268] but not large enough to compensate lower storage capacities provided by only one firm.

Adding demand for hydrogen as a fuel for FCEVs allows for a synergetic use of the technology and increases investment incentives for energy storage. Since we assume comparatively high sales prices in the mobility sector producer profits increase substantially. Surprisingly, the corresponding consumer losses due

268 This is partially also due to the substitution effect between storage and peak-load power plants, which compete to provide power in the same peak-load hours. Therefore in general, ceteris paribus the lower the storage capacity the higher the investments in peak-load power plants and vice versa.

to higher overall power demand are limited, as at the same time producers are motivated to build up new capacities and supply more electricity to the market. In this context, additional demand from the mobility sector can be viewed as beneficial for the power sector. However, at this point it is important to mention that the increase in social welfare should be compared with corresponding changes in the mobility sector itself as hydrogen is a substitute for conventional diesel and gasoline fuels.

In our analysis, GHG emissions correspond to the output of peak-load technology such that storage without additional demand in the mobility sector helps to reduce overall GHG production. In this context, we confirm observations made by Lise and Kruseman (2008) reporting that strategic behavior in an oligopolistic market decreases total emissions in the power sector. Similar to social welfare, the increased GHG emissions due to fuel supply in the mobility sector should be carefully compared with the corresponding GHG reductions in the mobility sector itself.

6. Conclusion

6.1 Summary of results and contribution to literature

This study focuses on the role of energy storage as a flexibility option for the integration of intermittent electricity generation into the German energy system. The analyses conducted in this thesis provide insight into the economics of electricity storage in combination with variable power production. In order to achieve this, adequate models from both the perspective of a single price-taking investor and of the whole power market with strategic players have been developed and applied in corresponding case studies in the context of the German electricity market. Thereby the research has also taken into account the role and value of additional demand from the mobility sector on the one hand and storing hydrogen as universal energy carrier on the other hand.

The analysis in chapter 3 compares the value of different storage technologies in combination with wind and PV feed-in in the power sector. It is based on an LP model from the perspective of a single investor operating a prototypical facility in a selected grid node. The results indicate that under current boundary conditions the value of storage for renewable electricity typically suffers from high technology costs and limited corresponding revenues which can be earned in the spot market. Accordingly in the short-term, storage utilization does not provide a positive business case and is characterized by an NPV which is lower than for the conventional alternatives such as dispatchable generation by a gas turbine or curtailment of excess renewable supply. However, among different storage technologies pumped-hydro storage provides best economic results. In this context, the analysis in this study supports the findings in the literature. Nevertheless, in the long-term, rising electricity price volatility and CO_2 certificate prices as well as technology costs reduction might increase the overall value of storage making investments in new capacities economically favorable especially for some large-scale technologies.

Interestingly, hydrogen storage tends to have a comparatively high value despite its low round-trip efficiency mainly due to low energy-related capital expenditures and the need for shifting large energy amounts on a seasonal basis. In general, the analysis reveals the advantage of large-scale storage technologies with limited energy-related investment outlays over batteries and complements the research on storage value through explicit modeling of seasonal demand and renewable production patterns. In contrast to the results of some other studies, we find that batteries are less suitable to balance intermittent electricity generation from PV than other large-scale storage technologies under such boundary conditions. Since solar feed-in varies substantially between winter and summer months, large energy-related storage capacities are needed to balance these seasonal differences. In this way, batteries are comparatively expensive due to high energy-related capital expenditures. In general, the analysis shows that the value of storage is higher for most technologies (except for batteries in combination with PV) when used to satisfy minimal demand rather than to avoid curtailment of excess intermittent electricity. The case study in chapter 3 also proves the ability of the proposed model for comprehensive analyses of different storage technologies under various boundary conditions from the perspective of a single investor.

Based on a similar modeling framework, chapter 4 calculates the specific costs of hydrogen from renewable sources for the power and mobility sectors. As expected, the analysis reveals that additional constraints on intermittent power availability for electrolytic hydrogen production increases the specific costs, and green hydrogen (i.e. hydrogen production is synchronized with intermittent power supply) is more expensive than grey hydrogen (i.e. hydrogen production is uncorrelated with intermittent power generation) by approx. 20 % – 130 %depending on the selected application. The corresponding costs vary between approx. 3 €/kg_{H2} and 11 €/kg_{H2} (or 90 €/MWh and 330 €/MWh) for green hydrogen and between approx. 1.5 €/kg_{H2} and 8.5 €/kg_{H2} (or 45 €/MWh and 255 €/MWh) for grey hydrogen being in a similar range as reported in the literature. In contrast to the results in some studies, we find that energy supply in the power sector is typically cheaper than in the mobility sector despite the additional investment and lower round-trip efficiency of the re-electrification unit. This is mainly due to the fact that in the power sector a substantial fraction of intermittent electricity can

be directly used to satisfy the corresponding demand without any efficiency losses, whereas in the mobility sector all renewable energy must be converted into hydrogen fuel. However, in the case with a dedicated wind park and cheap electrolysis the opposite is true.

Our research also shows that positive net present value from investments in hydrogen production can be achieved only in the mobility sector, as typically in this case the hydrogen sales price is high enough to cover the corresponding costs. Similar to chapter 3, however, the hydrogen costs can fall substantially with decreasing specific investment outlays, as currently the capital expenditures play an important role for the valuation of hydrogen production facility. These results are in line with the findings in the literature. An important contribution of our research to the literature is represented by explicit valuation of synergy effect from co-utilization of hydrogen facility to satisfy the demand in the power and mobility sectors. We show that simultaneous build-up and operation of hydrogen production plants for both sectors decreases the aggregated hydrogen costs substantially. Accordingly, the facility's net present value is higher in the synergetic case than in separate cases due to limited requirements for capacity investment, better facility utilization and more efficient use of renewable energy. In this way, hydrogen can be viewed as a universal energy carrier which is able to support the integration of renewable electricity into the energy system and to link the power and mobility sectors efficiently.

Finally, the analysis in chapter 5 is carried out from the perspective of the whole electricity market under Cournot oligopoly and open-loop information structure. We have developed a game-theoretic model formulated as a mixed complementarity problem and have applied it in a case study to analyze the role of electricity storage under different degrees of competition, storage ownership structures and hydrogen demand levels in the mobility sector. In this context, we analyze storage sizing and operation in the German power market assuming a large share of intermittent electricity as well as two potential types of storage (pumped-hydro and hydrogen) and dispatchable power plants (run-of-river as base-load and gas turbines as peak-load technology). Our analysis contributes to the literature by bringing together two research streams, one on the storage operation and another on capacity expansion

under the game-theoretic framework. Moreover, the case study in this chapter takes into account some additional market features such as seasonality of the renewable feed-in and electricity demand, different storage technologies and sector coupling between the electricity supply and sustainable mobility through hydrogen production. Hence, our contribution provides more realistic results on the role of electricity storage in the future power market in comparison to many existing studies.

The outcome of our research confirm the findings of the peak-load pricing literature stating that strategic investment and production behavior decrease investment incentives in new generation capacities. This is due to the fact that strategic firms exercise market power by avoiding the expansion of new capacities in order to increase the market prices and thus their own profits. In this way, suppliers benefit at the cost of consumers. Nevertheless, although storage substitutes peak-load technology, the overall installed electricity generation capacity is higher in cases with than without storage due to additional charging demand. However, in contrast to the literature on capacity expansion, we show that higher degree of competition in regard to storage operation under oligopolistic market structure does not decrease the overall investment incentives as investors anticipate the arbitrage profits form storage operation and build substantial capacities.

As predicted by the literature on storage operation, new storage capacities have a price-smoothing effect decreasing the overall electricity price volatility. However, storage utilization also increases the average electricity price and thus reduces the overall consumption potentially harming the end users. This effect is further exacerbated by the low round-trip efficiency of hydrogen technology. Our findings on the change in consumer and producer rent are in contradiction to some other studies due to different assumptions on overall storage and renewable production capacities and thus on the impact of arbitrage profits on the overall producer rent. Yet, since the decrease of the consumer rent is lower than the increase of the producer rent, we find a ositive effect of electricity storage on the overall social welfare. Moreover, although a more competitive operation of storage capacities (i.e. storage operated by all firms in case 3 versus by one firm in case 4) reduces the capacity of the dispatchable power plants, it increases the overall installed

generation capacities effectively, thereby contributing to the system stability. This outcome shows that the research on the optimal market design should take into account the role of electricity storage at least with regard to its impact on system reliability.

Furthermore, we find that additional demand from the mobility sector provides strong incentives for investments in new storage capacities such that the overall installed generation capacity in the power sector is higher than in the case without hydrogen fuel consumption. In addition, producer gains and the overall social welfare improvements are comparatively large due to the high sales price for hydrogen fuel and the corresponding revenues in the mobility sector. Although hydrogen production for FCEVs represents additional demand in the power sector, we report only moderate increase of average electricity prices and decrease of consumer rent. In this way, our analysis reveals that the power sector can also benefit from the synergy effects of the hydrogen technology. In our analysis the GHG emissions are proportional to power generation by peak-load power plants. Therefore, under oligopolistic market structure the emissions decrease with the rising utilization of the storage but increase when hydrogen is also sold in the mobility sector.

