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Market integration of power-to-gas during the energy transition—Assessing the role of carbon pricing

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Market integration of power-to-gas during the energy transition—Assessing the role of carbon pricing by Michael Bucksteeg, Jennifer Mikurda, Christoph Weber

Abstract

The expansion of wind and solar energy has primarily led to the decarbonisation of the electricity sector. Against this background, power-to-gas (PtG) is seen as a solution supporting the decarbonisation of other sectors, such as heating or transport. As the generation mix will transitionally be based on conventional generation technologies, the upcoming integration of PtG into electricity markets comes with several challenges. Notably, the design of environmental levies and carbon pricing should create efficient incentives for the utilisation of PtG, reflecting the value of the CO₂ emissions avoided by hydrogen or methane. This contribution studies the role of the regulatory framework in the integration of PtG, with special attention to carbon pricing. We extend an optimisation model by the PtG technology and competing flexibilities, such as storage or demand-side management. We develop several scenarios with regard to levies, levels of CO₂ price, techno-economic parameters of flexibilities and shares of variable renewable energy sources for the year 2025. We find that carbon pricing that considers the value of the CO₂ emissions avoided by hydrogen or methane supports the market integration of PtG, whereas too low CO₂ prices might lead to adverse effects. Subsequently, implications for energy policy are discussed.

Highlights

- Systematic analysis of the general effects of CO₂ pricing on power-to-gas
- Development of a model framework covering competing flexibility options
- Analysis of system effects and impacts on electrolyzers
- Carbon pricing that accounts for the value of the CO₂ emissions avoided by hydrogen or methane supports the market integration of power-to-gas
- In the case of too low CO₂ prices, inefficient price signals and adverse effects on CO₂ emissions are observed

Keywords: electricity market model, carbon pricing, power-to-gas, energy policy

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1 Introduction

To reduce CO₂ emissions, energy policy measures have focused on supporting renewable energy sources (RESs) in Europe over the past two decades. The massive expansion of wind and solar energy has primarily led to the decarbonisation of the electricity sector. In contrast, other sectors, such as heating or transport, remain below climate targets, calling for additional CO₂ reduction measures and strategies (European Environment Agency, 2019). Against this background, power-to-gas (PtG) is seen as a solution supporting the decarbonisation of other sectors. Consequently, the coupling of sectors has gained importance in academic and political debates and has become an integral part of the energy transition. PtG comprises the conversion of electrical power to hydrogen (PtH₂) by electrolysis and to methane (PtM) when further combined with CO₂. Currently, there are several small-scale demonstration projects with electrolyser sizes of up to several MW in implementation (e.g. Quarton & Samsatli, 2018; Wulf et al., 2018). In line with the European hydrogen strategy, with a target for 40 GW of electrolyzers by 2030, European transmission system operators for gas and electricity are planning modular large-scale projects with sizes of up to 100 MW in the years to come (European Commission, 2020; Wulf et al., 2020). Still in its early stages, PtG is not only seen as an option for decarbonising other sectors but also provides flexibility to the power system for balancing variable RESs and managing grid congestion. However, the generation mix will transitionally be based on conventional coal- and gas-fired generation technologies, which will lead to challenges with regard to the upcoming integration of PtG into electricity markets.

Several studies have analysed the integration of PtG with a focus on modelling the operation of electricity and gas networks, including a detailed representation of the physical properties of hydrogen and methane. Other studies took the system perspective and focused on long-term development and the economic aspects. These contributions mainly comprise bottom-up energy system models with a simplified representation of operational restrictions (for an overview, see Quarton & Samsatli, 2018). Although addressed in different ways, the competitiveness of PtG is of interest in most of the studies. Amongst others, Schiebahn et al. (2015), Emonts et al. (2019), Böhm et al. (2020) and Ruhnau (2020) find competitive scenarios for PtG in the industry and transport sector in 2050. In contrast, Glenk & Reichelstein (2019) find no competitive applications for industrial-scale supply under the current regulatory and market environment in Germany and Texas. Likewise, Guandalini et al. (2015) and Roach & Meeus (2020) conclude that PtG technologies are not profitable without additional incentives in the near future, and Staffell et al. (2019) emphasise the importance of the policy support of hydrogen to reduce barriers.

The mentioned contributions point to some relevant aspects of assessing PtG projects, namely, the modelling of technical details while considering the system perspective. Moreover, the incorporation of economic aspects, such as regulation and support mechanisms, is needed to comprehensively assess incentives and potential developments. From the perspective of the power system, PtG technologies can be considered as flexibility options that balance load and RES fluctuations. Consequently, models should consider an adequate temporal resolution, e.g. hourly. Moreover, models should account for intertemporal constraints to model the arbitrage of flexibilities between different points in time. Finally, the consideration of competing flexibility options, such as demand-side management (DSM), storage or cross-border exchanges, impacts the role of PtG, which would otherwise be overestimated. Studying the economic aspects of PtG and competing flexibility options requires an adequate modelling of energy markets. Electricity forms the major input of the conversion process and is usually traded on sequential markets. The general strategy of an electrolyser is to buy electricity and produce hydrogen or methane whenever the electricity price is below (or equal to) the expected revenues to be achieved. This is the case particularly in situations with a high infeed from technologies with low marginal costs, such as variable RESs. Consequently, relevant market segments are spot markets, i.e. day-ahead and intraday markets. Moreover, electrolyzers might provide balancing services—e.g. the provision of positive control reserve through the reduction of electricity consumption (see also Guandalini et al., 2015).

When considering PtG as an option to decarbonise other sectors, a closer look at its regulatory treatment is needed. As mentioned above, PtG facilities consume electricity to produce hydrogen or methane. Given the existence of mainly small-scale demonstration projects, electrolyzers have so far been treated as end consumers under European jurisdictions. Consequently, the environmental components of electricity prices, e.g. CO₂ prices or levies, impact the procurement and operation costs of electrolyzers. For instance, in Germany, the consumed electricity of electrolyzers is (partly) taxed with environmental levies. More importantly, the avoided CO₂ emissions associated with the use of green hydrogen or methane in other sectors are not credited under today's regulatory framework. This results from the European Emissions Trading Scheme (EU-ETS) not covering all relevant sectors. Consequently, the costs of synthetic gases do not reflect their true CO₂ abatement costs. Overall, this leads to relatively high production costs for electrolysis and inconsistent economic incentives across different sectors.

This paper studies the role of the regulatory framework for the future integration of PtG facilities into the European power market from a company and an energy system perspective. With special attention to CO₂ pricing, we aim to answer the question of whether consistent pricing of CO₂ emissions can support the development of PtG. By 'consistent' we understand that the design of environmental levies, as well as the pricing and crediting of CO₂ emissions, should create

incentives for the utilisation of PtG reflecting the value of CO₂ emissions avoided by hydrogen or methane. To the authors' knowledge, only Guandalini et al. (2015) have so far included a carbon tax in their analysis, but with a focus on a small-scale power system and without an in-depth examination of its incentives and regulatory implications. We therefore use an optimisation model covering the electricity and heating markets and extend the model by PtG technologies and competing flexibilities, such as storage and demand-side management. We develop several scenarios with regard to levies, levels of CO₂ price, techno-economic parameters of flexibilities and shares of variable RESs for the year 2025 and study the implications using the example of Germany. Consequently, our focus is not to evaluate long-term transition paths for PtG but to assess and describe the impacts of incentive schemes as an input for political decisions regarding a reduction of entry barriers during the energy transition.

The remainder of this paper is organised as follows. After briefly introducing the utilised market model, we explain the methodology for modelling PtG technologies and other flexibility options in Section 2. We subsequently describe the scenario framework and data in Section 3. When discussing the results in Section 4, we focus on the impacts of levies, CO₂ pricing and RES share on PtG as well as the potential interactions with other flexibility options. The study concludes by drawing recommendations for policy makers.

2 General effects of CO₂ pricing on power-to-gas

The conversion of electricity to hydrogen or methane creates a link between the electricity sector and other sectors, such as gas, industry or transport (see also Figure 4). The pricing of CO₂ emissions has a longer history in the electricity sector but is also gaining importance in other sectors. However, as electricity is the major input for the conversion process, we focus on the pricing of CO₂ emissions in the electricity sector and its effects on PtG in this section.

Böcker & Weber (2015) show that the value of the converted gas corresponds to the opportunity costs of the gas users, which arise when they use other fuels. It is hence mainly determined by the natural gas price c_t^{gas} and corresponding costs for CO₂ certificates c_t^{CO2} . This assumes unlimited storage capacity (of the gas infrastructure) and a situation where the gas users, e.g. gas-fired power plants, have the choice to use either the output of the PtG facility or conventional natural gas. According to Equation (1), we define the *use value* $\xi_t^{PtG,use}$ of the respective PtG technology as:

$$\xi_t^{PtG,use} = (c_t^{gas} + f_{gas}^{CO2-factor} \cdot c_t^{CO2}) \cdot \eta_{PtG} \quad (1)$$

Restrictions (2) and (3) are obtained as Karush-Kuhn-Tucker (KKT) condition from the first order derivatives with respect to the electricity consumption W_t^{DA} and the contribution margin π_t of

the Lagrangian of the corresponding linear optimisation problem (Böcker & Weber, 2015). Accordingly, an electrolyser consumes electricity ($W_t^{DA} > 0$) when the left-hand side of restriction (2) is satisfied with equality. This implies that the procurement costs determined by the electricity market price λ_t^{el} are lower than (or equal to) the use value $\xi_t^{PtG,use}$, which is derived from the value of the converted gas under consideration of the conversion rate. Otherwise, the electrolyser would be out of the money and the contribution margin π_t would get negative violating restriction (3).

$$\xi_t^{PtG,use} - \lambda_t^{el} - \pi_t \leq 0 \perp W_t^{DA} \geq 0 \quad (2)$$

$$W_t^{DA} \leq w^{MAX} \perp \pi_t \geq 0 \quad (3)$$

The electricity market price λ_t^{el} in turn is determined by the variable generation costs of the marginal generation unit u which are determined by fuel costs c_t^{fuel} , costs of CO₂ certificates c_t^{CO2} , conversion rate η_u and other variable operation and maintenance costs $c_u^{O\&M}$ (see Equation (4)):

$$\lambda_t^{el} = \frac{c_t^{fuel} + f_{fuel}^{CO2-factor} \cdot c_t^{CO2}}{\eta_u} + c_u^{O\&M} \quad (4)$$

Consequently, whenever a generation technology with marginal generation costs lower than (or equal to) the *use value* is price-setting, the PtG facility will have an incentive to operate and convert electricity to hydrogen or methane.

