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The Potential of Power-to-Gas for Congestion Management

Utilising Synthetic Natural Gas in Redispatch

Masteroppgave i Sustainable Energy Systems and Markets
Veileder: Ruud Egging-Bratseth & Pedro Crespo del Granado
Juli 2020

Masteroppgave

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Kunnskap for en bedre verden

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Preface

This master thesis concludes the dual master programme *Sustainable Energy Systems and Markets (SESAM)*. The programme is the result of a cooperation between Norges teknisk-naturvitenskapelige universitet (NTNU) and Technische Universität Berlin (TU Berlin).

With the goal of addressing the interdisciplinary profile of SESAM, our master thesis considers challenges from a techno-economical as well as regulatory perspective. The foundation of this thesis was laid out in the first semester of our studies at NTNU. As part of our specialisation project, we build a first model to evaluate the potential of Power-to-Gas in redispatch, using a small-scale test grid. What started as an idea for using valuable renewable energy instead of curtailing, resulted in a deep dive into regulatory frameworks, sequential modelling approaches and implementing innovative technologies, i.e., Power-to-Gas as flexibility option. We are proud to have submitted the results of this journey to Energy Economics and Applied Energy.

We would like to thank our supervisors Prof. Ruud Egging-Bratseth and Pedro Crespo del Granado for supporting and challenging us from the very start. We are grateful for the numerous debates and feedback rounds. We would like to especially emphasise on the freedom given to us in developing our own topic and ideas.

A joint programme such as SESAM requires high coordinational efforts. Without the teamwork of Ruud and Jens Weibezahn (TU Berlin), we probably would have been defeated by all the organisational obstacles. Thank you two for being so flexible and available at all times.

For tips on how to survive SESAM and providing insights as first generation SESAM candidates, we like to thank Alexandra Lüth and Jan Zepter. Your experience was extremely valuable for us.

Thanks to the TU Berlin math cluster, for letting us use your computational capacity. Without access to the high-performance cluster, we would probably still be waiting for our model results. On this occasion also a special thanks to Mario Kendziorski who has helped us setting up the server.

Last but not least, we want to thank Elisabeth Predel. You managed to arrange accommodation and a quiet environment for us, so that we were able to work together on our thesis in times of COVID-19.

Berlin and Trondheim, 3 July 2020

Summary

The increase of renewable energy infeed in the German electricity system is pushing the transmission grid to its limit. Large amounts of wind generation from the north need to be transported to high demand centres in the south. This causes congestion in the transmission grid, resulting in vast amounts of renewable energy to be curtailed and calls for expensive measures by system operators. Due to lagging grid expansions, other flexibility options capable of balancing load and generation on a temporal and spatial dimension need to be explored. As a sector-coupling technology, Power-to-Gas may provide the required flexibility by shifting load from the electricity to the gas system.

In two submitted journal articles, we assess the potential of Power-to-Gas in redispatch. Instead of curtailing renewable electricity, system operators may use Power-to-Gas to generate synthetic natural gas. By utilising transmission capacities of the gas infrastructure, connected gas-fired power plants can use synthetic natural gas to generate electricity behind congested lines. With the goal of reducing curtailment measures and increasing the infeed of renewables, the following research questions arise:

1. To what extent can Power-to-Gas provide flexibility in low carbon energy systems?
2. Do current regulatory frameworks enable Power-to-Gas utilisation in congestion management?

Our strategy to answer these questions is twofold: First, we formulate a techno-economic model, incorporating the German electricity day-ahead spot market and subsequent congestion management. With a limited foresight of 24 hours, we imitate the sequential interaction of market clearing and power transmission. Using findings from state-of-the-art Power-to-Gas projects, we implement the technology as an option for additional flexibility in redispatch. Following our model-based evaluation in our first submitted article, we investigate in a second article whether liberalised electricity markets of today allow for the incorporation of Power-to-Gas facilities by system operators. For a deeper understanding, we examine the potential of Power-to-Gas and existing barriers in two different regulatory environments, i.e., Germany and the United States.

Based on our holistic research approach, including Power-to-Gas in redispatch measures may reduce renewable energy curtailment by $12\,\%$ over the course of a year. With the flexibility of generating synthetic natural gas in times of high renewable infeed, congestion in the transmission grid can be alleviated. This enables the decoupling of renewable electricity injection from bottlenecks in the transmission grid. At the same time, we can achieve higher effective shares of renewables in the electricity mix. On a geographical level, we find that a small set of locations in the grid may strongly benefit from additional flexibility through Power-to-Gas. While attractive from a flexibility perspective, positioning Power-to-Gas within existing regulatory frameworks is challenging: A lack of clear definitions and legal classifications limits the utilisation of Power-to-Gas by the system operators under unbundling rules in place.

Sammendrag

Kapasiteten av fornybar energi i det tyske elsystemet øker stadig, og det setter press på høyspenningsnettet: Mens vindmøllene i Nord-Tyskland producerer en betydelig mengde strøm, trenges den i Sør-Tyskland. Dette fører til en overbelastning i strømnettet og resulterer i at fornybar energi blir begrenset ved dyre tiltak fra nettselskapene. På grunn av manglende nettutvidelser må andre fleksibilitetsalternativer utforskes som er i stand til å balansere etterspørsel og elproduksjon i en tidsmessig og romlig dimensjon. Teknologien Power-to-Gas presenterer en mulighet til sektorintegrasjon og åpner for fleksibilitet ved å skifte belastning fra elnettet til gassystemet.

I to innsendte tidsskriftsartikler vurderer vi potensialet av Power-to-Gas som redispatch teknologi. I stedet for å begrense fornybar elektrisitet, kan nettselskaper bruke Power-to-Gas for å produsere syntetisk naturgass. Ved bruk av det eksisterende gasnettet kan gasskraftverkene omdanne syntetisk naturgass til strøm, og dermed unngå elnettet i perioder med høy last. Med målet om høystbruk av fornybar energi, presenterer vi svar til to forskningsspørsmål:

1. I hvilken grad kan Power-to-Gas introdusere fleksibilitet til karbonnøytrale energisystemer?
2. Gjør gjeldende regelverk det mulig for Power-to-Gas utnyttelse i flaskehalshåndtering?

Vår strategi for å svare på disse spørsmålene er todelt: Først formulerer vi en tekno-økonomisk modell som representererdet tyske markedet med spotmarkedet sitt og den påfølgende styringen flaskehalshåndtering. Med et begrenset framsyn på 24 timer etterligner vi den sekvensielle interaksjonen mellom markedsklaring og kraftoverføring. Basert på aktuelle resultater fra Power-to-Gas-prosjekter implementerer vi teknologien som et alternativ for ytterligere fleksibilitet i redispatch. Etter vår modellbaserte evaluering undersøker vi om liberaliserte strømmarkeder i dag tillater bruk av Power-to-Gas for nettselskaper. Vi analyserer potensialet til Power-to-Gas og eksisterende barrierer i to forskjellige reguleringsmiljøer, Tyskland og USA.

Basert på vår helhetlige forskningstilnærming, inkludert Power-to-Gas i flaskehalshåndtering, kan redusere fornybar energi reduseres med 12 % i løpet av et år. Med fleksibiliteten til å produsere syntetisk naturgass i tider med høy fornybar tilførsel kan overbelastning i høyspenningsnettet reduseres. Dette muliggjør en frakobling av fornybar strøminnsprøytning fra flaskehalser i strømnettet. Samtidig kan vi oppnå høyere effektive andeler av fornybar energi i strømblandingen. Fra et geografisk perspektiv finner vi ut at en liten andel av steder i nettet kan godt profitere av ekstra fleksibilitet gjennom Power-to-Gas. Selv om det er attraktivt fra et fleksibilitetsperspektiv, er det utfordrende å lokalisere Power-to-Gas innenfor det eksisterende regelverket: Manglende klare definisjoner og juridiske klassifiseringer begrenser bruket av Power-to-Gas av nettselskapene etter at det foreligger adskillelsesregler.

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Acronyms

AC Alternating Current.
ACPF Alternating Current Power Flow.
AEL Alkaline Water Electrolysis.

BNetzA Bundesnetzagentur (Federal Network Agency).

CAISO California Independent System Operator.
CFR Code of Federal Regulations.
CHP Combined Heat and Power.
CM Congestion Management.
CRI Center for Renewable Integration.

DA Day-Ahead.
DC Direct Current.
DCPF Direct Current Power Flow.

ED Economic Dispatch.
EEM European Electricity Market.
ELPC Environmental Law and Policy Center.
EnWG Energiewirtschaftsgesetz (German Energy Industry Act).
ESR Electric Storage Resource.

FERC Federal Energy Regulatory Commission.
FTR Financial Transmission Rights.

GfG Gas-fired Generation.

HV	High Voltage.
HVDC	High Voltage Direct Current.
ID	Intraday.
ISO	Independent System Operator.
JuMP	Julia for Mathematical Programming.
LMP	Locational Marginal Price.
LP	Linear Program.
MC	Marginal Cost.
MILP	Mixed Integer Linear Program.
MISO	Midcontinent Independent System Operator.
MP	Market Clearing Price.
O&M	Operation and Maintenance.
OPF	Optimal Power Flow.
PEM	Polymer Electrolyte Membrane.
PHS	Pumped Hydroelectric Storage.
PSA	Power System Analysis.
PtG	Power-to-Gas.
PTO	Participating Transmission Owner.
pu	per unit.
PV	Photovoltaics.
RE	Renewable Energy.
RoR	Hydro Run-of-River.
RTO	Regional Transmission System Operator.
SATA	Storage as a Transmission Asset.
SATOA	Storage as a Transmission-Only Asset.
SM	Sequential Markets.
SNG	Synthetic Natural Gas.
SO	System Opertor.
SOEC	Solid Oxide Electrolyte Electrolysis.
TRM	Transmission Reliability Margin.
TSO	Transmission System Operator.

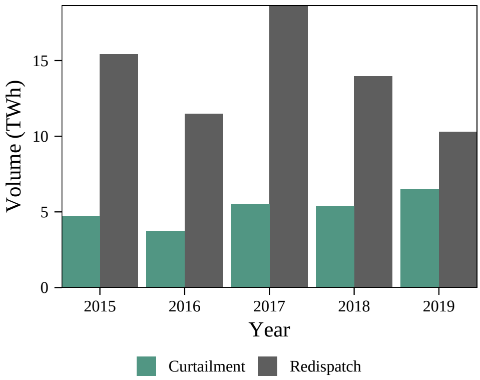
Chapter 1

Introduction

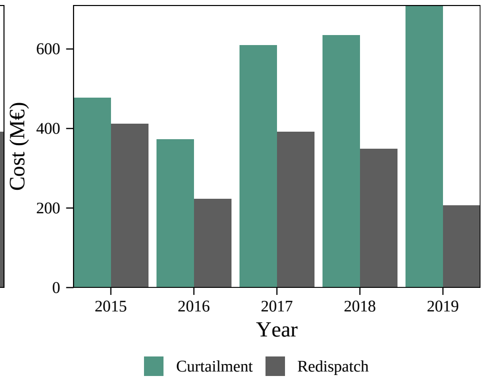
The German Energiewende is currently shaped by growing investments into both Renewable Energy (RE) capacities and extensive grid expansion projects throughout the next two decades (50Hertz et al., 2019). Coming from a centralised and fossil fuel based power generation, decentralised and intermittent RE generation is challenging the existing energy system. Not only has the direction of the flow changed, but also a larger number of smaller units is coupled to the electricity infrastructure. RE units are installed where their generation potential is maximised given the geographic weather conditions. As such, large amounts of wind generated electricity in areas with lower energy consumption have to be transported to load centres. In addition, unforeseen changes in weather conditions or higher expectations require a flexible reaction to balance load and demand at any time, at any location.

With the task of maintaining a stable grid and maximising RE infeed in the generation mix, the costs for overall Congestion Management (CM) have increased during past years to almost a billion euro (Figure 1.1b). As part of ancillary services and to alleviate line congestion, Transmission System Operators (TSOs) can make use of redispatch measures. Current redispatch procedures often result in curtailing RE in front of the transmission line and increasing electricity output of conventional, dispatchable power plants behind the congested lines. While the volumetric share of RE curtailment is lower than redispatch (Figure 1.1a), its share of total cost for CM has grown from around 50 % in 2015 to more than 75 % in 2019 (Figure 1.1b). Especially in light of transitioning to a low carbon or zero carbon energy system, the curtailment of RE and upwards adjustment of conventional, carbon-intense power plants is counterproductive, unecological and cost-intensive. While in the long term, large-scale grid expansion is in planning, these projects can take up to several decades until realised.

Meanwhile, flexibility potentials that could be provided by other energy sectors have not yet been explored. Therefore, more emphasis needs to be put on making full use of existing infrastructure and technologies. In recent years, the interest in Power-to-Gas (PtG) as a promising technology to couple the electricity and gas sector increased (dena, 2020). Producing carbon-neutral Synthetic Natural Gas (SNG) in times of high renewable infeed



(a) Volume



(b) Expenditure

Figure 1.1: Historic development of redispatch and curtailment in Germany
Source: Own illustration based on BNetzA (2016, 2017, 2018, 2019, 2020).

may reduce curtailment as well as the dependency on grid expansion. Furthermore it can support countries in reaching national emission targets and pass on emission reductions to other sectors (Brown et al., 2018; Pilpola and Lund, 2019). As such, Power-to-Gas (PtG) could provide flexibility by shifting pressure from the electricity to the gas system. While flexibility through sector coupling may provide economical and emission reducing advantages, the question arises whether TSOs are allowed to incorporate PtG in their asset portfolio. Since transmission infrastructures are natural monopolies, TSOs in many liberalised markets, are operating under a regulatory framework. In Germany, the four TSOs are regulated by the Bundesnetzagentur (Federal Network Agency) (BNetzA).

Driven by the opportunities provided by PtG as sector-coupling technology for Congestion Management (CM) and the limitations posed by the regulatory framework, our master thesis comprises of two research components. I) Within our model-based approach, we analyse how PtG can provide flexibility in redispatch to exploit the unused potential arising from RE curtailment. Due to the decentralised nature of RE and a resulting imbalance of load and generation, we refer to this type of flexibility as spatial flexibility. II) In order to evaluate whether PtG can be incorporated for the purpose of supporting the transmission grid, we furthermore explore possible positionings of PtG in the current regulatory framework. These two main components of our master thesis reflect the topics of our journal articles that we have submitted to Applied Energy and Energy Economics[1].

[1] We submitted our article *"Congestion management based on Power-to-Gas – Exploring potential implementations in liberalised regulatory frameworks"* to the special issue *"Electricity Markets in Transition"* (Energy Economics, ISSN: 0140-9883). Our second article with the title *"Spatial Flexibility in redispatch: Supporting low carbon energy systems with Power-to-Gas"* was submitted to *"System flexibility for a low carbon energy transition"* (Applied Energy, ISSN: 0306-2619).

1.1 Thesis structure

In Chapter 1 we first introduce electricity markets and the need for ancillary services. Herewith we provide the necessary background for our model-based evaluation with a regional focus on Germany. We then review recent literature on the topic of flexibility and PtG in energy system models, from which we derive research gaps and contributions in Chapter 2. Based on the research gaps we formulate our problem description in Chapter 3. The quality of modelling is determined by accurately representing underlying technical and physical circumstances. As such, we present a technological report on PtG as well as the physics of electricity transmission in Chapter 4. After drawing conclusions for modelling PtG, we develop a model framework in Chapter 5. This includes our assumptions, a mathematical formulation of our Linear Program (LP) model, and an overview on the software used. To analyse the potential of PtG for providing flexibility in the transmission grid, we apply our model to the German electricity system in Chapter 6. In Chapter 7 we address the implementation of PtG in CM from a regulatory perspective. Here, we compare two different liberalised electricity markets, i.e., Germany and the United States. Finally, we summarise our findings from our integrated analysis and draw conclusions in Chapter 8.

1.2 Electricity markets

In 1996, the European Commission agreed on establishing the European Electricity Market (EEM). This initiated the liberalisation of electricity markets (European Comission, 1996), creating a market for an increasing amount of participants. In contrast to other commodity markets, electricity markets display unique properties and challenges (Borenstein, 2002), e.g.:

- Demand and supply have to match at all times,
- Supply is based on demand forecasts,
- Storage capacities are not available or prohibitively expensive,
- Transmission line capacity is limited.

Preliminary considerations. In order to find solutions for these challenges, different approaches and market designs are put in place world-wide. However, the initial system setup remains the same. In its simplest form, every electricity market consists of suppliers and consumers. Supply is either locally connected to demand or delivered via transmission lines, forming a connected grid. In the supply chain of electricity, transmission grids are considered a regulated, natural monopoly (Zweifel et al., 2017). There is only one grid available for everyone.

Next, spatially related suppliers and consumers can be aggregated into nodes. Hence, every node has a specific demand (i.e., households, industries) and supply connected in form of power generation units. Nodes form the joints of the grid, interconnected through transmission lines. Exceeding generation can be transmitted to other nodes, in which demand might be higher than supply and vice versa. As a result, it seems obvious that market participants who own network and electricity generation could easily exercise market power, e.g., giving preferential treatment to transmission of their own electricity generation (Höffler and Kranz, 2011). For this reason, generation and transmission have been separated in the course of liberalisation. This development is also known as *unbundling* (Zweifel et al., 2017). While grids are either in possession of governmental institutions or companies regulated by governmental organs, power generation is competing in a market environment.

Uniform and discriminatory price auction. Assuming each supplier is given same conditions for participating in the market, however at different costs, we need to analyse how the market clearing price is formed. In most liberalised markets, prices are settled using a merit order. The merit order lists suppliers based on their bid and capacity they want to sell in ascending order (Zweifel et al., 2017). In a healthy market competition, bids are based on cost for producing one unit of electricity (usually MWh), also known as Marginal Cost (MC). The point of intersection between demand and supply sets the price. Generation above demand is not retrieved, i.e., dispatched (Zweifel et al., 2017). The resulting price is uniform, meaning every supplier on the left side of the merit order is remunerated the same price, although its bid might have been lower. In our paper we commonly refer to the uniform price as Market Clearing Price (MP) (Ding and Fuller, 2005). Apart from uniform pricing, other options exist, such as discriminatory price auctions i.e., every dispatched supplier gets its bidding price. This approach leads to different market behaviour, which we will not go into further detail at this point. Holmberg and Lazarczyk (2012) compare discriminatory and uniform pricing in constraint transmission grids. They conclude, that while the dispatch volume stays the same, the distribution of payments to suppliers differs.

Nodal and zonal pricing. By connecting a price auction mechanism with topological factors, we determine the size of a market. At the same time, physical constraints in transmission lines need to be considered. Two different approaches exist: Nodal and zonal market designs. Nodal market design describes a price setting for each node. Still, nodes can interact with other nodes based on the capacity of connected transmission lines. Surplus supply is exported to nodes where demand exceeds supply. This usually results in similar Market Clearing Price (MP) for linked, neighbouring nodes (Maurer et al., 2018). However, if capacities limits are reached, unrestricted trading with other nodes is no longer available. Therefore nodal prices in higher demand and low supply express scarcity and increase (Ding and Fuller, 2005). On the other hand, nodal prices are reduced in nodes with generation surplus. Nodal pricing is also referred to as Locational Marginal Price (LMP), because they express the value of electricity in a specific location (node) due to transmission constraints (Trepper et al., 2015; Maurer et al., 2018). This approach is used e.g., in New Zealand, Texas and Australia.

However, a different market design is more common in Europe, i.e., zonal pricing. A zone is the conglomerate result of joining several nodes into one market. Zones are often created based on national borders (e.g., Germany, France) but can also split countries into several so called bidding zones (e.g., Norway, Maurer et al. 2018). In comparison to nodal markets, zonal markets increase the volume traded on the electricity market and has a positive, inclusive effect on market participants. Interzonal trading is possible with restrictions for maximum capacities. To foster market participation within a zone, the monetary market is decoupled from physical grid constraints. Simplified, it is assumed that the zone consist of a copper plate, neglecting all physical transmission constraints (Zweifel et al., 2017). Within one zonal region, a single MP emerges. Since the price does not reflect the physical limits of the grid, a subsequent (ex-post) adjustment of electricity generation is necessary (Schewe and Schmidt, 2019). These ex-post adjustments are made by the network operator which we discuss in more detail in Chapter 1.3 for Germany.

Day-ahead and intraday spot market. One challenge of electricity markets is to match supply and demand at all times, with the latter being based on forecasts. To alleviate deviations between demand and supply, auctions are split into different time intervals. As we focus on the German electricity system in this paper, we present the country-specific market proceedings in the following section. Note that throughout the last years, cross-border electricity trading within Europe has continued to be unified.

Electricity is either traded on stock markets or by bilateral contracts, so called Over-The-Counter trades (Zweifel et al., 2017). By volume, most of the electricity is traded on stock markets. For Germany, these are the EPEX Spot in Paris and the EXAA in Austria (Würfel, 2017). Stock markets provide different products for electricity. Products differ in terms of point of trade and duration of supply. The Day-Ahead (DA) market is open to receive bids until 12 pm on the day before delivery. Bids for selling and buying are possible for each hour of the next day, resulting in an hourly MP based on merit order. Also, full time blocks can be traded. DA markets are especially important to calculate power flows for the next day. The Intraday (ID) market starts at 3 pm. Instead of hourly products, traded products for the next day are now sized at 15 min intervals. Meanwhile, continuous trading begins for hourly products. Continuous trading for quarter-hourly products starts at 4pm (EPEX, 2019). Due to the intermittent nature of RE, energy generation has become more unpredictable. In order to ensure matching of demand and supply, the gap between trading and delivery has decreased in the last years. As of today, trading is possible until five minutes before delivery (Maurer et al., 2018). Apart from trading products on the DA and ID market, futures are also available. These are contracts for delivery in the future. Futures are traded at the EEX stock exchange in Germany (EPEX, 2019).

1.3 The need for ancillary services

In addition to the "monetary" side of electricity markets, this Section presents the need for ancillary services. Physical characters of electricity transmission also have to respected, as they are not accounted for in the electricity auctions. In Germany, the system operators are responsible for the operation of a secure and safe electricity grid. Four system operators are in charge of the high voltage grids, which are called Transmission System Operators (TSOs). To maintain a stable electricity grid, a TSO is able to make use of different mechanisms. These mechanisms are specified and legally approved in the German Energy Act (Energiewirtschaftsgesetz) EnWG 13 and can be split into three categories: i) grid related measures, ii) market related measures, and iii) further reserves.

Grid related measures. Grid related measures are based on changes in the grid topology, e.g., shut down of specific transmission lines (EnWG 13 §1). The use of **further reserves**, e.g., standby power plants, are only needed in emergency situations (EnWG 13d).

Market related measures. Market related measures contain all services the TSO can procure due to contracts or based on the regulatory framework. With regard to quantity, redispatch is the most frequently used congestion management measure (see Figures 1.1a and 1.1b). Redispatch is the adjustment of power generation to alleviate congestion on transmission lines. Power injection is decreased in front of the congested transmission line and increased behind to match the demand on the high demand and low supply side (Nüßler, 2012; Burstedde, 2012). Total generation therefore remains the same, only the location of production is modified. The design of redispatch varies throughout Europe and is implemented either following a market or regulatory approach. The latter is often also referred to as cost-based redispatch (Hirth et al., 2019). Connect (2018) provides an overview of different configurations for redispatch. In Germany, redispatch is cost-based with an individual remuneration for the generated or reduced power.

Market participants are obliged to take part in redispatch. Suppliers have to provide their cost structure for power generation ex-ante to the TSO, who decides how to solve congestion based on cost and efficiency. Ideally, redispatch is profit neutral for the supplier, meaning the supplier is indifferent between spot market and redispatch participation (Connect, 2018). Therefore, the TSO is in charge of compensating the supplier for opportunity costs. Opportunity costs arise in reduced flexibility on the spot market. Specifically, by participating in a redispatch sequence, the supplier looses its flexibility to react to occurring price fluctuations on the intraday market (bdew, 2018)[2]. Calculating the value of opportunity costs is one of the biggest challenges in cost-based redispatch approaches (Connect, 2018). A method to quantify the cost for lost opportunity is represented by Weber (2015). It is based on a geometrical Brownian normal distribution of intraday prices: Changes in the price are stochastically independent from each other, but follow a standard normal distribution. Hence it is possible to calculate an expected price based on mentioned parameters, which are already available before redispatch occurs (Weber, 2015; bdew, 2018).

Redispatch also includes a mechanism called countertrading. Countertrading is used between different bidding zones. Instead of changing the power plant schedules, the system operator actively trades electricity in order to avoid congestion (BNetzA, 2019). In contrast to conventional redispatch, countertrading accounts for only a very small share of the overall redispatch volume and expenses. Apart from redispatch the TSO is able to curtail electricity produced from RE sources (Einspeisemanagement), under specific circumstances. The circumstances and regulations for those cases are defined in the Renewable Energy Act (Erneuerbare Energien Gesetz), see EEG 14. Nonetheless, the TSO is obliged to inject the highest possible quantity of RE in the grid (EEG 14 §1). In case of RE curtailment, the TSO has to cover 95% of the lost profits to the supplier. If curtailment accounts for more than 1% of the yearly profits, the TSO has to cover for 100% of lost

[2] The Federal Association of the German Energy and Water Industries (bdew) represents German energy supplier, as well as water supplier and waste management companies

profits (EEG 15 §1). For each curtailment of RE, the system operator has to declare the necessity for intervention.

Operational adjustments. Normal adjustments in the grid, which occur due to changes in the scheduled and forecasted demand, are also handled by the TSO. Regulations which affect the balance of electricity input and output, as well as frequency and voltage maintenance are called system services (Systemdienstleistungen) (Zweifel et al., 2017). Balancing energy (Regelenergie) is part of system services and needs to be considered separately from redispatch. Balancing energy can be either positive or negative and also differentiated by the time it needs to be available and the duration of its commitment. In contrast to redispatch, obtaining balancing energy is market-based. The total volume for the balancing energy is bought by the TSO in an auction, on which eligible power suppliers can make an offer for an advertised energy position (Zweifel et al., 2017). Overall, the system operator can make use of various mechanisms to either maintain a stable electricity grid and to take action, if required. Differences exist in temporal availability, reasons for intervention and the procurement of services. A summary of ancillary services and CM mechanism is displayed in Table 1.1.

Table 1.1: Ancillary services and CM mechanisms in Germany

Name	Service	Procurement	Measure	Legal confirmation
Redispatch	Congestion management	Compulsion	Market related	EnWG 13a
Countertrading	Congestion between bidding zones	Contract basis	Market related	EnWG 13
RE curtailment	Congestion management	Compulsion	Market related	EnWG 13, EEG 14,15
Balancing energy	Balance of in- and output	Market-based	System service	EnWG 13 with EnWG 22,23

Chapter 2

Literature review

In this Chapter, we first review different approaches to the term flexibility in academic literature (Section 2.1). Based on these insights, we position PtG among the flexibility classifications. Furthermore, we review past and recent publications that assess the potential of PtG in energy systems with an increasing share of RE sources (Section 2.2) . We use widely available, commercial online databases, accessible through the eduroam network, including Web of Science (Clarivate Analytics), Scopus (Elsevier), and Google Scholar.

2.1 Flexibility

Flexibility is often described as the ability to react to imbalances between load an generation (Heggarty et al., 2019; Huber et al., 2014). Imbalances can occur both on demand and supply side (Ma et al., 2012) as well as due to external effects (Rosen, 2015; Perera et al., 2019). From a technical perspective, flexibility is required in an electrical grid, to keep frequency and voltage at a desired operational level (Lund et al., 2015). Therefore, flexibility is not new to electric power systems and has historically been provided by System Operators (SOs) through ancillary services (Lund et al., 2015). In contrast to power systems based on dispatchable, conventional electricity generation, electricity production by RE units increases variability and uncertainty (Heggarty et al., 2019). As such, with larger amounts of RE infeed, the need for flexibility is increasing.

Demand-side and supply-side flexibility In the literature, flexibility is commonly grouped into demand-side and supply-side options (Kondziella and Bruckner, 2016; Schill, 2014; Castagneto Gissey et al., 2019). Supply-side flexibility is directed at power generators and their adaptability to changes. In this case, flexibility is often described in terms of technical parameters of the specific technology. Ela et al. (2016) use three parameters to describe supply flexibility, i.e., absolute power output capacity in MW, ramping times in MW/min and duration of maintaining an output level. Demand-side flexibility on the other hand refers to actively imposed changes in energy consumption either by increasing, decreasing or rescheduling demand (Gelazanskas and Gamage, 2014). There are ongoing projects in Germany, in which TSOs offer incentives for more flexible energy consumption to prevent curtailment (Hodurek, 2020), either by increase (adjustable load) or decrease (interruptible load) demand[1].