6.2 Implications for utilities, consumers and politics

From the perspective of individual investors, large-scale storage technologies such as hydrogen storage might be an interesting option to increase the income in a market with a large share of intermittent power. However, the actual profitability of the electricity storage depends on the development of specific investment outlays and on the expected market price volatility. Both parameters are rather uncertain and the corresponding risk should be taken into account when making the investment decision. If a company already owns some dispatchable capacities it should also carefully examine the impact of storage on the profitability of its existing generation portfolio as new storage facilities decrease the income of peak-load power plants.

Moreover, production of hydrogen as a fuel for transportation represents a good strategic investment opportunity for utilities for three reasons. First, hydrogen

fuel has a greater value and thus higher sales price in the mobility sector than in the power sector. Hence, utilities might earn above-average margins when providing hydrogen fuel. Second, sector coupling generates additional demand for electricity and in this way it increases the utilization and income of the existing power plants. Third, hydrogen producers who operate in the power and mobility sectors might take advantage of the synergy effect of the hydrogen technology. In fact, our analysis shows that individual firms can maximize their profits by producing hydrogen fuel in hours with low electricity prices and storing it for sale in the subsequent periods. Since large storage capacities are built anyway in the power sector for arbitrage activities, such strategy typically does not require any additional investment outlays.

From the consumer perspective, the analysis also shows that the average electricity price increases when storage is added to the system under the specific assumptions of our case study. Such development on the one hand benefits the producers but on the other hand it also harms the consumers, although overall social welfare increases. The additional burden for the consumers can be viewed as unavoidable costs for intermittent electricity in a fully-renewable energy system. Hence, these costs should be carefully compared to the benefits of renewable power generation and GHG emission avoidance in a renewable energy system. In general, consumers could also benefit from utilization of storage directly connected to the power consumption. However, this effect is rather limited since individual end users typically install only small and decentralized storage units and are not able to operate large-scale facilities such as pumped-hydro power plants or underground salt caverns.

From the perspective of politics and regulatory bodies, utilization of electricity storage represents an interesting strategy to achieve the GHG emissions reduction targets. As a flexibility option, large-scale storage helps to integrate intermittent electricity into the energy system by substituting conventional power plants potentially based on fossil fuels and increasing the overall system reliability. However, the regulatory bodies should either allow large electricity price volatility or introduce a different compensation mechanism to justify investment outlays for new storage capacities. Moreover, our analysis shows that the support for electricity storage as a flexibility option is more efficient for renewable capacity firming than for avoiding curtailment.

In addition, policy support is needed to further decrease the costs of new technologies such as electrolysis or hydrogen storage. Such policy support might include funds for research and development activities or regulatory initiatives to prepare new markets related to energy storage (e.g. development of capacity markets for flexible power generation or compulsory targets for GHG emission reduction in the mobility sector to generate additional demand for hydrogen fuel). Furthermore, future electricity markets should be as competitive as possible in order to increase the investment incentives and thus the system reliability, as well as to maximize the overall social welfare. In particular, under the oligopolistic market structure, storage should be operated by as many firms as possible rather than concentrated around only one large firm. Therefore, regulators should be interested in reducing market entrance barriers for new competitors. Since the storage types analyzed in our study complement each other we also recommend a diversification of storage technologies in the future market.

6.3 Limitations and further research work

The research in this work is limited with respect to several aspects. First, our study is generally based on one prototypical year with given power demand, renewable feed-in and electricity price patterns. The intermittent profiles are derived from aggregated data for Germany as a whole including geographical compensation of the feed-in from single power plants. In particular in chapters 3 and 4, a combination of wind and PV might have a substantial impact on the optimal storage sizing and operation and thus its value, since both renewable energy sources compensate each other to some extent. In addition, in both chapters the analysis is conducted from the perspective of a single investor neglecting the price-smoothing effect of storage on the power prices. Therefore, an interesting research area would be a comparison of different load, renewable production and power price profiles for various prototypical years in order to provide additional insight regarding the robustness of the presented investment and operation decisions.

Second, in our analysis we omit uncertainties and assume perfect foresight for all hours of the year potentially underestimating the required storage size.

We also do not account for differences in predictability between wind and PV on various time scales which might change the value of storage when combined with corresponding intermittent generation. Thus, approaches including such uncertainties might provide more adequate results.

Third, the value of storage from the investor's perspective is calculated only for renewable capacity firming and curtailment avoidance. Although we find some additional time-shifting effects, we neglect all other benefits of storage such as balancing services or end user applications. Another limitation of our analysis in chapters 4 and 5 is represented by the fact that we consider only two market applications for hydrogen technology. In reality, beside the power and mobility sectors, hydrogen can be also used as a feedstock for the chemical industry or as an energy carrier in the heat market. Hence co-utilization of the hydrogen production facility for additional markets might change its optimal sizing and operation regime. In this context, the impact of the subsequent infrastructure for hydrogen delivery to end users and the corresponding technical constraints also remain an interesting research area. A comprehensive comparison of all benefits from storage use in different constellations represents an interesting research question from the perspective of both profit maximization of single investors and cost minimization of the entire energy system.

Fourth, from the system perspective in chapter 5, we assume current capacity ownership structure including four large generation firms and a competitive fringe. In reality, in the long term this structure might change due to mergers and acquisitions and new entrants. In particular, the role of hydrogen technology is analyzed only for two different constellations, namely investment and operation by one existing firm or by all existing firms. Other ownership structures, especially when hydrogen storage is utilized by a new player responsible for the corresponding infrastructure, could provide relevant insight into the potential benefits of this technology. In this context, further research could include the comparison of our results to scenarios with other market and ownership structures, especially with a different number of market participants. In addition, future analyses might be based also on different modeling approaches in particular under S-adapted and closed-loop information structures.

Fifth, in order to improve the model's numerical tractability, in chapter 5 we use average demand and renewable feed-in for each time period according to predefined load levels. In this way however, we distort the actual relationship between power demand and availability of intermittent electricity. Therefore, better time resolution of the input data might provide more precise results.

Finally, in our case study in chapter 5, we consider only two different dispatchable and storage technologies as well as additional energy demand only for hydrogen in the mobility sector. A comprehensive sensitivity analysis in regard to varying technology constellations and major input parameters such as demand elasticity, specific investment outlays and storage efficiencies might help to test the robustness of our findings.

In general, the research in this work shows that electricity storage and additional power demand from the mobility sector might play an important role in the energy system with a large share of intermittent power. On the one hand from the system perspective, electricity storage might be beneficial for the integration of large amounts of the intermittent electricity in the long term, but on the other hand from the perspective of the single investor, most storage technologies in combination with wind or PV become profitable only under substantial changes of the boundary conditions. This is in line with the conclusions drawn by a number of system studies such as VDE (2012) or Schill (2014) suggesting that energy storage will be required only for a large amount of renewable electricity.

Furthermore, the seasonal pattern of intermittent electricity generation and additional demand from the mobility sector are important drivers for the income of large-scale storage technologies such as hydrogen storage. Therefore, an analysis which does not take into account both effects might underestimate the value of such storage, leading to incorrect conclusions on the optimal investment decision and structure of the future energy system. In oligopolistic markets storage utilization might provide different investment incentives for peak-load capacities than predicted by some contributions without explicit storage modeling. This issue should be also considered when comparing different designs of the future electricity market.

Future research should focus on analyzing the possibilities to bridge the gap between the storage value from the system and business perspective with regard to goal definition for the German and European energy policy, future power markets design as well as development of potential support mechanisms for different storage technologies. In this way, the research can contribute to a better understanding of the role of electricity storage as an important instrument to overcome the challenges of the energy system of tomorrow.

Appendix A.1: Nomenclature in chapter 3

Sets and indices:

$T,\ t$	Set and index of hourly periods

Decision variables:

Variable	Description	Unit
q_t^{Ren}	Electricity sales by renewable power plant in period t	MWh
q_t^{Th}	Electricity sales by thermal power plant in period t	MWh
q_t^{Out}	Electricity sales by electricity storage in period t	MWh
q_t^{In}	Storage input from renewable power plant in period t	MWh
s^i	Storage level in the first and last period	MWh
I^{Th}	Investment in thermal capacity	MW
I^{In}	Investment in power-related input capacity	MW
I^{St}	Investment in energy-related storage capacity	MWh
I^{Out}	Investment in power-related output capacity	MW

Auxiliary variables:

Variable	Description	Unit
f^{Th}	Annual fixed operating costs of thermal power plant	€
f^{In}	Annual fixed operating costs of new power-related input capacity	€
f^{St}	Annual fixed operating costs of new energy-related storage capacity	€
f^{Out}	Annual fixed operating costs of new power-related output capacity	€
V^{Th}	Salvage value of thermal power plant	€
V^{In}	Salvage value of storage power-related input capacity	€
V^{St}	Salvage value of energy-related storage capacity	€
V^{Out}	Salvage value of power-related output capacity	€
s_t	Storage level at the end of period t	MWh

Parameters:

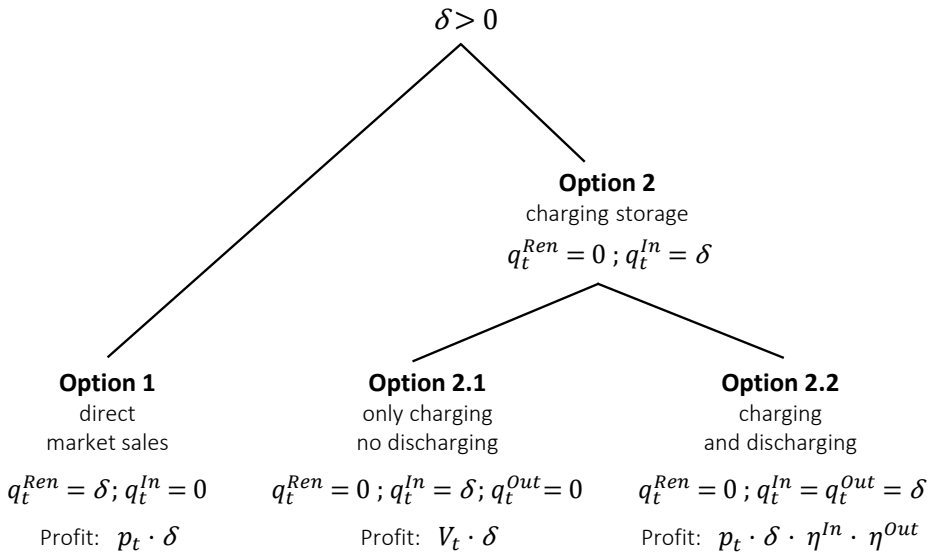
Parameter	Description	Unit
AF	Annuity factor	—
r	Interest rate	%
n	Number of periods within the planning horizon	—
p_t	Electricity price in period t	€/MWh
c^{Th}	Total variable costs of thermal power plant	€/MWh
e^{Th}	Specific investment expenditures for thermal power plant	€/MW
e^{In}	Specific investment expenditures for power-related input capacity	€/MW
e^{St}	Specific investment expenditures for energy-related storage capacity	€/MWh
e^{Out}	Specific investment expenditures for power-related output capacity	€/MW
φ^{Th}	Fixed cost share of expenditures for thermal power plant	%
φ^{In}	Fixed cost share of expenditures for power-related input capacity	%
φ^{St}	Fixed cost share of expenditures for energy-related storage capacity	%
φ^{Out}	Fixed cost share of expenditures for power-related output capacity	%
l^{Th}	Lifetime of thermal power plant	a
l^{In}	Lifetime of power-related input capacity	a
l^{St}	Lifetime of energy-related storage capacity	a
l^{Out}	Lifetime of power-related output capacity	a
p^{Th}	Average price for fossil fuel	€/MWh
p^{CO2}	Average price for CO_2 certificates	€/t_{CO2}
v^{Th}	Other variable costs of thermal power plant	€/MWh
ε^{Th}	Specific emission factor of thermal power plant	t_{CO2}/MWh
η^{Th}	Efficiency of thermal power plant	%
η^{In}	Efficiency of storage input unit	%
η^{Out}	Efficiency of storage output unit	%
$\bar{k}_t^{Ren}$	Available renewable generation in period t	MWh
$\underline{k}_t^{Ren}$	Minimum output of renewable power plant	MWh
$\bar{k}_t^{Out}$	Upper bound for storage output in period t	MWh
K^{Th}	Initial capacity of the thermal power plant	MW
$\overline{K}^{St}$	Initial capacity of energy-related storage capacity	MWh
$\underline{K}^{St}$	Minimal storage level	MWh
K^{In}	Initial capacity of storage input	MW
K^{Out}	Initial capacity of storage output	MW
$\bar{I}^{Th}$	Maximal capacity of thermal power plant	MW
$\bar{I}^{Out}$	Maximal capacity of storage output unit	MW
$\underline{d}_t$	Minimal grid load (minimal demand) in period t	MW
$\bar{g}_t$	Maximal grid capacity in period t	MW

Appendix A.2: Proof for separate storage charging or discharging in the storage model

As discussed in chapter 3.3.3 equation (3.19) and (3.41) ensure that that in most cases the storage is either charged or discharged but not both at the same time. In particular, this additional constraint is helpful when grid capacity constraint in equation (3.18) holds and there is minimal renewable uptake requirement as defined by equation (3.16), i.e., if $\underline{k}_t^{Ren} > 0$. This is true especially when we enforce storing renewable electricity due to grid constraints (i.e., $\underline{k}_t^{Ren} > \underline{g}_t$) which requires costly investments in additional storage capacities. First we show that there is never an incentive to charge and discharge the storage at the same time when constraints in equation (3.16) and (3.18) do not hold. Then we proof that the constraints in equation (3.19) and (3.41) ensure accurate storage operation in the sense of separate electricity storing or releasing when grid capacity and minimal renewable uptake constraints hold.

Proposition 1:
Under the assumptions in chapter 3.3.1 and 3.3.3 the operator has never an incentive to charge and discharge the storage at the same time and is always better off with only one operation mode when the minimal renewable uptake constraint and the maximal grid capacity constraint as defined in equation (3.16) and (3.18), respectively, do not hold.

Proof.
In general, for each additional unit of available renewable electricity δ the operator of the facility within the storage model has three decision options: he can sell δ directly to the market (option 1) or store and keep it for later sales (option 2.1) or store it and at the same time discharge to sell δ to the market (option 2.2). Note that option 2.2 is possible as both decision variable on storage input and output q_t^{In} and q_t^{Out}, respectively, are independent from each other. Following figure provides an overview over the potential options and the corresponding profits:



In our model we do not allow for electricity purchase from the market and the only source for charging the storage is represented by the intermittent production. Hence if renewable electricity is not available in a given period then storage charging is not possible and the actual decision on storage output does not matter in this context. However, if renewable electricity is available then the operator will choose one of the three options whichever maximizes his profit. In particular, he will always decide to sell renewable electricity directly to the market if the current market value $p_t \cdot \delta$ is higher than the discounted value of storing electricity $V_t \cdot \delta$. In this case storage will be not charged and the discharging decision is not relevant. If V_t is higher than the market value of additional unit δ (i.e. if $V_t \cdot \delta > p_t \cdot \delta$), then he will always decide to store electricity but will never decide to discharge at the same. This must be true since per definition the round-trip efficiency $\eta^{In} \cdot \eta^{Out}$ is always lower than 1 and hence $V_t \cdot \delta > p_t \cdot \delta > p_t \cdot \delta \cdot \eta^{In} \cdot \eta^{Out}$. Moreover this proof is also true if storing δ requires storage capacity extension. In this case the additional investment outlays have to been taken into account analogously.

■

Proposition 2:

Under the assumptions in chapter 3.3.1 and 3.3.3 and under the assumption of positive sales prices (i.e., $p_t > 0 \quad \forall t \in T$) the operator has never an incentive to charge and discharge the storage at the same time, if the maximal storage output in each period is constrained by the upper bound

$$\bar{k}^{Out} = \begin{cases} 0 & \text{if } \bar{g}_t \leq \underline{k}_t^{Ren} \quad \forall t \in T \\ \bar{g}_t - \underline{k}_t^{Ren} & \text{otherwise} \end{cases} \tag{A2.1}$$

taking into account the minimal renewable uptake and maximal grid capacity constraint as defined in equation (3.16) and (3.18), respectively.

Proof.
According to the assumption of positive market prices p_t in each period t, selling electricity provides always positive revenues either in the selected period t or in any subsequent period whichever is more profitable. The only issue which might make charging and discharging at the same time more advantageous refers to the costly investments in additional storage capacities. Capacity investments might be necessary if renewable electricity has to be used by the operator as defined in equation (3.16) on the one hand but the grid capacity is not large enough as formulated in equation (3.18) on other hand. In such cases decreasing storage level as much as possible (by simultaneous charging and discharging) might help to avoid storage capacity expansion in the subsequent periods.

The first part of the constraint in equation (A2.1) is trivial. As soon as minimal electricity uptake requirement exceeds the grid capacity (i.e. if $\underline{k}_t^{Ren} \geq \bar{g}_t$) storage must be charged and we suppress any storage discharging. In the other case if $\bar{g}_t > \underline{k}_t^{Ren}$ and if storage output is not bounded by the additional constraint in equation (A2.1), then the operator might have an incentive to charge and discharge the storage at the same time. This could happen if for example the operator prefers to reduce storage level as much as possible in order to avoid costly capacity extension required to use all renewable electricity in subsequent periods. In detail, in some cases he is better off when he first stores all renewable electricity $\underline{k}_t^{Ren}$ and then discharges the storage up to the full grid capacity $\bar{g}_t$ rather than selling $\underline{k}_t^{Ren}$ directly to the market and discharging the storage only by the remaining grid capacity $\bar{g}_t - \underline{k}_t^{Ren}$. In the former case (simulations charging and discharging) the storage level changes by

$$\Delta_1 = \underline{k}_t^{Ren} \cdot \eta^{In} - \bar{g}_t \cdot \frac{1}{\eta^{Out}} \tag{A2.2}$$

whereas in the latter case (direct renewable sales) by

$$\Delta_2 = -1 \cdot \left(\bar{g}_t - \underline{k}_t^{Ren}\right) \cdot \frac{1}{\eta^{Out}} = \underline{k}_t^{Ren} \cdot \frac{1}{\eta^{Out}} - \bar{g}_t \cdot \frac{1}{\eta^{Out}} \ . \tag{A2.3}$$