In the context of a simple supply stack (or merit order) model, we can derive the (mirrored) price duration curve and subsequently determine the utilisation hours of the PtG facility that are given at the intersection of the *use value* with the price curve (see e.g. Kirschen & Strbac, 2019; Stoft, 2002). Figure 1 schematically depicts this principle, whereby two *use values* are differentiated. Here, it must be noted that the *use value* $\xi_t^{PtG,use}$ as defined above includes the value of the CO₂ emissions avoided by synthetic gas. This implicitly assumes that the current regulatory framework entails a crediting (or accounting) of the CO₂ emissions avoided by hydrogen or methane, which is not the case. Consequently, in our analysis, we will differentiate between a *use value* with crediting the avoided CO₂ emissions and a *use value* without crediting the avoided CO₂ emissions. Considering Equation (1), the *use value* that includes crediting the avoided CO₂ emissions will be higher than the one without crediting, impacting the utilisation of PtG, as indicated in Figure 1.

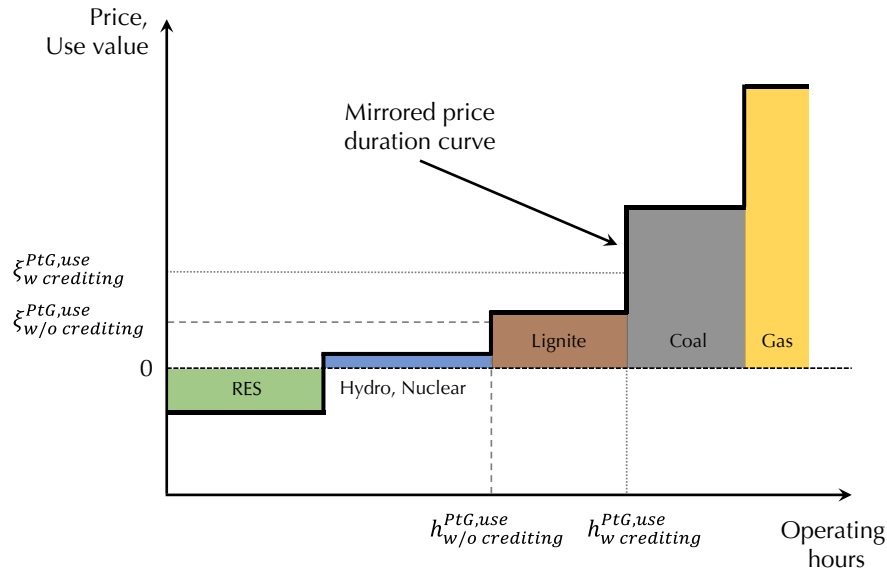


Figure 1: Schematic representation of the utilisation of PtG
 * Marginal generation technologies indicated by colour

Moreover, Figure 1 implies that electrolyzers might run during hours when CO₂-neutral, but also CO₂-emitting, technologies are setting the prices in electricity markets¹. However, when it comes to reaching climate targets, primarily ‘green’ hydrogen or methane will be able to support the decarbonisation of other sectors. Consequently, PtG facilities should have an incentive to operate when electricity market prices are set by CO₂-neutral technologies. However, the following analysis reveals that, in the case of low prices for CO₂ certificates, CO₂-emitting generation technologies based on lignite or hard coal may also set electricity prices partly well below the use value of PtG. Thus, the underlying energy mix of the produced hydrogen or methane would not be CO₂-neutral nor support climate targets.

Figure 2 shows the cost curves of different generation technologies based on fuel prices from selected studies and scenarios for the year 2025². For reasons of simplicity, the figure depicts the corridor of generation costs for each fuel type, given by the minimum and maximum cost curve. While the costs for CO₂-neutral technologies, such as RESs or nuclear, remain constant, the variable costs for CO₂-emitting power plants, such as lignite, hard coal or gas fired plants, increase with a rising CO₂ price.

¹ This is supported by a simplified analysis of the prices and marginal technologies for the German electricity market in 2018 as shown in Figure 17 in the appendix.

² For the further calculations in this paper, fuel prices are based on respective future prices from 2019 (see also Section 4.1). The fuel prices from the IEA WEO and the grid development plan of the German TSOs relate to 2025 or 2030.

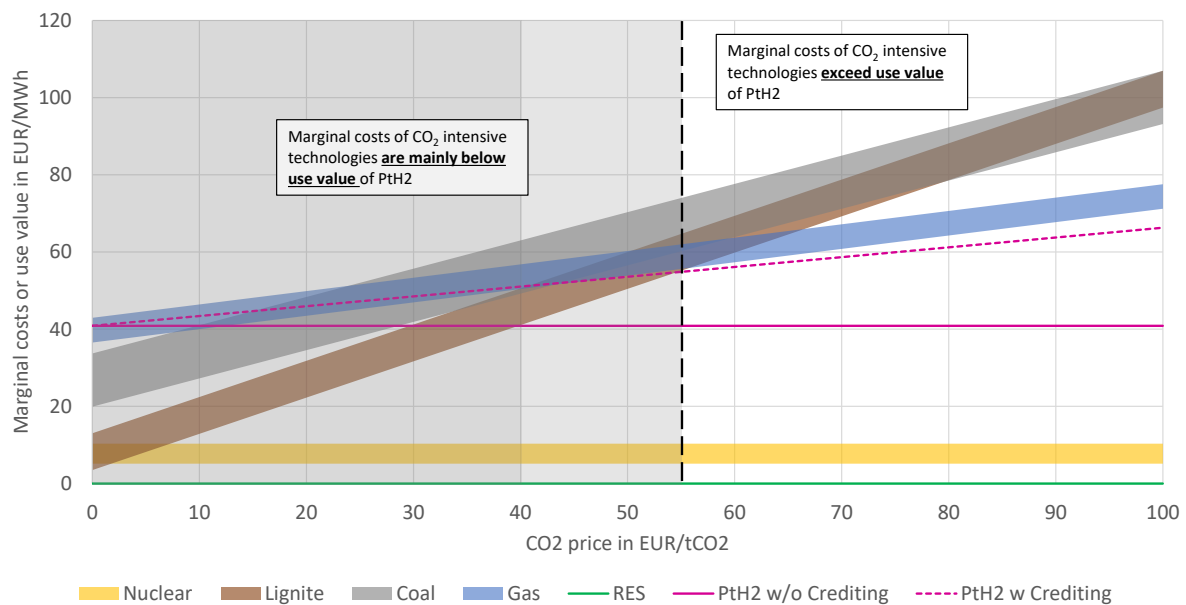


Figure 2: Variable cost curves of generation technologies and use values of PtH₂ for different CO₂ prices
Sources: DENA, 2018; energate, 2020; International Energy Agency, 2018; ÜNB, 2017, 2019

Of special interest is the part of the graph where the marginal costs of CO₂-emitting technologies are below the use value of PtH₂ (see the purple line in Figure 2). Consequently, at CO₂ prices of up to 40 EUR/tCO₂ (the intersection of PtH₂ w/o Crediting and Lignite or dark grey area in Figure 2), electrolyzers would have an incentive to operate when CO₂-emitting technologies are price-setting. In case the substituted natural gas is also subject to CO₂ pricing (or equivalently the electrolyser output receives carbon credits for substituting fossil fuels), this effect is even more pronounced as the increasing use value of PtH₂ (see the purple dotted line in Figure 2) shifts the intersection up to CO₂ prices of 55 EUR/tCO₂ (dark + light grey area). Although the analysis is limited to some selected studies, this simple comparison already reveals the adverse effect of low CO₂-prices on the utilisation of PtG, compromising the objective of supporting the decarbonisation of other sectors.

In the case of PtM, this adverse effect is comparatively low, as the use value of PtM (see the cyan line in Figure 3) is less than that of PtH₂ (given the lower conversion rate) and as most CO₂-emitting technologies have marginal generation costs higher than the use value. Consequently, only at very low CO₂-price levels (13 EUR/tCO₂ in our example below) would the marginal costs of lignite be lower than the use value of PtM.