Transmission Apart from generation and load connected to the power system, the transmission grid itself is a key element in providing flexibility. In order to allow a high percentage of RE infeed, grid extension and reinforcements are necessary to cope with the challenges of decentralised energy generation (Kondziella and Bruckner, 2016; Perera et al., 2019). Additionally, the size of the system can have a beneficial effect on flexibility. Huber et al. (2014) point out that interconnections of smaller areas reduce the need for overall flexibility. On the system level, uncorrelated local imbalances can compensate each other. While grid extension may reduce the overall need for flexibility (Steinke et al., 2013), ongoing grid projects face great opposition in the public, resulting in long project duration and legal challenges (Kamlage et al., 2020).

Storages Another option for flexibility can be found in storage technologies. Depending on the technology they can either increase electricity demand (e.g., by storing in the form of chemical, potential, or kinetic energy) and/or increase supply (release of electricity). Østergaard (2012) argues to position storages as third option between supply and demand response. He analyses different technologies, including electricity, heat, and biogas storages. In his case study on a Danish city, assuming 100 % RE generation, electrical storages are a beneficial, yet expensive option to increase RE infeed. However according to Kondziella and Bruckner (2016), storage may not be the most cost-effective technology in a system wide scope. In their study, covering the German energy system, flexible power generation in combination with curtailment seem to provide enough flexibility, without incorporating storages. These different outcomes show the importance of system boundaries and objectives for flexibility.

System flexibility Depending on the scope of observation, flexibility can be analysed for specific technologies, regions or entire energy systems. The latter is defined by Denholm and Hand (2011) as system flexibility, which describes the ability of generators in a power system to react to changes in load due to uncertainty or variable energy sources such as intermittent RE. In the study, they analyse system flexibility in the Texas transmission grid (ERCOT) with regards to high wind and solar Photovoltaics (PV) infeed of up to 80 %. They conclude that power system flexibility needs to be increased in accordance with the volume of RE infeed. Denholm and Hand (2011) argue that a combination of different approaches, such as storages, curtailment, and demand response is necessary to reach an infeed of 80 %. This has also be shown by Kawajiri et al. (2019) for the Japanese electricity grid. Following Denholm and Hand (2011), they use the term grid flexibility, equivalent to system flexibility. They find that grid flexibility can be increased if the share of power plants with high must-run obligations, such as coal-fired generators and nuclear power plants is reduced.

[1] The regulatory framework for adjustable (‘zuschaltbare Lasten") and interruptible load (“abschaltbare Lasten") is provided in EnWG 13 §6.

Curtailment As most grid infrastructures were built to accommodate dispatchable and centralised power generation, flexibility in the grid is often not matched with variable and decentralised power generation by RE sources. This often results in another measure of flexibility, that is curtailment of RE infeed. Curtailment occurs if other available flexibility options in the grid are not sufficient (Ma et al., 2012). Hence, the amount of curtailment can be seen as indicator for flexibility requirements. Allard et al. (2020) use the volume of curtailment as an indicator to analyse the flexibility benefits provided by storages. Ma et al. (2012) also use curtailment for assessing flexibility in a power system. Based on installed capacities and technical parameters such as ramping, they calculate probabilities for different volumes of wind curtailment (“loss wind estimation").

Flexibility through sector coupling Flexibility can also be provided by coupling different energy sectors, i.e., electricity, gas, heat, and transport (Lund et al., 2015; Maruf, 2019). By shifting an energy carrier from one infrastructure to the other (e.g., electricity to gas), flexibility options from both systems can be used. Pilpola and Lund (2019) and Brown et al. (2018) investigate how the share of renewable infeed can be increased through flexibility by sector coupling. On the demand side, technologies include PtG, Power-to-Heat, smart charging of electric vehicles, thermal, and electricity storages. On the supply side they incorporate wind power curtailment and Vehicle-to-Grid. In addition, both studies find that sector coupling can reduce the dependency on cross-border electricity imports. For coupling with the transport sector, Emonts et al. (2019) find that the production of hydrogen from RE is beneficial for both the electricity and transport sector. While additional flexibility in the electricity sector is provided through hydrogen production, emission reductions can be passed on to the transport sector. Flexibility by PtG and possible locations have also been analysed by Haumaier et al. (2020). In one of their scenarios, surplus wind onshore generation is used to produce H_2 and SNG. They conclude, while the potential for PtG exists, currently consumer charges, electricity tariffs, and taxes pose a barrier to PtG becoming a competitive, feasible flexibility option. Available literature shows that from the perspective of the electricity sector, sector coupling is often primarily seen as a demand-side flexibility. In the course of our paper, we therefore refer to PtG as a sector coupling technology, providing demand-side flexibility.

2.2 Power-to-Gas in energy system models

A large share of research on PtG impacts in electricity systems is conducted with the help of techno-economic optimisation models. We discuss key findings and implications of representative models given in Tables 2.1 and 2.2. An extensive literature review of existing PtG models is presented by Quarton and Samsatli (2018).

Using a Mixed Integer Linear Program (MILP), de Boer et al. (2014) analyse the economic and environmental system consequences of multiple storage-based technologies, including PtG, pumped hydro, and compressed air energy, for different levels of wind penetration. They apply their model to the Dutch electricity system and observe cost reductions for total electricity supply. They find that cost savings are particularly high in energy systems with high wind penetration, and resulting surplus electricity in times of low demand and high infeed. In the case of the Netherlands, they conclude that PtG might not be an optimal storage system from both an economic and environmental perspective. Rather, PtG might be more suitable for regions with an extensive, meshed gas grid or where the conditions for pumped hydro or compressed air energy storage are limited.

Jentsch et al. (2014) quantify the optimal capacity and spatial deployment of PtG units for a $85\,\%$ RE share in Germany. Motivated by an increasing share of intermittent RE generation, they see an increased need for balancing both on a temporal as well as spatial dimension. Given the unequal spatial distribution of wind generation in the north and load centres in the south, PtG is primarily installed in the northern region. By incorporating PtG with a capacity ranging from 6 GW to 12 GW, a significant share of surplus feed-in electricity could be integrated.

Heinisch and Le Anh Tuan (2015) evaluate the regional potential of PtG in Denmark for the years 2014 and 2030. While they do not model the gas grid explicitly, they reflect its storage capacity. By optimally scheduling PtG units, Heinisch and Le Anh Tuan (2015) observe a reduction in total system costs by $4.1\,\%$ and wind power curtailment by up to $2\,\%$.

By implementing a non-linear, combined gas and electricity network optimisation model, Qadrdan et al. (2015) analyse the role of PtG in an integrated gas and electricity system for Great Britain for a typical low and high demand day in 2020. Assuming a depletion of national natural gas resources, capacities in the gas grid become available for hydrogen injections. By only considering hydrogen and permitting a maximum share in the gas grid of $5\,\%$, they find that wind curtailment can be reduced by $62\,\%$ on a typical low electricity demand day and by $27\,\%$ on a high demand day.

Sun et al. (2017) argue that many publications find overly optimistic incorporations of PtG in energy systems by neglecting uncertainty and security constraints. Sun et al. (2017) address the slow dynamical characteristics of the gas infrastructure and implement security constraints in the gas system. To account for uncertainty from load and wind infeed forecasting, they implement a probabilistic optimal power flow. They apply their model to the IEEE-RTS24 test case (Ordoudis et al., 2016) coupled with a 20-node representation of the Belgian network. By allowing for bi-directional energy conversion in both systems, they find that PtG reduces both transmission line congestion and contributes to peak shaving in times of high electricity demand. Zeng et al. (2017) also take the interaction of the electricity and gas system into account by formulating an iterative MILP.

While the impact of PtG on reducing wind curtailment is assessed in above-mentioned literature, Gholizadeh et al. (2019) analyse how the synergies between PtG and Combined Heat and Power (CHP) can smoothen electricity and gas demand. When applied to a residential hub, they observe reduction in total system costs of $17\,\%$ and decrease electricity and natural gas demand standard deviations by $8.34\,\%$ and $66.64\,\%$, respectively. The presented method for simultaneous peak shaving and valley filling of electricity and gas profiles, essentially yields a trade-off between energy cost saving and demand smoothing.

Khani et al. (2019) propose a real-time optimal scheduling algorithm to enable a PtG–Gas-fired Generation (GfG) joint unit to optimally contribute to congestion management. They propose a mechanism through which the utility operator is financially compensated by the system operator. By introducing an asymmetric “modulation factor", a joint PtG–GfG operator is allowed to buy electricity at less than the market clearing price to relieve congestion by injecting SNG to the gas grid. Likewise, the joint plant operator receives a higher than market clearing price when generating electricity in GfG units to alleviate congestion.

Apart from PtG as an emerging, potential flexibility in the energy system, there are many established technologies, such as pumped hydro storage, already available today. Pavičević et al. (2019) use the open source Dispa-SET model, developed within the Joint Research Centre of the EU Commission to compare different model formulations for future power systems with high shares of renewable infeed. They provide a detailed model for the Western Balkan power sector and include pumped hydro storage, as well as battery-powered electric vehicles. In analysing the year 2015 and two future scenarios 2030 and 2050, they find that a high share of flexible technologies could potentially integrate up to 30 % of RE without compromising the stability and integrity of the electricity system. They also take into consideration ongoing and future transmission expansion projects. If all future transmission expansion projects were to be realised, additional 17 % of RE could be integrated by the year 2030.

Table 2.1: PtG in energy system models (I). • denotes included, - not included.

Reference	Modelling scope	Modelling approach	Time horizon	Electric grid represent.	Gas grid represent.	SM	CM	PtG	Region/case
Kunz (2011)	Future CM cost in Germany given increase in RE. CM through redispatch and network topology optimisation. Impact of nuclear phase-out.	Min. system operation cost. Two-step MILP: Spot market + CM model.	2008, 2015, 2020. Full year (8760 decoupled hours).	DCPF.	-	•	•	-	Germany.
de Boer et al. (2014)	Economic and environmental system consequences PtG, pumped hydro, and compressed air energy storage in an electricity system at different wind power penetration levels.	Min. system operation cost. Single-step MILP. Varying capacities of PtG and storage systems.	2015. Full year (8760 hours).	Yes, not specified.	-	-	-	•	Netherlands.
Jentsch et al. (2014)	Perspectives of PtG in an 85 % RE scenario for Germany. Optimal capacity and spatial deployment of PtG.	Min. system operation cost. Single-step MILP. Varying capacities of PtG.	n/a.	DCPF.	-	-	-	•	Germany (18 nodes).
Heinisch and Le Anh Tuan (2015)	Effect of PtG on energy system. Optimal scheduling of PtG units.	Min. system operation cost, incl. profit from selling SNG. Single-step MILP.	2014, 2030. Full year (8760 hours).	DCPF.	Single gas storage.	-	-	•	Denmark (18 nodes).
Qadrdan et al. (2015)	Role of PtG in an integrated gas and electricity system.	Min. system operation cost (electricity + gas + unserved energy). Non-linear program.	2020. Full day (24 hours).	DCPF.	Non-linear.	-	-	•	Great Britain (16-node with 9-node gas network).

Source: Own illustration.

Table 2.2: PtG in energy system models (II). ● denotes included, - not included.

Reference	Modelling scope	Modelling approach	Time horizon	Electric grid represent.	Gas grid represent.	SM	CM	PtG	Region/case
Vandewalle et al. (2015)	Effects of large-scale PtG on the power and gas sector and CO_2 emissions.	Min. system operation cost (electricity + gas + CO_2. Single-step MILP.	Full year (15 min intervals).	Yes, not specified.	Yes, not specified.	-	-	●	based on Belgium.
Sun et al. (2017)	Optimal power flow of electricity system under security constraints of the gas system. Correlation between electric and gas loads. Role of PtG units for wind power curtailment.	Min. system operation cost (electricity + gas). Single-step MILP. Integrated electric and natural gas system.	Full day (24 hours).	DCPF.	Linearised.	-	-	●	IEEE-RTS24 with 20-node Belgium gas network.
Zeng et al. (2017)	Coordinated operation of the electricity and natural gas network with bi-directional energy conversion. Effect of PtG on the daily dispatch.	Min. system operation cost (electricity + gas). Iterative MILP. Integrated electric and natural gas system.	Full day (24 hours).	DCPF.	Linearised.	-	-	●	IEEE-9 with 7-node gas network.
Gholizadeh et al. (2019)	Coordinated operation of the electricity and natural gas network. Impact of PtG and CHP.	Min. system operation cost (electricity + gas), CO_2 emissions, and smoothing of net power demand. Single-step MILP. Integrated electric and natural gas system.	Full year (8760 hours).	Transport model.	Transport model.	-	-	●	10-node electric and gas energy system.
Khani et al. (2019)	Enabling PtG-GfG systems for CM on distributional level. Integrated electricity and gas distribution grids.	Max. arbitrage profit for the PtG-GfG system. Non-linear program.	One hour (5 min intervals).	ACPF.	Non-linear.	-	●	●	33-node electric and gas energy system.

Source: Own illustration.

2.3 Research gaps and contribution

We conclude that there is a large interest in evaluating the benefits of PtG in energy models. Nevertheless, existing models either capture the sequential nature of electricity markets and grid services (Kunz, 2011), *or* incorporate PtG in a single-step optimal dispatch with transmission constraints. While the technical benefit of PtG units in energy systems has been thoroughly researched in the past, we contribute by taking into account Sequential Markets (SM), i.e., spot market followed by ex-post CM, as well as limited foresight.

Further, most flexibility approaches focus on temporarily changes at specific locations. Redispatch however implies to increase flexibility on both sides of congested lines, e.g., storing energy on one side still does not solve the load situation on the other side. Specific approaches evaluating flexibility by in redispatch are therefore under-represented. Based on our literature review, we position PtG as a sector coupling, demand-side flexibility option. By combining redispatch and flexibility through PtG in Chapter 6, we fill the previously determined research gap. Using SNG as energy carrier, stress on transmission lines in the electricity system may be reduced, while demand can be still satisfied after a congested element. Especially for considering PtG in CM, the technology may bring geospatial advantages that are often neglected in model-based approaches. As Haumaier et al. (2020) has shown, the location of PtG in the transmission system plays a crucial role in determining the potential of PtG. Hence, we propose not to only assess the temporal but also the locational aspect of flexibility through PtG.

Our literature review also yields a lack of putting insights from model-based evaluations into perspective of the real world. While many models present the technological benefits of PtG, regulatory obstacles are often neglected. Most analyses are conducted from the perspective of a single, benevolent system optimiser that can jointly optimise the electricity market and grid. We point out that an analysis including transmission systems in Europe only make sense, if the regulatory circumstances are respected. As grids are natural monopolies, their ownership and operation by TSOs underlie strict regulation. By taking account the regulatory aspect in Chapter 7, we are able to provide a more complete picture on the topic.

Chapter 3

Problem description

In this chapter, we describe the objective of our research project, including the problem scope, setting and characteristics. To construct the foundation for the mathematical model, we further elaborate on the decisions to be made and the available information, restrictions and assumptions, under which the problem operates. The aim of this Chapter is to provide a standalone description of the problem by including a brief overview on the motivation, the technologies, and mechanisms involved.

Throughout our research project, we analyse the effect of PtG (PtG) on CM, including redispatch[1] and curtailment[2] volumes and costs. Specifically, we assess the potential of PtG as a bridging technology between the electricity and gas grid, to provide flexibility in times of high RE infeed. Our modelling approach requires an utilisation PtG by the TSO. However, while this may conflict with current regulations. the following research questions emerge:

- To what extent can Power-to-Gas provide flexibility in low carbon energy systems?
- Do current regulatory frameworks enable Power-to-Gas utilisation in congestion management?

Increasing shares of fluctuating, non-dispatchable RE (RE) sources pose challenges to managing the electric power system. PtG is a promising technology that can help mitigating congestion in future low carbon energy systems. PtG consist of two steps, namely methanation and electrolysis producing as end product SNG. Technical and chemical procedures of both steps are provided in Section 4.2. SNG can be stored and transported via existing gas pipelines and used in dispatchable GfG units to generate electricity. For the purpose of our analysis, we refer to PtG, as the combination of both technologies.

Several power markets in Europe, including the German one, have a country-wide uniform price for electricity. In such uniform pricing systems, the market assumes a copper

[1] Redispatch is the adjustment of power generation in order to alleviate congestion on transmission lines. For further information see chapter 1.3

[2] Curtailment describes the feed-in reduction of renewable energy by TSO due to congestion or insufficient demand.

plate. The economic dispatch does not consider physical capacity restrictions in the electricity transmission system. However, the actual transmission network has capacity limits, which have to be accounted in the dispatch of power plants and the routing of power flows. Increasing shares of RE typically cause larger differences between power supply and demand, higher inter-regional flow volumes and more physically restricted power flows. This typically leads to larger CM costs in systems with higher RE shares. In order to capture congestion in the electricity transmission network imposed by an ex-ante electricity market with uniform pricing, we apply a two-stage approach. We first obtain the dispatch of generation units from the market. Next, the market clearing is followed by redispatch and curtailment measures that are required to maintain stable grid operation (Figure 3.1) to account for physical capacity restrictions while balancing load and generation at all times. We assume that all capacities are given, and do not account for the risk of possible line breakdowns.

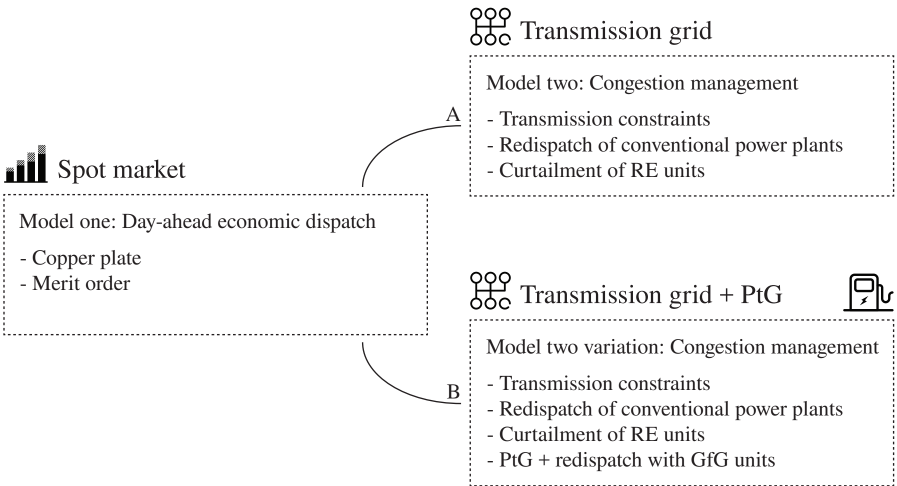


Figure 3.1: Overview of the problem stages. To the left, the day-ahead spot market for the Economic Dispatch. To the right the two considered Congestion Management variants.
Source: Own illustration.

For evaluating the contribution of PtG to CM, we analyse two variants in the CM stage, following the same first-stage day-ahead Economic Dispatch (ED). The benchmark variant (Figure 3.1, right upper part) reflects typical CM measures and technologies, including producing more or less with dispatchable power plants and partially shutting off RE units. In a second variant (Figure 3.1, right lower part) in the CM stage we allow the usage of PtG as a technology by TSOs. We enable gas power plants to make use of the synthetic methane for electricity generation. Unused SNG can be stored.

3.1 Replicating the day-ahead spot market

The ED reflects the market-based, cost-minimal scheduling of generation units to meet exogenously given, inelastic demand. Scheduling for every available dispatchable power plant and RE technology (i.e., wind and solar PV) is determined by a merit order. The merit order is an established method in liberalised electricity markets to rank power plants according to their Marginal Cost (MC).

To capture the interactions of various technologies and resulting price formations during the day, we require a sufficiently high spatiotemporal model resolution. The output of each power plant is constrained by its capacity. Lower bounds, such as must-run obligations, are not considered. Decision variables include the power output of every generation unit and MP for each time step.

3.2 Managing congestion with redispatch

Based on the market results from the ED, the CM stage must reconcile, at minimal cost, the supply and demand loads with physical network constraints by adjusting production volumes and power flows. CM decides which conventional generation units are required to ramp up or down, and which RE units to curtail. Within the CM stage, the objective is to minimise the system-wide congestion mitigation costs over all periods, i.e., payments to producers associated with producing more and compensation payments for producing less as well as curtailment. Power plants, that in a period must increase their output in comparison to their ED commitment are reimbursed by their marginal generation cost. In case of an output decrease, the power plant is compensated by its lost profits, i.e., the difference of the MP minus its marginal generation cost in that period. Adjustment of production of dispatchable power plants is limited by unit specific maximum ramping parameters and remaining available capacity.

While restrictions of the ED must still hold in the CM model, the CM model includes physical limitations of the transmission grid. As explained in chapter 4.1, most parts of the transmission grid transmit three-phase Alternating Current (AC) power, which yield non-convex constraints. Following a well-established approach, we linearise AC power flows using a Direct Current (DC) power flow approximation. Thus, in the CM stage, decisions are determined by the transmission network and capacity, voltage angles and reactances.

3.3 Integrating Power-to-Gas as flexibility option

In the second variant, we consider PtG as a demand-side flexibility option in CM. PtG units can only use electricity from RE units to produce SNG, which is then available for electricity generation by GfG units. Additional decisions in CM Variant Two include how much electricity is converted to SNG. Electricity generation from SNG by GfG units is therefore added to the objective function and constraints of the CM model. Instead of curtailing RE units, the CM model has the option to create SNG. Energy stored in the new energy carrier, i.e., SNG can be transported through the gas system to GfG units. GfG units can use the SNG in the CM stage to generate electricity instead of higher production of other dispatchable power plants, if this leads to lower overall CM cost. The power output of GfG units is restricted by their capacity, of which some may have been dispatched in the ED. For an evaluation of PtG from the regulatory perspective, we explore current definitions and possible conceptions of PtG within the legal framework. We determine how PtG can be utilised in a market environment and whether a TSO is allowed to possess or operate PtG units in liberalised electricity markets. Considering the current market design of ancillary services, we address obstacles within the regulatory framework and evaluate whether CM based on PtG could be provided by TSOs.

Chapter 4

Technical background

In this chapter, we provide the technical background that our research is built on. First, we present the fundamentals of Power System Analysis (PSA) based on Glover et al. (2017) in Section 4.1. As solving AC power flow is a non-linear problem, we use the DC power flow method to incorporate linearised power flow constraints in our CM model. Secondly, we review state-of-the-art PtG technologies in Section 4.2, including electrolysis and methanation. We briefly present the underlying chemical reactions and system efficiences. Finally, we discuss and conclude on the suitability of different processes for the purpose of providing flexibility in redispatch.

4.1 Transmission system

Within the scope of this research and this section, the term PSA refers to *electric* power systems, including generation, load, and the transmission grid. A PSA is usually performed for the design and planning or the operation of power systems. For an adequate representation of power flow distribution in the CM model, we need to incorporate the physical properties of transmission lines.

4.1.1 Power system analysis

Apparent power. Today, most of the electricity generated is transported through three-phase High Voltage (HV) transmission lines, as AC. In AC power systems, the complex, apparent power $\underline{S}$ is defined as

$$\underline{S} = P + jQ = \underline{V} \cdot \underline{I}^* \tag{4.1}$$

where the real component P is active power and the imaginary part Q is reactive power, $\underline{V}$ is the complex voltage and $\underline{I}^*$ the conjugate of the complex current.

Components of a power system Usually, a power system consists of *nodes* (n, n), *lines* (subset of nodal pairs), generation, and load units. At a node n, a voltage magnitude $|V_n|$ and angle Θ_n can be measured (or calculated). The key parameter of a power line $l \in (n, m)$ in PSA is its impedance $\underline{Z}$, a physical property primarily determined by material choice, temperature, and length.

$$\underline{Z} = R + jX \tag{4.2}$$

where R represents the resistance and X the reactance. Due to the inverse relationship between power flow and impedance, the complex impedance $\underline{Y}$ is commonly used. Being the reciprocal of the impedance, it can be written as

$$\underline{Y} = \frac{1}{\underline{Z}} = \frac{1}{R + jX} = G + jB \tag{4.3}$$

where G denotes the conductance and B the susceptance. As the name suggests, admittance is a measure of how easily a current and hence, power can flow when a voltage is applied.

Nodal admittance matrix In power flow calculations, the admittance for all lines connecting two nodes is collected in the symmetric $\underline{Y}_{bus}$ matrix. The (nodal) admittance matrix $\underline{Y}_{bus}$ relates the complex current $\underline{I}$ and complex voltage $\underline{V}$ by

$$\underline{I} = \underline{Y}_{bus} \cdot \underline{V} \tag{4.4}$$

Nodal power injection Intuitively, it makes sense to regard generation as positive and load as negative values. Then, nodal *injection* can be defined as the net difference of generation and load. By regarding injection at a node n, as depicted in Fig. 4.1, we derive the equations for nodal power injections.

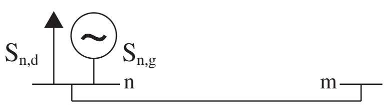


Figure 4.1: Nodal power injection setup
Source: Own illustration.

Connected to node n are a generation unit $\underline{S}_{n,g}$, load $\underline{S}_{n,d}$ and a transmission line to its adjacent node m. Note, that a line between n and m is modelled as a π-equivalent circuit. Hence, the net injection $\underline{S}_n$ at node n can be written as

$$\underline{S}_n = \underline{S}_{n,g} - \underline{S}_{n,d} = \underline{V}_n \cdot \underline{I}_n^* \tag{4.5}$$

For an injection at node n, we take a look at the entries $\underline{y}_{n,m}$ in the n-th row of the nodal admittance matrix (4.4) and obtain

$$\underline{I}_n = \sum_m \underline{y}_{n,m} \cdot \underline{V}_m \tag{4.6}$$

Inserting Eq. (4.6) to Eq. (4.5) yields

$$\underline{S}_n = \underline{V}_n \cdot \underline{I}_n^* \tag{4.7}$$

$$= \underline{V}_n \Big(\sum_m \underline{y}_{n,m} \cdot \underline{V}_m \Big)^* = \underline{V}_n \sum_m \underline{y}_{n,m}^* \cdot \underline{V}_m^* \tag{4.8}$$

Using the definitions

$$\underline{V_n} = |V_n| \angle \Theta_n = |V_n| e^{j\Theta_n} \tag{4.9}$$

$$\Theta_{n,m} = \Theta_n - \Theta_m \tag{4.10}$$

$$\underline{y}_{n,m} = g_{n,m} + jb_{n,m} \tag{4.11}$$

we can rewrite Eq. (4.8) to obtain

$$\underline{S}_n = \underline{V}_n \sum_m \underline{y}_{n,m}^* \cdot \underline{V}_m^* \tag{4.12}$$

$$= \sum_m |V_n||V_m| \Big[\cos(\Theta_{n,m}) + j \sin(\Theta_{n,m}) \Big] (g_{n,m} - jb_{n,m}) \tag{4.13}$$

For examining power injection, the driving state variables are the nodal voltage magnitude V_n or V_m and its affiliated nodal voltage angle Θ_n and Θ_m, respectively. Voltage magnitude and relative voltage angle differences $(\Theta_n - \Theta_m)$ determine active and reactive power injection at node n. By decomposing Eq. (4.13) into its real and imaginary component, we obtain for active and real power

$$P_n = \sum_m |V_n||V_m| \Big[g_{n,m} \cos(\Theta_n - \Theta_m) + b_{n,m} \sin(\Theta_n - \Theta_m) \Big] \tag{4.14}$$

$$Q_n = \sum_m |V_n||V_m| \Big[g_{n,m} \sin(\Theta_n - \Theta_m) - b_{n,m} \cos(\Theta_n - \Theta_m) \Big] \tag{4.15}$$

where $g_{n,m}$ is the conductance and $b_{n,m}$ is the susceptance.

Per unit system. In PSA, the per unit (pu) system is commonly used to scale all available parameters and units to a defined reference base power. This allows for easier calculations and comparisons between values. All power flow calculations within our model are conducted in per unit and scaled back to units of MW for evaluation and analyses. We chose a base power of $\underline{S}_{base} = 100\,\mathrm{MVA}$.

4.1.2 Linearisation using DC power flow

As Eq. (4.14) and (4.15) are non-linear, simplifying assumptions are required to perform linear Optimal Power Flow (OPF) calculations. In large-scale power networks, we can make the following assumptions (Kirschen and Strbac, 2004, 186).

1. The resistance of transmission lines is significantly lower then its reactance. For $R \to 0$, we obtain for Eq. (4.3),

$$\underline{Y} = \frac{R - jX}{R - jX} \frac{1}{R + jX} = \frac{R - jX}{R^2 + X^2} \overset{R \to 0}{=} -j\frac{1}{X} \tag{4.16}$$

   and hence, for every entry (denoted in lowercase) one the admittance matrix,

$$g = 0 \text{ and } b = -\frac{1}{x} \tag{4.17}$$

2. The magnitude of voltage at a bus is close to its nominal value (flat voltage profile),

$$|V_n| \approx 1 \text{ p.u.} \tag{4.18}$$

3. Consequently, the difference between voltage angles at the buses n and m, connected by a transmission line is small and can be approximated with,

$$\cos(\Theta_n - \Theta_m) \approx 1 \tag{4.19}$$

$$\sin(\Theta_n - \Theta_m) \approx \Theta_n - \Theta_m \tag{4.20}$$

Applying Eq. (4.17), (4.18), (4.19), and (4.20) to the power flow Eq. (4.14) and (4.15), we get,

$$P_n = \sum_{m=1} b_{n,m}(\Theta_n - \Theta_m) \tag{4.21}$$

$$Q_n = -\sum_{m=1} b_{n,m} \tag{4.22}$$

In Eq. (4.22), the only parameter, i.e., the susceptance, is given. Under the three above assumptions, the reactive power flow Q_n is thus known at all times. Only the active power flow P_n and voltage angle in Eq. (4.21), need to be calculated.