From $\eta^{In} \cdot \eta^{Out} < 1$ follows that $\underline{k}_t^{Ren} \cdot \eta^{In} < \underline{k}_t^{Ren} \cdot \frac{1}{\eta^{Out}}$ and therefore $\Delta_1 < \Delta_2$. In this way simultaneous charging and discharging reduces storage level more than direct sales of renewable electricity helping to avoid costly capacity expansion. However, due to the proposed upper bound for storage discharging in equation (A2.1) the storage output is restricted by $\bar{g}_t - \underline{k}_t^{Ren}$ and the remaining grid capacity can be used to sell renewable electricity directly to the market. In particular, under such circumstances simultaneous charging and discharging would result in a storage level change by

$$\Delta_3 = \underline{k}^{Ren} \cdot \eta^{In} - \left(\bar{g}_t - \underline{k}_t^{Ren}\right) \cdot \frac{1}{\eta^{Out}} = \underline{k}_t^{Ren} \cdot \eta^{In} + \underline{k}_t^{Ren} \cdot \frac{1}{\eta^{Out}} - \bar{g}_t \cdot \frac{1}{\eta^{Out}} \ . \tag{A2.4}$$

Now comparing Δ_2 and Δ_3 clearly shows that $\Delta_2 < \Delta_3$ and direct renewable sales to the market is always better than simultaneous charging and discharging in the context of avoiding costly storage capacity extension.

■

At this point it is important to mention that positive electricity price is a critical assumption for Proposition 2. In reality also negative electricity prices occur and there might be situations where charging and discharging at the same time might be more advantageous (e.g., if due to storage capacity constraints and minimal renewable uptake requirement renewable electricity has to be sold at negative prices in a given period). Such behaviour cannot be avoided in our model. However as mentioned, in practice this undesirable operation mode does not occur in our simulations and the proposed framework is sufficient to suppress simultaneous charging and discharging.

Table A3: Optimal facility operation in a prototypical year and overall financial results in case A.

Parameter	Unit	Wind						PV					
		Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen	Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
Optimal facility operation in a prototypical year													
GT or storage output	GWh	3	12	11	9	7	2	19	40	37	27	25	19
Storage input	GWh	n/a	16	15	11	10	6	n/a	51	49	34	36	67
Initial storage level	MWh	n/a	110	111	134	142	162	n/a	424	442	480	554	7,327
Number of cycle equivalents	#	n/a	92	85	67	53	5	n/a	27	24	19	15	3
Utilization storage input[a)]	%	n/a	36	34	46	38	86	n/a	16	16	13	10	35
Utilization GT or storage output[a)]	%	6	28	26	20	16	4	36	13	12	51	47	35
Overall financial results													
Revenues renewable generation[b)]	M€	50.3	47.1	47.3	47.9	48.2	48.6	57.5	45.1	45.7	49.6	49.4	37.2
Reveneus GT or storage output[b)]	M€	1.3	4.8	4.5	3.7	3.0	0.6	5.7	14.5	12.2	8.7	7.9	5.3
Total cash inflow	M€	51.5	51.9	51.8	51.5	51.2	49.3	63.2	59.6	58.9	58.2	57.4	42.5
Total annual costs[b)]	M€	1.3	0.5	1.0	0.8	1.8	0.5	9.4	5.6	11.7	5.5	19.0	7.4
Net investment outlays[c)]	M€	1.5	38.9	69.1	2.8	5.8	2.6	1.8	419.0	776.3	18.7	61.6	30.9
Total cash outflow	M€	3.0	39.4	70.1	3.6	7.6	3.1	11.2	424.6	778.0	24.2	80.6	38.3
NPV	**M€**	**48.5**	**12.5**	**−18.3**	**47.9**	**43.6**	**46.2**	**52.0**	**−365.0**	**−729.1**	**34.0**	**−23.2**	**4.3**
Cost of renewbale integration	**M€**	**1.8**	**37.8**	**68.7**	**2.4**	**6.7**	**4.2**	**5.5**	**422.5**	**786.6**	**23.4**	**80.6**	**53.2**

a) Full load hours divided by the total number of hours in a year (8 760 h = 24 h/d · 365 d).

b) Calculated as total present value, i.e. the annual value is multiplied by the annuity factor of approx. 7 in order account for discounting of annual cash flows within the detailed planning horizon.

c) Calculated as actual investment outlays less discounted salvage value of the investment at the end of the detailed planning horizon. Note that all figures are rounded and therefore deviations might occur in some calculations.

Table A4: Optimal facility operation in a prototypical year and overall financial results in case B.

Parameter	Unit	Wind						PV					
		Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen	Gas turbine	NaS Battery	Redox Flow	Pumped hydro	AA-CAES	Hydro-gen
Optimal facility operation in a prototypical year													
GT or storage output sales	GWh	0	63	60	64	53	12	0	59	54	53	42	11
Storage input	GWh	n/a	81	80	80	76	41	n/a	75	72	66	60	39
Initial storage level	MWh	n/a	3,284	3,141	3,760	3,357	3,561	n/a	442	425	656	459	1 225
Number of cycle equivalents	#	n/a	6	6	6	5	3	n/a	133	127	90	105	16
Utilization storage input[a)]	%	n/a	11	11	11	11	6	n/a	10	9	8	8	5
Utilization GT or storage output[a)]	%	0	9	8	30	21	37	0	7	7	25	17	32
Overall financial results													
Revenues renewable generation[b)]	M€	42.4	33.9	34.2	34.3	35.1	42.2	47.0	38.6	39.6	41.2	42.7	46.9
Reveneus GT or storage output[b)]	M€	0.0	24.3	23.2	24.1	20.9	4.3	0.0	23.3	21.4	19.3	15.8	3.7
Total cash inflow	M€	42.4	58.2	57.4	58.4	56.0	46.5	47.0	61.8	31.1	60.5	58.5	50.6
Total annual costs[b)]	M€	0.0	41.4	77.3	32.7	97.5	25.1	0.0	2.2	4.5	8.7	11.5	27.2
Net investment outlays[c)]	M€	0.0	3,085.4	5,145.4	104.9	316.1	105.5	0.0	162.5	296.6	32.1	37.1	114.5
Total cash outflow	M€	0.0	3,126.8	5,222.7	137.6	413.5	130.6	0.0	164.6	301.0	40.8	48.6	141.7
NPV	**M€**	**42**	**−3,069**	**−5,165**	**−79**	**−358**	**−84**	**47**	**−103**	**−240**	**20**	**10**	**-91**
Cost of renewable integration	**M€**	**8**	**3,119**	**5,216**	**130**	**408**	**134**	**10**	**160**	**297**	**38**	**48**	**149**

a) Full load hours divided by the total number of hours in a year (8 760 h = 24 h/d · 365 d).

b) Calculated as total present value, i.e. the annual value is multiplied by the annuity factor of approx. 7 in order account for discounting of annual cash flows within the detailed planning horizon.

c) Calculated as actual investment outlays less discounted salvage value of the investment at the end of the detailed planning horizon. Note that all figures are rounded and therefore deviations might occur in some calculations.

Appendix B.1: Nomenclature in chapter 4

Sets and indices:

$H,\ h$	Set and index of hourly periods in a prototypical year

Decision variables:

Variable	Description	Unit
q_h^r	Direct electricity sales from renewable generation in hour h	MWh_{el}
q_h^d	Direct electricity sales from the grid in hour h	MWh_{el}
q_h^g	Electricity sales in power sector through re-electrification in hour h	MWh_{el}
q_h^m	Direct hydrogen sales in mobility sector in hour h	MWh_{H2}
q_h^s	Hydrogen sales in mobility sector the storage in hour h	MWh_{H2}
x_h^r	Renewable electricity used for hydrogen production in hour h	MWh_{el}
x_h^e	Hydrogen storage input in hour h	MWh_{el}
x_h^p	Electricity purchase from the spot market for hydrogen production in hour h	MWh_{el}
I^r	Investment in renewable generation capacity	MW_{In}
I^e	Investment in electrolysis capacity	MW_{In}
I^c	Investment in compressor capacity	MW_{In}
I^s	Investment in energy-related storage capacity	MWh_{H2}
I^d	Investment in drying capacity	MW_{Out}
I^g	Investment in gas turbine capacity	MW_{Out}

Auxilary variables:

Variable	Description	Unit
s_h	Storage level in hour h	MWh_{H2}
TR_h	Total revenues in hour h	€
TEC_h	Total electricity costs in hour h	€
SC_h	Standby costs of the electrolysis in hour h	€
TOC_h	Total other variable costs in hour h	€
TFC	Annual total fixed costs	€
TI	Total investments outlays	€
TRV	Total residual value	€

Parameters:

Parameter	Description	Unit
r	Interest rate	%
T	Number of periods within the planning horizon	a
AF	Annuity factor	—
p_h^e	Hourly electricity prices	€/MWh$_{\text{el}}$
p_h^m	Hourly sales price in mobility sector	€/MWh$_{\text{H2}}$
λ^r	Lifetime of renewable power plant	a
f^r	Fixed costs fraction of renewable power plant	%
e^r	Specific investment expenses of renewable power plant	€/MW$_{\text{el}}$
K^r	Initial capacity of renewable power plant	MW$_{\text{el}}$
ρ_h	Hourly availability factor for renewable generation	%
$\bar{I}^r$	Maximal investment size for renewable power plant	MW$_{\text{el}}$
η^e	Efficiency of electrolysis	%
σ^e	Stand-by fraction of the electrolysis capacity	%
λ^e	Lifetime of electrolysis	a
ν^e	Specific variable costs of electrolysis	€/MWh$_{\text{H2}}$
f^e	Fixed costs fraction of electrolysis	%
e^e	Specific investment expenses of electrolysis	€/MW$_{\text{el}}$
K^e	Initial capacity of electrolysis	MW$_{\text{el}}$
$\bar{I}^e$	Maximal investment size for electrolysis	MW$_{\text{el}}$
γ^c	Specific electricity consumption of compressor	MWh$_{\text{el}}$/MWh$_{\text{H2}}$
λ^c	Lifetime of input compressor	a
f^c	Fixed costs fraction of input compressor	%
e^c	Specific investment expenses of input compressor	€/MW$_{\text{H2}}$
K^c	Initial capacity of input compressor	MW$_{\text{H2}}$
λ^s	Lifetime of hydrogen storage	a
f^s	Fixed costs fraction of hydrogen storage	%
e^s	Specific investment expenses of hydrogen storage	€/MWh
K^s	Initial capacity hydrogen storage	MWh

...

...

Parameter	Description	Unit
γ^d	Specific electricity consumption of drying unit	$\mathrm{MWh_{el}/MWh_{H2}}$
η^d	Efficiency of drying unit	%
λ^e	Lifetime of drying unit	a
f^d	Fixed costs fraction of drying unit	%
e^d	Specific investment expenses of drying unit	€/$\mathrm{MW_{H2}}$
K^d	Initial capacity of drying unit	$\mathrm{MW_{H2}}$
η^g	Efficiency of gas turbine	%
λ^g	Lifetime of gas turbine	a
f^g	Fixed costs fraction of gas turbine	%
e^g	Specific investment expenses of gas turbine	€/$\mathrm{MW_{H2}}$
K^g	Initial capacity of gas turbine	$\mathrm{MW_{H2}}$
$\underline{X}_h^p$	Lower bound for hourly electricity purchase	$\mathrm{MWh_{el}}$
$\overline{X}_h^p$	Upper bound for hourly electricity purchase	$\mathrm{MWh_{el}}$
$\underline{d}_h^e$	Minimal hourly electricity demand	$\mathrm{MWh_{el}}$
$\bar{d}_h^e$	Maximal hourly electricity demand	$\mathrm{MWh_{el}}$
$\underline{d}_h^m$	Minimal hourly demand for hydrogen in mobility sector	$\mathrm{MWh_{H2}}$
$\bar{d}_h^m$	Maximal hourly demand for hydrogen in mobility sector	$\mathrm{MWh_{H2}}$

Appendix B.2: Model formulation in chapter 4

$$\max NPV = AF \cdot \left[\left(\sum_{h \in H} TR_h - TEC_h - SC_h - TOC_h \right) - TFC \right] - TI + \frac{1}{(1+r)^T} \cdot TRV \tag{B2.1}$$

where:

$$AF = \frac{(1+r)^T - 1}{r \cdot (1+r)^T} \tag{B2.2}$$

$$TR_h = p_h^e \cdot \left(q_h^r + q_h^g + q_h^d \right) + p_h^m \cdot (q_h^m + q_h^s) \quad \forall h \in H \tag{B2.3}$$

$$TEC_h = p_h^e \cdot \left[q_h^d + x_h^p + \gamma^c \cdot x_h^e + \frac{\gamma^d}{\eta^d} \cdot \left(\frac{q_h^g}{\eta^g} + q_h^s \right) \right] \quad \forall h \in H \tag{B2.4}$$

$$SC_h = p_h^e \cdot \sigma^e \cdot \left(K^e + I^e - x_h^r - x_h^p \right) \quad \forall h \in H \tag{B2.5}$$

$$TOC_h = \nu^e \cdot (q_h^m + x_h^e) \quad \forall h \in H \tag{B2.6}$$

$$TFC = f^r \cdot e^r \cdot (I^r + K^r) + f^e \cdot e^e \cdot (I^e + K^e) + f^c \cdot e^c \cdot (I^c + K^c) + f^s \cdot e^s \cdot (I^s + K^s) + f^d \cdot e^d \cdot \left(I^d + K^d \right) + f^g \cdot e^g \cdot (I^g + K^g) \tag{B2.7}$$

$$TI = e^r \cdot I^r + e^e \cdot I^e + e^c \cdot I^c + e^s \cdot I^s + e^d \cdot I^d + e^g \cdot I^g \tag{B2.8}$$

$$TRV = e^r \cdot I^r \cdot \frac{\lambda^r - T}{\lambda^r} + e^e \cdot I^e \cdot \frac{\lambda^e - T}{\lambda^e} + e^c \cdot I^c \cdot \frac{\lambda^c - T}{\lambda^c} + e^s \cdot I^s \cdot \frac{\lambda^s - T}{\lambda^s} + e^d \cdot I^d \cdot \frac{\lambda^d - T}{\lambda^d} + e^g \cdot I^g \cdot \frac{\lambda^g - T}{\lambda^g} \tag{B2.9}$$

Subject to

Produktion constrains

$$x_h^r + x_h^p = \frac{1}{\eta^e} \cdot (q_h^m + x_h^e) \quad \forall h \in H \tag{B2.10}$$

$$\underline{X}_h^p \leq x_h^p + q_h^d \leq \overline{X}_h^p \quad \forall h \in H \tag{B2.11}$$

$$\underline{d}_h^e \leq q_h^r + q_h^g + q_h^d \leq \bar{d}_h^e \quad \forall h \in H \tag{B2.12}$$

$$\underline{d}_h^m \leq q_h^m + q_h^s \leq \bar{d}_h^m \quad \forall h \in H \tag{B2.13}$$

Capacity constraints

$$q_h^r + x_h^r \leq \rho_h \cdot (K^r + I^r) \quad \forall h \in H \tag{B2.14}$$

$$x_h^r + x_h^p \leq K^e + I^e \quad \forall h \in H \tag{B2.15}$$

$$x_h^e \leq K^c + I^c \quad \forall h \in H \tag{B2.16}$$

$$\frac{q_h^g}{\eta^g} + q_h^s \leq K^d + I^d \quad \forall h \in H \tag{B2.17}$$

$$q_h^g \leq K^g + I^g \quad \forall h \in H \tag{B2.18}$$

Storage contrains

$$s_h = s_{h-1} + x_h^e - \frac{1}{\eta^d} \cdot \left(\frac{q_h^g}{\eta^g} + q_h^s \right) \quad \forall h \in H \tag{B2.19}$$

$$s_h \leq K^s + I^s \quad \forall h \in H \tag{B2.20}$$

$$s_h = 0 \quad \forall\, h = 1 \tag{B2.21}$$

$$s_h = 0 \quad \forall\, h = 8760 \tag{B2.22}$$

Investment contraints

$$I^r \leq \bar{I}^r \tag{B2.23}$$

$$I^e \leq \bar{I}^e \tag{B2.24}$$

Non-negativity constraints

$$q_h^r \geq 0 \ \forall h \in H\,; \quad q_h^g \geq 0 \ \forall h \in H\,; \quad q_h^m \geq 0 \ \forall h \in H \tag{B2.25} \quad (B2.26) \quad (B2.27)$$

$$q_h^s \geq 0 \ \forall h \in H; \quad q_h^d \geq 0 \ \forall h \in H \tag{B2.28} \quad (B2.29)$$

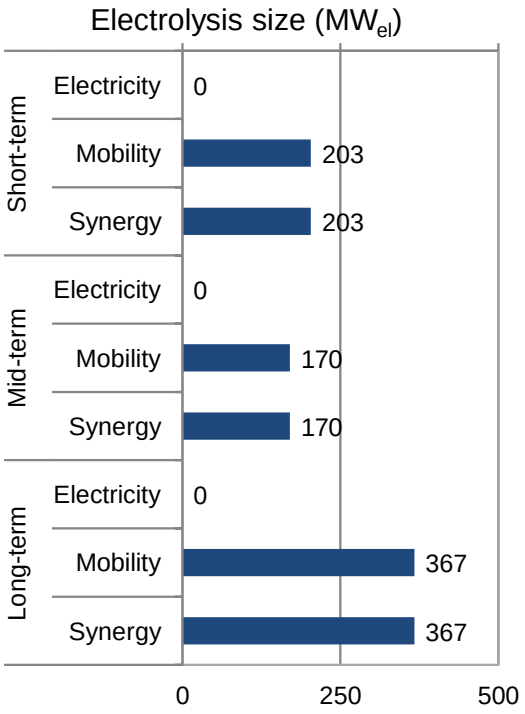
$$x_h^p \geq 0 \ \forall h \in H\,; \ x_h^r \geq 0 \ \forall h \in H; \ x_h^e \geq 0 \ \forall h \in H \quad \text{(B2.30)} \quad \text{(B2.31)} \quad \text{(B2.32)}$$