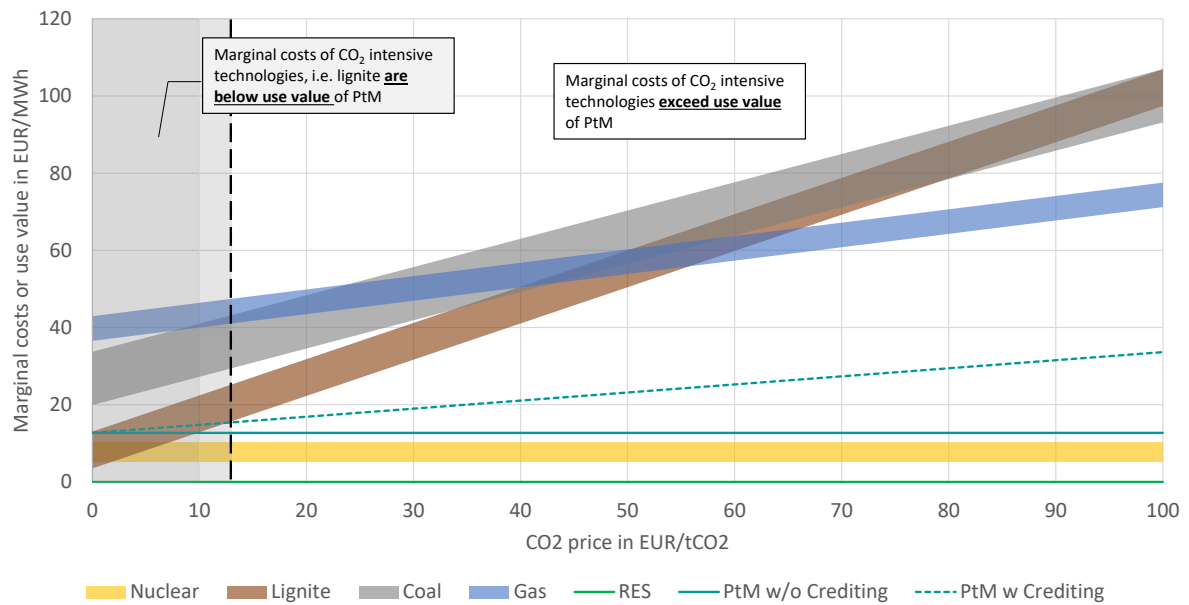


Figure 3: Variable cost curves of generation technologies and use values of PtM for different CO₂ prices
Sources: DENA, 2018; energate, 2020; International Energy Agency, 2018; ÜNB, 2017, 2019

When it comes to carbon pricing, the general setup introduced in this section implies two short-term effects on the utilisation of PtG:

1. **Generation cost effect:** the CO₂ price (together with the fuel price) determines the marginal generation costs of CO₂-emitting technologies and resulting market prices. Consequently, higher CO₂ prices lead to increased marginal generation costs and higher electricity prices. As a result, the utilisation of PtG is reduced.
2. **Use value effect:** the CO₂ price determines the value of the CO₂ emissions avoided by synthetic gas (see Equation (1)). Consequently, increased CO₂ prices lead to an increase in the value of the avoided emissions and the use value. As a result, the utilisation of PtG increases.

In the mid-term, the described generation cost effect might be balanced by investments in RESs and the corresponding merit order effect may result in a decrease in electricity prices (e.g. Sáenz de Miera et al., 2008; Weber & Woll, 2007). Moreover, the two effects will impact the CO₂ emissions leading to indirect effects in emissions trading systems. Price and volume effects of short-term changes of CO₂ emissions will yet spread over several years due to banking and borrowing mechanisms. For the sake of simplicity, we will refrain from considering such intertemporal effects in this study.

3 Methodology

3.1 Joint market model

To study the impact of CO₂ pricing on PtG quantitatively, we further develop and deploy the joint market model (JMM). The model allows for determining the dispatch of power plants and storages subject to techno-economic constraints. It is formulated as a linear optimisation problem and covers the European power system. It uses a rolling planning approach to consider sequential market design and reduce computational time. In the following, we focus on the day-ahead market, as we assume perfect foresight and do not consider information updates, such as forecasts of variable renewables during intraday. In this section, we concentrate on equations relevant to modelling PtG and other flexibility options. A more detailed model description can be found in Meibom et al. (2011), Trepper et al. (2015) and Weber et al. (2009).

The objective function corresponds to a minimization of variable system operation costs over the entire optimisation period, including costs for fuel $c_{a,t}^{fuel}$, CO₂ certificates $c_{a,t}^{CO_2}$, operation and maintenance $c_{a,i}^{O\&M}$ and start-up procedures $c_{a,i}^{STARTUP}$. Due to the rolling planning approach, an economic value has to be attributed to having energy collected in hydro, pumped and battery storages at the end of each optimisation period. Correspondingly, the shadow value $Sp_{a,i}^{STORAGE}$ of the content of storages $V_{a,i,T}^{STORAGE}$ at the last time step T of the planning horizon reduces the overall operation costs. For simplicity, further costs, such as variable costs for the provision of heat or taxes and subsidies, are not included in Equation (5).

$$\begin{aligned} \min C; C = & \sum_{i \in I^{DISPATCH}} \sum_{a \in A} \sum_{t \in T} \left(\frac{c_{a,t}^{fuel} + f_{fuel}^{CO_2} c_{a,t}^{CO_2}}{\eta_i} + c_{a,i}^{O\&M} \right) P_{a,i,t}^{DA} \\ & + \sum_{i \in I^{ONLINE}} \sum_{a \in A} \sum_{t \in T} c_{a,i}^{STARTUP} P_{a,i,t}^{STARTUP} \\ & - \sum_{i \in I^{STORAGE}} \sum_{a \in A} Sp_{a,i}^{STORAGE} V_{a,i,T}^{STORAGE} \end{aligned} \quad (5)$$

The core balance constraint of the JMM ensures that the electricity demand $d_{r,t}^{ELEC}$ on the day-ahead market is covered in all 8,760 hours of the year³:

$$\begin{aligned} \sum_{i \in I_{a(r)}^{DISPATCH}} P_{a,i,t}^{DA} + p_{r,t}^{RES} - p_{r,t}^{RES_{CURT},DA} + \sum_{(\bar{r},r) \in RR} (1 - \delta_{\bar{r},r}) \cdot P_{\bar{r},r,t}^{TRANS,DA} \\ = d_{r,t}^{ELEC} + \sum_{i \in I_{a(r)}^{STORAGE}} W_{a,i,t}^{DA} + \sum_{(r,\bar{r}) \in RR} P_{r,\bar{r},t}^{TRANS,DA} \end{aligned} \quad (6)$$

$$\forall t \in T^{SPOT}, r \in R$$

³ Equation (6) shows a reduced representation of the balance constraint regarding transmission and curtailment variables.

The electricity demand has to be met by production from hydro-thermal power plants $P_{a,i,t}^{DA}$, infeed from variable renewable energy sources $p_{r,t}^{RES}$ reduced by eventual curtailments $P_{r,t}^{RES,CURT,DA}$ and imports from neighbouring regions $P_{\bar{r},r,t}^{TRANS,DA}$. Moreover, the consumption from storages $W_{a,i,t}^{DA}$ and exports $P_{r,\bar{r},t}^{TRANS,DA}$ have to be covered. In this contribution, the cross-border trading of electricity is modelled based on a linear transportation model using the net transfer capacity (NTC) approach.

The modelling of regional heat markets depicts the potential constraints for the dispatch of combined heat and power (CHP) plants on the electricity market. Moreover, the dispatch of conventional power plants and storage is affected by the demand for ancillary services. Accordingly, the model includes the provision of control reserve power capacity, which is procured at the day-ahead stage. Equation (7) shows the general implementation of the corresponding demand restrictions for each control zone z , whereby the demand for control reserve $d_{z,t}^{ANC,\pm}$ is covered by reserved capacity from conventional generation units $P_{a,i,t}^{ANC,\pm}$ and storages $W_{a,i,t}^{ANC,\pm}$ located in the control zone. In the model, further similar restrictions are considered for modelling three different types of reserves implemented in most European power markets and positive and negative products (for upward and downward regulation).

$$\sum_{i \in I_{a(z)}^{ELEC}} P_{a,i,t}^{ANC,\pm} + \sum_{i \in I_{a(z)}^{STORAGE}} W_{a,i,t}^{ANC,\pm} = d_{z,t}^{ANC,\pm} \quad (7)$$

$$\forall z \in Z, t \in T^{SPOT}$$

The participation of generation and storage technologies in control reserve markets requires their technical capability for reserve provision, which is considered through an input parameter. The model includes further technical restrictions, such as start-up times, minimum operation and down times, part load efficiencies and minimum and maximum generation.

The modelled market prices correspond to the marginal generation costs. Further model results comprise the dispatch of hydro-thermal generation units, exchange balances, load or renewables curtailment and CO₂ emissions. In this contribution, we do not consider investment decisions. Nevertheless, the determination of contribution margins (i.e. revenues from the electricity markets minus variable and fixed operation costs) allows drawing conclusions with regard to the profitability and investment incentives.

Analysing the role of PtG in electricity markets requires the modelling of competing flexibility options, which enable a temporal shifting of electricity generation or consumption. In this paper, pumped storage and industrial DSM are considered besides PtG. Further flexibility options, such

as heat pumps with heat storage and electric vehicles, are expected to become more relevant beyond the scenario year 2025 of this study. The modelling is similar for all flexibility options using a slightly differing storage approach. While pumped storages are treated as physical storages, PtG and industrial DSM can be modelled as virtual storages as presented in the following.

3.2 Modelling of power-to-gas

While a distinction between PtM and PtH₂ can be made through different input parameters (i.e. conversion rate and use value), the general implementation of PtG is described in the following. As the focus of this contribution is on the economic perspective and interactions between the electricity market, CO₂ price and PtG, we refrain from a detailed technical modelling of the conversion process and a consideration of the demand for methane or hydrogen. As described in Section 2, the PtG facility is utilised when the electricity price is lower than (or equal to) the use value, corresponding to the value of the converted gas. This general strategy forms the basis for our implementation, which is shown schematically in Figure 4.