4.2 Power-to-Gas

The technology PtG can be split into two separate steps: the production of hydrogen (H_2) and methane (CH_4) using hydrogen. In this chapter, we elaborate on technical solutions for these two steps to identify i) which technology is suited best for providing flexibility and ii) which characteristics should be considered in our analysis. We do not address the supply and extraction of carbon dioxide (CO_2) needed for methane production.

4.2.1 Electrolysis

Hydrogen is obtained by splitting water into oxygen and hydrogen using electricity. The chemical reaction is called electrolysis (Vandewalle et al., 2015). Different types of electrolysers are available. Although they all follow the same principle, their structure and system architecture varies. In an electrolyser, cathode and anode are separated by an electrolyte medium. The electrolyte can be both liquid or solid (Zapf, 2017b). To split water, a cell potential of 1.23V is needed between the electrodes. Electrolysis is an equilibrium reaction which can be formulated as (Chi and Yu, 2018):

$$\text{Sum:} \qquad \mathrm{H_2O} \rightarrow \mathrm{H_2} + \frac{1}{2}\,\mathrm{O_2} \tag{4.23}$$

$$\text{Cathode:} \qquad \mathrm{H_2O} + 2\,\mathrm{e^-} \rightarrow \mathrm{H_2} + \mathrm{O^{2-}} \tag{4.24}$$

$$\text{Anode:} \qquad \mathrm{O^{2-}} \rightarrow \frac{1}{2}\,\mathrm{O_2} + 2\,\mathrm{e^-} \tag{4.25}$$

The reaction is endotherm, meaning that it absorbs surrounding heat. Three major electrolysers are common in the literature:

- Alkaline Water Electrolysis (AEL)
- Polymer Electrolyte Membrane (PEM)
- Solid Oxide Electrolyte Electrolysis (SOEC)

Alkaline Water Electrolysis (AEL) AEL is the most mature method. It uses a liquid electrolyte (potassium hydroxid, KOH) between two electrodes, which consist out of nickel or nickel plated steel (Chi and Yu, 2018). For upscaling, single cells are combined (stacked). Typical sizes range from 30 to 200 cells, making AEL suitable for large hydrogen production in the scale of Megawatts (MW). AEL has a system efficiency of 64 to 74 % (Lehner et al., 2014; Zapf, 2017b). System efficiency is defined as the ratio of energy output, i.e the heating value of the H_2, divided by the overall energy input, which is in this case electricity. Other efficiency rates exist for electrolysis, e.g voltage efficiency or current efficiency. For the purpose of our paper, system efficiency is most appropriate which we further denote as η^{E} (Lehner et al., 2014). Although AEL is mature and well established in industrial production of H_2, its usage in the PtG chain needs to be analysed. For the purpose of using surplus RE, flexibility in the operation of the electrolysis is of significant importance. Therefore, dynamic operation is necessary. AEL can be operated between 20 to 100 % of its rated power (Götz et al., 2016; Lehner et al., 2014). Below 20 % a decrease of the H_2 purity can be observed. Further, this type of electrolysis has high start up times of 30 to 60 minutes (Götz et al., 2016).

Polymer Electrolyte Membrane (PEM) One promising alternative to the AEL is PEM. In contrast to AEL, it can operate between 0 to $100\,\%$ load without decreasing H_2 purity (Table 4.1). Additionally, it can react fast on power fluctuations and has suitable start up and shutdown times (Zapf, 2017b). Instead of a liquid electrolyte, PEM consist of a solid membrane, which sits between two layers, acting as electrodes. This construction is called "membrane electrode assembly" and allows compact structures (Lehner et al., 2014). Stacks of around 60 single cells are common, yet not reaching the production capacity of AEL due to smaller membrane areas. PEM is in contrast to AEL still in research but shows promising features for PtG applications. Current designs have a system efficiency of 60 to 76 $\%$ (Quarton and Samsatli, 2018). Disadvantages lie in economic perspectives. PEM requires expensive materials and shows a high system complexity (Lehner et al., 2014). It also lacks in durability and therefore has not been used in large scale applications (Barbir, 2005).

Solid Oxide Electrolyte Electrolysis (SOEC) Most recently developed is the third option, namely (SOEC), also known as high temperature electrolysis. SOEC operates in temperature rates of 700-1000°C, which is almost ten times higher than both AEL and PEM (Salomone et al., 2019). The high temperature is beneficial for the energy consumption as a result in a reduction of the required voltage by 0.1 V. It therefore increases system efficiency to more than $90\,\%$ including the energy for elevated temperature (Lehner et al., 2014). But because of the high temperature, it is not suitable for input power fluctuations. The design is similar to PEM (Vandewalle et al., 2015). It consist of a ceramic based solid electrolyte between cathode (Nickel based) and anode (oxide based). So far, SOEC is still in an laboratory stage (Zapf, 2017b). Improvement in durability and material stability against the high temperatures are currently focus of research. in recent results, the Helmeth project has shwon promising results, by coupling SOEC with a methantion process and using excess heat of the latter process step (Gruber et al., 2018). Apart from that, SOEC shows the highest improvement rates of all three discussed techniques and is therefore also relevant for future considerations (Salomone et al., 2019; Prabhakaran et al., 2019; Chi and Yu, 2018).

Electrolysis and flexibility As discussed above, most common technologies chosen for electrolysis are AEL and PEM. Although SOEC can reach higher efficiency rates of more than $80\,\%$ it is still in laboratory stage (Zapf, 2017b). Both AEL and PEM are able to increase power input within seconds. Some electrolysis project have been used for secondary control reserve which requires ramping-up to a prequalified level (at least one MW) in under five minutes (Kopp et al., 2017). In terms of flexibility and application at control reserve markets, the PEM technology seems most advantageous for the purpose of providing flexibility, as it can also operate in lower capacity level (Kuprat et al., 2017). While AEL needs to run at minimum loads of around 20-40 $\%$ (Schiebahn et al., 2015), PEM is able be operated at less than $10\,\%$ (Schiebahn et al., 2015; Milanzi et al., 2018). We summarise the technical parameters in Table 4.1

Table 4.1: Overview of electrolysis parameters

Source	Electrolysis	Efficiency (%)	Ramping (%/s)	Min. input (%)
Thema et al. (2019)	n.a.	70	n.a.	n.a.
Milanzi et al. (2018)	AEL	74	33	20-40
	PEM	67	10	0-10
	SOEC	82	n.a.	n.a.
Quarton and Samsatli (2018)	AEL	73	n.a.	n.a.
	PEM	76	n.a.	n.a.
	SOEC	≥ 80	n.a.	n.a.
Götz et al. (2016)	AEL	70	n.a.	n.a.
	PEM	70	n.a.	n.a.
Schiebahn et al. (2015)	AEL	67	10	20-40
	PEM	67	10-100	5-10
Lehner et al. (2014)	AEL	60-80	n.a.	20-30
	PEM	60-70	100	0-10
	SOEC	≥ 90	n.a.	n.a.
Sterner et al. (2011)	n.a.	64-77	n.a.	n.a.

Source: Own illustration.

We conclude the analysis of the electrolysis in Table 4.2, summarising the main features and their benefits for PtG. We see that except for PEM all electrolyser lack flexibility when it comes to power input. On the other hand, flexibility comes with high system cost. Also, large scale empirical values are only available for AEL. By now, PEM is most suitable for usage in the PtG chain. Literature also reveal that PEM is most common used for PtG solutions (see Quarton and Samsatli, 2018).

Table 4.2: Comparison of electrolysis technologies

	Benefits	**Drawbacks**	**PtG utilisation**
AEL	• Low-cost materials • High empirical values • High durability	• Lack of flexibility in power input • High start up and shut down times	• Good for steady H_2 production • Not compatible with fluctuating energy input
PEM	• High flexibility • Good operational level adjustment • Solid system architecture	• Not economical feasible on large scale • Durability insufficient • Lack of scaling	• Fluctuating energy input possible • Not available in large scale implementation
SOEC	• High system efficiency • Shows best improvement rates	• High Degradation of material • Still in laboratory stage	• Currently not available for industrial use • Not suitable for power fluctuations

Source: Own illustration.

4.2.2 Methanation

The second step in the PtG chain is the production of methane (CH_4). On the input side of methanation are H_2 and CO_2. Different reactions occur in the process of methanation, such as the Sabatier-reaction (with CO (4.26) and CO_2 (4.27)), shift-conversion (4.28), and, as unwanted side reaction, the Boudard-equilibrium (4.29) (Younas et al., 2016).

$$\mathrm{CO} + 3\,\mathrm{H_2} \leftrightarrow \mathrm{CH_4} + \mathrm{H_2O} \tag{4.26}$$

$$\mathrm{CO_2} + 4\,\mathrm{H_2} \leftrightarrow \mathrm{CH_4} + \mathrm{H_2O} \tag{4.27}$$

$$\mathrm{CO_2} + \mathrm{H_2} \leftrightarrow \mathrm{CO} + \mathrm{H_2O} \tag{4.28}$$

$$\mathrm{CO_2} + \mathrm{C} \leftrightarrow 2\,\mathrm{CO} \tag{4.29}$$

Methanation is a highly exothermic reaction i.e., heat is released. Thereby, steam is often a byproduct. The efficiency and the economic viability depend on the utilization of not only the CH_4, but also of its byproducts. Efficiency rates of more than $90\,\%$ is possible (less than $83\,\%$ without heat utilization (Zapf, 2017b). In general, methanation can be classified in catalytic and biological methanation. For each branch, several different approaches are available.

Biological methanation Biological methanation relies on methanogenic bacteria of the Archaea family. Based on the used bacteria, the reaction is called acetoclastic methanogenesis (4.30) or hydrogenotrophic methanogenesis (4.31) (Zapf, 2017b)

$$\mathrm{CH_3COOH} \leftrightarrow \mathrm{CH_4} + \mathrm{CO_2} \tag{4.30}$$

$$\mathrm{CO_2} + 4\,\mathrm{H_2} \leftrightarrow \mathrm{CH_4} + \mathrm{CO_2} \tag{4.31}$$

Hydrogen is used in biological methanation as co-substrate together with biological sludge. Instead of thermal limitation, as we will see in catalytic methanation, the main limiting factor is the mass transport of the Hydrogen, or the supply of H_2 to the bacteria in the liquid sludge (Götz et al., 2016). H_2 is hardly solvable in aqueous solutions. Both biological methanation types are used in small scale plants. Due to the low production rate of methane, it is inadequate for large scale usage and therefore not qualified for our purposes in the PtG chain (Younas et al., 2016). Hence, we focus on catalytic methanation.

Catalytic methanation Catalytic methanation differs based on the used reactor type. The reactors mainly have different strategies to cope with the energy of the exothermic Sabatier-reaction. Over time, different approaches have been developed. The oldest, developed in 1902, is the adiabatic methanation with a fixed bed reactor. The catalyst, which is normally based on nickel, is fixed in one place (Götz et al., 2016). It is randomly placed in form of pellets, creating a bed, which gaseous educts need to pass. Based on the catalyst, different reactions can occur. By using nickel in combination with the educts H_2 and CO, the Sabatier-reaction takes place. If the H_2 concentration is high enough, also CO_2 is part of the equilibrium reaction (Rönsch and Ortwein, 2011). Nickel is also capable of executing the shift-reaction in case pressure and temperature is well adjusted. Although this step is normally performed in a previous step (Rönsch and Ortwein, 2011). In general, every metal in group VIII of the periodic system can be used for methanation. Nickel is used due to availability and cost factors. In order to control the temperature, the reactions are chained in single process steps split by coupled reactors with cooling of the gas stream in between. The number of steps can vary based on the fixed bed reactor type. These types of reactors are also used commercially (Lehner et al., 2014). In contrast to solid catalyst, the fluidized bed reactor provides the solid catalyst in an liquid environment. Because of the movement, the reaction is not adiabatic, yet almost isothermal. The heat is absorbed by a heat absorber (e.g., thermo oil), causing a more controlled temperature regulation of the process (Götz et al., 2016). Fluidized bed reactors can therefore belong to two-phase (gaseous educt and solid catalyst) or three-phase reactors (gaseous educt, solid catalyst and liquid heat absorber). The three-phase type is also known as Bubble columns (Younas et al., 2016). Further review of methanation processes (Table 4.3) shows the advantage of catalytic methanation with efficiency higher than $80\,\%$. Being an exothermic reaction, the theoretical maximum efficicency is $83\,\%$ (Salomone et al., 2019; Schiebahn et al., 2015). Total efficiencies of more than $83\,\%$ can only be achieved by utilising the remaining $17\,\%$ energy loss in the form of heat.

Table 4.3: Overview of methanation parameters

Source	**Methanation**	**Efficiency** (%)	**Ramping** (%/s)	**Min. input** (%)
Salomone et al. (2019)	catalytic	83	n.a.	n.a.
Boudellal (2018)	n.a. n.a.	≥ 80 93	n.a. n.a.	n.a. n.a.
Schmidt et al. (2018)	catalytic	70-85	n.a.	n.a.
Milanzi et al. (2018)	cath. & biological	80** 78*	n.a. n.a.	0.25 n.a.
Götz et al. (2016)	catalytic	78	n.a.	0.1-0.4
Schiebahn et al. (2015)	catalytic	83	n.a.	n.a.

* Literature median
** Project median

Source: Own illustration.

Methanation and flexibility Drawbacks on methanation applications for PtG are similiar to the disadvantages in most hydrogen technologies, namely the lack of flexibility. For methanation methods at large scale, such as fixed bed reactors, the temperature control, mass transfer and ramping times under flexibility seem to be the limiting factor. Minimum load for catalytic methanation is at around 20-40 % (Zapf, 2017a). Below 20 %, SNG purity is not high enough and a high energy input is required, as temperatures for reactions needs to be above 700 °C (Zapf, 2017a). Ramping for methanation are usually provided for running or standby units and not for cold starts. Different designs of reactors are in focus of ongoing research to control heat and educt input more independently, such as honeycomb and monolith structure designs (Younas et al., 2016). Further, the gas quality needs to be high enough in order to inject the output into the gas grid. In Germany, the gas quality requirements for biomethane can be found in DIN EN 16723-1, which also includes SNG. Note that the norm is currently being revised (DVGW, 2019).

4.2.3 From theory to modelling

The end of this section invites to a discussion about how to model a PtG unit. Handling electricity as input parameter to PtG is crucial to modelling the technology and evaluating its flexibility. Next to water, electricity is the primary input parameter of electrolysis. Hence we argue that the flexibility of electrolysis is the driving factor in determining the overall flexibility of a PtG unit. Regarding technological flexibility of electrolysis, that is ramping time and minimum load requirements, our overview in Table 4.1 shows that the PEM technology is more suitable to react to intermittent changes in electricity input. Further, the total flexibility of PtG can be increased by decoupling the “dynamic behaviour" (Gorre et al., 2020) of electrolysis and methanation using storage capacity for hydrogen.

A storage tank does not only increase flexibility but also overall efficiency, as methanation is able to run on a more stable, continuous basis. In order to achieve high efficiency and sufficient SNG purity, only catalytic methanation seems appropriate. A catalytic methanation also allows to increase overall efficiency by utilising process heat e.g., to keep standby temperatures for a longer period of time. From a technological perspective, a minimum load for methanation and hence a minimum SNG production is required to adequately represent the technology standard. However, for our modelling approach, the potential of PtG in redispatch may be seen as the mathematical difference between minimum output and overall SNG production. As such, neglecting minimum load may simplify the model without large effects on the accuracy of the results. We summarise our key take-aways for our model implementation of PtG in Figure 4.2.

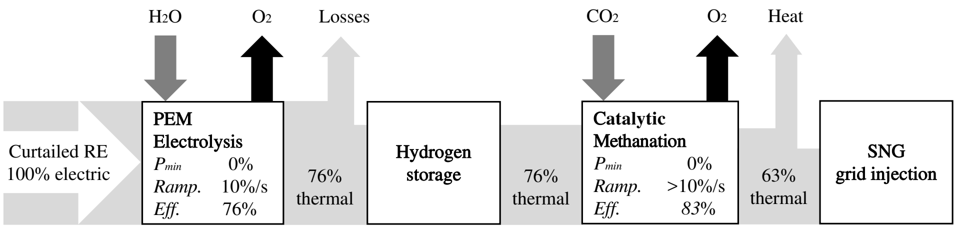


Figure 4.2: Sankey diagram on PtG assumptions
Source: Own illustration.

Chapter 5

Model framework

We implement a two-stage LP model, consisting of a DA market optimisation and a CM model including transmission constraints. To model the decoupled procedure of the ED and CM, we propose sequential market clearing, followed by hourly redispatch at a limited foresight of 24 hours. This structure reflects the DA spot market and current cost-based redispatch mechanism in Germany. Sequencing allows us to analyse longer periods day by day in a rolling horizon fashion. A schematic overview is presented in Figure 5.1. The short vertical arrows represent the individual 24 hours of a day in which are considered in the CM model.

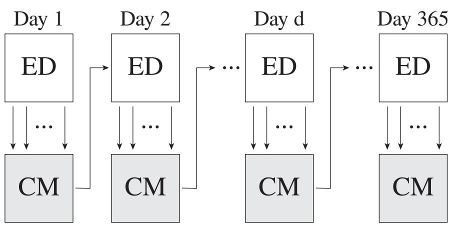


Figure 5.1: Schematic overview on sequential model runs including Economic Dispatch (ED) and Congestion Management (CM)
Source: Own illustration.

5.1 Model assumptions

With the aim of this paper to assess the potential of PtG in redispatch, we make some assumptions to maintain a balance between technical accuracy, computational complexity, and result quality. In the following we briefly present and explain our model assumptions.

Ramping The ramp rate describes a thermal power plant's ability to increase and decrease output per time (e.g., in MW/min). For rotating generation units (coal, nuclear, hydro, etc.) ramp-rates range from $2\,\%$ to $15\,\%$ per minute of their maximum output (Gonzalez-Salazar et al., 2018). As such, with an hourly modelling resolution, this would translate into possible ramp rates of $100\,\%$ per hour, making a ramping constraint non-binding. At an hourly level, we can hence neglect ramping constraints. This does not impact the model results but reduces the number of constraints by $2 * \mathcal{G} * (8760 - 1)$ and thus calculation complexity. Note that including ramping in models with quarter-hourly or minute resolutions significantly impacts the model outcome.

No commercial cross-border exchange Including historic cross-border exchange time series as a fixed parameter to the model directly translates into an increase in load in times of export and a decrease in times of import (Eq. 5.2). As such, an electricity export would yield an increased MP. However in reality, if electricity is exported from a country A to country B in a particular hour, a lower zonal MP in country A than in country B is indicated. For this reason we do not include historic cross-border trade. Alternatively, modelling the market and subsequent redispatch for Germany and all neighbouring countries would require larger data sets and computational times which are beyond the technical and contextual scope of this paper. As such, to be able to narrow down the potential impact of PtG and to keep computational times within acceptable limits, we only determine the Economic Dispatch (ED) and Congestion Management (CM) on a national level. We point out that by neglecting cross-border exchange, congestion that may be induced or alleviated through trade on interconnectors are not represented.

Virtual SNG storage To keep track of the amount of SNG in the gas grid (i.e., produced but not used yet), we assume the presence of a single virtual SNG storage. All PtG units can inject into the storage and all GfG units can withdraw SNG. In future research, this assumption may be substituted by modelling the gas grid.

5.2 Mathematical formulation

Using linear programming, we formulate the objective function, as well as market and technical constraints of our model. We include a list of our model terminology, including sets, variables, and parameters to explain our objective function and constraints. Variables are displayed in uppercase italic, while parameters are written in lowercase roman.

5.2.1 Model terminology

Sets Sets are denoted by scripted, uppercase letters and contain a finite number of indices used in the mathematical model.

$\mathcal{N}$	Set of nodes: n, m
$\mathcal{G}$	Set of all power plants: g
$\mathcal{R}$	Subset of $\mathcal{G}$, RE units: r
$\mathcal{E}$	Subset of $\mathcal{G}$, GfG units: e
$\mathcal{S}$	Set of PHS: s
$\mathcal{L}$	Set of transmission lines: $l \in (n, m)$
$\mathcal{T}$	Set of time slices in hours: t

Variables Variables are represented by uppercase letters and are endogenously optimised by the model. They can span over multiple sets.

Ψ_t	Market Clearing Price (MP) in €/MWh$_{\mathrm{el}}$
$P^{DA}_{g,t}$	Generated power on the spot market (day-ahead) in MW$_{\mathrm{el}}$
$P^{DA}_{s,t}$	Generated power from PHS on the spot market (day-ahead) in MW$_{\mathrm{el}}$
$P^{inj}_{n,t}$	Power injection at node n in MW$_{\mathrm{el}}$
$\Delta P^{+}_{g,t}$	Upwards adjustment of the spot market generation in MW$_{\mathrm{el}}$
$\Delta P^{-}_{g,t}$	Downwards adjustment of the spot market generation in MW$_{\mathrm{el}}$
$\Delta P^{+}_{s,t}$	Upwards adjustment of the spot market generation from PHS in MW$_{\mathrm{el}}$
$P^{lost}_{n,t}$	Lost load at node n in MW$_{\mathrm{el}}$
$P^{flow}_{n,m,t}$	Line flow from n to m in MW$_{\mathrm{el}}$
$\Theta_{n,t}$	Voltage angle at node n and m in rad
$P^{PtG}_{e,t}$	Generated power using SNG in MW$_{\mathrm{el}}$
$D_{s,t}$	Demand of PHS unit in MW$_{\mathrm{el}}$
$D^{PtG}_{r,t}$	Demand of PtG facility in at the location of r in MW$_{\mathrm{el}}$
$L_{s,t}$	Storage level of PHS unit in MWh$_{\mathrm{el}}$
L_t	Virtual SNG storage level in MWh$_{\mathrm{th}}$

Parameters Parameters are denoted by lowercase letters and are exogenously determined by input data. Their dimension can span over multiple sets. To link the two model parts and transfer the model output of the first parts to the second, we use *auxiliary parameters*. Results for variables in the DA model that are used as fixed input (parameters) for the CM model are depicted with an $\overline{\text{overline}}$.

$\mathrm{b}_{n,m}$	Susceptance entry (n, m)
$\mathrm{c}_g^{\mathrm{mc}}$	Marginal cost of power plant in €/$\mathrm{MWh_{el}}$
$\mathrm{c}_g^{\mathrm{mc,PtG}}$	Marginal cost of power plant in €/$\mathrm{MWh_{el}}$ using SNG
$\mathrm{c}^{\mathrm{fuel}}$	Fuel cost in €/$\mathrm{MWh_{el}}$
$\mathrm{c}_g^{\mathrm{OM}}$	Operation and maintenance cost in €/$\mathrm{MWh_{el}}$
$\mathrm{c}^{\mathrm{CO_2}}$	CO_2 price in €/tCO_2
$\mathrm{c}^{\mathrm{VOLL}}$	Value of lost load in €/$\mathrm{MWh_{el}}$
$\mathrm{d}_{n,t}^{\mathrm{load}}$	Load in $\mathrm{MW_{el}}$
$\mathrm{d}_r^{\mathrm{max}}$	Maximum PtG output/electricity demand in $\mathrm{MW_{el}}$
η_g	Efficiency of power plant in $\mathrm{MW_{el}}/\mathrm{MW_{th}}$
η_s	Pumping efficiency of PHS unit
η^{E}	Efficiency factor of electrolysis in $\mathrm{MW_{th}}/\mathrm{MW_{el}}$
η^{M}	Efficiency factor of methanation in $\mathrm{MW_{th}}/\mathrm{MW_{th}}$
$\mathrm{l}^{\mathrm{init}}$	Initial storage level of the virtual SNG storage in $\mathrm{MWh_{th}}$
λ_g	CO_2 factor of power plant in $tCO_2/\mathrm{MWh_{th}}$
$\mathrm{p}_g^{\mathrm{max}}$	Maximum power generation limit in $\mathrm{MW_{el}}$
$\mathrm{p}_g^{\mathrm{min}}$	Minimum power generation limit in $\mathrm{MW_{el}}$
$\mathrm{p}_s^{\mathrm{max}}$	Maximum power generation and pumping limit of a PHS unit in $\mathrm{MW_{el}}$
$\mathrm{p}_l^{\mathrm{max}}$	Line capacity in $\mathrm{MW_{el}}$
x_l	Line reactance in $\mathrm{MW_{el}}$
$\mathrm{l}_s^{\mathrm{max}}$	Storage capacity of PHS unit in $\mathrm{MWh_{el}}$
trm	Transmission Reliability Margin (TRM) between 0 and 1

5.2.2 Day-ahead economic dispatch

The Economic Dispatch (ED) model minimises total system costs for generation while considering MC, market clearing, and PHS constraints. Given the uniform pricing of the ED in Germany, the market assumes a single copper plate, i.e., physical transmission line constraints are neglected in the bidding process. From this optimisation step, we obtain total system costs and a cost-minimal dispatch for all generation units. We deliberately exclude binary variables, such as unit commitment, to obtain the market price as the dual to the market clearing constraint (Eq. 5.2).

Objective function The objective function (Eq. 5.1) minimises total generation costs summed up over all technologies and the total, 24 hour, time horizon.

$$\min_{P_{g,t}^{DA}} \sum_t \sum_g \mathrm{c}_g^{\mathrm{mc}} P_{g,t}^{DA} \tag{5.1}$$

Market clearing The market clearing constraint (Eq. 5.2) ensures that demand is satisfied by the generation units at all times.

$$\sum_g P_{g,t}^{DA} - \sum_n \mathrm{d}_{n,t}^{\mathrm{load}} = 0 \quad , t \in \mathcal{T} \tag{5.2}$$

Power generation A generation unit can only operate within a certain range (Eq. 5.3). The output of a generation unit is lower-bound by must-run obligations and upper-bound by its installed capacity.

$$\mathrm{p}_g^{\min} \leq P_{g,t}^{DA} \leq \mathrm{p}_g^{\max} \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{5.3}$$

PHS A Pumped Hydroelectric Storage (PHS) is defined by its maximum pumping (Eq. 5.4), generating power (Eq. 5.5) and storage capacity (Eq. 5.6). Its storage level can never exceed the maximum capacity and is calculated based on the previous storage level, plus electricity demand and minus generation of the previous period (Eq. 5.7).

$$D_{s,t} \leq \mathrm{p}_s^{\max} \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.4}$$

$$P_{s,t}^{DA} \leq \mathrm{p}_s^{\max} \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.5}$$

$$L_{s,t} \leq \mathrm{l}_s^{\max} \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.6}$$

$$L_{s,t} = L_{s,t-1} - P_{s,t-1}^{DA} + \eta^{\mathrm{s}} D_{s,t-1} \quad , s \in \mathcal{S}, t \in \mathcal{T} : t > 1 \tag{5.7}$$

Non negativity Eq. 5.8 ensures that the power output, PHS pumping and storage level can never be negative.

$$P_{g,t}^{DA} \geq 0 \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{5.8}$$

$$P_{s,t}^{DA} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.9}$$

$$D_{s,t}^{DA} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.10}$$

$$L_{s,t}^{DA} \geq 0 \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.11}$$

5.2.3 Congestion management

Following a previous formulation by Kunz and Zerrahn (2016), we implement a Congestion Management (CM) model which includes DC power flow grid constraints and decisions based on the market results, i.e., the Market Clearing Price (MP) and dispatch for each hour. In this modelling step, we calculate a system-wide cost minimal redispatch, i.e., upwards and downwards adjustments of dispatchable power plants and curtailment of RE units, required to meet the physical constraints of the transmission grid.