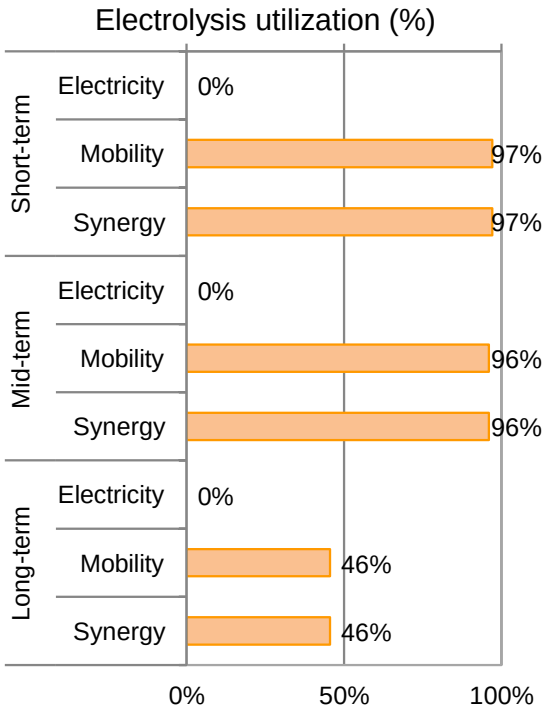
$$I^r \geq 0\,, \quad I^e \geq 0\,, \quad I^c \geq 0 \quad \text{(B2.33)} \quad \text{(B2.34)} \quad \text{(B2.35)}$$

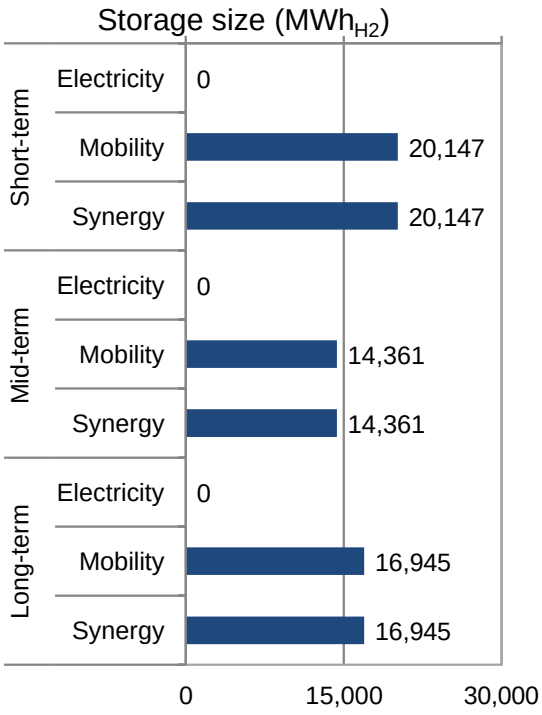
$$I^s \geq 0\,, \quad I^d \geq 0\,, \quad I^g \geq 0 \quad \text{(B2.36)} \quad \text{(B2.37)} \quad \text{(B2.38)}$$

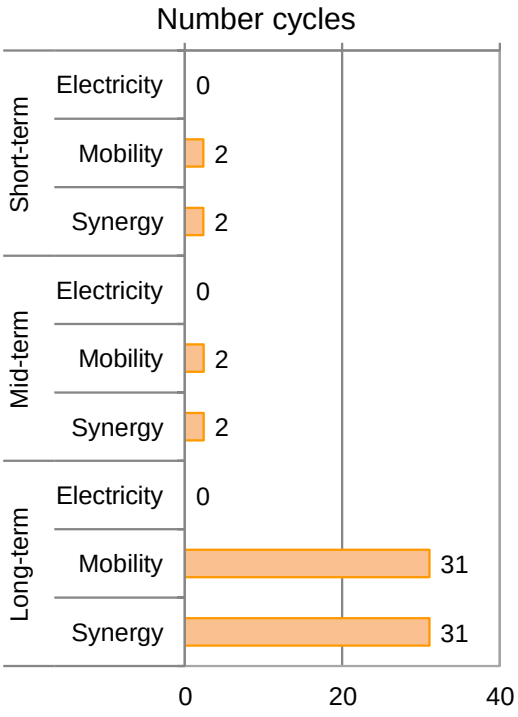
Appendix B.3: Detailed case study results in chapter 4

Case 1 and 2:

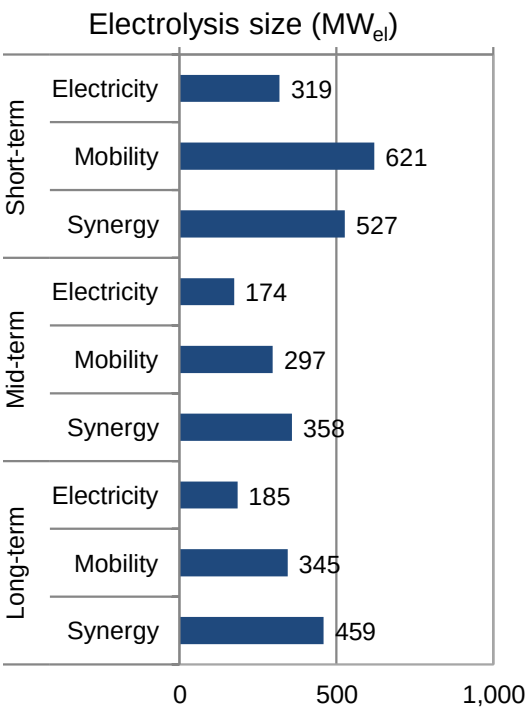


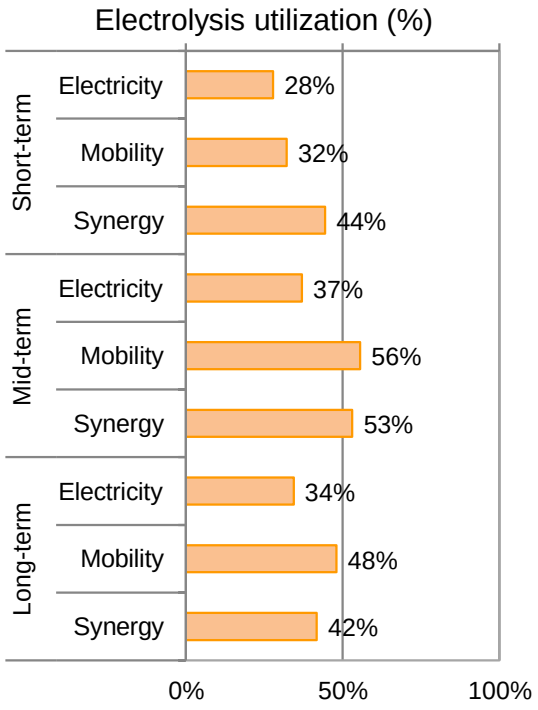


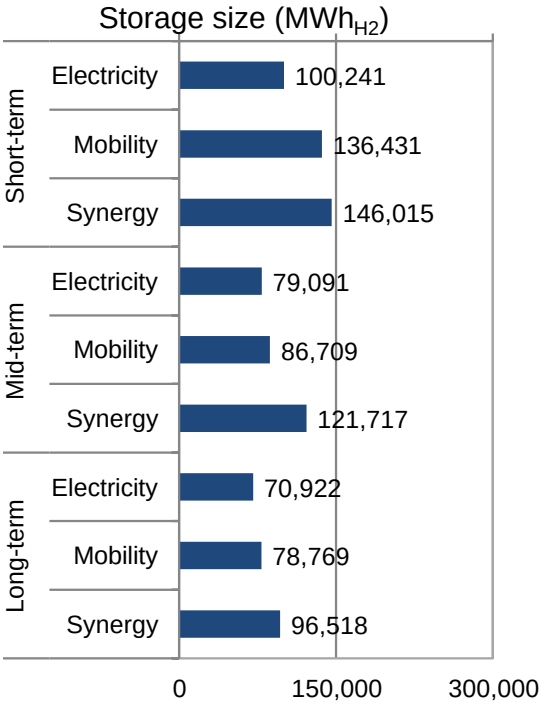


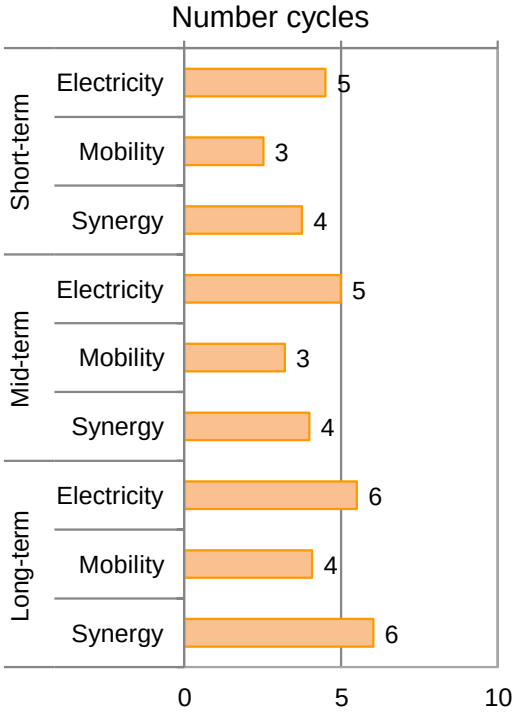


Case 3:

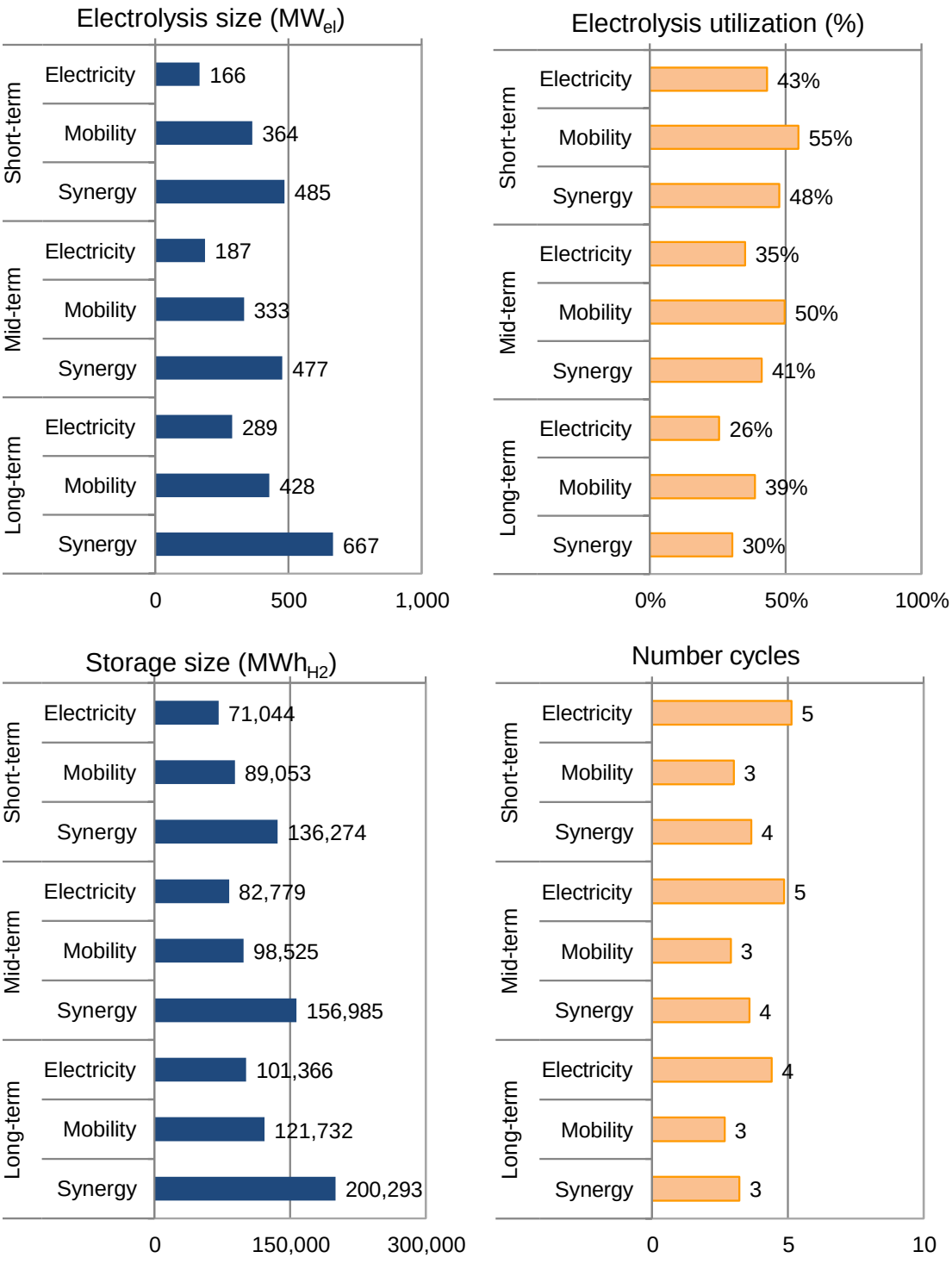

Electrolysis size (MW_{el})
Short-term
Electricity 319
Mobility 621
Synergy 527
Mid-term
Electricity 174
Mobility 297
Synergy 358
Long-term
Electricity 185
Mobility 345
Synergy 459
0
500
1,000


Electrolysis utilization (%)
Short-term
Electricity 28%
Mobility 32%
Synergy 44%
Mid-term
Electricity 37%
Mobility 56%
Synergy 53%
Long-term
Electricity 34%
Mobility 48%
Synergy 42%
0%
50%
100%


Storage size (MWh_{H2})
Short-term
Electricity 100,241
Mobility 136,431
Synergy 146,015
Mid-term
Electricity 79,091
Mobility 86,709
Synergy 121,717
Long-term
Electricity 70,922
Mobility 78,769
Synergy 96,518
0
150,000
300,000


Number cycles
Short-term
Electricity 5
Mobility 3
Synergy 4
Mid-term
Electricity 5
Mobility 3
Synergy 4
Long-term
Electricity 6
Mobility 4
Synergy 6
0
5
10

Case 4:


Electrolysis size (MW_{el})
Short-term
Electricity 166
Mobility 364
Synergy 485
Mid-term
Electricity 187
Mobility 333
Synergy 477
Long-term
Electricity 289
Mobility 428
Synergy 667
0
500
1,000
Electrolysis utilization (%)
Short-term
Electricity 43%
Mobility 55%
Synergy 48%
Mid-term
Electricity 35%
Mobility 50%
Synergy 41%
Long-term
Electricity 26%
Mobility 39%
Synergy 30%
0%
50%
100%
Storage size (MWh_{H2})
Short-term
Electricity 71,044
Mobility 89,053
Synergy 136,274
Mid-term
Electricity 82,779
Mobility 98,525
Synergy 156,985
Long-term
Electricity 101,366
Mobility 121,732
Synergy 200,293
0
150,000
300,000
Number cycles
Short-term
Electricity 5
Mobility 3
Synergy 4
Mid-term
Electricity 5
Mobility 3
Synergy 4
Long-term
Electricity 4
Mobility 3
Synergy 3
0
5
10

Appendix C.1: Nomenclature in chapter 5

Sets and indices:

$T,\ t,\ \tau$	Set and indices of time periods in a prototypical year
$F,\ f$	Set and index of firms
$D,\ d$	Set and index of dispatchable technologies
$S,\ s$	Set and index of storage technologies

Decision variables:

Variable	Description	Unit
$q^{d}_{f,d,t}$	Electricity supply by technology d of firm f in period t	MWh
$q^{o}_{f,s,t}$	Electricity supply by storage s of firm f in period t	MWh
$q^{i}_{f,s,t}$	Charging of storage s of firm f in period t	MWh
$q^{m}_{f,s,t}$	Energy sales in mobility sector by storage s of firm f in period t	MWh
$I^{d}_{f,d}$	Capacity investment in technology d of firm f	MW
$I^{s}_{f,s}$	Capacity investment in storage s of firm f	MW
$\sigma^{d}_{f,d,t}$	Shadow price of capacity constraint of technology d	€/MWh
$\sigma^{i}_{f,s,t}$	Shadow price of input-related capacity constraint of storage s	€/MWh
$\sigma^{o}_{f,s,t}$	Shadow price of output-related capacity constraint of storage s	€/MWh
$\sigma^{lb}_{f,s,t}$	Shadow price of lower bound constraint of storage s	€/MWh
$\sigma^{ub}_{f,s,t}$	Shadow price of upper bound constraint of storage s	€/MWh
$\sigma^{id}_{f,d,t}$	Shadow price of investment constraint of technology d	€/MW
$\sigma^{is}_{f,s,t}$	Shadow price of investment constraint of storage s	€/MW
σ^{m}_{t}	Shadow price of maximal demand in mobility sector	€/MWh

Auxilliary variables:

Variable	Description	Unit
$q_{f,t}$	Total electricity supply by firm f in period t	MWh
Q_t	Total electricity supply in power sector in period t	MWh
FC_f	Fixed costs of firm f	€
NI_f	Net investment outlays of firm f	€

Parameters:

Parameter	Description	Unit
r	Interest rate	%
n	Number of periods within the planning horizon	a
AF	Annuity factor	—
D_t	Load duration in period t	h
p_t^e	Electricity price in period t	€/MWh
p^m	Energy price in mobility sector	€/MWh
c_d	Variable production costs of technology d	€/MWh
$K_{f,d}$	Initial capacity of technology d of firm f	MW
$K_{f,s}$	Initial power capacity of storage s of firm f	MW
$\overline{K}_{f,s}$	Initial energy capacity of storage s of firm f	MWh
η_s^i	Input efficiency of storage s	%
η_s^o	Output efficiency of storage s	%
μ_s	Sales ability in mobility sector of storage s	0 or 1
υ_s	Energy and power-related capacity ratio of storage s	MWh/MW
$\bar{I}_{f,d}$	Maximal capacity investment in technology d by firm f	MW
$\bar{I}_{f,s}$	Maximal capacity investment in storage s by firm f	MW
φ_d	Fixed cost friction of technology d	%
ε_d	Specific capital expenditures for technology d	€/MWh
λ_d	Lifetime of technology d	a
φ_s	Fixed cost friction of storage s	%
ε_s	Specific capital expenditures for storage s	€/MWh
λ_s	Lifetime of storage s	a
M_t	Maximal demand in mobility sector in period t	MWh
A_t	Adapted reference price in period t	€/MWh
B_t	Constant slope of demand function in period t	€/MWh
q_t^r	Intermittent electricity feed-in in period t	MWh
γ_t	Market power parameter for firm f	0 or 1