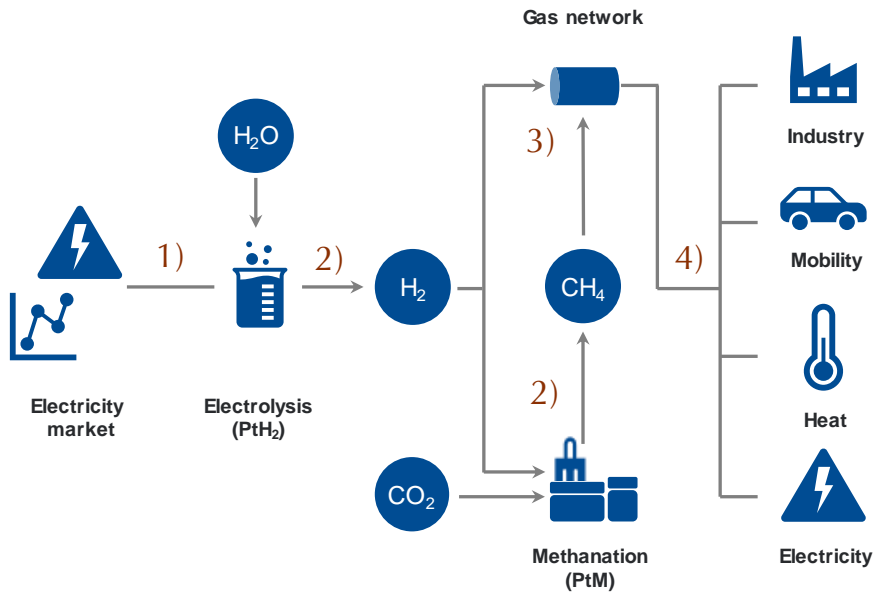


Figure 4: Schematic representation of the PtG process

The utilisation of a PtG facility leads to an additional electricity consumption $W_{t,a,i}^{DA}$ on the electricity market in a specific area a in the system (see step 1) in Figure 4). In general, the electricity is converted to synthetic gas, which is then fed into a gas network (see steps 2) and 3) in Figure 4). This process can be interpreted as filling a virtual storage, whereby the variable $V_{t,a,i}^{PtG}$ denotes the storage filling level in Equation (8). Moreover, the conversion is associated with losses considered via the conversion rate $\eta_{a,i}$.

$$V_{t,a,i}^{PtG} = V_{t-1,a,i}^{PtG} + \eta_{a,i} \cdot W_{t,a,i}^{DA} - P_{t,a,i}^{PtG} \quad (8)$$

$$\forall a \in A, i \in I^{PtG}, t \in T$$

To model the extraction of synthetic gas from the gas network, the decision variable $P_{t,a,i}^{PtG}$ is introduced into Equation (8) (see also step 4) in Figure 4)⁴. For simplicity, the reconversion of synthetic gases to electricity is not considered in this case study. It is assumed that these gases are used in other sectors, e.g. industry or mobility, so that storage discharging does not contribute to the electricity generation of the system.

The implementation of PtG requires adjustments to the objective function and the relevant balance equations (indicated in grey in the following). Correspondingly, the objective function is extended by the decision variable $P_{a,i,t}^{PtG}$ together with the use value, which represents an input parameter, as determined by Equation (1).

$$\min C'; C' = C - \sum_{i \in I^{PtG}} \sum_{a \in A} \sum_{t \in T} \xi_{a,i,t}^{PtG,use} P_{a,i,t}^{PtG} \quad (9)$$

The electricity consumption of the electrolyser $W_{t,a,i}^{DA}$ is added to the balance constraint according to Equation (6) and increases the electricity demand that has to be covered by generation and imports:

$$\begin{aligned} \sum_{i \in I_{a(r)}^{DISPATCH}} P_{a,i,t}^{DA} + p_{r,t}^{RES} - p_{r,t}^{RES,SCURT,DA} + \sum_{(\bar{r},r) \in ERR} (1 - \delta_{\bar{r},r}) \cdot P_{\bar{r},r,t}^{TRANS,DA} \\ = d_{r,t}^{ELEC} + \sum_{i \in I_{a(r)}^{STORAGE}} W_{a,i,t}^{DA} + \sum_{i \in I_{a(r)}^{PtG}} W_{a,i,t}^{DA} + \sum_{(r,\bar{r}) \in ERR} P_{r,\bar{r},t}^{TRANS,DA} \end{aligned} \quad (10)$$

$$\forall t \in T, r \in R$$

PtG facilities can take part in the provision of reserve capacities. In the case of an electricity surplus and the need for negative reserve power, the utilisation of a PtG facility and therefore the electricity consumption can be increased, whereas positive reserves can be provided by decreasing the utilisation.

$$\sum_{i \in I_{a(z)}^{ELEC}} P_{a,i,t}^{ANC,\pm} + \sum_{i \in I_{a(z)}^{STORAGE}} W_{a,i,t}^{ANC,\pm} + \sum_{i \in I_{a(z)}^{PtG}} W_{a,i,t}^{ANC,\pm} = d_{z,t}^{ANC,\pm} \quad (11)$$

$$\forall z \in Z, t \in T$$

⁴ Due to the focus on electricity markets, the extraction of synthetic gases and its usage in other sectors is not further considered in this contribution.

According to restriction (12), the electricity consumption $W_{t,a,i}^{DA}$ including the provision of negative control reserve power $W_{t,a,i}^{ANC,-}$ (through additional electricity consumption) is restricted by a maximum filling rate per hour (MWh/h), which corresponds to the installed PtG capacity $w_{a,i}^{MAX}$.

$$W_{t,a,i}^{DA} + W_{t,a,i}^{ANC,-} \leq w_{a,i}^{MAX} \quad (12)$$

$$\forall a \in A, i \in I^{PtG}, t \in T$$

Constraint (13) ensures that the provision of positive control reserve power $W_{t,a,i}^{ANC,+}$ (through reduced electricity consumption) does not exceed the planned electricity consumption $W_{t,a,i}^{DA}$.

$$W_{t,a,i}^{DA} - W_{t,a,i}^{ANC,+} \geq 0 \quad (13)$$

$$\forall a \in A, i \in I^{PtG}, t \in T$$

The maximum storage capacity $v_{a,i}^{PtGMAX}$ is chosen with regard to the maximum tolerance level of the gas infrastructure for synthetic gases. According to constraint (14), the content of the storage $V_{t,a,i}^{PtG}$ is further restricted in case of provision of control reserve power $W_{a,i,t}^{ANC,-}$, i.e. reservation of storage capacity for providing negative control reserve through additional electricity consumption. However, due to the high storage capacity of the gas network in comparison to the installed PtG capacity, the influence of the assumed maximum storage capacity is limited and the value of the gas does not change over time.

$$V_{t,a,i}^{PtG} + \eta_i \cdot W_{a,i,t}^{ANC,-} \cdot \Delta t \leq v_{a,i}^{PtG,MAX} \quad (14)$$

$$\forall a \in A, i \in I^{PtG}, t \in T$$

To include PtG in the JMM based on the approach described in this section, the following parameters must be defined:

- Installed electrolyser capacity $w_{a,i}^{MAX}$ [MW]
- Conversion rate η_i [-]
- Use value $\xi^{PtG,use}$ [Euro/MWh]
- Maximum storage capacity $v_{a,i}^{PtGMAX}$ [MWh]
- Minimum storage capacity $v_{a,i}^{PtGMIN}$ [MWh]

3.3 Modelling of demand-side management

To include the load shifting of industrial DSM, virtual storages are also implemented into the market model. Consequently, additional electricity consumption is modelled through loading the storage, whereas reduced electricity consumption is considered via unloading the storage.

A filling-level-balancing equation ensures intertemporal relationships between loading $W_{t,a,i}^{DA}$, unloading $P_{t,a,i}^{DA}$ and the filling level $V_{t,a,i}^{STORAGE}$ subject to standstill losses δ_i^{STAND} , e.g. for cooling down of intermediate thermal storages.

$$V_{t,a,i}^{STORAGE} = (1 - \delta_i^{STAND}) \cdot V_{t-1,a,i}^{STORAGE} + \eta_i^{LOAD} \cdot W_{t,a,i}^{DA} - \frac{1}{\eta_i^{UNLOAD}} \cdot P_{t,a,i}^{DA} \quad (15)$$

$$\forall a \in A, i \in I^{DSM}, t \in T$$

It has to be noted that the modelling of DSM makes use of the decision variables already implemented in the modelling of pumped storages. Consequently, the loading and unloading according to Equation (15) are also included in the core balance constraint (see Equation (6) or (10)).

The loading is restricted by the corresponding capacity for available DSM. By analogy with constraint (12), the sum of the loading $W_{t,a,i}^{DA}$ plus the provision of negative control reserve power $W_{t,a,i}^{ANC,-}$ has to be less or equal the loading capacity $w_{a,i}^{MAX}$. In line with restriction (13), a further constraint ensures that the provision of positive control reserve power $W_{t,a,i}^{ANC,+}$ (through reduced electricity consumption) does not exceed the planned electricity consumption $W_{t,a,i}^{DA}$.

Similar to the modelling of PtG, the filling level of the virtual storage for DSM is limited by an upper bound and a lower bound restriction, representing the maximum and minimum storage capacities, respectively. Deviating from constraint (14), restriction (16) also includes the option of providing negative control reserve $P_{a,i,t}^{ANC,-}$ through reduced unloading of the storage.

$$V_{t,a,i}^{STO} + \eta_i^{LOAD} \cdot W_{t,a,i}^{ANC,-} + \frac{1}{\eta_i^{UNLOAD}} \cdot P_{a,i,t}^{ANC,-} \leq v_{a,i}^{STO,MAX} \quad (16)$$

$$\forall a \in A, i \in I^{DSM}, t \in T$$

In contrast to the other flexibility options, the filling level of industrial DSM can be negative. Therefore, the minimum storage capacity $v_{a,i}^{STO,MIN}$ in constraint (17) is defined as a negative parameter. This reflects the possibility of load shifting to previous time steps.

$$V_{t,a,i}^{STO} - \frac{1}{\eta_i^{UNLOAD}} \cdot P_{t,a,i}^{ANC,+} - \eta_i^{LOAD} \cdot W_{t,a,i}^{ANC,+} \geq v_{a,i}^{STO,MIN} \quad (17)$$

$$\forall a \in A, i \in I^{DSM}, t \in T$$

To include DSM in the JMM based on the approach described in this section, the following parameters must be defined. One should also note that, for DSM, no losses are considered. The loading and unloading efficiency (η_i^{LOAD} and η_i^{UNLOAD}) are hence assumed to be 1.