Objective function The CM model minimises the total cost for redispatch and feed-in management (Eq. 5.12). Following the formulation by Kunz (2011, 7) and based on current remuneration schemes (bdew, 2018; Connect, 2018) redispatch is profit-neutral:

Power plants that increase their output to their previous bid are reimbursed by their MC. At the same time, an output decrease of a power plant is compensated by its lost profit, i.e., the difference of the MP at a time t minus its Marginal Cost (MC). We include additional costs for an increase of output by Pumped Hydroelectric Storage (PHS) accounting for efficiency losses. In addition, we include costs for lost load.

$$\begin{aligned}\min_{\Delta P^+_{g,t},\Delta P^-_{g,t}} \sum_t \sum_n \Bigg[\sum_g \left(\mathrm{c}^{\mathrm{mc}}_g \Delta P^+_{g,t} + (\overline{\Psi}_t - \mathrm{c}^{\mathrm{mc}}_g) \Delta P^-_{g,t} \right) \\ + \sum_s \frac{\overline{\Psi}_t}{\eta^{\mathrm{s}}} \Delta P^+_{s,t} + \mathrm{c}^{\mathrm{VOLL}} P^{lost}_{n,t} \Bigg]\end{aligned} \tag{5.12}$$

In the CM model, we use variables $P'_{g,t}$ to denote the composition of the day-ahead dispatch, plus upwards and downwards power adjustments in the CM model (Eq. 5.13).

$$P'_{g,t} = \overline{P}^{DA}_{g,t} + \Delta P^+_{g,t} - \Delta P^-_{g,t} \tag{5.13}$$

Nodal balance and power injection The market clearing constraint from the ED now has to hold at each node (Eq. 5.14). Power injection at a node n is defined as the net difference between all connected generation (positive) and load (negative). Using the susceptance entry on the admittance matrix, the voltage angles are linked to the nodal injection (Eq. 5.15).

$$\sum_g P'_{g,t} - \mathrm{d}^{\mathrm{load}}_{n,t} = P^{inj}_{n,t} \quad , n \in \mathcal{N}, t \in \mathcal{T} \tag{5.14}$$

$$\begin{aligned}\sum_m b_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{inj}_{n,t} \\ , n \in \mathcal{N}, t \in \mathcal{T}\end{aligned} \tag{5.15}$$

Line power flow Using the line reactance and voltage angles at the from-node n and to-node m, we calculate the power flow on a transmission line (Eq. 5.16). The line flow must not exceed its thermal capacity limit including the Transmission Reliability Margin (TRM) at all times (Eq. 5.17 and 5.18). The parameter trm is a value between 0 and 1. This constraint holds true in both flow directions.

$$\begin{aligned}x^{-1}_{n,m}(\Theta_{n,t} - \Theta_{m,t}) = P^{flow}_{n,m,t} \\ , n, m \in \mathcal{N} : n \neq m, t \in \mathcal{T}\end{aligned} \tag{5.16}$$

$$P^{\mathrm{flow}}_{l,t} \leq p^{\max}_l (1 - \mathrm{trm}) \quad , l \in \mathcal{L}, t \in \mathcal{T} \tag{5.17}$$

$$-\left[p^{\max}_l (1 - \mathrm{trm})\right] \leq P^{\mathrm{flow}}_{l,t} \quad , l \in \mathcal{L}, t \in \mathcal{T} \tag{5.18}$$

Power generation Without the use of binary variables, we can avoid a power plant being adjusted both upwards and downwards at the same time step by adjusting the constraint for power generation limits.

$$\overline{P}_{g,t}^{DA} + \Delta P_{g,t}^{+} \leq \mathrm{p}_g^{\max} \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{5.19}$$

$$\mathrm{p}_g^{\min} \leq \overline{P}_{g,t}^{DA} - \Delta P_{g,t}^{-} \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{5.20}$$

$$P_{s,t}^{DA} + \Delta P_{s,t}^{+} \leq \mathrm{p}_s^{\max} \quad , s \in \mathcal{S}, t \in \mathcal{T} \tag{5.21}$$

Non negativity Non-negativity constraints (Eq. 5.22) also apply here, with $\overline{P}_{g,t}^{DA}$ being replaced by $P'_{g,t}$.

$$P'_{g,t} \geq 0 \quad , g \in \mathcal{G}, t \in \mathcal{T} \tag{5.22}$$

5.2.4 Power-to-Gas extension

We extend the CM model from Section 5.2.3 with Power-to-Gas (PtG) facilities at all nodes where RE units feed into the grid. To be able to track how much SNG is available in the system and used, we introduce an additional power generation variable $P_{e,t}^{PtG}$ for all GfG units.

Objective function Fuel costs for PtG units occur when electricity is used to generate SNG. As such, the MP has to be paid, accounting for efficiency losses during electrolysis and methanation. To use SNG to generate electricity, the variable Operation and Maintenance (O&M) costs of GfG units are accounted for (Eq. 5.23).

$$\begin{aligned} \min_{\Delta P_{g,t}^{+}, \Delta P_{g,t}^{-}, E_{g,t}} \sum_{t} \sum_{n} \Bigg[& \sum_{g} \left(\mathrm{c}_g^{\mathrm{mc}} \Delta P_{g,t}^{+} + (\overline{\Psi}_t - \mathrm{c}_g^{\mathrm{mc}}) \Delta P_{g,t}^{-} \right) \\ + \sum_{s} \frac{\overline{\Psi}_t}{\eta^{\mathrm{s}}} \Delta P_{s,t}^{+} + \mathrm{c}^{\mathrm{VOLL}} P_{n,t}^{lost} + & \sum_{r} \frac{\overline{\Psi}_t}{\eta^{\mathrm{E}} \eta^{\mathrm{M}}} D_{r,t}^{PtG} + \sum_{r} \mathrm{c}_e^{\mathrm{OM}} P_{e,t}^{PtG} \Bigg] \end{aligned} \tag{5.23}$$

Power to gas capacity As an alternative to RE curtailment, PtG facilities can use the electricity. PtG facilities can only make use of remaining available output (volume of curtailment) of a solar PV or wind generation unit (Eq. 5.24) or its capacity limit (Eq. 5.25).

$$P'_{r,t} - D_{r,t}^{PtG} \leq \mathrm{p}_r^{\max} \quad , r \in \mathcal{R}, t \in \mathcal{T} \tag{5.24}$$

$$D_{r,t}^{PtG} \leq \mathrm{d}_r^{\max} \quad , r \in \mathcal{R}, t \in \mathcal{T} \tag{5.25}$$

SNG storage level Efficiency rates from electrolysis and methanation are accounted for in the demand for electricity from the PtG unit. The storage level (Eq. 5.26) is determined by the level at the end of the previous period, subtracted by what is withdrawn for power generation, plus the SNG produced by PtG units. With (Eq. 5.27), the initial storage level in period 1 of the gas grid is set. At the beginning of the first modelling day, the storage level is set to zero.

$$L_t = L_{t-1} - \sum_e \frac{1}{\eta_e} P^{PtG}_{e,t-1} + \eta^{\mathrm{E}}\,\eta^{\mathrm{M}} \sum_r D^{PtG}_{r,t-1} \quad , t \in \mathcal{T} : t > 1 \tag{5.26}$$

$$L_1 = \mathrm{l}^{\mathrm{init}} \tag{5.27}$$

Gas-fired Generation As an alternative to using natural gas as input fuel, GfG units use SNG. However, SNG can only be used as long as it is available in the virtual storage (Eq. 5.28), accounting for the individual thermal efficiency of GfG units.

$$\sum_e \frac{1}{\eta_e} P^{PtG}_{e,t} \leq L_t \quad , t \in \mathcal{T} \tag{5.28}$$

Nodal balance and power injection The nodal power injection constraint needs to be adjusted to incorporate the electricity demand by PtG units and re-electrification of SNG in GfG units.

$$\sum_g P'_{g,t} + \sum_e P^{PtG}_{e,t} - \mathrm{p}_d - \sum_r D^{PtG}_{r,t} = P^{inj}_{n,t} \quad , n \in \mathcal{N}, t \in \mathcal{T} \tag{5.29}$$

Relations between the ED and CM (Eq. 5.13), as well as nodal angles (Eq. 5.15), line power flow constraints (Eq. 5.16, 5.17, and 5.18), remain unchanged.

Power generation For conventional, non-GfG units and RE units, the constraints for generation limits stay the same (Eq. 5.19 and 5.20) . For GfG units, the sum of power generation from fossil and SNG must not exceed its capacity limit (Eq. 5.30).

$$\begin{gathered} \overline{P}^{DA}_{g,t} + \Delta P^{+}_{g,t} + P^{PtG}_{e,t} \leq \mathrm{p}^{\max}_e \\ , e \in \mathcal{E} :, t \in \mathcal{T} \end{gathered} \tag{5.30}$$

Non negativity In addition to Eq. 5.22, the electricity demand from PtG units (Eq. 5.31) and generation from SNG can never be negative (Eq. 5.32).

$$D^{PtG}_{r,t} \geq 0 \quad , r \in \mathcal{R}, t \in \mathcal{T} \tag{5.31}$$

$$P^{PtG}_{e,t} \geq 0 \quad , e \in E, t \in \mathcal{T} \tag{5.32}$$

5.3 Implementation and software toolbox

We implement our Linear Program (LP) in the open-source language Julia (v.1.3.1), using the Julia for Mathematical Programming (JuMP) package. In addition, we have built an entire data evaluation toolchain in R (v.4.0.0) using ggplot2 and leaflet that allows us to visualise model results. We solve our problem using the TU Berlin high-performance math cluster.

Chapter 6

Spatial flexibility in redispatch: Supporting low carbon energy systems with Power-to-Gas

To assess the potential of PtG in large-scale, liberalised electricity systems, we apply our formulated model framework from Chapter 5 to Germany. In Section 6.1 we first introduce the underlying data set that we use for answering our research questions. We then present and discuss the valuable model results and insights in Section 6.2.[1] Further, we provide additional in-depth analyses in Section 6.4 that we have conducted after submitting the paper.

6.1 Data

We use an open access reference data set (version 1.0.0), which covers the entire German electricity, heat, and natural gas sector as of late 2015 (Kunz et al., 2017b). For the purpose of performing an economic dispatch and subsequent redispatch, we extract data on electric load, installed capacities of conventional and RE generation units, transmission line capacities, resistance, and reactance, prepared by Weibezahn and Kendziorski (2019). In the following paragraphs, we provide a brief overview on the used data. To obtain more detailed insights on how the geospatial data was collected, we refer to the data documentation by Kunz et al. (2017a).

[1]The results of this Chapter are part of the journal article submission to Applied Energy.

6.1.1 Overview

Transmission grid The data set includes 724 AC transmission lines. (Table 6.1).

Table 6.1: Overview of transmission lines

Voltage kV	Circuits #	Thermal Capacity MW	Lines #
220	Single	490	228
220	Double	490	129
220	Triple	490	2
380	Single	1700, 2300	244
380	Double	1700, 2300	118
380	Triple	1700	3

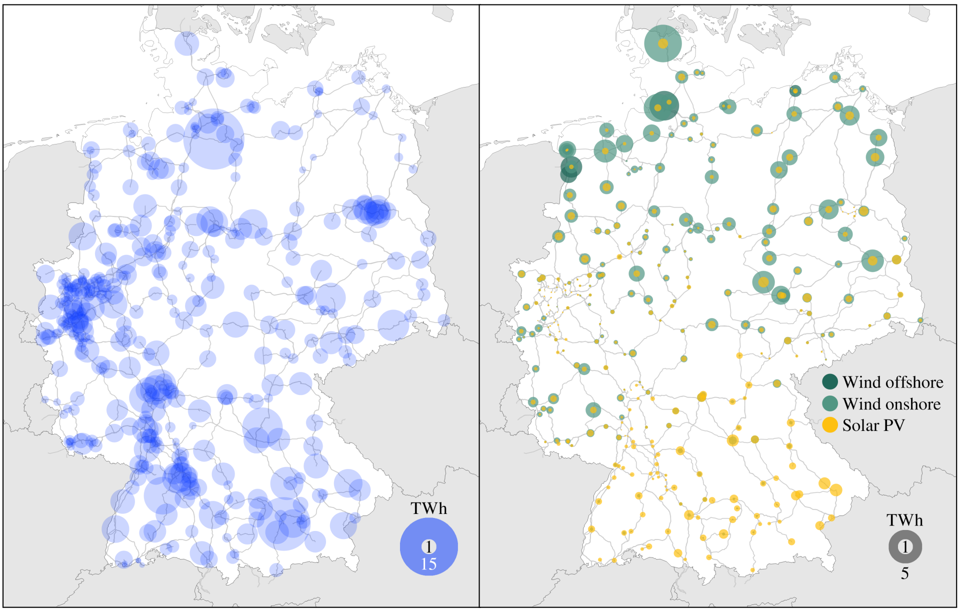
Source: Own illustration based on Kunz et al. (2017b).

Table 6.2: Installed capacity and availability

Fuel	**Installed capacity (GW)**	**Average availability**
Wind onshore	41.2	0.190
Wind offshore	3.3	0.259
Solar PV	39.3	0.096
Biomass	8.1	0.575
RoR	3.7	0.532
PHS	8.8	–
Geothermal	0.03	0.310
Natural gas	23.6	0.800
Nuclear	12.1	0.823
Lignite	20.9	0.774
Hard coal	28.6	0.720
Oil (light)	3.1	0.800
Oil (heavy)	0.6	0.800
Waste	1.6	0.700
Other fuels	2.5	0.530

Source: Own illustration based on Kunz et al. (2017b).

Generation The data set includes 613 individual thermal power plants and 33 PHS units, mapped to nodes. RE generation units are aggregated at nodal level. As of the end of 2015, the installed capacity of generation units in Germany totaled 197.4 GW, of which 93 GW are accounted by conventional thermal power plants, 20.6 GW by flexible RE power plants



(a) Load

(b) Maximum electricity generation by intermittent RE

Figure 6.1: Spatial distribution of load and intermittent RE
Source: Own illustration based on Kunz et al. (2017b).

(biomass, Hydro Run-of-River (RoR), PHS, and geothermal) and 83.8 GW by intermittent RE generation units, such as wind and solar PV (Table 6.2). The generation of wind onshore, offshore, and solar PV is calculated using weather infeed data at hourly resolution (Kunz et al., 2017a). A geospatial distribution of RE generation infeed is presented in Figure 6.1.

Load The total annual load of 540.339 TWh is distributed across 427 national nodes at hourly resolution (Figure 6.1a). Load centers are located in large metropolitan areas and the southwestern region of Germany.

Merit order Marginal generation costs (Eq. 6.1) are calculated based on power plant efficiency, fuel costs, variable O&M costs and emission factors (Table B.2). A CO_2 price of 7.59 €/t is used for the year 2015 (Kunz et al., 2017a).

$$c_g^{mc} = \frac{c^{fuel} + c^{CO_2}\lambda_g}{\eta_g} + c_g^{OM} \quad , g \in \mathcal{G} \tag{6.1}$$

Based on the installed capacities of RE units and conventional power plants of 2015 (Table 6.2) (Kunz et al., 2017a), this yields the following merit order (Figure 6.2).

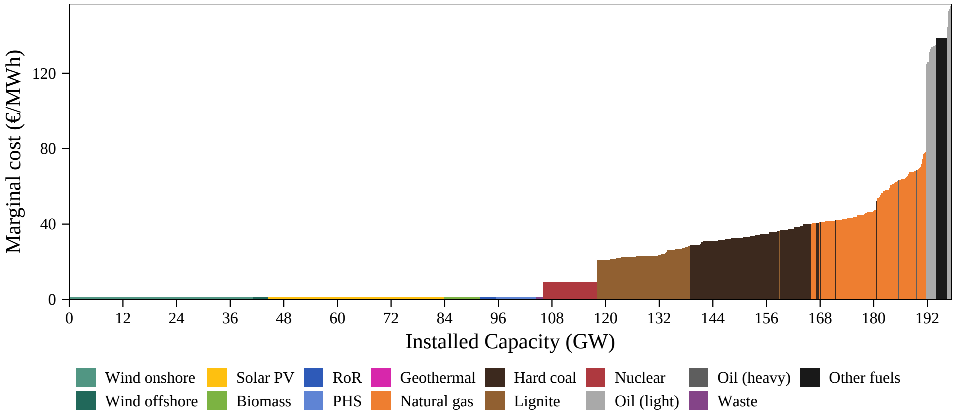


Figure 6.2: ED merit order
Source: Own illustration based on Kunz et al. (2017a).

6.1.2 Data assumptions

In the following, we briefly present our assumptions within and beyond the data set we have used.

Must-run While we have technically formulated must-run in the model, minimum generation obligations in the data set are not considered, i.e., $\mathrm{p}_g^{\min} = 0$. While some studies endogenously approximate must-run obligations from combined heat and power plants based on heat demand, these methods require additional modelling (Beran et al., 2019). In addition, the implementation of must-run generation is equivalent in reducing the remaining dispatch for endogenous optimisation. As such the merit order (Figure 6.2) is shifted to the right, and by obtaining the MP from the dual to the market clearing condition, this yields a lower price. Meanwhile, must-run capacities are remunerated through individual, long-term contracts which we cannot replicate in the model. We further deliberately do not assume a flat fuel- or technology-specific must-run share (Gonzalez-Salazar et al., 2018) for two reasons: i) This overestimates the redispatch volume required as basically all thermal generations might be redispatched to satisfy both must-run and transmission constraints; ii) By including must-run, in some hours, a share of RE is curtailed in the ED already. Under these circumstances, more renewable electricity is available which may lead to an over-estimation of PtG. We point out that due to a lack of must-run obligations, which primarily concerns GfG units, our model underestimates the share of natural gas in the dispatch, given its position in the merit order (Figure 6.5).

Availability of power plants To adequately represent power plant outages, as well as scheduled and unscheduled shutdowns, we use fuel-specific, monthly availability factors provided by Kunz et al. (2017a). Further calibration to historic data (BNetzA, 2016) is done by scaling down nuclear power plant availability.

Pumped Hydroelectric Storage (PHS) Incorporating PHS and assessing a water value is a challenging topic on its own. As a direct result of cost-minimisation problems, there is no incentive to leave a PHS remaining storage level, i.e., the PHS storage level at the end of a modelling period is zero if not explicitly defined otherwise. To represent PHS in redispatch measures, we make the simplifed assumption, that $80\,\%$ of the of the maximum PHS storage capacity is available for economic dispatch and $20\,\%$ for redispatch. We point out that this assumption can definitely be further improved. The German online grid transparency platform (50Hertz, 2016) provides data on redispatch volume by utility. In the case of PHS, data for the largest PHS utility is aggregated with RoR. Due to limited data available on the cost of electricity that PHS utilities have to pay, we further assume that an increase generation output in the redispatch is remunerated by the MP, incorporating efficiency losses, given that the utility had to pay for its electricity demand from the market.

Transmission Reliability Margin To account for planned and unplanned line outages, we follow Weibezahn and Kendziorski (2019) and apply a Transmission Reliability Margin (TRM) of $25\,\%$ (effectively a reduction of the thermal line capacity, see Eq. 5.17 and 5.18).

Power-to-Gas and costs In the CM model, PtG is primarily defined by the efficiency of electrolysis η^{E} and methanation process η^{M}. Based on state-of-the-art data of both components (Tables 4.1 and 4.3), we assume an efficiency of $\eta^{\mathrm{E}} = 76\,\%$ and $83\,\%$, yielding a total PtG efficiency of $63\,\%$. Given an average efficiency of $\eta_e = 49\,\%$ for GfG units, electricity generation using SNG yields a total average round-trip efficiency of $30.1\,\%$. Operational costs for PtG are defined by two factors, i.e., the MP and carbon neutrality. As no system-wide remuneration schemes for PtG exist to-date, we assume an indiscriminatory market, meaning that electricity demanded by PtG units is to be paid with the MP. We point out that this assumptions results in a rather conservative competitiveness of the technology. This is in parts compensated by the re-electrification of SNG through GfG units: While the MC for utilising natural gas in GfG units includes a CO_2 price per emitted ton, we assume SNG to be a carbon neutral fuel, as it is only generated from renewable wind and solar PV infeed. As such, for using SNG in GfG units, no costs for CO_2 emissions occur.

6.2 Results

First, we briefly present the DA market results from the ED. We then assess the required redispatch accounting for transmission constraints with the CM model. In a final step, we compare the results of the model run where we implement PtG as a technology for providing flexibility in redispatch.

6.2.1 Economic dispatch

The objective of ED is to find a cost-minimal solution for meeting the total demand for each day, which sums up to $540.3\,\mathrm{TWh}$ over the course of a year. As a copper plate is

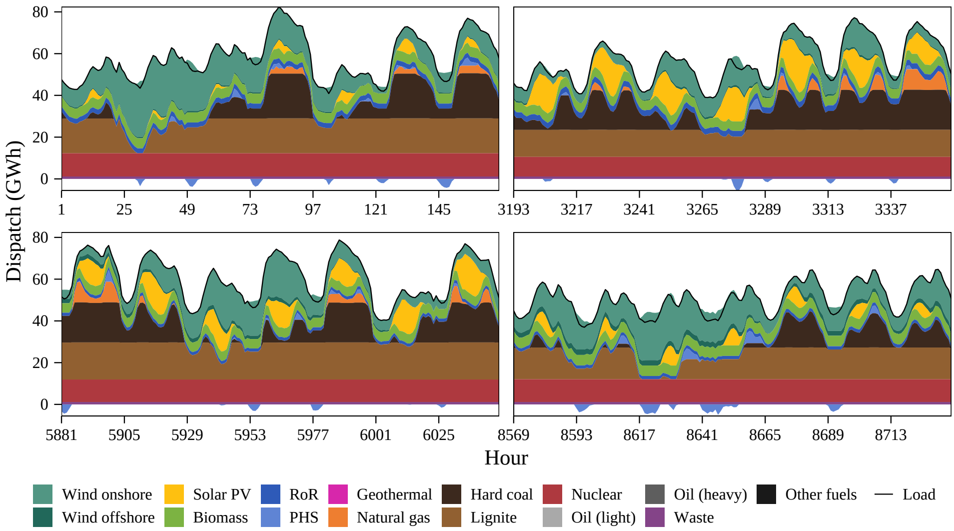


Figure 6.3: Exemplary ED weeks for every quarter of the year
Source: Own illustration.

assumed at stage, electricity generation follows load, including demand by PHS. Figure 6.3 illustrates four exemplary dispatch weeks at hourly resolution. After the intermittent RE generation, nuclear and lignite, being the most cost-efficient technologies, provide a stable generation at all times and mostly operate at maximum capacity. This base load follows their position in the merit order (Figure 6.2). Generation by intermittent RE on the other hand is defined by solar PV and wind infeed, and shows higher variability throughout the year. Seasonal patterns can be observed, as renewable generation in winter periods is dominated by wind on- and offshore (top left and bottom right, Figure 6.3), while the summer shows a higher share of solar PV (top right and bottom left, Figure 6.3). As we have no must-run obligations in the data set which might cause curtailment of surplus RE, all available RE generation is dispatched in the market. In times of high RE infeed and low demand, a low MP can be observed and vice versa (Figures A.1 to A.4, Appendix) Demand Peaks and high fluctuations in RE infeed cause GfG units to be dispatched. Further peak shaving is provided by PHS. Storing electricity using PHS occurs in periods with low market prices[2]. Note that electricity demand by PHS is displayed on the negative Y-axis. Although prices are lower in times of high RE infeed, higher fluctuations in prices occur. Comparing average prices in winter and summer, both the average and median price during winter (mean 36.6 €/MWh) are 2 % lower (Figure 6.4) than in summer (mean 37.4 €/MWh).

[2]For a representation of the full model year including MP, we refer to Figures A.1 to A.4 in the Appendix. A geospatial distribution of generation by dispatchable power plants is provided with Figure A.9.

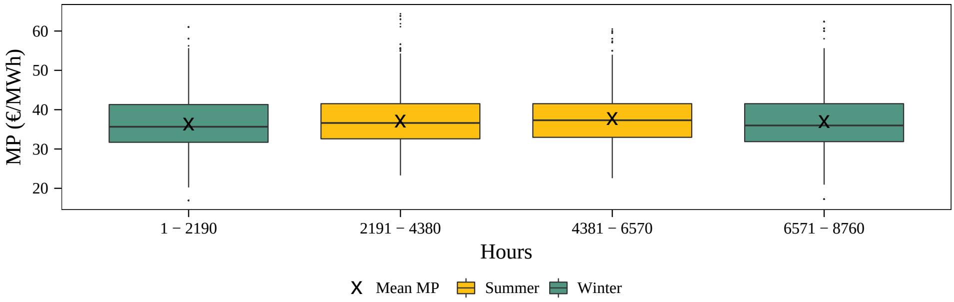


Figure 6.4: Seasonal market clearing price spread
Source: Own illustration.

High wind infeed during winter times cause fluctuations in the price and a larger spread of the 50th percentile MP (31.7-41.5 €/MWh in winter vs. 32.6-41.5 €/MWh in summer, see Figure 6.4). Storages can benefit from price changes, as it is possible to store energy at lower prices and inject stored energy in times of higher prices. This is also confirmed by the behaviour of PHS.

Comparison Comparing our endogenous dispatch results to historical data provided by BNetzA (2016) gives us an insight to the accuracy of the model. In Figure 6.5, we visualise the share of different generation technologies by BNetzA (2016) (left), from our ED model (centre) and after redispatch (right). It should be noted, that the BNetzA (2016) data shows generation composition in retrospect, assumingly incorporating after-market corrections. As such, we primarily compare the first and last plot in Figure 6.5. The gap is due to omitting cross-border exchange in our model and accounts for Germany's net export surplus of about 51 TWh in 2015 (BNetzA, 2016). We obtain high accuracy at both nuclear and lignite as well as PV and wind (both on and offshore). Further differences in the share of conventional technologies are related to the lack of must-run obligations.

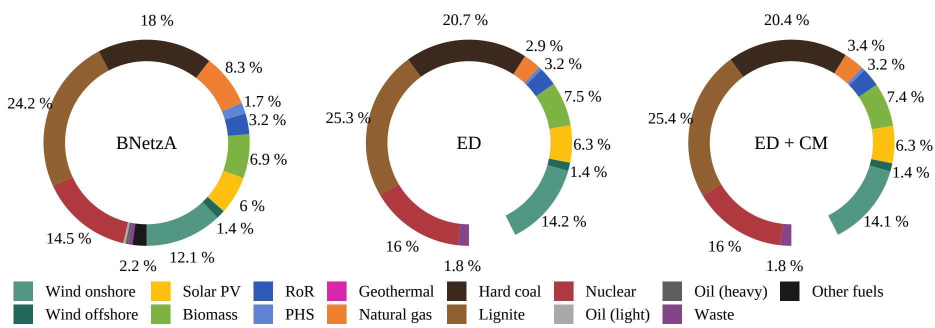


Figure 6.5: Generation mix 2015. Historic data by BNetzA (2016) (left), ED market results (center), and after CM (right).
Source: Own illustration.

Given the high MC of GfG units, the high share of 8.3 % can be traced back to must-run primarily of CHP plants. Oil-based electricity generation, with a percentage of less than 1 % at historical data, is hardly ever used in our model, being by far the most expensive option (Figure 6.2). The generation share of PHS in our model is 0.6 % only, four times lower as BNetzA (2016). This is mainly a result of limited foresight in our model, as we do not include an incentive for "left-over" PHS storage levels at the end of a day. Overall we consider the model outputs representative for the real situation in 2015 and an adequate basis for further analysis.

6.2.2 Congestion management and Power-to-Gas utilisation

Under consideration of DC power flow transmission constraints, our CM model determines the cost-minimal redispatch of generation units across the electricity system. To respect grid constraints, that is keep transmission flows within line capacity minus TRM, the TSO makes adjustments to the market results. Potential line congestions are alleviated by reducing power injection before and increasing power output behind the affected line[3]. The impact on the ED can especially be seen in a 0.5 percentage point higher share of GfG after redispatch (Figure 6.5 right plot). In Figure 6.6, displaying the aggregated redispatch

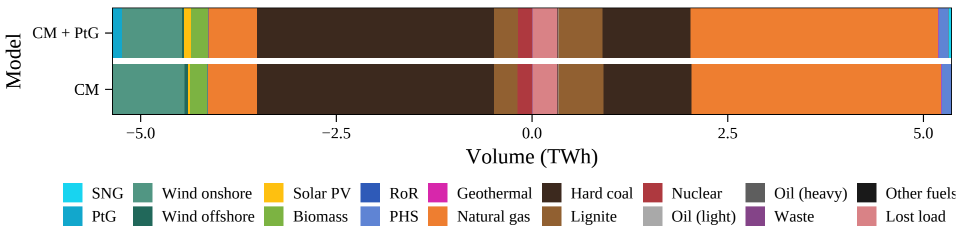


Figure 6.6: Aggregated redispatch volume over a year
Source: Own illustration.

volume over a year, a power increase is denoted positive, a reduction or curtailment of RE negative.[4] As the market has to be balanced on a nodal level, hourly upwards and downwards adjustments are symmetric in volume[5]. Given the imbalanced distribution of RE, especially wind onshore and offshore in the north, and load centres in the south, we observe a high share of wind curtailment. This is especially true during the winter, with higher seasonal wind infeed. Redispatch measures in winter account for 70 % of the total annual redispatch volume. Hard coal, being the cheaper option in the merit order (Figure 6.2, is dispatched in the market but reduced in the redispatch model in favour of natural gas. In times of curtailment and redispatch peaks, PHS are adjusted upwards, accounting for 2.6 % of the total upward adjustments.