Appendix C.2: Mixed complementarity problem in chapter 5

As described in chapter 5.3 KKT optimality conditions in equation (C2.1) to (C2.6) with respect to corresponding decision variables and constraints together with the constraints in equations (C2.7) – (C2.13) and the market clearing conditions in equation (C2.14) and (C2.15) form a mixed complementarity problem where $\perp$ indicates complementarity. Parameter γ_f can be used to include or exclude the market power of firm f in the spot market by assuming a value of 1 or 0, respectively.

$$AF \cdot D_t \cdot \left[p_t^e\big(Q_t\big) - \gamma_f \cdot B_t \cdot q_{f,t} - c_d \right] - \sigma_{f,d,t}^{d} \leq 0 \quad \perp q_{f,\,d,\,t}^{d} \geq 0 \quad \forall f, d, t \tag{C2.1}$$

$$\begin{aligned} AF \cdot D_t \cdot \left[p_t^e\big(Q_t\big) - \gamma_f \cdot B_t \cdot q_{f,\,t} \right] - \sigma_{f,\,s,\,t}^{o} - \sum_{\tau=t}^{n} \left[\frac{1}{\eta_s^o} \cdot \left(\sigma_{f,\,s,\,\tau}^{lb} \cdot D_\tau \right) \right] \\ + \sum_{\tau=t}^{n} \left[\frac{1}{\eta_s^0} \cdot \left(\sigma_{f,\,s,\,\tau+1}^{ub} \cdot D_{\tau+1} \right) \right] \leq 0 \quad \perp q_{f,\,s,\,t}^{o} \geq 0 \quad \forall f, s, t \end{aligned} \tag{C2.2}$$

$$\begin{aligned} AF \cdot D_t \cdot \left[-p_t^e\big(Q_t\big) + \gamma_f \cdot B_t \cdot q_{f,\,t} \right] - \sigma_{f,\,s,\,t}^{i} + \sum_{\tau=t}^{n} \left(\eta_s^i \cdot \sigma_{f,\,s,\,\tau}^{lb} \cdot D_\tau \right) \\ - \sum_{\tau=t}^{n} \left(\eta_s^i \cdot \sigma_{f,\,s,\,\tau}^{ub} \cdot D_\tau \right) \leq 0 \quad \perp q_{f,\,s,\,t}^{i} \geq 0 \quad \forall f,\ s,\ t \end{aligned} \tag{C2.3}$$

$$\begin{aligned} p^m \cdot \mu_s \cdot D_t \cdot AF - \sum_{\tau=t}^{n-1} \left(\mu_s \cdot \sigma_{f,s,\tau}^{lb} \cdot D_\tau \right) + \sum_{\tau=t}^{n} \left(\mu_s \cdot \sigma_{f,s,\tau+1}^{ub} \cdot D_{\tau+1} \right) \\ - \sigma_t^m \leq 0 \quad \perp q_{f,s,t}^{m} \geq 0 \quad \forall f, s, t \end{aligned} \tag{C2.4}$$

$$\varepsilon_d \cdot \left(1 - \frac{\lambda_d - n}{\lambda_d \cdot (1+r)^n} \right) + \sum_{t=1}^{n} \sigma_{f,\,d,\,t}^{d} - \sigma_{f,\,d}^{id} \leq 0 \quad \perp I_{f,\,d}^{d} \geq 0 \quad \forall f,\ d \tag{C2.5}$$

$$\varepsilon_d \cdot \left(1 - \frac{\lambda_s - n}{\lambda_s \cdot (1+r)^n}\right) + \sum_{t=1}^{n} \sigma^{i}_{f,\,s,\,t} + \sum_{t=1}^{n} \sigma^{o}_{f,\,s,\,t} + \sum_{t=1}^{n} \left(\nu_s \cdot \sigma^{ub}_{f,\,s,\,t}\right) - \sigma^{is}_{f,\,s} \leq 0 \quad \perp I^{s}_{s,\,d} \geq 0 \quad \forall f, s \tag{C2.6}$$

$$q^{d}_{f,d,t} - K_{f,d} - I_{f,d} \leq 0 \quad \perp \sigma^{d}_{f,d,t} \geq 0 \quad \forall f \in F, d \in D, t \in T \tag{C2.7}$$

$$q^{i}_{f,s,t} - K_{f,s} - I_{f,s} \leq 0 \quad \perp \sigma^{i}_{f,s,t} \geq 0 \quad \forall f \in F, s \in S, t \in T \tag{C2.8}$$

$$q^{o}_{f,s,t} - K_{f,s} - I_{f,s} \leq 0 \quad \perp \sigma^{o}_{f,s,t} \geq 0 \quad \forall f \in F, s \in S, t \in T \tag{C2.9}$$

$$\frac{1}{\mu^{o}_{s}} \cdot \sum_{\tau=1}^{t} D_t \cdot q^{o}_{f,s,\tau} + \mu_s \sum_{\tau=1}^{t} D_\tau \cdot q^{m}_{f,s,\tau} - \eta^{i}_{s} \sum_{\tau=1}^{t} D_\tau \cdot q^{i}_{f,s,\tau} \leq 0 \quad \perp \sigma^{lb}_{f,s,t} \geq 0 \quad \forall f \in F, s \in S, t \in T \tag{C2.10}$$

$$\eta^{i}_{s} \cdot \sum_{\tau=1}^{t} D_\tau \cdot q^{i}_{f,s,\tau} - \frac{1}{\eta^{o}_{s}} \cdot \sum_{\tau=1}^{t-1} D_\tau \cdot q^{o}_{f,s,\tau} - \mu_s \cdot \sum_{\tau=1}^{t-1} D_\tau \cdot q^{m}_{f,s,\tau} - \overline{K}_{f,s} - \upsilon_s \cdot I_{f,s} \leq 0 \quad \perp \sigma^{ub}_{f,s,t} \geq 0 \quad \forall f \in F, s \in S, t \in T \tag{C2.11}$$

$$I_{f,d} - \bar{I}_{f,d} \leq 0 \quad \perp \sigma^{id}_{f,d} \geq 0 \quad \forall f \in F, d \in D \tag{C2.12}$$

$$I_{f,s} - \bar{I}_{f,s} \leq 0 \quad \perp \sigma^{is}_{f,s} \geq 0 \quad \forall f \in F, s \in S \tag{C2.13}$$

$$\sum_{f \in F} \sum_{s \in S} q^{m}_{f,s,t} \leq M_t \quad \perp \sigma^{m}_{t} \geq 0 \quad \forall t \in T \tag{C2.14}$$

$$A_t - B_t \cdot Q_t - p^{e}_{t}\left(Q_e\right) = 0 \quad p^{e}_{t} \; free \quad \forall t \in T \tag{C2.15}$$

Table C3: Detailed case study results in chapter 5.

Item	Unit	Perfect competition				Imperfect competition				Demand in mobility sector			
		A1	A2	A3	A4	B1	B2	B3	B4	C1	C2	C3	C4
Installed capacities													
Base-load	GW	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Peak-load	GW	29.4	29.1	21.3	21.3	23.0	22.7	16.3	19.0	20.9	20.9	16.1	17.6
Pumped-hydro	GW	0	6.4	6.4	6.4	0	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Hydrogen	GW	0	0	12.9	12.9	0	0	10.4	6.0	29.1	29.1	23.4	14.2
Utilization and CO_2 emissions													
Base-load	h	7,601	7,621	8,364	8,303	7,587	7,608	8,331	7,808	8,344	8,264	8,336	7,657
Peak-load	h	2,487	2,504	3,240	3,240	2,403	2,422	3,174	2,814	4,026	4,026	5,059	3,257
Pumped-hydro	h	0	83	85	80	0	86	86	82	39	42	41	112
Hydrogen	h	0	0	296	288	0	0	304	264	30	29	28	16
Total CO_2 emissions	kt_{CO2}	31,892	31,762	30,143	30,143	24,107	23,970	22,620	23,271	36,650	36,650	35,634	25,044
Welfare effects													
Consumer rent	M€	1,313,041	1,310,958	1,253,535	1,253,535	1,203,687	1,201,558	1,154,889	1,173,213	1,234,624	1,234,624	1,215,884	1,295,284
Producer rent	M€	141,629	144,534	208,445	208,445	247,084	250,034	302,931	282,706	276,064	276,064	291,553	202,116
Overall welfare	M€	1,454,670	1,455,493	1,461,980	1,461,980	1,450,771	1,451,592	1,457,820	1,455,919	1,510,687	1,510,687	1,507,437	1,497,400
Electricity price													
Average	€/MWh	79.41	80.02	96.39	96.39	115.18	115.82	128.87	123.48	103.71	103.71	109.36	85.13
Volatility	€/MWh	127.13	125.55	82.87	82.87	146.72	145.18	111.60	125.21	82.73	82.73	113.49	142.22

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