- Load shifting potential (i.e. loading capacity) $w_{a,i}^{MAX}$ [MW]
- Costs of shifting load c^{DSM} [Euro/MWh]
- Maximum storage capacity $v_{a,i}^{STOMAX}$ [MWh]
- Minimum storage capacity $v_{a,i}^{STOMIN}$ [MWh]

4 Results and discussion

4.1 Data and scenario framework

The simulations cover the European electricity markets with a focus on a transitional period—namely, the year 2025. The analyses are performed using the example of Germany. The input data is based on publicly available information and is described in this section (with a focus on PtG). Further details can be found in Appendix A.

Time series for renewable infeed and demand profiles are based on the weather year 2016. ENTSO-E (2018a) and Eurostat (2018) provide power demand profiles and national annual power consumption, which are assumed to remain constant. The profiles for the renewable infeed are taken from Open Power System Data (2020) and scaled according to generation capacities for the year 2025. The assumed hydrothermal and renewable generation capacities are based on the ‘Best Estimate 2025’ scenario ENTSO-E (2018b). The installed generation capacities from bioenergy, other renewables and other non-renewables are assumed constant at the 2016 level. The cross-border exchanges between European countries were modelled using net transfer capacities from ENTSO-E (2018b) and Rippel et al. (2019).

The analyses are performed considering two scenario dimensions regarding different CO₂ price levels and regulatory frameworks impacting the use value of PtG. Fuel prices are based on the average 2022 futures prices from the second quarter of 2019 (energate, 2020). The average marginal costs for (modern) German lignite-, coal- and natural-gas-fired power plants are shown in Table 1. The CO₂ prices were chosen in such a way that the scenarios ‘moderate’ and ‘ambitious’ induce a fuel switch between natural gas and hard coal or lignite.

For both PtH₂ and PtM, 2 GW of installed capacity are assumed. This follows from a linear interpolation of the status-quo in Germany and the targets stipulated by the national hydrogen strategy (see also Figure 16 in Appendix B). The main difference between both technologies is in the conversion efficiency, which is assumed to be 0.73 for PtH₂ and 0.6 for PtM (for details, see Figure 14 and Figure 15 in Appendix A). The latter conversion rate includes the conversion from electricity to hydrogen and subsequently to methane. For PtM, the use value is determined by the natural gas price, assuming that the converted synthetic methane replaces natural gas in, for example, gas-fired power plants. Due to the focus on the mid-term, synthetic hydrogen is

assumed to be mainly used in the industrial sector replacing conventional hydrogen based on steam reforming (see e.g. IEA, 2019). Accordingly, the use value of PtH₂ can be determined by the hydrogen production cost from natural gas via steam reforming. We base the use value on the mean production cost of three recent studies (Dagdougui et al., 2018; IEA, 2019; Kayfeci et al., 2019), applying an adjustment to the natural gas price level used in the present study.

The considered use values are shown in Table 1 and distinguished between three different regulatory frameworks. The first regulatory setting assumes that electrolyzers are exposed to the EEG levy (as stipulated by the Renewable Energy Act (REA; in German, *Erneuerbare-Energien-Gesetz* (EEG)) and have to pay 60 Euro/MWh for the consumed electricity⁵. Consequently, accounting for the EEG levy leads to a negative use value, which means that the electrolyzers are utilised only in the case of clearly negative electricity prices below the respective use value.

Table 1: Scenario matrix: CO₂ prices, average marginal costs and use values

Scenario		CO ₂ low	CO ₂ mod	CO ₂ amb
CO₂ price	€/tCO ₂	26.00	66.75	107.50
Average marginal costs				
Lignite	€/MWh _{el}	28.80	67.73	106.66
Hard coal	€/MWh _{el}	44.15	78.20	112.25
Natural gas	€/MWh _{el}	53.03	69.73	86.43
Use value incl. EEG levy				
PtH ₂	€/MWh _{el}	-19.61	-	-
PtM	€/MWh _{el}	-47.28	-	-
Use value without CO₂ crediting				
PtH ₂	€/MWh _{el}	40.39	40.39	40.39
PtM	€/MWh _{el}	12.72	12.72	12.72
Use value with CO₂ crediting				
PtH ₂	€/MWh _{el}	47.03	57.45	67.86
PtM	€/MWh _{el}	15.87	20.81	25.75

For the other two regulatory settings, an exemption from the EEG levy is assumed, leading to positive use values. Furthermore, the two frameworks differ in terms of crediting the avoided CO₂ emissions. Under a framework without CO₂ crediting, the resulting use values are independent of the CO₂ price and hence constant for the three CO₂-price scenarios. In the case of crediting the avoided CO₂ emissions, the use value increases with an increasing CO₂ price, as electrolyzers receive a compensation for the CO₂ abatement in the industry or gas sector. For simplicity, this compensation is based on the same CO₂ price. For PtH₂, we assume avoided CO₂ emissions of 0.350 tCO₂/MWh by substitution of steam reforming (Parkinson et al., 2019). In the case of PtM,

⁵ According to a recent amendment of the REA, electrolyzers can be exempted from the EEG levy, i.e. when the consumed electricity is 100 % based on renewables and the renewables generation is not supported by the REA (Renewable Energy Act (EEG 2021), 2021). Since 2014 the EEG levy ranges between 61.70 and 68.80 Euro/MWh (cf. ÜNB, 2020). The considered 60 Euro/MWh for the year 2025 represent a lower bound and assume a continuation of the stabilisation of the EEG levy by State resources (cf. BMWi, 2020a).

the avoided CO₂ emissions are determined by the CO₂ intensity of the substituted natural gas, i.e. 0.202 tCO₂/MWh (see also Section 2) (Juhrich, 2016).

For comparison, we consider a reference scenario without the implementation of PtG. Moreover, we perform a sensitivity analysis covering selected parameters (see Appendix C). The technical parameters of PtG facilities (e.g. the conversion rate) remain the same in all scenarios and sensitivities.

4.2 Impact of levies and CO₂ pricing on power-to-gas

This section provides an overview of the model results, making a distinction between the system and market perspective⁶ and the individual perspective of the electrolyser.

4.2.1 System and market perspective

Generation and imports. Under a conventional regulatory framework, electricity consumption in PtG facilities is treated like any other consumption. This means in the case of Germany, that notably the EEG levy would be applied to the electricity consumption of an electrolyser, increasing its variable costs by (more than) 60 Euro/MWh (see also Section 4.1). This is considered under scenario *2-w PtG, EEG levy, CO₂ low*, where no utilisation of PtG occurs (or would only occur in the case of strong negative electricity prices). When this barrier is removed, the model results reveal a market-driven utilisation of 2.1 TWh of PtG—of PtH₂ in particular (compare scenarios *1-w/o PtG, CO₂ low* and *3-CO₂ low*). In general, considering PtG leads to additional electricity consumption and increasing generation or imports to balance supply and demand. As shown in Figure 5, the additional consumption is mainly provided by dispatchable generation technologies, such as lignite, hard coal and natural gas (+0.6 TWh), and imports from the neighbouring countries (+1.1 TWh).

⁶ Note that the system and the market perspective coincide under the assumption of perfectly competitive markets with price formation based on short-run marginal costs and costs in the system model reflecting all cost components paid by market participants.