[3]We provide a spatial visualisation of line utilisation after CM in Figure A.10 in the Appendix
[4]We include a full-year representation at daily aggregation with Figures A.5 to A.8 in the Appendix
[5]Note that a total share of 3.08 % of the total redispatch volume of 10.7 TWh is attributed to lost load. 87 % of all lost load in the model is due to node 272 (Stuttgart-Weilimdorf), for which the transmission capacity of a single-circuit 220 kV line (thermal capacity of 490 MW, TRM not included) is insufficient to meet nodal load. In our case, lost load is hence mostly attributed to discrepancies between nodal load distributions assumed in the data set (Kunz et al., 2017a) and real life.

Spatial distribution of redispatch Fig. 6.7 shows the spatial distribution of positive (green) and negative (red) redispatch. Negative adjustments are mostly required in the northern regions with high wind infeed. Upwards adjustments occur from north to south on the western part of Germany.
Further redispatch measures can be observed in the north east of Germany. Interestingly, the course of redispatch measures from north to south follow the planned High Voltage Direct Current (HVDC) lines (project names “A-Nord" and “Ultranet") (50Hertz et al., 2019). Both are justified, among other reasons, by the transfer of surplus electricity from wind power parks in the North Sea (50Hertz et al., 2020). Our redispatch model accounts for $69\,\%$ of the documented $15.436\,\mathrm{TWh}$ (redispatch) (BNetzA, 2020; Hirth et al., 2019). The difference is the result of an applied TRM of $25\,\%$ as a simplified representation of (n-1), no must-run, and no cross-border exchange. Omitting the first two yields less required redispatch, as (n-1) and must-run are more binding constraints than our simplification. The effect of cross-border exchange is two-fold: Depending on the temporal simultaneity and geospatial location of congested elements, it can increase or reduce the total congestion volume. Excluding the value of lost load, the total redispatch cost found by our model is 279 M€, $68\,\%$ of the documented 412 M€ (BNetzA, 2020).

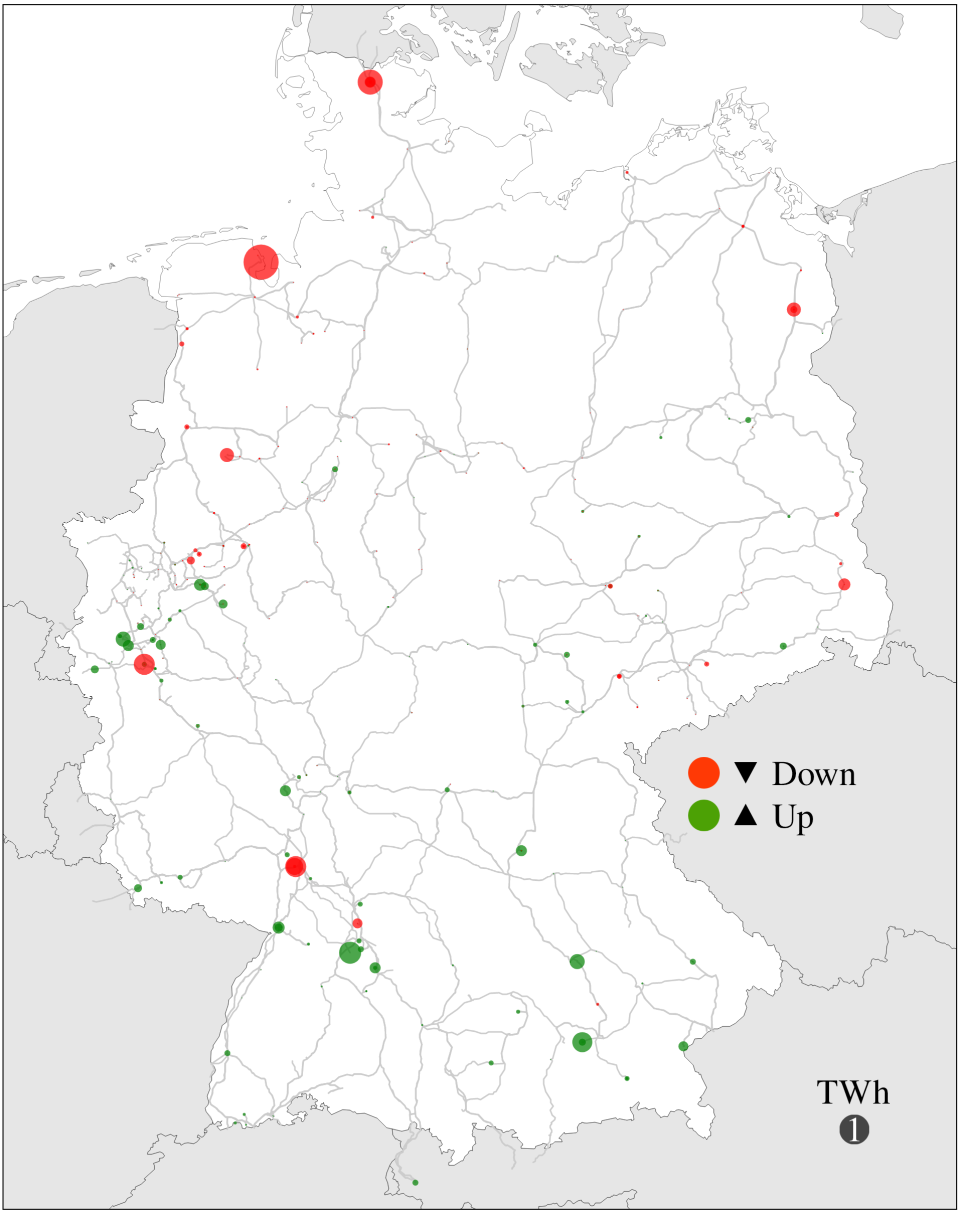


Figure 6.7: Redispatch: Up- and downwards adjustments over a year
Source: Own illustration.

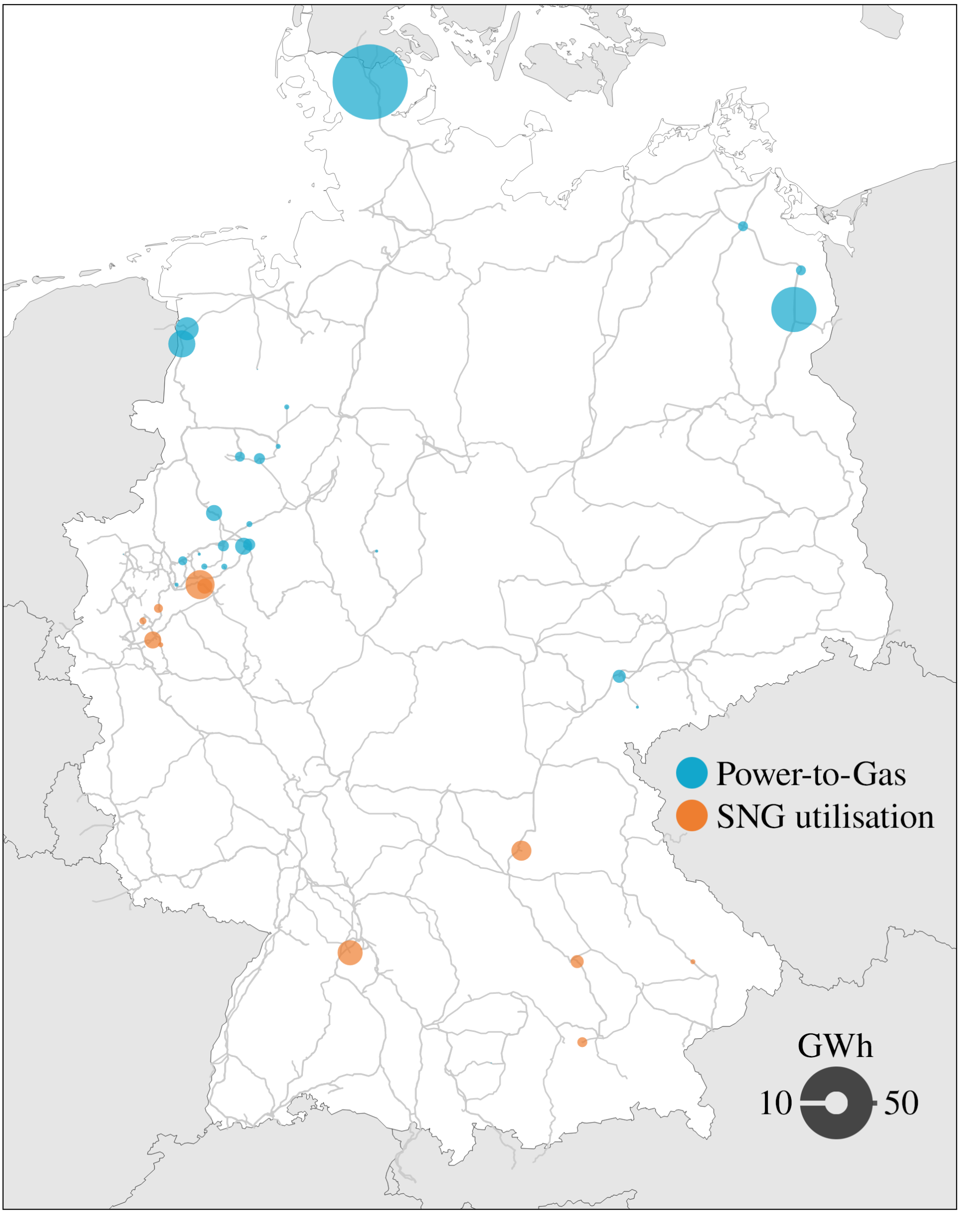


Figure 6.8: PtG and SNG utilisation over a year
Source: Own illustration.

Flexibility by PtG With the addition of PtG in the CM model, the TSO is able to use the previously curtailed electricity to generate SNG. SNG can then be used as a substitute for natural gas in upwards generation, shifting energy from the north to the south without increasing pressure on the electricity grid. This alternative is attractive at a sufficiently low MP, often the case in times of high RE infeed. Therefore SNG is produced especially in the winter time, when both wind availability and curtailment are high. Figure 6.9 and A.5 to A.8 in the Appendix illustrate this behaviour graphically. Our results show that in 173 hours of the year, it is feasible to make use of PtG, of which more than 80 % of PtG usage occurs during the winter. In 379 hours, SNG partially replaces natural gas in GfG units. Effectively, this leads to a total reduction in RE curtailment (negative redispatch) by 12.1 % and a substitution of natural gas for positive redispatch by 1.2 % (Figure 6.6).

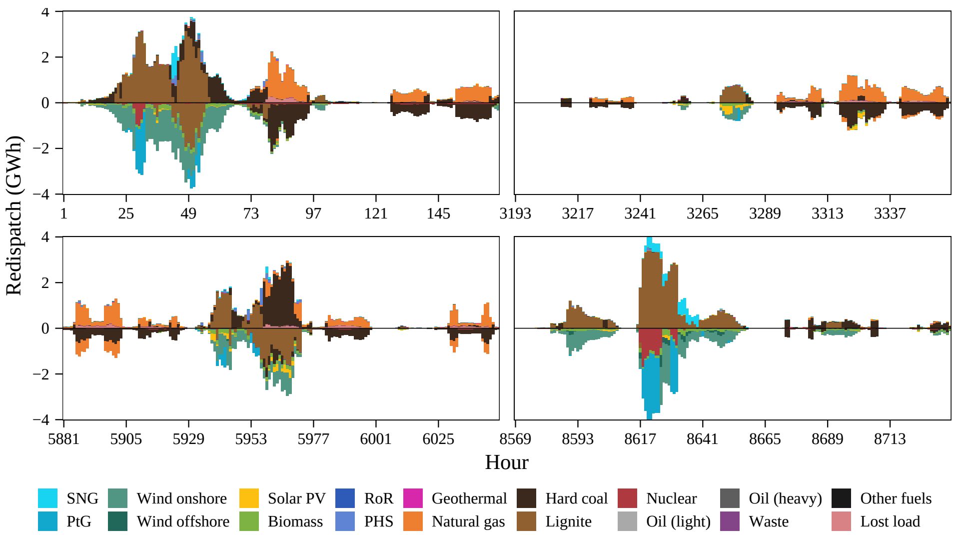


Figure 6.9: Exemplary redispatch weeks including PtG for every quarter of the year
Source: Own illustration.

Location of PtG units In Figure 6.8 we display all nodes where PtG is utilised and SNG re-electrified through GfG units. As the production of SNG is directly related to the volume of wind curtailment, the locations match nodes with high wind availability and redispatch volumes. We list the top five locations of PtG utilisation for providing flexibility in Table 6.3. Similarly, SNG is used in location where positive redispatch through GfG most cost-effective impact to mitigate line congestion. Interestingly, our research results are in very close proximity to two ongoing PtG projects. The first being “hybridge" (Amprion and Europe, 2019), a 100 MW electrolyser to be installed in Lingen, close to the Dutch border. It is a joint project by one of the German electricity TSO Amprion in cooperation with the gas TSO Open Grid Europe. The latter one is a cooperation between the German electricity TSO TenneT, gas TSOs Gasunie and Thyssengas at the estuary of the river Ems, connected to the substation in Diele (Table 6.3). “ElementEins" also consists of a 100 MW electrolyser and primarily aims at utilising wind offshore and onshore electricity (TenneT et al., 2018). Given their good connection to natural gas storages and access to biogenic CO_2, both projects are planned to also include a separate methanation unit. Further, the locations also overlap with optimal locations for PtG units determined by Haumaier et al. (2020). This indicates that these locations are not only of interest from a transmission-supporting, but also from an economic point of view for future PtG operators.

Table 6.3: Top five locations for PtG utilisation

Substation (Node)	Latitude (°)	Longitude (°)	Electricity demand (GWh_{el})
Flensburg	54.716	9.317	55.3
Bertikow	53.252	13.957	25.8
Diele	53.126	7.312	10.1
Rhede	53.026	7.254	8.0
Geithe	51.673	7.931	3.6

Source: Own illustration.

Cost savings through PtG From a system cost perspective, minimal cost savings through reduced upwards adjustments of more cost-intensive conventional power plants, can be achieved.

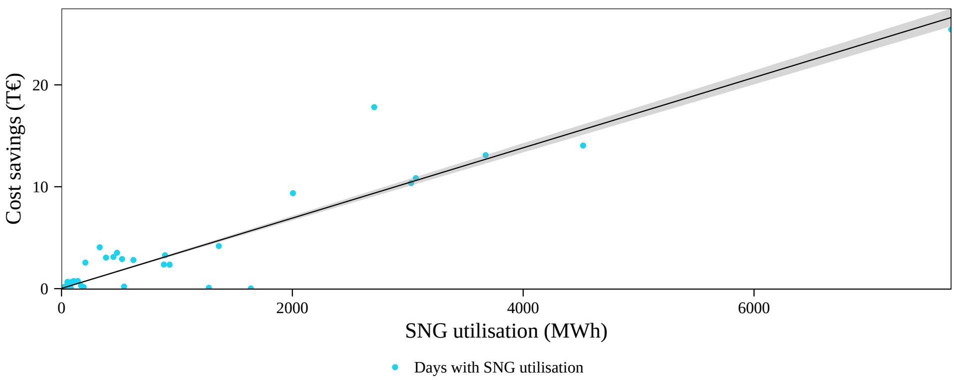


Figure 6.10: Linear regression: Cost savings to SNG utilisation relationship. The plot is based on N = 365 (8760 hours aggregated over days) data points from our model results. Black line represents the linear regression. Grey fill displays the confidence interval (95 %). The less data entries, the wider the interval.
Source: Own illustration.

Over the model horizon of a year, incorporating PtG reduces operational expenditures in redispatch by 0.05 % which translates into 140.5 T€. While this is a marginal amount of economic savings, we point out that these savings are only occurring in the 379 hours of SNG utilisation. There are no cost-savings directly related to RE curtailment, as we assume an indiscriminatory market, i.e., the PtG operator has to pay for the curtailed renewable electricity (Section 6.1). As such, a higher utilisation of SNG in GfG units yields more cost-savings. This is particularly interesting, if surplus RE electricity is available[6]. In Figure 6.10, the linear relationship between cost savings in T€ and SNG utilisation (MWh) can be observed. We calculate cost savings by subtracting the objective value of the CM model including PtG from the objective value of the CM model without PtG[7]. A higher share of SNG based electricity in redispatch yields more cost savings. At a confidence level of $95\,\%$, cost savings of effectively 3.4 € per utilised MWh_{el} of SNG utilisation can be achieved on average.

6.2.3 Sensitivity to variations in Power-to-Gas efficiencies

In our model we have used an efficiency rate of $76\,\%$ for electrolysis and $83\,\%$ for methanation. As our overview in Section 1 shows, efficiencies found in literature vary depending on different factors and underlying technologies. One of the main factors we have found is the utilisation of heat. Since the methanation process is an exothermic reaction, high quality steam is produced as byproduct. By using the produced process heat, a higher efficiency for methanation can be achieved. resulting in an increase of system efficiencies (Younas et al., 2016). We find that the used efficiency for PEM electrolysis is already at the high end of the spectrum.

Table 6.4: Sensitivity runs and parameter variations: Eletrolysis η_{E}, methanation η_{M}, and total η

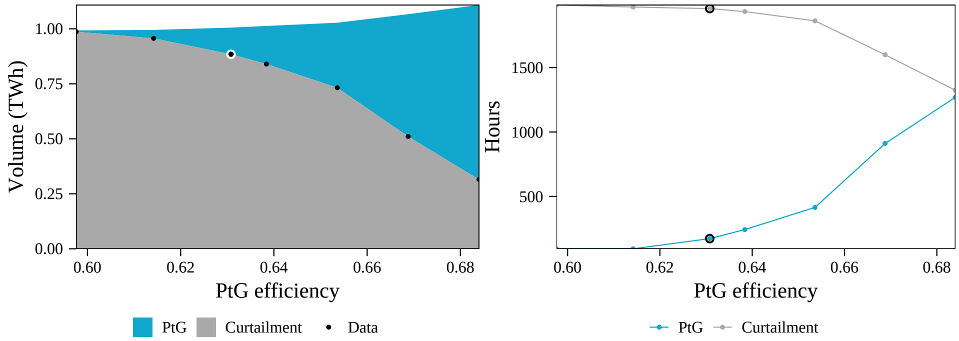
η_{E}	.72	.74	.76	.76	.76	.76	.76
η_{M}	.83	.83	.83	.84	.86	.88	.90
η	.60	.61	.63	.64	.65	.67	.68

Source: Own illustration.

Based on our PtG technology overview in Tables 4.1 and 4.3 we run sensitivities with decreased electrolysis and increased methanation efficiencies (Table 6.4). Our additional model runs show that the assessed potential of PtG is highly sensitive to changes in efficiency. Figures 6.11a and 6.11b display the relation between a marginal change in total PtG efficiency to the volume of PtG utilisation and RE curtailment based on the total volume and hours over the year.

As the costs for PtG are directly determined through the MP and efficiency losses (Eq. 5.23), an efficiency increase directly translates into a higher competitiveness of the technology. A total PtG efficiency of $65.36\,\%$ already leads to PtG utilisation in 415 hours of the year, which corresponds to more than two-times the utilisation of our reference case. With a methanation efficiency of $\eta_{\mathrm{M}} = 0.90$, PtG is used in 1269 hours, decreasing curtailment measures in 1957 hours down to 1324 hours. Accordingly, the demanded electricity

[6] For this we refer to our IEEE-RTS24 case study in Section C.1 of the Appendix.
[7] We account for the value of lost load in both variations



(a) Volume **(b)** Hours

Figure 6.11: Sensitivity of PtG utilisation to varying efficiencies
Source: Own illustration.

by PtG for SNG production sees a rise from 173 GWh to 793 GWh, reducing overall curtailment volume by 64 % in comparison to our reference. On the other hand, a total PtG below 61 %, makes PtG effectively non-competitive, given the MP structure of our model over the year.

6.3 Conclusion

In this Chapter, we have assessed the potential of PtG providing flexibility specifically to support redispatch measures, given the geographical mismatch of load and RE infeed as well as limited transmission capacities. We have argued, that the need for flexibility increases not only with the variability and fluctuation of RE, but also because of spatial imbalances between generation and demand. Through the utilisation of PtG at nodes facing high RE curtailment, we add flexibility to the system both on a spatial and temporal level. Through sector coupling, a higher level of RE injection into the generation mix at lower or equal stress on congested transmission lines can be achieved.

We illustrate that a few bottlenecks in the transmission grid are responsible for most of the curtailment. These location are primarily characterised by high wind infeed, especially in the winter season. In order to meet demand in the south, GfG units provide positive redispatch. By implementing PtG, otherwise curtailed electricity from the north has been shifted towards load centres in the south of Germany, making use of existing gas infrastructures.

Our results also give an indication of attractive PtG locations in the transmission grid that lack flexibility, i.e nodes with large amounts of curtailed RE. Instead of curtailing RE sources, we are able to utilise RE in a reasonable way. Effectively, PtG can be seen as a measure of demand-side flexibility. Unlike PHS or battery-based storages, the combination of PtG and SNG utilisation is not bound to a single location. Given the well-developed, meshed gas infrastructure in Germany, it allows for injecting to and extracting from different locations. We point out that the attractiveness and competitiveness of PtG depends on investment cost and additional applications outside of congestion management. For example, synergies with other technologies and sectors, such as the heat and transportation sector should be investigated in future research. To a certain share of the total gas volume, a direct injection of hydrogen into the gas grid may be possible. This would circumvent the methanation process and improve both energy and cost efficiency, significantly.

Given the price sensitivity of our model, representing must-run obligations in our model may impact the assessed potential of PtG. If must-run capacity were to be implemented, the underlying data have to be robust to yield reliable model results. Similarly, the potential for PtG increase with higher RE shares and longer periods with low electricity prices. In addition, further research may as well include a European perspective, including the modelling of cross-border trade and countertrading. Possibly, this will result in both increases as well as alleviations of inland congestion in certain hours. We point out that our sensitivity analysis based on marginal efficiency changes of PtG is equivalent to varying the MP, e.g., as a result of future changes in fuel prices, incorporation of must-run, or cross-border exchange. The results in our paper show that PtG deserves attention as a potential flexibility provider in future low carbon energy systems with high shares of renewables.

Apart from a technical and economical point of view, an analysis of the regulatory framework should also be part of further research. Grid infrastructures are natural monopolies and TSOs in liberalised energy markets are regulated entities. As such, adaptations of current frameworks with regards to utilisation of PtG by TSOs, e.g., as transmission assets, may be necessary. Comparing different regional electricity markets can provide additional insights into best-practices, as the positioning of PtG within the regulatory framework may vary. This will be the focus of Chapte 7.

6.4 Additional in-depth analyses

This Section is dedicated to gaining deeper insight to how the model and underlying data set reacts to changes in input parameters. For this purpose, we run the model at full year, hourly resolution for every change, individually. Given the future additions of RE capacities 50Hertz et al. (2019), we first investigate sensitivities to an increase in in RE shares. Specifically, we only vary installed capacities of intermittent RE, i.e., solar PV, wind offshore, and onshore. Furthermore, we explore how a different CO_2 price may impact the potential of PtG in redispatch. Before we dive into the results, we present our intuitions and expectations of the sensitivity outcome. Note that all model runs do not consider future transmission expansion plans.

6.4.1 Increasing the share of renewable energy sources

In four separate model runs, we vary increase the installed capacities of intermittent RE at every node by 10 up to 40 %. The maximum generation of RE sources still follows the same availability time series from our data set.

Expectations Naturally, an growth of intermittent RE capacities will proportionally result in increasing generation by solar PV and wind in the ED. As the underlying grid infrastructure and electricity demand does not change, we expect higher rates of curtailment in the redispatch. Based on our previous results in Chapter 6, we expect a higher utilisation of PtG as the volume of RE curtailment increases.

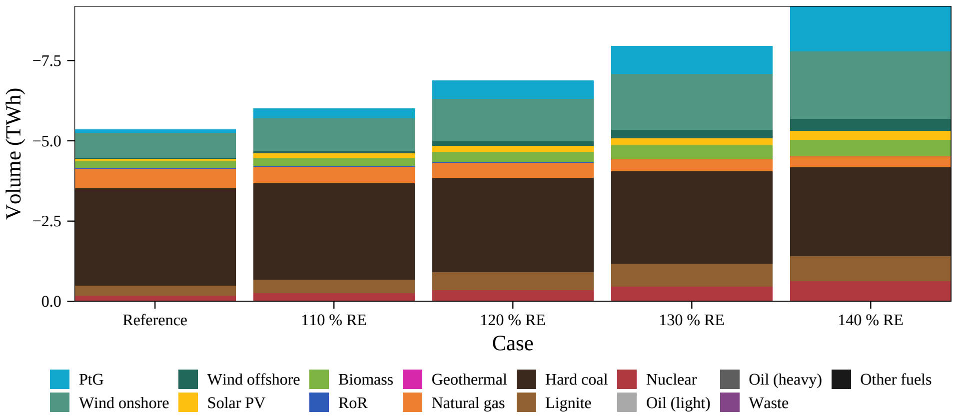


Figure 6.12: Downwards adjustments in redispatch for increasing RE shares
Source: Own illustration.

Results As we expected, curtailment of RE increases almost proportionally with higher installed RE capacities. In Figure 6.12, we see an increase of intermittent RE by $10\,\%$ translates to close to doubling of PtG utilisation. A temporal depiction of the increase in total redispatch volume as well as PtG and SNG utilisation is presented with Figure 6.13. While in our reference case PtG utilisation lies at $121.3\,\mathrm{GWh}$, we see an increase to $1415\,\mathrm{GWh}$ with $140\,\%$ of the installed intermittent RE capacities. The reasons for this behaviour are twofold, one being that more curtailed renewable electricity is available. The second reason is that more RE in the day-ahead spot market (ED) pushes all conventional power plants in the merit order to the right, resulting in a lower MP. Figure 6.14 shows the duration curve of the MP for the model year. It can be observed that the MP decreases by about 2 to $2.5\,\%$ from one sensitivity case to the next.

As for the downwards adjustment of conventional power plants, there are multiple effects to be observed (Figure 6.12): Negative changes to hard coal based electricity generation remain very stable at 2.8 to $3.0\,\mathrm{TWh}$. Negative redispatch of GfG units decreases from $621\,\mathrm{GWh}$ (reference) to $336\,\mathrm{GWh}$ ($140\,\%$ RE). As for nuclear and lignite power plants, downwards adjustments grow from $178\,\mathrm{GWh}$ and $303\,\mathrm{GWh}$ (reference) to $626\,\mathrm{GWh}$ and $769\,\mathrm{GWh}$ ($140\,\%$ RE), respectively. The explanation for the two counteracting developments is as follows: Based on the merit order in Figure 6.2, the average load in the German electricity is covered by hard coal as the marginal generating technology. Following our above explanation, more expensive fuels such as natural gas have been crowded out from the market, already. As such, with an increase in RE and less natural gas based electricity in the dispatch, the CM model receives a lower natural gas volume that can be reduced through negative redispatch. The opposite can be said for both nuclear and lignite, being left of hard coal in the merit order.

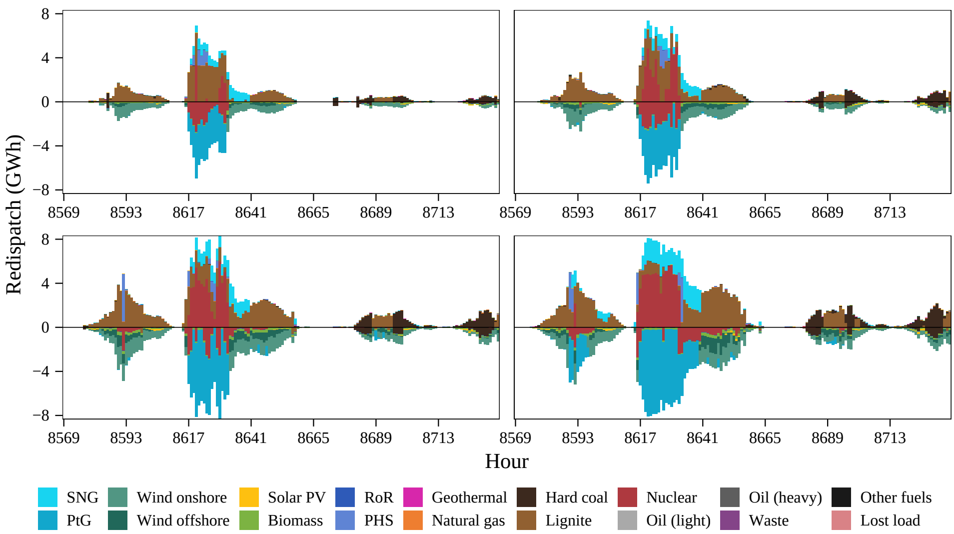


Figure 6.13: Exemplary redispatch week for increasing RE shares. 110 % RE (top left), 120 % RE (top right), 130 % RE (bottom left), 140 % RE (bottom right).
Source: Own illustration.