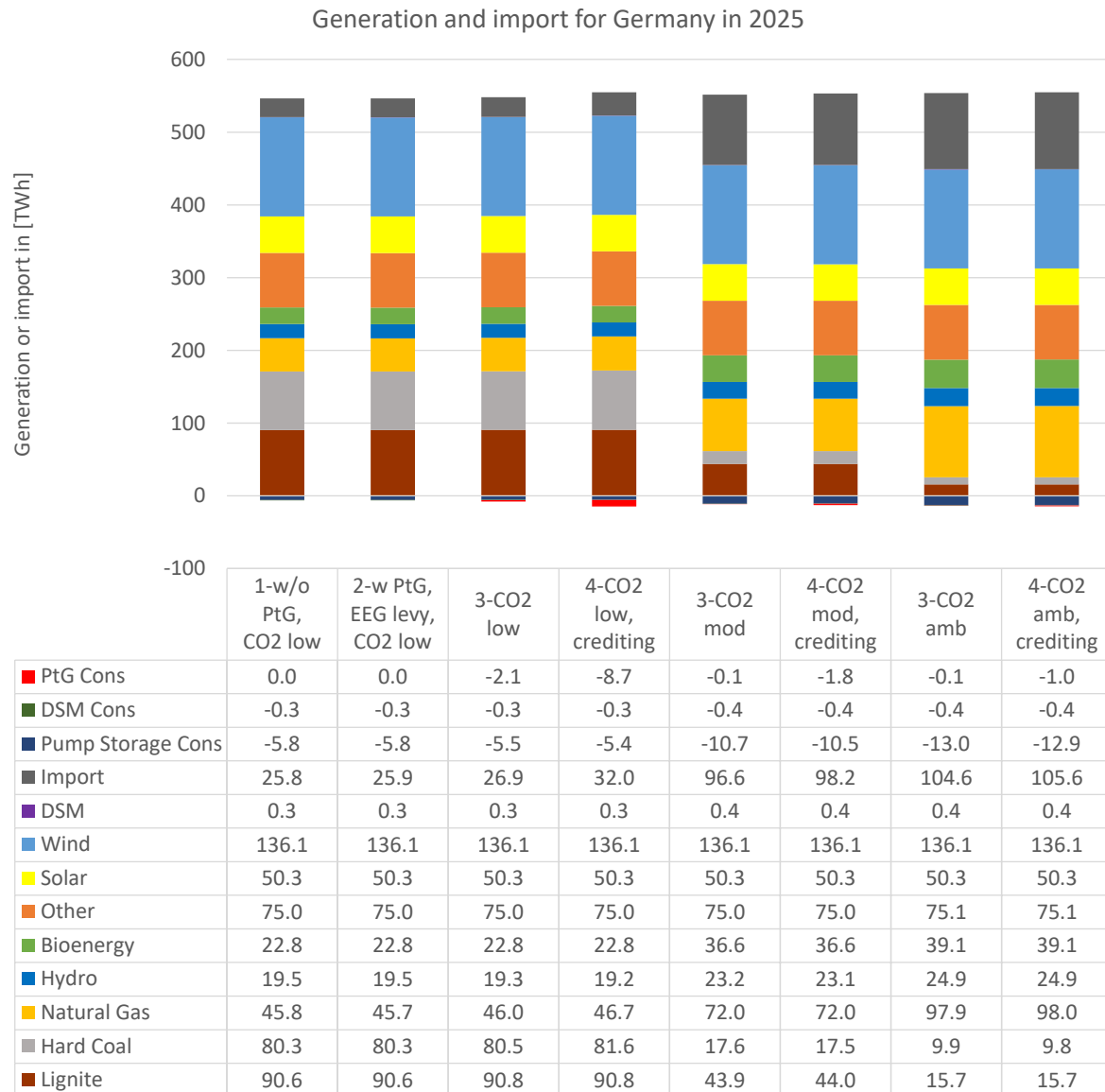


Figure 5: Generation and import for Germany in 2025 (Cons: consumption of flexibilities)

Instituting higher CO₂ prices is one of the key instruments of environmental policy. While this practice targets reducing CO₂ emissions, related interactions in electricity markets can be observed. Comparing scenarios *3-CO2 low*, *3-CO2 mod* and *3-CO2 amb*, we find a considerably lower overall generation from lignite and hard coal in Germany (from 171.3 TWh to 25.6 TWh). This reduction is mainly compensated by increasing generation from natural gas (+51.9 TWh) and higher imports from surrounding countries (+77.7 TWh from, e.g. France, the Netherlands, Austria and United Kingdom). The differences between scenarios *3-CO2 mod* and *3-CO2 amb* are relatively smaller than those between *3-CO2 low* and *3-CO2 mod*, showing that even a limited increase in the CO₂ price may cause a remarkable change in the generation mix. The fuel switch from coal to gas with an increasing CO₂ price comes along with a lower provision of flexibility and balancing services by coal plants, mainly compensated by pumped storage plants. However, for PtG, we find decreasing utilisation, as higher CO₂ prices result in higher electricity

prices, which in turn push the electrolyzers out of the market (decrease of utilisation from 1.9 TWh to 0.1 TWh).

In this context, the crediting of avoided CO₂ emissions associated with hydrogen and methane deserves particular attention. As introduced in Section 4.1, CO₂ crediting for PtG leads to a higher use value, which in turn increases the number of hours with PtG being in the money. For this reason, we find a considerably higher utilisation of PtG under scenario *4-CO₂ low crediting*. The additional electricity consumption from electrolyzers is mainly supplied by higher imports, partly from increased hard coal and lignite generation in the Czech Republic and Poland and generation from hard coal and natural gas in Germany. The latter result is an adverse effect of CO₂ crediting in the case of too low CO₂ prices, since the marginal costs of CO₂-intense technologies are lower than the use value of PtG. Comparing scenarios *4-CO₂ low crediting*, *4-CO₂ mod crediting* and *4-CO₂ amb crediting*, we again find a decreasing utilisation of PtG with increasing CO₂ prices. However, this effect is partly compensated for by the higher use value through the crediting of avoided CO₂ emissions (cf. the *generation cost* and *use value effect* in Section 2). Regarding the provision of control reserves, PtG makes no difference for the transition period, as balancing reserves are provided by conventional technologies at lower costs and by DSM with increasing CO₂ prices and RES shares (see also Figure 24 in Appendix B).

Electricity prices. The increased electricity consumption from electrolyzers leads to increasing market prices. Although this effect is smaller than the effect of increased CO₂ prices, the electricity prices mirror the effects regarding the generation, imports and utilisation of PtG discussed above. Under all scenarios with crediting the avoided CO₂ emissions from green hydrogen and methane, there is an increase in electricity prices compared with a situation without CO₂ crediting (compare scenario families 3 and 4 in Figure 6). This result is driven by the use value effect and the corresponding higher utilisation of PtG. However, it must be noted that with increasing CO₂ prices, this effect is partly compensated by the generation cost effect leading to a lower utilisation of PtG.

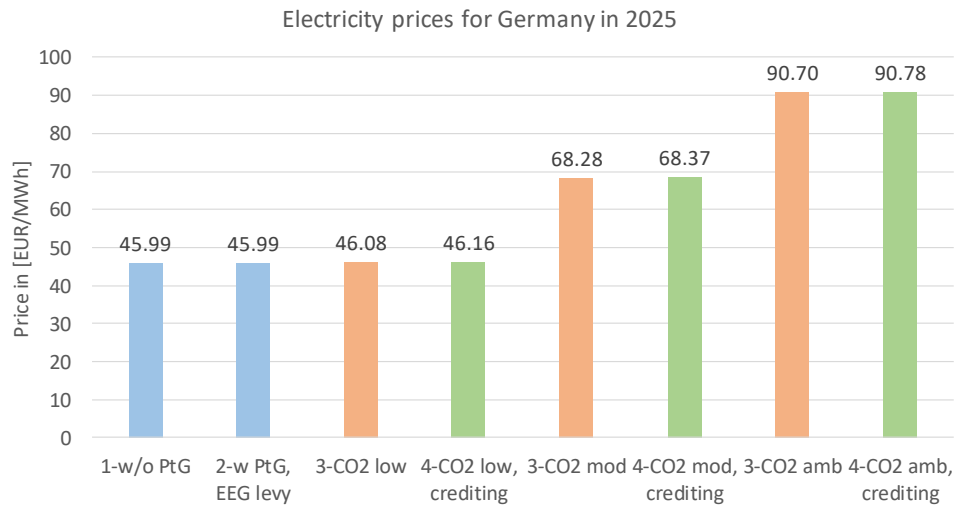


Figure 6: Electricity prices for Germany in 2025

Moreover, we find a higher volatility of electricity prices (5.89 to 17.72 €/MWh) with increasing CO₂ prices, indicating a higher value of flexibility and supporting the increased utilisation of flexibility options. However, flexibility is provided by DSM and pumped storage plants rather than PtG.

CO₂ emissions. The reductions of CO₂ emissions for Germany are in line with the impacts on the generation mix. Consequently, we find decreasing CO₂ emissions with an increasing CO₂ price. As shown in Figure 7, emissions reductions are relatively higher for the moderate scenario, which is driven by the coal–gas switch already occurring in this scenario. With regard to crediting the avoided CO₂ emissions of hydrogen or methane, we observe increasing CO₂ emissions of up to 1.1 Mt CO₂ in the electricity sector in Germany, since the additional utilisation of PtG is (due to adverse effects) associated with higher generation from lignite, hard coal and natural gas plants. As mentioned above, the additional consumption from electrolyzers is further compensated by imports, leading to an additional 2.9 Mt CO₂ at a European scale. With an increasing level of the CO₂ price, this effect (almost) disappears, which can be mainly attributed to the generation cost effect and corresponding lower utilisation of PtG but also to the decreasing role of lignite and hard coal.

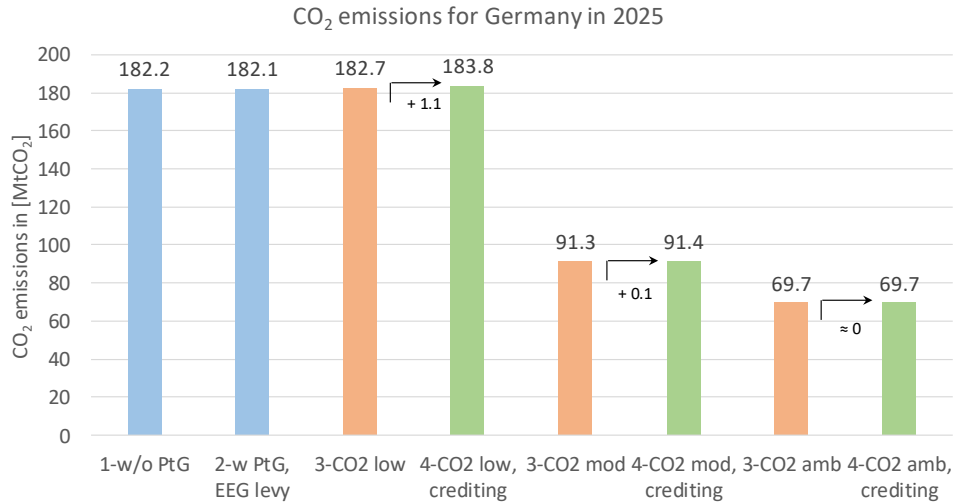


Figure 7: CO₂ emissions for Germany in 2025

4.2.2 Perspective of the electrolyser

To better understand the interactions between PtG, carbon pricing and electricity markets, the operator perspective is also relevant. In this context, indicators such as utilisation hours and contribution margins provide insights into incentives for the operation and expansion of PtG in Germany.