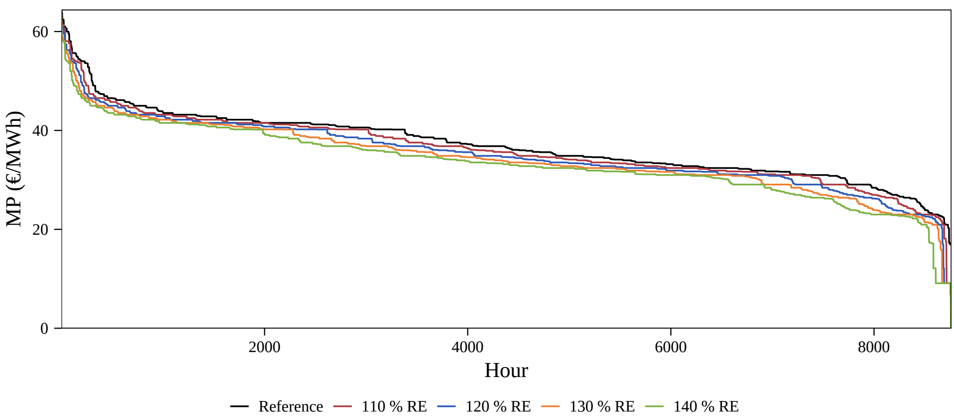


Figure 6.14: Market clearing price duration curve for increasing RE shares
Source: Own illustration.

6.4.2 Changing the CO_2 price

In 2015, every emitted tonne of CO_2 was priced at only 7.59 €/MWh on average Kunz et al. (2017b). However, developments in recent years show a surge in CO_2 emission costs[8]. As such, we investigate how a higher CO_2 price affects the potential of PtG.

Expectations A higher price for CO_2 emissions favours electricity generation of RE sources as the MC of conventional, fossil fuel based power plants increase. SNG is assumed to be carbon-neutral (see Section 6.1) and is in direct competition with natural gas. Therefore, a higher CO_2 price should improve its competitiveness in redispatch.

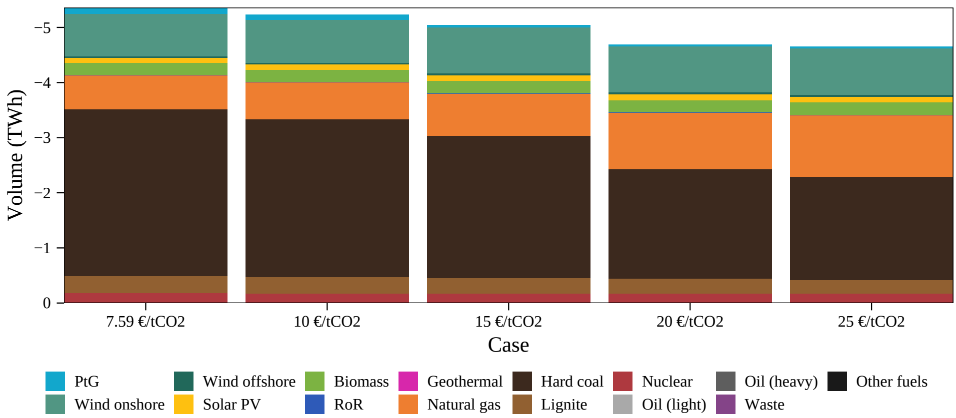


Figure 6.15: Downwards adjustments in redispatch for increasing CO_2 prices
Source: Own illustration.

Results To our surprise, our intuitions could not be confirmed with the results of this sensitivity analysis. In Figure 6.15 we observe the complete opposite. At a CO_2 price of 10€per emitted tonne, PtG utilisation has already decreased by 15 %. A CO_2 price of 25 €/tCO_2 pushes PtG utilisation down to 35 GWh. While counter-intuitive at first, there is a logical explanation for this behaviour, that is the dynamic interaction between i) the ED and CM model and ii) the direct dependency of costs for PtG on the MP.

I) With the lowest emission factor of only 0.49 tCO_2 per MWh_{th}, natural gas has a 47 % lower emission rate then its neighbouring fuel in the merit order, hard coal. As such, natural gas as a generation technology is affected much less by an increase in CO_2 price relative to all other conventional technologies. As such, now being a much cheaper option, natural gas is in parts substituting the dispatch of hard coal. From the perspective of the CM model, this leads to less hard coal and more natural gas being downward adjusted (Figure 6.15). In addition we observe an overall reduction in required redispatch volume with a lower share of hard coal based electricity generation in the economic dispatch (Figure 6.15). From the change 20 to 25 €/tCO_2 price, the reduction in total downwards

[8] A real-time development of CO_2 emission allowance price can be found in *https://markets.businessinsider.com/commodities/co2-european-emission-allowances*

adjustments remains close to unchanged. Given the more beneficial locations of natural gas power plants after frequently congested lines in the German electricity system compared to hard coal (cf. Figures A.10 and A.9a), total redispatch volume decreases. The two last columns in Figure 6.15) can hence be seen as the “minimum" in required downward adjustments given the German grid topology of 2015.

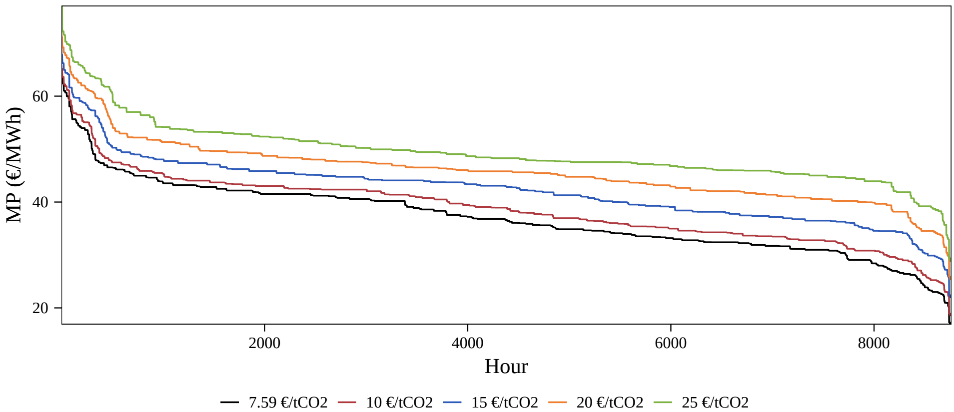


Figure 6.16: Market clearing price duration curve for increasing CO_2 prices
Source: Own illustration.

II) Not only in comparison to all other fossil fuels, natural gas based electricity is now much more competitive, but also compared to SNG based electricity. This is due to the fact, that one of our key assumptions in the model is an indiscriminatory market. To utilise PtG to produce SNG, electricity has to be paid for at the MP. In Figure 6.16, we can see that an increase in CO_2 costs effectively shifts the average MP proportionally. Given the total average round-trip efficiency by SNG based electricity of $30.1\,\%$ (including the thermal efficiency of GfG units), PtG now becomes a very cost-intensive technology. These increases in costs are not compensated by the mitigation of CO_2 costs when using SNG for generating electricity in GfG units.

We point out that this sensitivity does not mean that PtG is an infeasible or uneconomical technology given a higher CO_2 price. With an increasing share of RE in the future, both the volume of RE and a higher CO_2 price can push fossil fuel based generation entirely out of the merit order. This again would result in a larger price spread, making PtG attractive again. What we take from this analysis however is the fact that given our underlying assumption of an indiscriminatory market, PtG utilisation is highly sensitive to the remuneration mechanisms and MP in place.

Chapter 7

Exploring Power-to-Gas implementations in regulated electricity markets

Being operators of natural monopolies, SOs in many liberalised markets, such as Germany and the United States, are operating under a regulatory framework that may restrict the ownership or usage of PtG facilities. In this Chapter we hence address our second key research question, i.e., whether current regulatory frameworks are enabling PtG utilisation through SOs in CM.

In order to tackle the question, we first we give a brief introduction to differences in CM measures, as part of ancillary services, in the Europe and the United States in Section 7.1. Figure 7.1 provides an overview of key ancillary services and their equivalents in both regions. While the measures are similar in the two regions, specific implementations may differ due to their individual market design and regulatory framework. Under consideration of the current regulatory framework, we investigate, how PtG can be positioned as i) electricity storage, ii) gas producer, iii) electricity consumer, and iv) as grid component or transmission asset.[1]

7.1 Congestion management in Europe and the US

In the United States, CM is an integral part of the market design, i.e., nodal pricing. The limited capacity of transmission lines is directly reflected in the nodal price. As transmission capacities limits are reached, unrestricted trading with other nodes is no longer possible. As such, nodes with an electricity generation surplus display lower nodal prices as opposed to nodes with generation deficit (Ding and Fuller, 2005). This usually results in similar MP for linked, neighbouring nodes (Maurer et al., 2018). Nodal pricing is also

[1]The results of this Chapter are part of the journal article submission to Energy Economics.

referred to as LMP, as it expresses the value of electricity in a specific location (node) due to transmission constraints (Trepper et al., 2015; Maurer et al., 2018).

Nodal pricing is considered to foster efficient usage of the grid by market participants (Yusoff et al., 2017). One reason is that it provides signals for investment decisions in the grid infrastructure at locations where they are needed (Kirby, 2002). Market participants can also secure, or hedge their price for electricity by buying Financial Transmission Rights (FTR) before delivery. FTR cover any possible difference between two specified nodes and reduce uncertainty due to congestion (Kirby, 2002; Umale and Warkad, 2017). Kirby (2002) defines LMP as centralized method. In addition to centralised CM, decentralised CM, such as market-to-market trading is available, where different market areas are coupled by so called “flowgates". The decentralised method is equivalent to countertrading between zones in Europe. As in the US, countertrading in Europe is done by TSOs of different market areas via interconnectors.

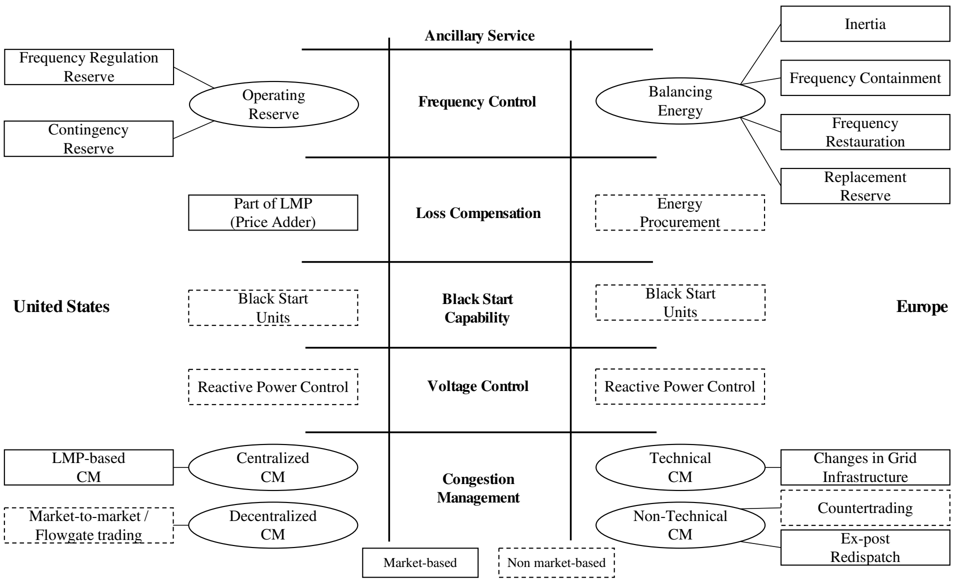


Figure 7.1: Ancillary service in Europe and the US
Source: Own illustration based on Kaushal and Hertem (2019); Zhou et al. (2016); Kirby (2002).

Instead of a nodal market design, European markets follow zonal pricing system. In countries with high RE injection, such as Germany, TSOs use redispatch to alleviate congestion on transmission lines. However, redispatch has been described as “slow and ineffective" (Yusoff et al., 2017). Unlike LMP which can be procured in real-time, e.g., in PJM energy market, redispatch is day-ahead based and requires manual interventions. In addition, costs for redispatch are not reflected in the MP, but are passed on as part of network charges.

While LMP-based CM is completely market-based, redispatch is *primarily* market-based. This means that in times of congestion, market-based solutions are used first before non-market based measures: With Regulation (EU) 2019/943 redispatch “shall be selected from among generating facilities, energy storage or demand response using market-based mechanism" (Regulation (EU) 2019/943 Art. 13 §2 cl.1). However, market-based redispatch has yet to be implemented by some of the member states. In the case of Germany, redispatch is still cost-based (Connect, 2018).

7.2 Power-to-Gas under German and US regulation

As ex-post redispatch underlies the obligations of a SO, we address in this Section, whether PtG can be included under current regulatory frameworks in liberalised energy markets such as Germany and the United States.

7.2.1 Definitions within the regulatory framework

Before presenting our key findings, we introduce the entities in charge of system operations and possible considerations of PtG within existing definitions.

TSO, ISO, and RTO In Germany, the TSO is not only operating the transmission grid, but also in possession of the grid. This natural monopoly is highly regulated by the BNetzA. Different models exist for SO The model of ownership unbundling is used by German and other TSOs across Europe although other possible models are available based on Directive (EU) 2009/72/EG (Meletiou et al., 2018). This applies for both electricity and gas sector.

In the United States, at the recommendation of Federal Energy Regulatory Commission (FERC), Independent System Operators (ISOs) and Regional Transmission System Operators (RTOs) are formed to operate the regional electricity grids and administer the wholesale electricity markets (Fernández-Muñoz et al., 2020; DOE, 2015), e.g., energy, capacity and ancillary services. Based on FERC's orders, ISO/RTO formulates its regional set of ancillary services, requirements, and market mechanisms. In contrast to TSOs, the ISO and the RTO is not in possession of the grid and only responsible for the operation (Singh, 2008).

In order to differentiate between the United States and Europe and their arrangement regarding unbundling of transmission and generation, we use the term TSO for European TSOs and ISO/RTO for US SO. When referring to all three entities, we use the term SO. Further, as PtG includes various steps and couples two sectors, a variety of definitions for the technology in the regualory framework can apply.The definition may even depend on the perspective of a market participant. The perspective chosen in this paper is the possibility of PtG utilisation by a SO. In sum, four different definitions are analysed in this Chapter.e Common to all four definitions, PtG uses electricity in order to generate hydrogen in a first step, and Synthetic Natural Gas (SNG) in a second step.

PtG as electricity storage If the SNG will be used later to generate electricity, from the power system perspective we can see PtG as a form of temporary electricity storage. However, because SNG can be used for generation of electricity or other forms of energy, e.g., heat, we distinguish electricity storage from energy storage. From the SO perspective, the gas grid functions as storage facility.

PtG as gas producer In case we do not use SNG as a temporary form of storing excess electricity, but rather only inject it to the gas grid without the purpose of re-electrification, a PtG operator becomes a gas producer.

PtG as electricity consumer This definition only considers the power consumption by PtG and disregards the purpose of the power consumption.

PtG as grid component or transmission asset A grid component (Germany) or transmission asset (United States) is utilised by the SO in order to maintain stable grid operation. This does not include any kind of ancillary services.

7.2.2 Power-to-Gas in Germany

In Germany, the regulatory frameworks for electricity and gas supply are settled in the Energiewirtschaftsgesetz (German Energy Industry Act) (EnWG). First, we connect the four definitions of PtG to the respective regulatory frameworks. Afterwards, we discuss conflicts between the PtG definition in the EnWG, and potential operation of PtG facilities by electricity and gas SOs. After clarifying the frameworks, we aim to analyse under which circumstances a SO might be allowed to build and operate PtG facilities in Germany. Apart from the EnWG, we also consider the European Directive (EU) 2019/944. In mid-April 2020, the directive was not yet implemented in German law. However, according to Art. 71, this should be done by 31. December 2020 latest. Hence, we need to consider the EU directive when assessing the German regulatory framework.

All quoted phrases below are authors' own translations of German original texts. Approaches to analyse PtG in the current regulatory framework has been investigated already from different literature. Schäfer-Stradowsky and Boldt (2015) analysed a possible operation by SOs. Kreeft (2018) compares different regulatory frameworks, namely in Italy, Switzerland, and Germany. Kreeft (2018) considers the perspective from both a transmission and distribution SO, as well as other regulatory aspects of constructing a PtG facility, such as environmental sustainability.

PtG as end-consumer An end-consumer buys electricity for its own consumption (EnWG 3 §25). Within the PtG technology it is questionable, whether electricity is consumed or processed in order to create further energy carriers such as hydrogen and SNG. The precise interpretation of an end-consumer was also subject to a decision by the German Federal Supreme Court in 2009 which stated that "the purpose of consumption is irrelevant" (Decision of 17 November 2009 by the German Federal Supreme Court, EnVR 56/08)(Kreeft, 2018). Background for the decision was the question whether pump hydro storages are to be defined as end-consumers. As pump hydro storage also convert electricity to potential energy, the decision can also be interpreted for other technologies whose purpose is to not consume energy for itself, but rather to transform it. Hence PtG could also be seen as an end-consumer. Being an end-consumer impacts fees and charges, which have to be paid in order to use the grid. If we define PtG as end-consumer, then this could mean that it is considered as a different market participant. An enquiry made to the BMWi about how storages are considered participating in the market yields that they are seen as end-consumer but with benefits regarding taxes and charges (BMWi, 2019). However, this concludes that end-consumer have an own market participant status. Regarding PtG as end-consumer, the purpose of PtG within the electricity system impacts whether a SO is allowed to operate it, i.e., if it is in line with unbundling rules. If, for example, the purpose of the PtG facility is ultimately electricity generation (e.g., through re-electrification), a vertical integrated undertaking is created. This would interfere with existing unbundling rules. We conclude, that PtG can be seen as end-consumer. However, for an SO the purpose is highly necessary in order to state whether this is still in line with his regulations for an SO.

PtG as electricity storage To assess whether PtG facilities could be operated as Electric Storage Resource (ESR) by a SO, we break down the question into two essential components:

(a) Can a PtG facility be considered a storage unit under current legal definitions?
(b) Under which circumstances is an SO allowed to operate storage facilities?

Germany law contains no legal definitions for electricity storages EnWG 3§31, defines energy facility (Energieanlage) as a “facility for generation, storage, transport or release of energy” which means that regulations for general energy facilities apply to storages too. Further, the term “facility for electric energy storage ” (Anlage zur Speicherung elektrischer Energie) is generally co-mentioned with “generation facility” (Erzeugungsanlage) (EnWG 1a §3, 12 §4 cl.4). Hence in this context, the legislation describes storage as a power releasing rather than a storing technology. It should further be noticed that the term “facility for electric energy storage” is not mentioned in EnWG 3, Hence it can not be seen as a legal definition.

EnWG 118 §6 cl.6 considers energy storage in its most narrow sense and ensures, that “facilities in which hydrogen is created through electrolysis or in which gas or biogas is produced using hydrogen through subsequent methanation” benefit from the same advantages for fees and charges, as “facilities for storing electrical energy” which is mentioned in EnWG 118 §6 cl 1. Therefore, it can be argued, that PtG is considered as an electricity storage. This however poses another question about the purpose of storing electrical energy. The question arises if classification for PtG as electricity storage under the regulatory framework still holds if the generated hydrogen or SNG is used for other purposes than re-electrification. A more general approach of storing energy instead of electricity can be found in Directive (EU) 2019/944. Art. 2 §59 defines energy storage as “conversion of electrical energy into a form of energy, which can be stored”. Based on this definition, we can see PtG as a mean for storing electrical energy in the form of hydrogen or SNG. For the gas sector, storages have to be separated from grid operation (see EnWG 7b). Being both SO and storage operator would create a vertical integrated undertaking by EnWG 3 §38, which is prohibited by the unbundling rules in accordance with EnWG 8. At the moment, the definition of storages in the EnWG is unclear. As such, a full statement for electricity SOs is only possible to some extent. Directive (EU) 2019/944 tries to bring clarity in this situation. It does not only introduce a definition for energy storage, but also relates the definition to the role of a SO. Art. 54 §1 states, that a “transmission system operator shall not own, develop, manage or operate energy storage facilities”.

PtG as grid component The German regulation makes use of the term “grid component” (Netzkomponente) in EnWG 12 §3 cl.2. Although the term is not defined explicitly, SOs are allowed to use “technical facilities in order to provide reactive and short circuit power”. These facilities are not allowed to be electricity generation facilities. The Section does not limit grid components to certain technologies, as long as the chosen technology is suitable to provide the service. As such, PtG is neither explicitly excluded or included, but further research is necessary to examine whether PtG is technically feasible to provide reactive and short circuit power. Apart from grid component, Directive (EU) 2019/944 introduces another term called “fully integrated network component which is defined in Art. 2 §51. “Fully integrated network components” are “network components that are integrated in the transmission or distribution system, including storage facilities” but “for the sole purpose or ensuring a secure and reliable operation of the transmission or distribution system”. Further, the use for balancing or CM is explicitly prohibited. In exception to Art. 54 §1, “transmission system operators may own, develop, manage or operate energy storage facilities”, if they are fully integrated network components and

a) “other parties [...] have not been awarded [...] or could not deliver those services”;
b) “such facilities or non-frequency ancillary services are necessary for the system operator [...] and they are not used to buy or sell electricity in the electricity market”;
c) “the regulatory authority has assessed the necessity of such derogation [...]”.

Here, a PtG facility can only be a fully integrated network component, if the technology was regarded as energy storage facility in an earlier stage. But from a broader perspective, a network component is not defined by its technology but rather its suitability for the operation of a secure and reliable transmission grid.

PtG as gas producer In addition to viewing PtG as a storage facility, it can be considered as a producer of hydrogen and/or SNG. This view is especially considered by the German grid regulator, BNetzA. In its position paper published 2014, it is stated that “conversion [...] to synthetic methane, which can be injected to the gas infrastructure, stored and transported to different customers, is a promising integration of renewable energies”(BNetzA, 2014). Although the paper also sees potential of storing SNG and hydrogen in the gas grid, it focuses on the benefit of producing biogas. Biogas is defined in sect. 3 para. 10c and explicitly lists synthetic methane and hydrogen on condition that its production is predominantly based on renewable energy. This also applies for carbon dioxide used in the methanation process. Predominantly in this context means at least 80 % in the yearly average (BT-Drs. 17/6072, S. 50)(Kreeft, 2018). Biogas enjoys benefits regarding taxes and charges, which are situated in the Gas Grid Charges Law (Gasnetzentgeltverordnung, GasNEV) in GasNEV 19 §1, GasNEV 20a as well as GasNEV 20b. The BNetzA follows with this view also the definition of biogas which speaks of “producing” (Kreeft, 2018). The term “producing” is also used for gas defined in EnWG 3 §19a, which also list hydrogen and synthetic methane. In the case of producing gas, type of energy input for production is irrelevant. Therefore, the BNetzA follows the definition of PtG especially as gas producer with the benefit of biogas. Another possible gas definition can be found in the renewable energy law (Erneuerbare Energie Gesetz, EEG). Storage gas (Speichergas) is defined as “every gas, which is not a renewable energy but was produced only with electricity from renewable energy sources with the purpose for intermediate storage” (EEG 3

§42). However, neither the EnWG nor the position paper by BNetzA consider the term storage gas or its relation to PtG. Bösche et al. (2012) argues, that the term is genuinely seizes the purpose of applying feed-in tariffs also to intermediate stored electricity in the gas grid (EEG 119 §3). In conclusion, PtG produces storage gas which is only used for temporarily storing electricity.[2] Hence it could be considered as an electricity producer entitled to receiving feed-in tariffs for the stored electricity.

PtG as gas producer might conflict with SOs being vertical integrated undertaking, however across two different energy sectors. In its role as SO, the company becomes a vertical integrated undertaking if it further performs a function in exploration or sales of gas. As exploration and production can be seen similar in this case, the operation of a PtG facility creates a vertical integrated undertaking in terms of EnWG 3 §38. In accordance with EnWG 8, unbundling rules of vertical integrated undertakings apply. As the production is in the gas sector, no *vertical* integration occurs from the perspective of an electricity SO in terms of EnWG 3 §38. However, unbundling does not only apply for vertical, but also *horizontally* integrated undertakings (Schäfer-Stradowsky and Boldt, 2015). A definition of a horizontal integrated undertaking can be found in Directive (EU) 2019/944. Art. 2 §54 states that an "electricity undertaking performing at least one of the functions of generation for sale, or transmission, or distribution, or supply, and another non-electricity activity" is to be denoted as a horizontally integrated undertaking". Therefore, unbundling applies as well. This also holds true if the gas is defined as storage gas, as this would then be denoted electricity generation.

Tables 7.1 to 7.3 summarises the possible definitions and conclusion for Germany. The table differentiates between possible interpretations for gas and electricity SO. Some of the definitions are more related to the gas, than electricity sector. However, in order to have a complete view on the topic, these results are valuable for a matching of definitions and possible operations for ancillary services in a later stage.

[2] Analogy: In this context, storage gas can be regarded as the equivalent to water in a PHS. Water (or gas) are only used as a platonic medium for storing electricity.

Table 7.1: Positioning PtG as storage in Germany

				Relevance and assessment for	
Definition	**Perspective**	**Source**	**Wording**	**Electricity SO**	**Gas SO**
Storage	Storage facility ("Speicheranlage")	EnWG 3 §31	Facility to store gas.*	Only relevant for gas system.	Vertical unbundling: SO not allowed to operate both grid and storage facilities.
	Energy facility ("Energieanlage")	EnWG 3 §15	Facility for generation, storage, transport or release of energy.*	Appendable to both SO types. Term in EnWG is very broad and not further specified in the context of an SO.	
	Facility for storing electric energy ("Anlagen zur Speicherung elektrischer Energie")	EnWG 1a §3, 12 §4 cl.4	Facility for storage of electrical energy.*	Often comes with generation of electrical energy. Storage character of the term only of secondary importance.	Only relevant for electricity system.
	Energy storage ("Energiespeicher")	Directive (EU) 2019/944 2 §59	Deferring the final use of electricity to a moment later than when it was generated, or the conversion of electrical energy into a form of energy which can be stored, the storing of such energy, and the subsequent reconversion of such energy into electrical energy or use as another energy carrier.	Clarifies the term storage and also applies to conversion into other energy forms. Here, reconversion is part of storage, but it does not make assumption about spatial differentiation of storing and reconversion.	Only relevant for electricity system.

* Translation by the authors. Disclaimer: We clearly distinct between "electrical energy" and "energy".

Source: Own illustration.

Table 7.2: Positioning PtG as gas producer or electricity consumer in Germany

<table>
<tr><th rowspan="2">Definition</th><th rowspan="2">Perspective</th><th rowspan="2">Source</th><th rowspan="2">Wording</th><th colspan="2">Relevance and assessment for</th></tr>
<tr><th>Electricity SO</th><th>Gas SO</th></tr>
<tr><td rowspan="3">Gas producer</td><td>Biogas</td><td>EnWG 3 §10c</td><td>Biomethane [. . .] as well as hydrogen, produced through electrolysis, and synthetic methane if the electricity used for electrolysis and the carbon oxides originate predominantly from renewable sources.</td><td colspan="2" rowspan="2">Production of either gas or any other form of energy transport medium interferes with unbundling rules (either horizontally or vertically for SO). Building and operation of a gas production facility by an SO is not permitted under the regulatory framework.</td></tr>
<tr><td>Gas</td><td>EnWG 3 §19a</td><td>[...] Hydrogen which was produced through electrolysis and synthetic methane which is produced through methanation of hydrogen.</td></tr>
<tr><td>Storage gas (“Speichergas")</td><td>EEG 3 §42</td><td>Every gas [...] produced only by renewable energy with the purpose of intermediate/temporary storage.</td><td colspan="2">Not adapted by the EnWG yet, which sets the framework for SO. Possible to see as storage medium for electricity producer, hence only temporarily storage for later re-electrification</td></tr>
<tr><td>Electrcity consumer</td><td>End-consumer (“Letztverbraucher")</td><td>EnWG 3 §25</td><td>Natural or legal entities who purchase energy for their own usage.</td><td colspan="2">Definition is valid for every consumption regardless of its purpose, this also includes storing of energy. A PtG facility can be seen as end-consumer, whether it can be operated by an SO depends on its purpose.</td></tr>
</table>

Source: Own illustration.

Table 7.3: Positioning PtG as grid component in Germany

				Relevance and assessment for	
Definition	**Perspective**	**Source**	**Wording**	**Electricity SO**	**Gas SO**
Grid component	Technical facilities ("Technische Anlage")	EnWG 12 §3 cl.2	[...] Suitable technical equipment, for example for the provision of reactive and short-circuit power [...], which are not installations for the production of electrical energy.	The technical feasibility of PtG as grid component is the driving factor. Other technologies might be more "suitable".	
	Fully integrated network component	Directive (EU) 2019/944 §51	Network components that are integrated in the transmission or distribution system, including storage facilities, and that are used for the sole purpose of ensuring a secure and reliable operation of the transmission or distribution system, and not for balancing or CM.	Article opens new possibilities for SO to ensure grid reliability. PtG could be one new possibility if proven to be beneficial for grid operation. In case PtG is seen as storage and shall work as fully integrated network component, restrictions of Directive (EU) 2019/944 54 §2 apply.	

Source: Own illustration.

7.2.3 Power-to-Gas in the US

In the United States, the transmission and wholesale of electricity, natural gas, and oil is regulated by the FERC. The legal framework for these sectors as well as authorisation for FERC as their regulating organ is covered in Title 18 “Conservation of Power and Water Resources", Volume 1, Chapter 1 of the Code of Federal Regulations (CFR)[3].

Power-to-Gas as storage On February 15, 2018, FERC issued Order 841 which directs ISO/RTOs to enable participation of electric storages in wholesale electric markets and remove existing barriers to date (FERC, 2018). For the first time, FERC provides a legal definition by amending §35.28 (b) through adding a new paragraph (9). An Electric Storage Resource (ESR) “[...] means a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid" (FERC, 2020). In its order, FERC additionally clarifies that the definition is intended to cover ESR “regardless of their storage medium" (FERC, 2020, 29). Given the definition, PtG as a technology undoubtedly fulfills the first part to be considered an ESR, as it is indeed a resource capable of receiving electric energy. However, it remains unclear whether the second part of the definition requires ESR to be capable of *both* withdrawing and injecting electricity from and to the grid. Unlike exemplarily mentioned stationary technologies in Order 841, such as “batteries, flywheels, compressed air, and pumped-hydro" (FERC, 2018, 29) which withdraw, store and inject electricity based on the same technology at the same geographical location, PtG only performs the *receiving* component. Coupled with a gas storage or the gas infrastructure, a storing property is also given. Injection back to the grid requires re-electrification using i.e., fuel cells (for hydrogen) or GfG units, the latter most likely connected to a different geographical location within the electricity and gas grid.

In its current formulation, §35.28 (b) para. 9 does not explicitly require all features of an ESR to be provided by the same *resource*, nor at the same geographical location. The general formulation of the definition allows the ESR participation model to accommodate both “existing and future technologies" (FERC, 2020, 61). As such, based on the latest amendment through Order 841, PtG may be considered as an ESR.

To answer the second component of our evaluation, we need assess whether operating a PtG facility as an ISO/RTO would conflict with unbundling rules in place. With Order 888 (FERC, 1997) and Order 889 (FERC, 1996), functional unbundling was introduced in 1996 to assure non-discriminatory open access transmission and break up previous vertically integrated utilities. A detailed overview on the implications of deregulating the US electricity sector is presented by Joskow (2000) and (Joskow, 2008). With the recent Order 841, ISO/RTOs are directed to establish tariffs to open the markets for capacity, energy, and ancillary services to ESR, mitigating discriminatory and case-by-case treatment. It aims to bring ESR to level playing field, i.e., equal compensation for all of the above-mentioned services as any conventional generation resource. As Order 841 treats ESR as electricity generation resource, ISO/RTOs are not allowed to operate PtG facilities under vertical unbundling rules. However, it leaves open the question whether ESR, including PtG could be utilised as transmission assets instead of generation (Konidena, 2019), which we will discuss below.

[3] An openly accessible, online version of the Code of Federal Regulations (CFR) can be found on *https://www.ecfr.gov*.

PtG as transmission asset Both California Independent System Operator (CAISO) and Midcontinent Independent System Operator (MISO) have developed interest in implementing storage technologies as Storage as a Transmission Asset (SATA) and Storage as a Transmission-Only Asset (SATOA) into their transmission planning/expansion processes, respectively. MISO's pending proposal to FERC provides a framework for ESR to be selected as an alternative solution to transmission issues, such as line capacity expansion (MISO, 2019). Its goal is to provide more options to making the electric system more efficient and reliable.

In their proposal, MISO proposes to include the following definition for SATOA: "An Electric Facility connected to or to be connected to the Transmission System and approved for inclusion [...], as a transmission facility that is part of the Transmission System, that is capable of receiving Energy from the Transmission System and storing Energy for injection to the Transmission System, and is operated only to support the Transmission System. The SATOA shall not participate in the Transmission Provider's markets except to the extent necessary to receive energy from the Transmission System and to inject energy into the Transmission System to provide the services for which the SATOA was included in the [MISO Transmission Expansion Plan]." (MISO, 2019, 15)

Based on the definition, MISO clearly states that an SATOA would be only approved for transmission purposes only and not allowed to participate in the market.[4] In its proposal MISO bases its argumentation on a previous ruling by FERC from January 21, 2010. Among other conflicts, FERC was asked to determine whether the proposed storage projects could be seen as wholesale transmission facilities (MISO, 2019; FERC, 2010). In the ruling, Western Grid would operate the storage projects as Participating Transmission Owner (PTO)[5] for transmission purposes, amongst others, under the following requirements (FERC, 2010):

(a) Operation by Western Grid only as wholesale transmission facilities under direction of CAISO;
(b) No bidding and participation in CAISO's markets;
(c) Paying and receiving retail electricity prices for charging and injecting;
(d) Providing transmission services, i.e., voltage support and addressing thermal overload, at CAISO's instruction.

With the points mentioned in the proposal, MISO aims to maintain independency as ISO, as it would not be responsible for retail process for charging and discharging the facilities. The proposal has however faced criticism from Environmental Law and Policy Center (ELPC) and Center for Renewable Integration (CRI) (CRI, 2020). In their motion to intervene, ELPC and CRI argue that MISO's proposal is discriminatory, resulting in "unjust and unreasonable rates" (CRI, 2020, 6) through preferencing transmission owners over other actors in the transmission expansion planning process (CRI, 2020), disregarding Order 890 (FERC, 2007).

[4] CAISO's proposal from October 16, 2018 (CAISO, 2018), which would allow SATA to participate in the DA market on top of providing transmission services, is currently on hold.

[5] Participating Transmission Owner (PTO): "A party [...] who has placed its transmission assets and [e]ntitlements under the CAISO's [o]perational [c]ontrol [...]" (CAISO, 1998)

7.3 Conclusion

We have shown that different definitions for PtG create various possible considerations for the operation of PtG by SOs. We have argued that the purpose of operating a PtG facility in an electricity system is highly relevant to answering the question, whether it can be operated by an SO.

PtG in Germany As long as no legal definition of energy storage and/or electricity storage exists in the German regulatory framework, only analytical assumptions can be made. Some uncertainties will be resolved as soon as the Directive (EU) 2019/944 is ratified into German law, which will be the case by end of 2020. Based on this we conclude that defining PtG as storage allows SOs under specific circumstances to build and operate a PtG facility. However, its operation is limited to specific tasks. These tasks exclude e.g., CM and moreover only those tasks which are not market-based, such as balancing power. Further, operating a PtG facility in terms of a grid component highly relies on the technical suitability of PtG to fulfil the tasks. But if this is the case, a grid component is not constraint by specific technologies and allows the operation of PtG by an SO. For gas grid SOs, the regulatory framework is more articulate: Due to present unbundling rules, the SO cannot operate a storage facility. Defining PtG as gas producer interferes with the unbundling mechanism for SOs. Production of gas or electricity can only be seen as an additional role of the undertaking based on EnWG 3 §38 EnWG. In the case of unbundling in accordance with EnWG 8 it is irrelevant whether the integration is vertically (gas SO) or horizontally (electricity SO). However, the assumptions regarding the operation of PtG facilities by SOs does not affect a possible utilisation of PtG through market based ancillary services (see EnWG 13 §1 cl.2) such as balancing power. If the storage or gas production facility is built and operated by a market participant who is not the SO.

PtG in the United States In the simplest form, PtG facilities could be seen and operated as electricity consumer (see Section 7.2.2). However, concluding from the previous Sections, the purpose of the PtG facility, i.e., freely participating in the market or used for transmission purposes and services, is the driver for determining, whether it could be operated by an ISO/RTO. Seen as a pure gas producer, an ISO/ISO would violate unbundling rules present both in Germany and the United States.

As of now, it is unclear if PtG are included in the definition for ESR in the United States. Including the technology as a mean of storage sets a framework for participating in all three markets, i.e., energy, capacity, and ancillary services (FERC Order 841), however would conflict with possible direct usages from an ISO/RTO under unbundling rules. Allowing ESR in the transmission planning and expansion process as proposed by MISO could potentially be of economical and infrastructural benefit. In the case of PtG, its technology-specific advantages of an existing gas infrastructure and locational distribution of GfG units comes into place, potentially reducing the necessity of electricity grid expansion, significantly. However, the outcome of the pending proposal remains to be anticipated, leaving open whether PtG, if seen as storage, could be operated as transmission assets by ISO/RTOs.

Chapter 8

Concluding remarks

This Chapter is dedicated to reflecting and informing about the outcome of our master thesis. Furthermore, we critically analyse on our assumptions and model approaches. We also provide areas for further research that have been either neglected due to limited time and capacity or have resulted from our thesis. All in all we believe, that our work provides a solid evaluation on flexibility by PtG from a technical, economical, and regulatory perspective. Finally, we collect and summarise our key findings, providing a holistic conclusion.

8.1 Critical reflection

To obtain qualitative results in a feasible amount of time, and to guarantee scalability of the model for future applications, we have made simplifying assumptions and trade-offs. This, however, comes at the cost of technical detail.

Power-to-Gas For the implementation of PtG, we use two single efficiency factors η^{E} and η^{M} to represent losses occurring during electrolysis and methanation. As such our results directly depend on the parameters chosen, as our sensitivity analysis in Section 6.2.3 has shown. Allowing for PtG utilisation at every node where solar PV, wind offshore, and onshore are connected to yields the maximum potential that would be theoretically exploitable. There are also no upper-bound limitations on the throughput of PtG, i.e., all curtailed RE electricity at a node can be used to generate SNG. We also assume a sufficient CO_2 support in order to establish the methanation process. From an investment perspective however, PtG facilities will most likely not be rolled-out at such a large scale. Instead, a justified choice from a subset of our results could be considered for further evaluation (e.g., Table 6.3). Concerning the operation of PtG units, we assume no minimal run-time requirement and as such, flexibility relies on electrolysis and not methanation. While this is in stark contrast to the current state of art (Chapter 4.2), we have argued that primarily methanation needs to be operated at constant load to maintain stable and feasible production. We have argued to bridge this limitation by assuming a hydrogen storage before the methanation process that guarantees a constant production of SNG. Furthermore, our model is also based on the assumption that the amount of generated SNG can be subsequently injected without significantly impacting security constraints of the gas grid. This may be true to a certain extent but needs further analysis, when applied to real-life energy systems.

Costs for Power-to-Gas From our additional in-depth analysis in Section 6.4, we have found that our assumption of an indiscriminatory market makes the potential of PtG directly dependent on the MP. We point out, this is the “worst case" from the perspective of a PtG operator.

Limited foresight The implementation of a limited foresight of 24 hours has both technical and contextual reasons. For one, it allows us to model longer periods (i.e., a whole year) at the computational expense of *number of days times 24 hours*, instead of an exponential increase. In addition, this procedure reflects the day-ahead spot market. However, this form of implementation does not include anticipation of hours or days after. As we have previously mentioned, there is no left over SNG at the end of a modelling day. A limited foresight does not account for synergies that occur over a period of multiple days. For example, anticipating that redispatch expenditures in two days will be very expensive, PtG utilisation may increase today to make use of a lower MP. The take way is as follows: The longer the modelling horizon or foresight, the higher the potential for PtG to reduce spreads in redispatch expenditures.

Transferability Concerning the formulation of our CM model, the objective function is tailored to the German electricity market and needs to be adapted on a case-by-case basis, if the model was applied to other regions or markets. We point out that outside of the objective function, the model framework is highly scalable and can be easily applied to a different case. The modular nature of our model allows for simply reading in different data sets.

Data availability Our data set is based on the German electricity system as of late 2015. While the high-voltage transmission grid has largely remained the same, the installed capacities of solar PV and wind offshore and onshore have increased. As such, updating the data set to 2020 may impact the model outcome. Given the increase in intermittent RE to the electricity mix, we expect that the potential for PtG will increase in the next decades to come.

8.2 Further research

From our model results and critical reflection, we have obtained additional field of interests that could be investigated in future research.

Investment Not covered in our approach is economical feasibility of PtG units from an investment perspective. Investments in PtG represents a long-term commitment and do not only depend on electricity prices. Having mentioned this, a positive expected return heavily depends on the utilisation level of the PtG unit and its competitiveness against other energy carriers. As such, the price of natural gas is an important factor. Higher prices may result in a higher substitution by SNG.[1]

CO_2 availability Also the combination of PtG with locations of CO_2 should be analysed. Depending on the source of CO_2 SNG can be considered as biogas, hence increasing both economic and ecologic value of SNG.

Hydrogen only alternative From a technical view on PtG the two process steps of PtG may be split into two different steps, allowing for producing “hydrogen only" as well. As hydrogen can be directly injected into the gas system to a certain extend, this would not only increase economic feasibility, but also flexibility on the demand side.

Coupling with heat and transport sector Additional potential does also lie in sector coupling e.g., transportation sector implementation of additional sectors seems promising not only for hydrogen but also SNG. In particular the heat sector could benefit from PtG and vice versa. Using the thermal potential of SNG instead of electricity generation increases efficiency rates for utilisation. It also allows the usage of methanation byproducts, such as high quality steam and therefore increasing PtG system efficiency.

Impact of market design and changing the perspective Particularly interesting for PtG in meshed energy systems are nodal markets, such as in the United States. PtG operators in nodal markets could use cheap electricity in nodes with high generation and low prices, to produce SNG for utilisation in high demand, low generation nodes. Arbitrage profits might be possible in this set up, making PtG a more competitive and attractive technology from a long-term investment perspective.

Regulatory design for PtG With regard to low carbon energy system, regulatory frameworks need to provide enough flexibility to use the full potential of sector coupling. Research topics should therefore include the improved utilisation of different energy carriers for transmission. It may be helpful to consider a fully connected energy system instead of partial responsibilities based on the energy carriers. This would provide new options for electricity SO to use capacities in the gas grid. However, due to unbundling rules, the exploitation of these flexibility potentials are currently highly constrained for SOs.

8.3 Conclusion

This master thesis has provided an integrated evaluation of implementing PtG in Congestion Management (CM) by developing a techno-economic model, as well as including a

[1] We provide a sensitivity analysis for a the modified IEEE-RTS24 test case with surplus RE in Section C.1 of the Appendix. Results confirm this assumption.

regulatory perspective. From our model-based analysis and application to a large-scale electricity system, we demonstrated how incorporating PtG can support alleviating congestion by providing temporal and spatial flexibility. We have shown that only a few locations can significantly benefit from increased flexibility, i.e., provided by PtG utilisation. The model results have shown that PtG in redispatch may yield beneficial effects in the form of i) reduced curtailment volumes, ii) reduced system-wide congestion costs in times of SNG usage, and iii) increased share of RE in the total electricity mix. As such, the introduction of PtG to CM can reduce the dependency on time-intensive transmission expansion projects. The increasing demand for flexibility will be especially important with the continuous additions of intermittent of RE in the future, as our analysis in Section 6.4 has shown. While transmission expansion projects are in planning (50Hertz et al., 2019), PtG can be seen as an additional alternative to provide means to transport high RE infeed to load centers.

Our research has also addressed regulatory questions that may currently limit the overall potential of PtG. While using PtG in congestion management may increase flexibility and support a low carbon energy system, the current regulatory framework only allows its implementation to a certain extent. To be considered in redispatch, technology must be provided by market participants. As a direct result, a SO can only perform congestion management using the technologies available on the market. Yet, our assessment on the regulatory frameworks in the United States and Germany shows that a clear classification of PtG is not available at the moment. This is however crucial in deciding whether PtG will potentially be used by market actors, such as utilities or could be used to provide ancillary services by SOs. Clear vertical unbundling rules in place would only allow for either of the two or both under specific circumstances (if explicitly defined and indiscriminatory). From the perspective of sector coupling, PtG may be a very promising bridging technology, connecting the electricity and gas infrastructure. However, horizontal unbundling rules may limit cooperation and potential applications between the two sectors.

With the goal of reaching a low carbon energy system, it is in the common interest of all energy sectors to efficiently make use of available and new RE capacities. To achieve the technological potential of PtG, current regulatory frameworks need to provide a clear classification. At the same time, sector coupling technologies are by design non-binary and require a more flexible, fluid consideration. Only then, PtG can be successfully utilised for providing flexibility and to cooperate beyond the system boundaries of electricity and gas.

Appendix A

Additional figures

Seasonal dispatch and market clearing price

Figures A.1 to A.4 show the relationship between MP and dispatch. In times of high RE infeed and low electricity demand, a low MP can be observed. During the year we observe different patterns in RE infeed. While wind onshore covers large amounts in the winter, we clearly see the high infeed of PV during summer. Peak loads are served by utilising more expensive GfG units, thus increasing the MP. The “steps" of electricity generated by conventional power plants illustrated in the Figures represent the fuel-specific availability factors from Kunz et al. (2017b).

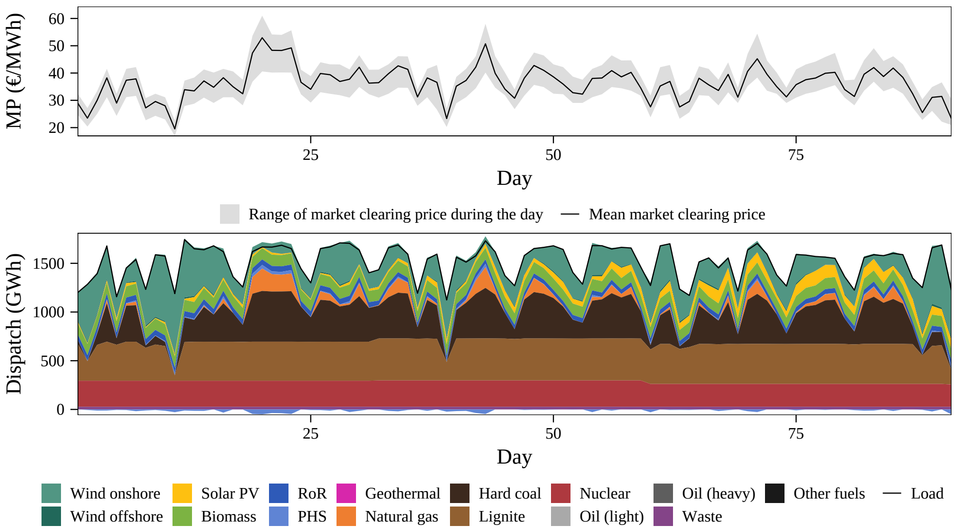


Figure A.1: Seasonal dispatch and market clearing price – First quarter
Source: Own illustration.

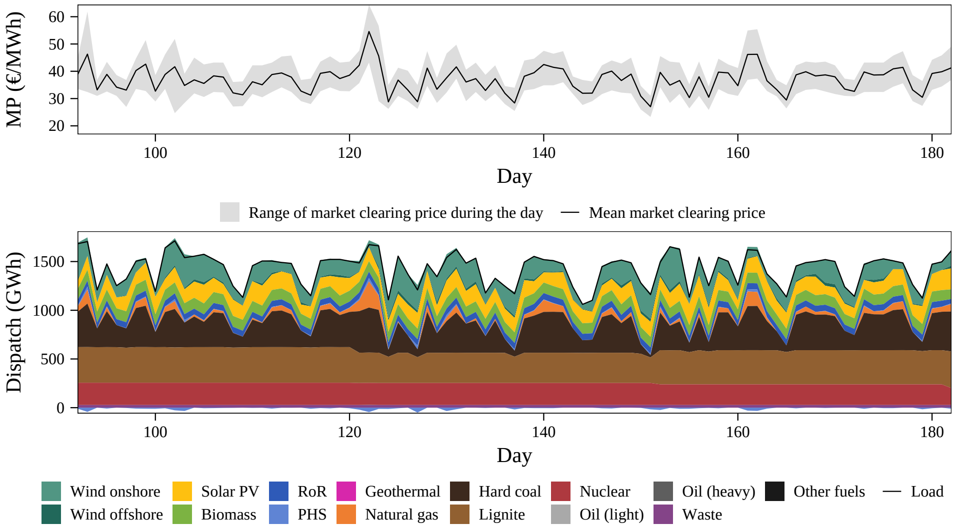


Figure A.2: Seasonal dispatch and market clearing price – Second quarter
Source: Own illustration.

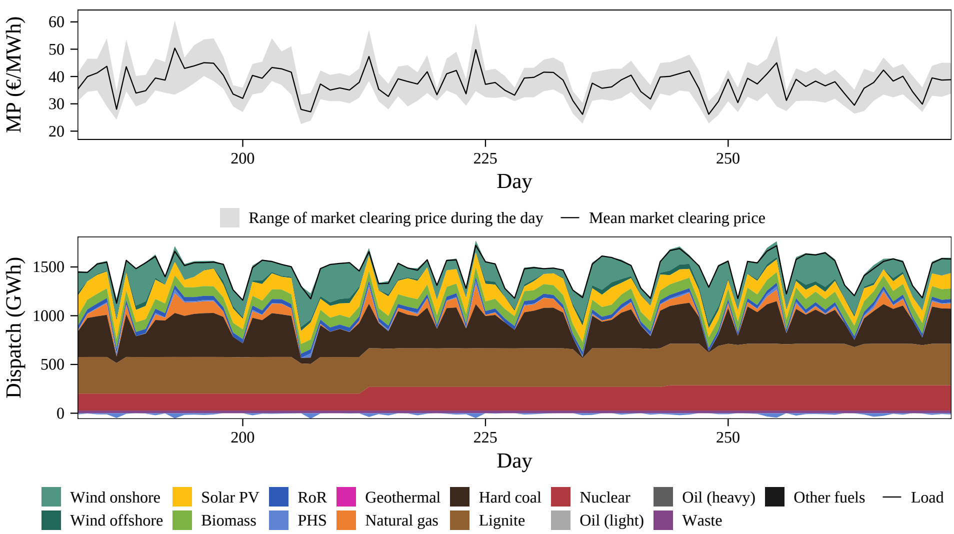


Figure A.3: Seasonal dispatch and market clearing price – Third quarter
Source: Own illustration.

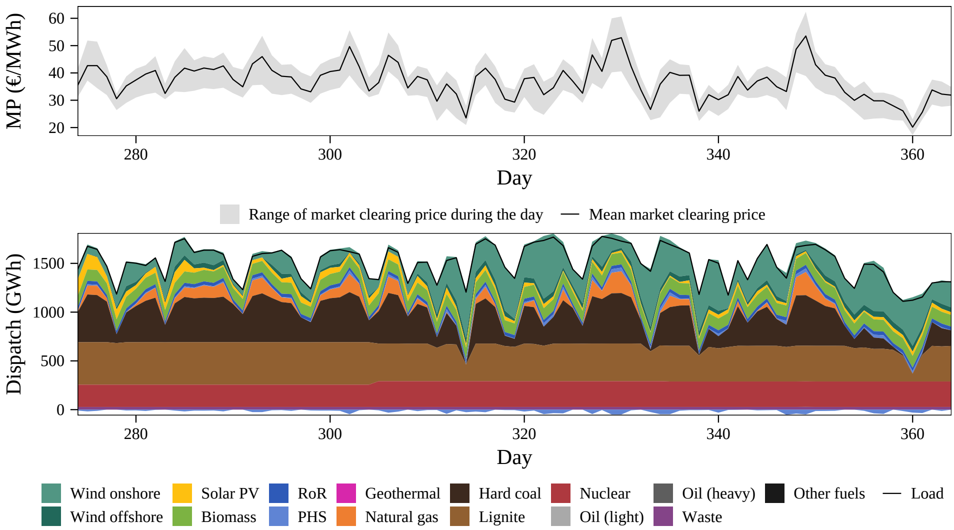


Figure A.4: Seasonal dispatch and market clearing price – Fourth quarter
Source: Own illustration.

Seasonal redispatch and Power-to-Gas utilisation

Figures A.5 to A.8 compare redispatch without (top) and with (bottom) PtG for each quarter of the year. Downwards adjustments in redispatch, including RE curtailment are denoted negative, while upwards adjustments are shown as positive values. Note that we sum up the hourly redispatch over the day. During the year we observe high redispatch volumes in the first and last quarter, correlating with high wind infeed (Figures A.1 to A.4.

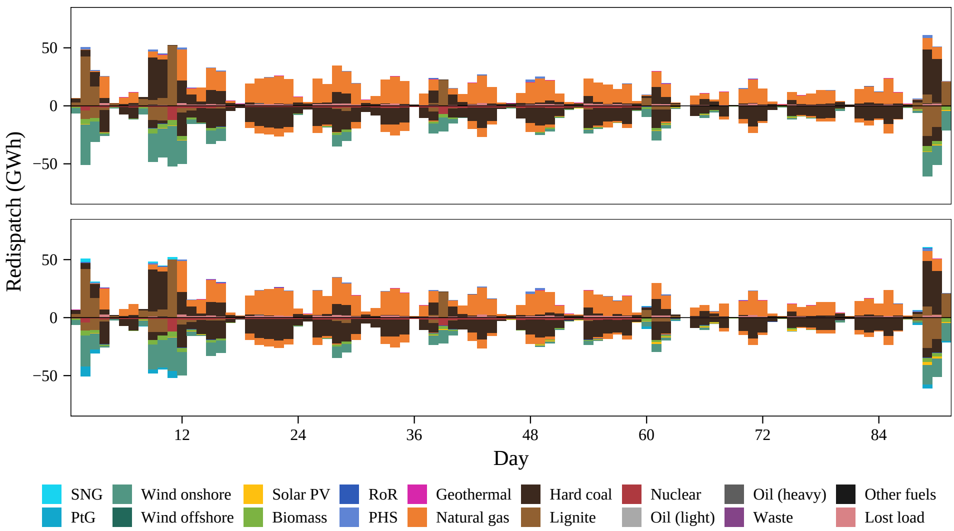


Figure A.5: Seasonal redispatch and PtG utilisation – First quarter
Source: Own illustration.

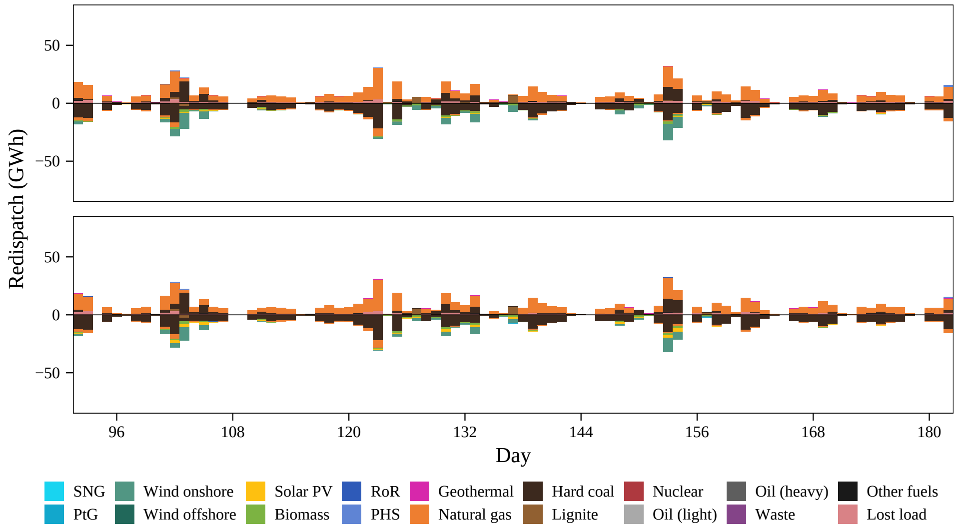


Figure A.6: Seasonal redispatch and PtG utilisation – Second quarter
Source: Own illustration.

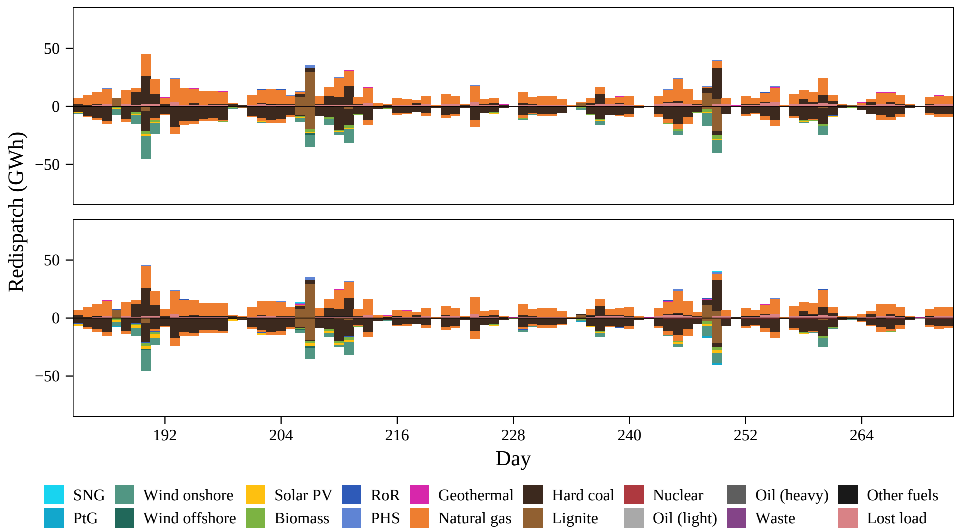


Figure A.7: Seasonal redispatch and PtG utilisation – Third quarter
Source: Own illustration.