EEG levy. With exemption from the EEG levy, the utilisation of PtH₂ significantly increases from 0 to 953 hours per year, showing the effectiveness of the recent amendment of the EEG (see also Section 4.1). For PtM, utilisation slightly increases from 0 to 15 hours per year. This small effect can be explained by the lower conversion rate and the lower use value of methane as well as interdependencies with the resulting electricity market prices. However, as will be discussed later, care must be taken when electrolyzers are not operated on-site (e.g. in combination with a wind farm) but integrated into electricity markets.

Generation cost effect of CO₂ pricing. As already described in Chapter 2, the pricing of CO₂ emissions is associated with two different effects that are relevant for the utilisation of PtG: the *generation cost effect* and *use value effect*. The first effect describes the impact of a higher CO₂ price on the marginal generation costs of fossil-fired generation technologies. Consequently, during the hours when lignite, coal or gas power plants are price-setting, higher electricity market prices can be observed. For the utilisation of PtG, this means less hours with market prices below (or equal to) the use value (see Equation (2)). In other words, higher CO₂ prices and correspondingly higher electricity prices push PtG out of the electricity market. The effect on the utilisation hours of PtH₂ is shown in Figure 8. Under a setting without crediting the avoided CO₂ emissions (3-w/o crediting), a low CO₂ price of 26 Euro/tCO₂ is associated with a utilisation of 953 hours per year. With higher CO₂ prices, utilisation hours drop to 15 hours per year. Figure 8 also reveals that the *generation cost effect* is independent from the crediting of CO₂ emissions

avoided by synthetic hydrogen and hence can be observed under both settings (*3-w/o crediting* and *4-crediting*). For PtM, this effect does not occur under the considered scenario framework, as PtM is only utilised when renewable energy sources are setting the electricity market price (see Figure 9).

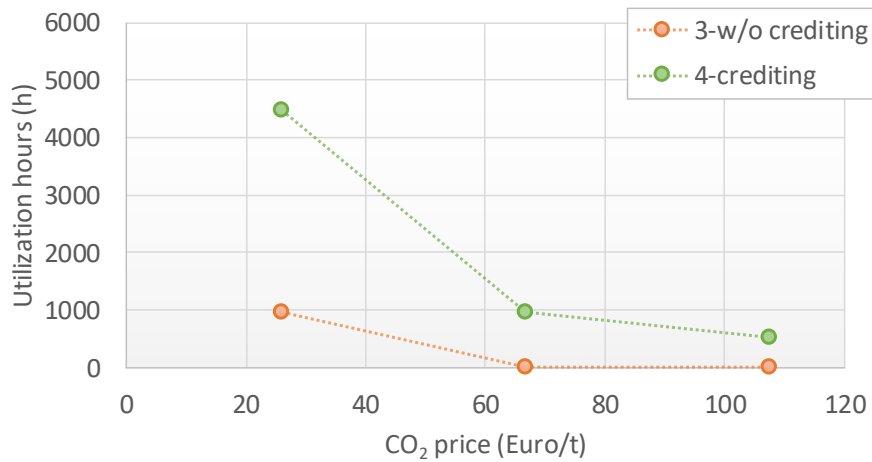


Figure 8: Utilisation hours per year of PtH₂

Use value effect of CO₂ pricing. The second effect materialises in the case of crediting the avoided CO₂ emissions, where a higher CO₂ price leads to a rising use value (see also Table 1 in Section 4.1). Again, for PtM, the utilisation hours are almost not influenced by this effect (see Figure 9). In contrast, for PtH₂, the higher use value due to crediting of avoided CO₂ emissions increases the utilisation hours under all CO₂ price scenarios (e.g. from 953 to 4479 hours per year for the low CO₂ price and from 15 to 529 hours for the ambitious CO₂ price). This effect dominates the *generation cost effect* but becomes less pronounced with increasing levels of CO₂ prices (see Figure 8). Nevertheless, the model results indicate that consistent CO₂ pricing with crediting of CO₂ emissions avoided by synthetic hydrogen supports the integration of PtH₂.

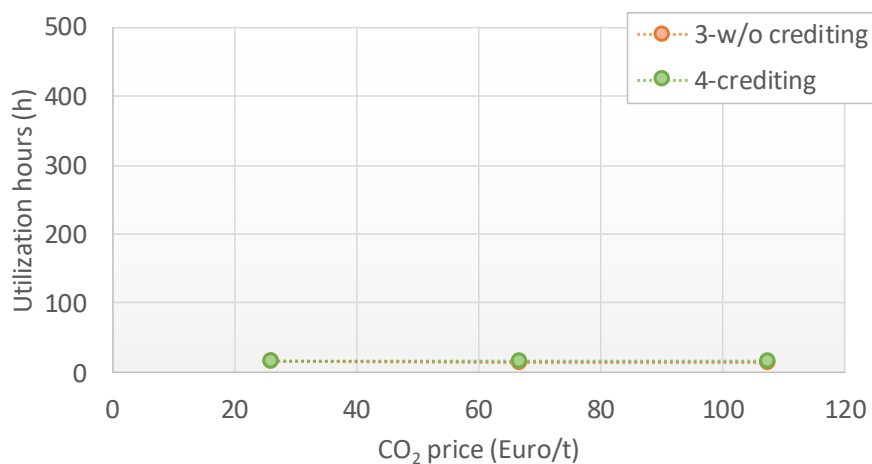


Figure 9: Utilisation hours per year of PtM

Market-driven investment incentives. The utilisation of PtG facilities is closely linked to profitability, which can be measured by contribution margins (calculated as the difference between revenues and variable costs). Given the link between utilisation and profitability, a similar picture emerges for the contribution margins of PtH₂ and PtM, as shown in Figure 10 and Figure 11. Without crediting the avoided CO₂ emissions, contribution margins are low and further decrease with increasing CO₂ prices due to the *generation cost effect*. When considering a framework with CO₂ crediting, contribution margins can be increased, reflecting the impact on utilisation hours, as discussed before. For PtH₂, the *use value effect* induces a considerable increase in the contribution margin, which is in the range of investment costs for alkaline electrolysis being achievable in the medium term (see low CO₂ price in Figure 10). However, in the case of increasing CO₂ prices, contrary effects on contribution margins can be observed, depending on whether the *generation cost effect* or the *use value effect* dominate. While for PtH₂ contribution margins decrease, they increase for PtM. In the latter case, the increasing CO₂ price does not impact utilisation as PtM is mainly utilised when renewables (and nuclear plants outside Germany) are price-setting (i.e. when market prices are below the use value). At the same time, a higher CO₂ price leads to increasing revenues (use value multiplied by converted quantity), as PtM is clearly in the money when operating and the use value effect leads to an increasing use value. In contrast, for PtH₂, increasing CO₂ and electricity prices lead to lower utilisation hours and contribution margins of PtH₂, which can only partly be compensated for by CO₂ crediting. As mentioned before, the *generation cost effect* dominates here the *use value effect* but becomes less pronounced with an increasing level of CO₂ prices. One reason for this is that PtH₂ is the marginal technology in up to 20% of the operating hours. As a result of the *generation cost effect* in the case of increasing CO₂ prices, PtH₂ is pushed out of the market during the corresponding hours, leading to lower revenues.

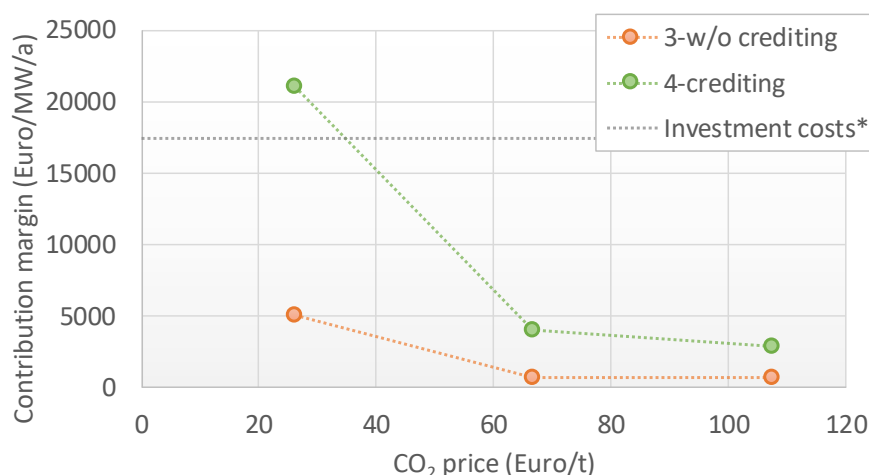


Figure 10: Contribution margins for PtH₂

* Minimum annual investment costs for alkaline electrolysis in China 2019, Source: IRENA (2019)

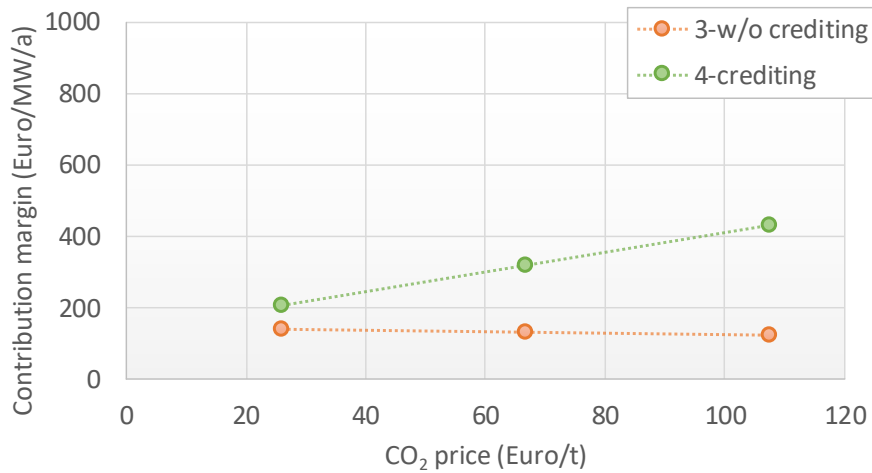


Figure 11: Contribution margins for PtM

Adverse effect of low CO₂ prices. So far, the analysis has shown that low CO₂ prices can lead to profitable utilisation rates for PtH₂. Figure 12 creates a connection between the (mirrored) price duration curves and the utilisation of PtH₂. Accordingly, with a use value of 40.39 Euro/MWh electrolyzers are incentivised to operate not only when renewables are price-setting but also when coal plants are marginal with variable costs between 28.80 and 44.15 Euro/MWh (see also Table 1). This effect is amplified by the crediting of avoided CO₂ emissions, leading to a higher use value of synthetic hydrogen and a higher utilisation of PtH₂. In contrast, in a scenario with a high CO₂ price, the effect is limited by the steeper price duration curve. Consequently, when coal plants are marginal, electrolyzers are no longer operated. This illustrates that (a generalised) CO₂ crediting may support the integration of PtH₂ into electricity markets but can be environmentally questionable depending on the CO₂ price level.