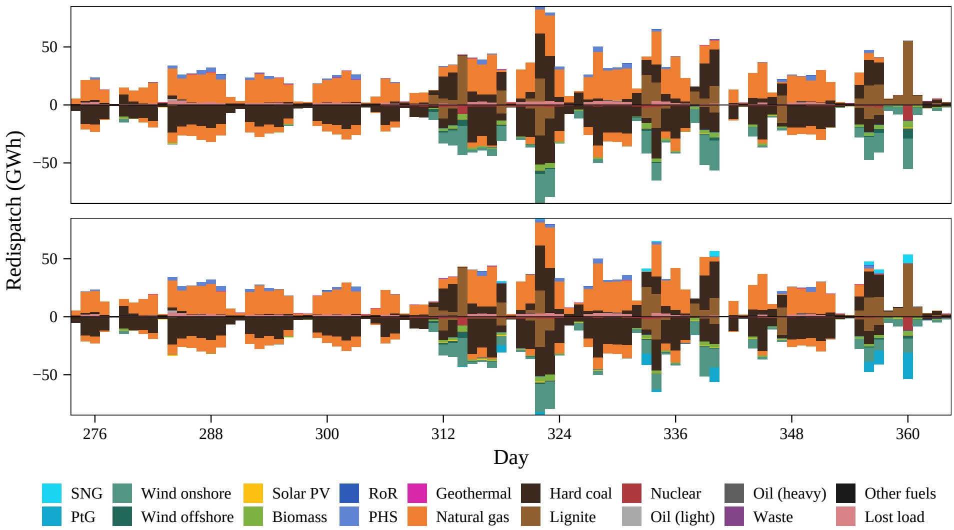
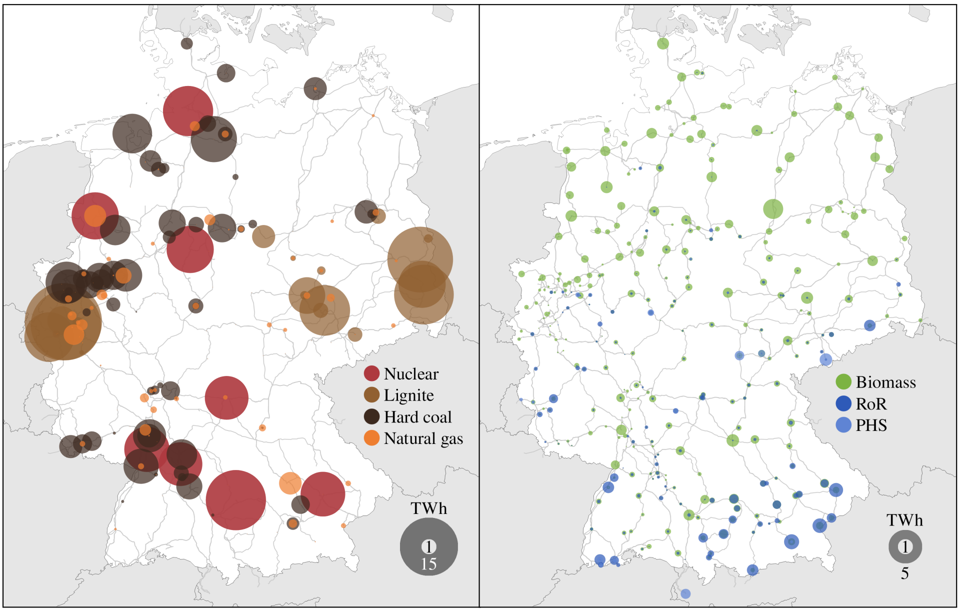


Figure A.8: Seasonal redispatch and PtG utilisation – Fourth quarter
Source: Own illustration.

Dispatchable power generation

Figures A.9a and A.9b display the electricity generation by conventional power plants and flexible RE sources summed up over the course of a year. The circle area is proportional to the generated volume.



(a) Conventional power plants

(b) Flexible RE sources

Figure A.9: Spatial distribution dispatchable power generation
Source: Own illustration.

Line utilisation

Figure A.10 illustrate which lines are facing a high average load during the year. It thus points out bottlenecks and likely congested elements in the transmission grid. The colouring from yellow to dark red indicates to what extend the lines relative to their maximum capacity. In our case, we assume a Transmission Reliability Margin of 25 %. Therefore the maximum average utilisation is 75 %. We point out, that this average is calculated after CM, meaning that all transmission constraints have already been respected.

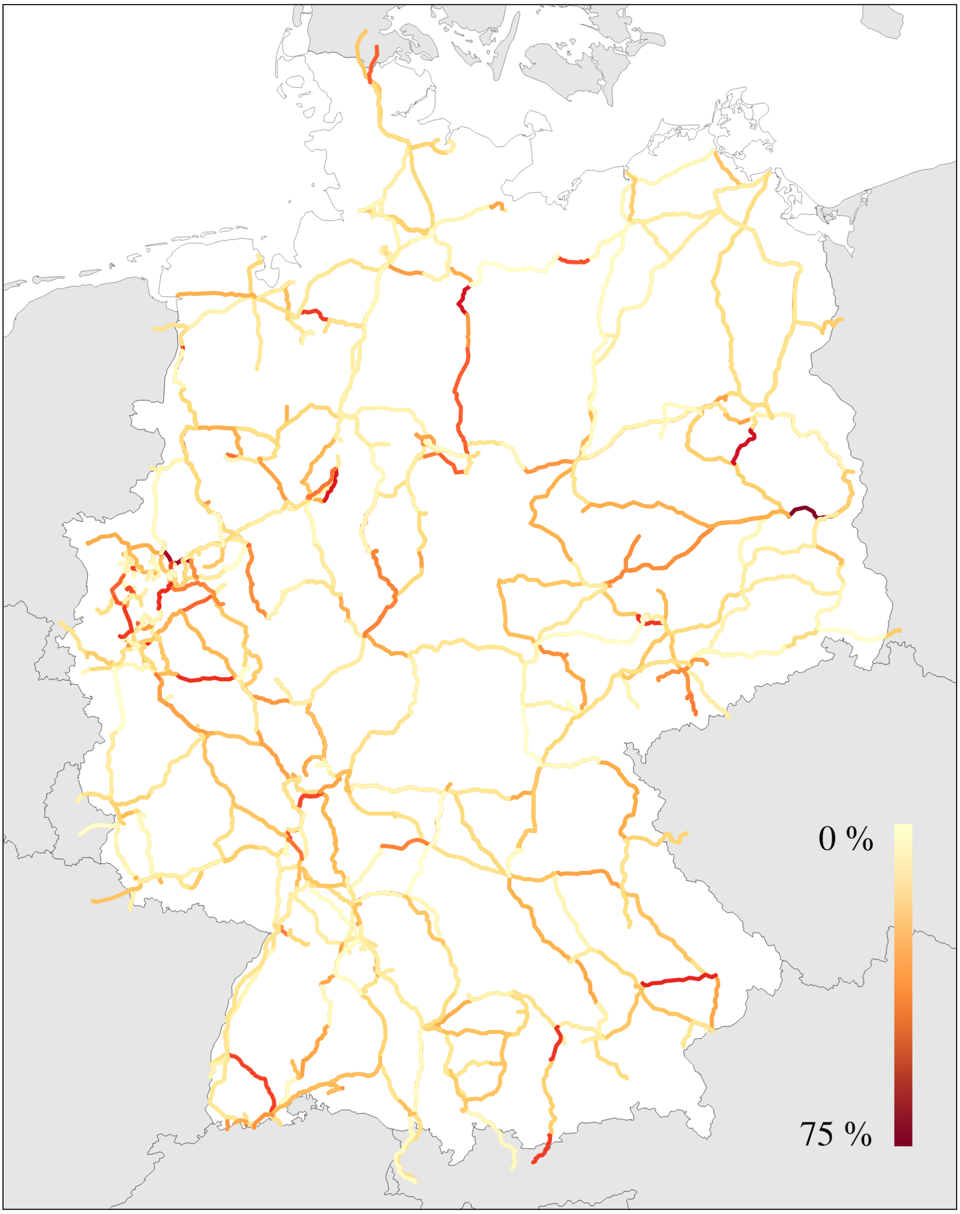


Figure A.10: Average transmission line utilisation after CM
Source: Own illustration.

Appendix B

Additional data

Table B.1: PtG projects in Germany

Name	Year	Status	Electrolysis	Methanation	Max input (kW_{el})	Min input	Max output (Nm^3/h)*	Eff.	Ramping	Source
BioPower2 Gas	2016	ended	PEM	biological	300	n.a.	15	n.a.	n.a.	dena (2020); Aryal et al. (2018); Heidrich et al. (2017)
Store&Go at Falkenhagen	2018	active	AEL	chemical	2000	n.a.	57	0.58	n.a.	dena (2020); StoreandGo (2019)
Exytron Demo	2015	active	AEL	chemical	21	n.a.	1	0.9**	n.a.	dena (2020)
Exytron Compact PtG	2019	active	AEL	chemical	62.5	n.a.	2.5	0.9**	n.a.	dena (2020)
Methanation at Eichhof	2015	ended	n.a.	biological	25	n.a.	4	n.a.	n.a.	dena (2020)
Exytron Alzey	2019	active	AEL	chemical	500	n.a.	n.a.	n.a.	n.a.	dena (2020)
PtG at Eucolino	2012	active	n.a.	biological	108	n.a.	5.3	n.a.	n.a.	dena (2020)
Helmeth	2012	ended	SOEC	chemical	n.a	20%	60 kW_{th}	0.76**	n.a.	Gruber et al. (2018)
Audi e-gas	2013	active	AEL	chemical	6000	n.a.	325	0.54	$\geq$ 1MW per 5min	Ghaib and Ben-Fares (2018)
PtG 250	2011	ended	AEL	chemical	250	70%	n.a.	0.496	n.a.	Zuberbuehler (2014)

* A standard cubic meter (Nm^3) is the amount of gas (in this case CH_4 at 1.01325 bar and 273.15 K

** Including heat utilisation of the methanation process

Source: Own illustration.

Table B.2: Data: Fuel costs, variable O&M costs, and emission factors

Technology	**Avg. power plant efficiency** η_g (%)	**Fuel costs** c^{fuel} (€/MWh_{th})	**Var. O&M costs** c_g^{OM} (€/MWh_{el})	**Avg. emission factor** λ_g (tCO_2/MWh_{th})
Nuclear	33.0	3.00	0	0
Lignite	37.5	6.22	0	0.98
Hard coal	40.2	10.61	0.53 – 6.53	0.86
Natural gas	42.6	22.76	0	0.49
Oil (heavy)	37.5	22.04	0	0.78
Oil (light)	34.5	45.74	0	0.78
Waste	33.2	0	0	0
Other fuels	33.3	45.74	0	0

Source: Own illustration based on Kunz et al. (2017a).

Appendix C

Modified IEEE-RTS24 test case

Every time we implement new core functionalities to our model framework, we use the modified IEEE-RTS24 test case by Ordoudis et al. (2016) for validation purposes. To confirm our intuitions or to correct errors, the test case is ideal, as this allows for shorter solving times and lower memory utilisation.

Lines While we keep most of the original line parameters of the test case, we introduce bottlenecks in the system to induce congestion: (3–24) 400 MW to 200 MW, (9–11): 400 MW to 200 MW, (10–12): 400 MW to 200 MW, (15–21): 500 MW to 250 MW, and (16–17): 300 MW to 250 MW.

Load The original case distributes load across the twenty-four nodes by a consistent nodal share across all time steps (see Table C.1). Originally, only twenty-four load hours are included. To assess a week at hourly resolution, we scale load data from Open Power System Data (2018) to the test case.

Table C.1: Case study – Load distribution. Load is depicted as nodal share of the total system load for each time step.

Node	p_d	**Node**	p_d	**Node**	p_d
1	0.038	7	0.044	15	0.111
2	0.034	8	0.060	16	0.035
3	0.063	9	0.061	18	0.117
4	0.026	10	0.068	19	0.064
5	0.025	13	0.093	20	0.045
6	0.048	14	0.068		

Source: Own illustration based on Ordoudis et al. (2016).

Generation The IEEE-RTS24 system includes twelve dispatchable power plants with cost parameters. However, the values for cost are arbitrary and not further elaborated in their documentation. Hence, to mimic the variety of different fuels CO_2 prices, and efficiencies available on the spot market, we assign a technology type and efficiency to the power plants, as displayed in Table C.2. In addition, we add RE generation units to the test case, as proposed by Ordoudis et al. (2016). We place a 200 MW solar PV unit at node (2), a 200 MW wind onshore unit at node (22), and two 200 MW wind offshore units at (18) and (21), respectively. The time series data is unique to every location and obtained from renewables.ninja, a free-to-access, open source platform to simulate the power output from wind and solar farms. The tool is documented in both Pfenninger and Staffell (2016), and Staffell and Pfenninger (2016).

Table C.2: Case study – Dispatchable power plants. Generation limits are given in MW_{el}, ramping in MW_{el}/h, efficiency in MW_{el}/MW_{th}.

Node	**Unit**	**Technology**	p_g^{max}	p_g^{min}	p_g^{rup}	p_g^{rdn}	η_g
1	1	Natural gas	152	30.4	40	40	0.467
2	2	Natural gas	152	30.4	40	40	0.463
7	3	Lignite	150	75	70	70	0.340
13	4	Nuclear	591	206.85	180	180	0.350
15	5	Oil	60	12	60	60	0.350
15	6	Natural gas	155	54.25	30	30	0.470
16	7	Natural gas	155	54.25	30	30	0.465
18	8	Hard coal	400	100	400	400	0.370
21	9	Hard coal	400	100	400	400	0.350
22	10	Lignite	300	300	300	300	0.330
23	11	Lignite	310	108.5	60	60	0.320
23	12	Hard coal	350	140	40	40	0.390

Source: Own illustration.

Merit order Assuming a CO_2 price of 25 €/tCO_2, we obtain the following merit order (Figure C.1).

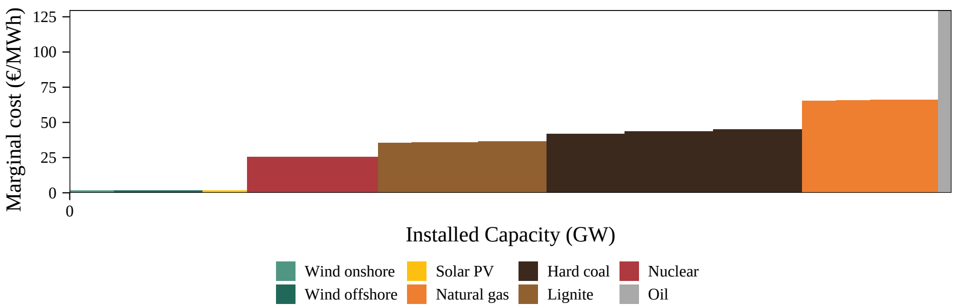


Figure C.1: IEEE-RTS24 test case – Merit order

C.1 Case study: Surplus renewable electricity

Applying our model framework to the IEEE-RTS24 test case provides additional insights into PtG mechanisms in place. Figure C.2 shows the relationship between the Market Clearing Price (MP) (top), ED and PtG utilisation (center), as well as the storage level of SNG (bottom). We can observe the SNG production and utilisation pattern invoked by the limited foresight of 24 hours in the bottom plot. Note that there is no incentive to leave a storage level above zero, as there is no anticipation of the next day. Unique to this case is the frequent occurrence of a MP = 0 €/MWh. Prices of zero occur on the market if demand is lower than RE generation in combination with must-run capacities. At a MP of below ca. 19.3 €/MWh, SNG is in direct competition to natural gas for the utilisation in GfG units (Figure C.2).

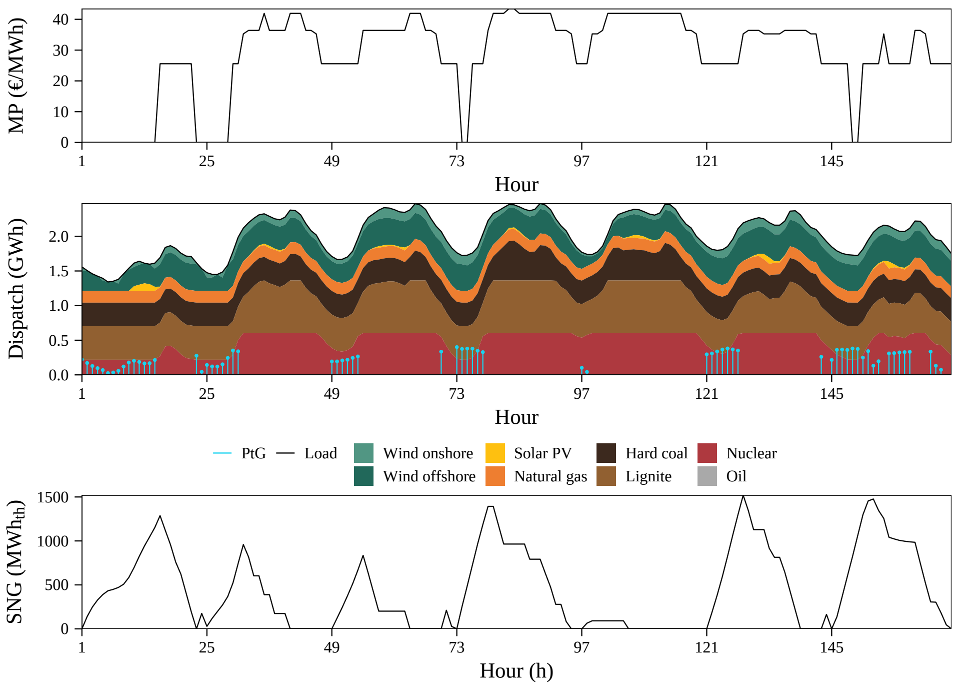


Figure C.2: Case study: Surplus RE – PtG mechanisms
Source: Own illustration.

Overview In this test case, the utilisation of PtG in redispatch can reduce curtailment of wind offshore by 38 % during this single winter week (Figures C.3 and C.4). In times of low MP and high curtailment, PtG is used to generate SNG, while in times of high MP SNG can be used by GfG to generate electricity, thereby reducing the need for upwards adjustments of other, more cost-intense power plants.

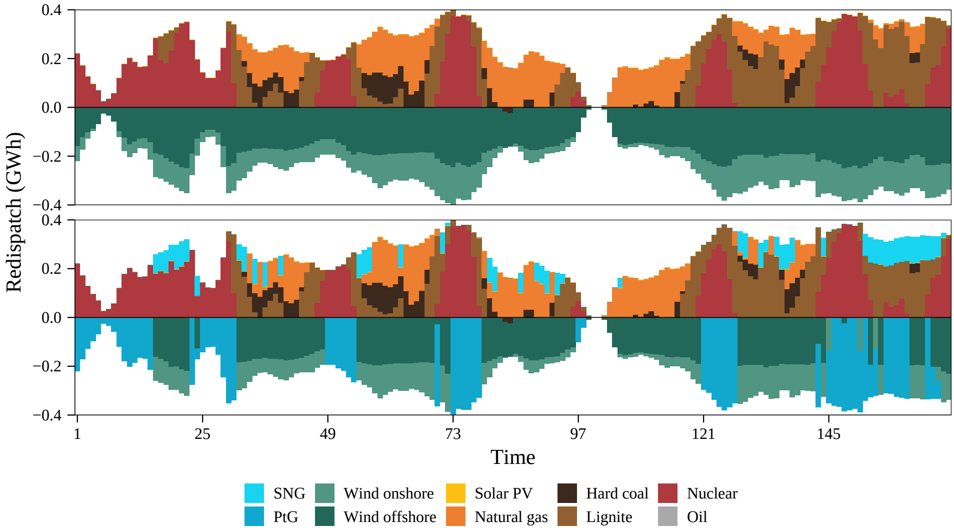


Figure C.3: Case study: Surplus RE – Redispatch without (top) and with PtG (top)
Source: Own illustration.

Cost savings and redispatch volume reduction Incorporating PtG in CM provides valuable insights in two effects, occurring in electricity systems with a very high share of RE. Given the "over capacities"[1], and a resulting MP of zero, cost savings of 0.9 % can be achieved in this particular winter week. In addition, we observe an overall reduction in redispatch volume (Figure C.4).

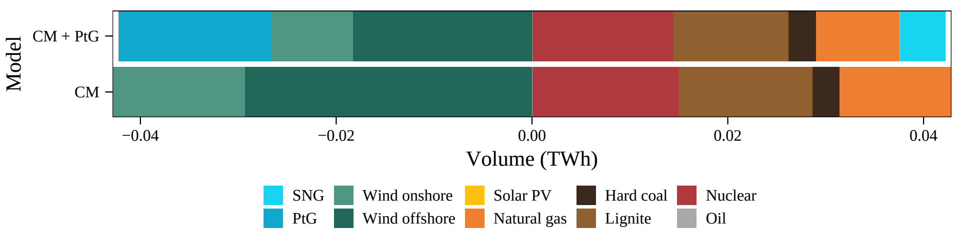


Figure C.4: Case study: Surplus RE – Total redispatch volume over a week
Source: Own illustration.

[1]Hereby we mean that in particular hours, the available RE capacity can satisfy load and leave a surplus of generation.

C.2 Case study: Sensitivity to the gas fuel price

This section provides a relationship of the competitiveness of PtG with a varying gas fuel price. Before start the sensitivity analysis, we need to bear the following observations in mind. In the modified IEEE-RTS24 test case, GfG are at the higher end of the merit order (see Figure C.1), only superceded by oil. Given the high MC, GfG units will most likely only serve residual demand, that is in times of low RE infeed and high demand.

A reduction of gas fuel costs to 20 €/MWh$_{th}$ yields MC of 51.55 €/MWh$_{el}$ to 52.20 €/MWh$_{el}$ including CO_2 emission costs. This does not change or decrease the position of GfG units in the merit order, as its closest neighbour on the lower bound is hard coal with MC of 45.04 €/MWh$_{el}$. On the higher side, even an increase of gas fuel costs to 45 €/MWh$_{th}$ will not let the MC of GfG units superceed oil. Must-run capacities do not participate in bidding on the spot market. This behaviour is reflected in our model by choosing the shadow price of the market clearing constraint as our market clearing price. Hence, the selected gas fuel costs range of 20 €/MWh$_{th}$ to 45 €/MWh$_{th}$ of our sensitivity analysis does not impact the topological dispatch order. GfG units never set the market clearing price in our case study. For our particular sensitivity analysis, this is important, as we can exclude effects that could potentially occur on the market side (ED) and focus on impacts on Congestion Management (CM) without and with the implementation of PtG.

Natural gas and SNG are fuels used in GfG units. Hence, in the CM model with PtG they are direct competitors. As such, an increase in gas fuel costs most likely makes the use of SNG more attractive.

Findings and mechanisms. We perform a sensitivity analysis on varying gas fuel costs in the range of 20 €/MWh$_{th}$ to 45 €/MWh$_{th}$, for the winter week displayed in Figure C.3. Figure C.5 (left) presents the total use or dispatch of electricity using SNG in GfG units. Figure C.5 (right) shows the relative cost savings, when comparing the total system costs in the CM model with PtG to the CM model without. The dots in the figure represent individual model runs.

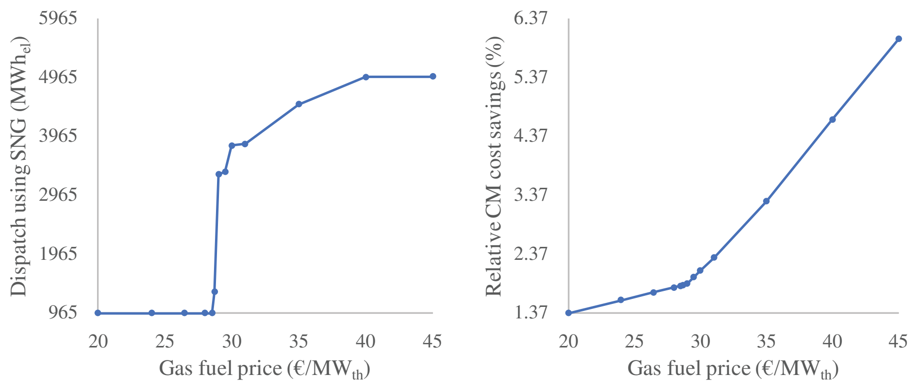


Figure C.5: Gas fuel cost sensitivity: SNG usage for CM (left) and relative cost savings with the implementation of PtG (right).
Source: Own illustration.

In the interval of 0 €/MWh$_{th}$ to 28.7 €/MWh$_{th}$, we observe no noticable change in SNG dispatch (marginal dispatch increase with fuel cost increase). 29 €/MWh$_{th}$ is the threshold where an increase in gas fuel costs leads to a non-linear increase of SNG usage in the CM model. We find that increases in the interval from 29 €/MWh$_{th}$ to 35 €/MWh$_{th}$ are the highest, after which relative increases flatten and level off. The reason for the non-linear increase can be explained by two factors: For one, the impact of a marginal change in fuel costs for gas does not translate into a linear change (see Eq. 6.1). In addition, for every retracted MWh of conventional, natural gas based electricity, other fuel-based technologies are also competing with PtG. The second reason explains the shape of Figure C.5 (left). As PtG units can only generate SNG from RE by definition (see Eq. 5.24), it is upper-bound by maximum infeed, i.e. RE curtailment and excess electricity unused in the ED. In addition, GfG units can only produce electricity using SNG as long as it is available in the virtual SNG storage. Hence, there is a limit to SNG usage in CM.

Relative cost savings, displayed in Figure C.5 increase with higher gas fuel costs. There are two factors influencing the above defined two intervals. Below the threshold value of 29 €/MWh$_{th}$, relative cost savings increase solely due to the fact, that total system costs in the CM model without PtG are higher than in the CM model with PtG, as GfG units are used to alleviate congestion. With an increase in gas fuel costs, total CM system costs increase (see Figure C.6, to the left). In the CM model with PtG, the increase in total system costs can be countered with a higher use of SNG (see Figure C.6, to the right), substituting shares of conventional natural gas in redispatch.

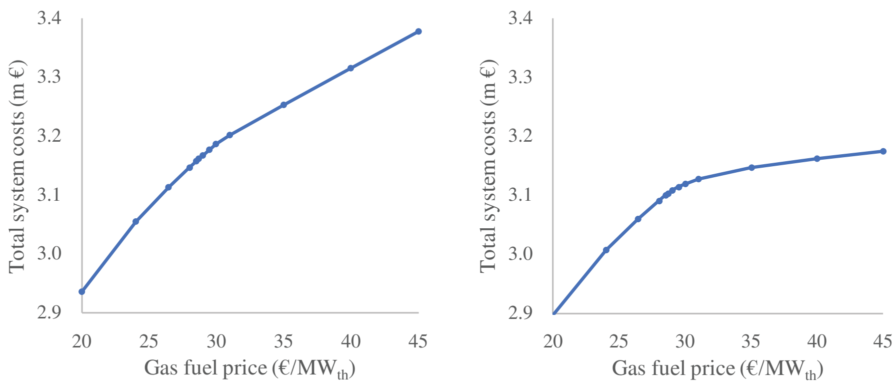


Figure C.6: Gas fuel cost sensitivity: Total system costs for CM (left) and CM + PtG (right).
Source: Own illustration.

From the threshold value of 29 €/MWh$_{th}$ upwards, we observe a much steeper increase in cost savings (Figure C.5, to the right), rising to 6.02 % for gas fuel costs of 45 €/MWh$_{th}$. This behaviour can be explained using the underlying absolute components in Figure C.6. An increase in gas fuel costs leads to an increase in total system costs in both CM models. However, this absolute increase is much lower in the CM model (Figure C.6), as SNG becomes more competitive relative to natural gas. Hence, the CM model with PtG displays lower absolute cost increases (slope), relative to the CM model without PtG. This translates into a steeper increase in relative cost savings displayed in Figure C.5.

From our sensitivity analysis we gain the following insights:

1. SNG is directly competing with natural gas in GfG units, as it is substituting areas previously covered by natural gas. This substitution is increasing with higher gas fuel costs.

2. With increasing gas fuel costs, PtG units are operating and creating SNG even when the MP is higher than zero.

3. Higher gas fuel costs make other technologies, such as hard coal and lignite more competitive relative to natural gas.

Point (3) is particularly interesting from the perspective of emissions. While higher gas fuel costs may make the use of PtG and SNG more attractive, other cheap and emission-intense technologies, such as hard coal and lignite are more likely to be used for CM as well. The use of SNG in GfG units is carbon neutral and may reduce total system emissions. At the same time however, hard coal and lignite have a higher emission factor than natural gas and counteract this decrease.

Appendix D

Model code

We provide our JuMP and R framework including the used data sets for further research purposes. The entire code can be cloned from NTNU GitLab through

git clone *https://gitlab.stud.idi.ntnu.no/sesam-2019/master-thesis.git*

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