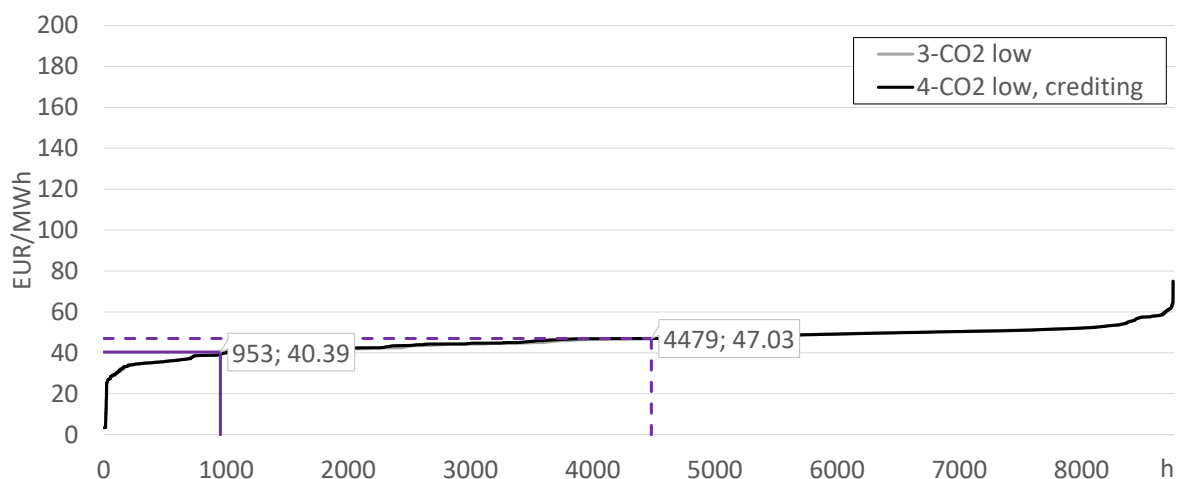


Figure 12: Inverse price duration curve and utilisation of PtH₂ for a low CO₂ price

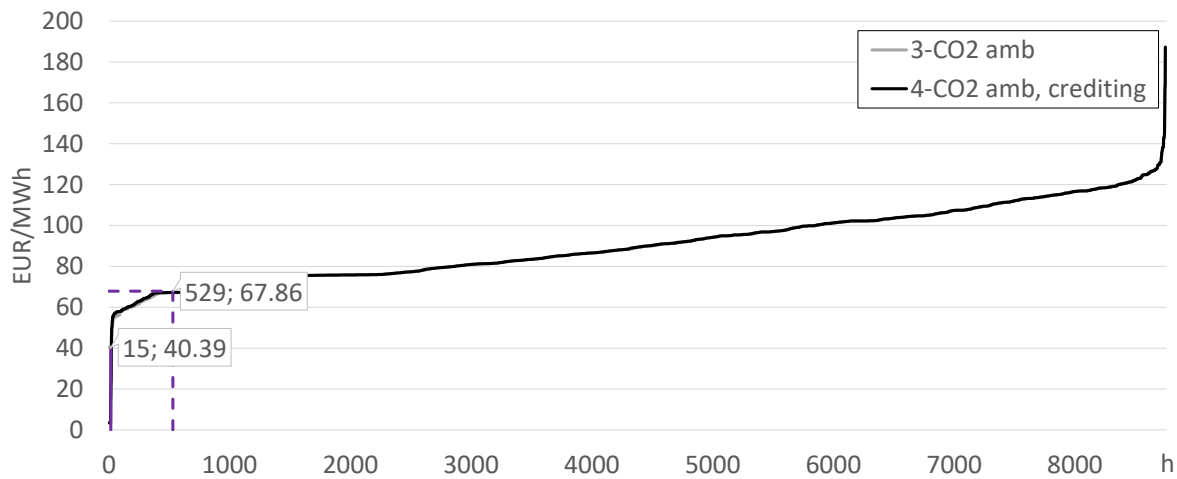


Figure 13: Inverse price duration curve and utilisation of PtH₂ for an ambitious CO₂ price

5 Conclusions and policy implications

This contribution is motivated by the growing importance of PtG and current regulatory barriers due to levies and inconsistent pricing of CO₂ emissions across different sectors. With our analysis, we shed light on the role of carbon pricing and the treatment of synthetic gas within this framework for the integration of PtG into electricity markets. To do so, we introduce a framework to model different flexibility options using a virtual storage approach. The case study covers the European electricity markets and focuses on the year 2025 as representative of the transitional period.

Based on the modelling results and a comparison of scenarios and sensitivities, the following five policy implications for the integration of PtG into electricity markets can be drawn:

1. An exemption of electrolyzers from levies (such as those introduced for renewable hydrogen in a recent amendment of the German Renewable Energy Act) is supported by our analysis in two respects. First, the modelling results reveal that electrolyzers being exposed to the EEG levy are not utilised in electricity markets, as the related additional costs implicitly reduce the value of the converted gas (i.e. the use value). Second, with exemption from the EEG levy, the utilisation of PtH₂ is significantly increased, although the utilisation hours achieved still do not support a profitable operation in the mid-term. Nevertheless, the results show that a reduction in levies improves the competitiveness of PtG and reduces market entry barriers.
2. When electrolyzers are not operated on-site (e.g. in combination with a wind farm) but integrated into electricity markets, the corresponding market prices determine their procurement costs for electricity. As the generation mix will transitionally be based on conventional coal- and gas-fired generation technologies, electrolyzers may also be incentivised to operate when CO₂-emitting technologies are price-setting. According to

the results, the electricity consumption of electrolyzers is supplied by additional generation from lignite and coal, leading to an increase of CO₂ emissions of the electricity sector in the short-term. During a transitional period, support schemes for PtG may amplify this effect. One strategy for coping with this adverse effect lies in creating a link between additional electricity consumption through electrolysis, renewable expansion targets and a certification of renewable or low-carbon synthetic gases, as stipulated by the European Renewable Energy Directive (EU, 2018).

3. Besides the short-term effect of increased CO₂ emissions from PtG, there are indirect effects in emissions trading systems as mentioned in section 2 that tend to compensate the direct effects. These price and volume effects of changes of CO₂ emissions will yet spread over several years due to banking and borrowing mechanisms. In the actual implementation of the EU ETS, the market stability reserve may further complicate the overall effects (cf. Perino, 2018; Rosendahl, 2019). Moreover, consistent incentives would require an EU-ETS covering all sectors and including all the natural gas and hydrogen consumed in the EU. If PtG is mainly seen as an option for decarbonising other sectors, such as transport, industry or heat, the economic value of renewable hydrogen or methane should reflect the value of the CO₂ emissions avoided - depending on the substituted fuel, this may vary according to the application. As an alternative to a challenging further extension of the EU-ETS to all relevant sectors, the proposed crediting of the CO₂ emissions avoided by synthetic gas would create consistent economic incentives for the market-driven utilisation of PtG. In this regard, the results of our model illustrate the role of CO₂ crediting in the integration of PtG through the considerable increase in utilisation hours and revenues. However, these results also point to some challenges arising with lignite and hard-coal power plants in the generation mix during the transition period.
4. As the model results show, the contribution of synthetic gases to decarbonisation heavily depends on the level of the CO₂ price. Reversely seen, the CO₂ price level determines whether synthetic gases contribute to or even compromise decarbonisation. Consequently, in the case of CO₂ crediting (and without a further extension of the EU-ETS to all relevant sectors), strengthening the EU-ETS will create benefits in two ways. First, a higher CO₂ price will increase the value of the converted gas, improving the competitiveness and market integration of synthetic gas. Second, with high CO₂ prices, a reduction (or avoidance) of adverse effects on CO₂ emissions through PtG will be achieved.
5. Finally, an improved regulatory framework with a reduction of burden from levies and cross-sectoral consistent CO₂ pricing will be instrumental to integrate PtG into electricity

markets. However, to go beyond small-scale pilot plants, further measures might be required, as the model results do not indicate market-driven investment incentives for PtG in the medium term. To close this gap and provide initial support, complementing mechanisms (e.g. carbon contracts for difference⁷, auction-based systems or quotas) should be considered.

Further research on the role of CO₂ pricing in the integration of PtG may focus on a longer time horizon beyond a transitional period and should consider further flexibility options (heat pumps and electric vehicles), including investment decisions. Moreover, we refrained from a detailed modelling of the EU-ETS, which means that we consider an exogenous CO₂ price in our model instead of a constant CO₂ budget as under the EU-ETS. Overall, this limits our analysis to short-term effects of CO₂ prices on PtG without consideration of feedback effects in emissions trading systems. Hence, further research should extend on an explicit modelling of CO₂ budgets.

⁷ Carbon contracts for difference between governments and private companies provide a premium over expected carbon prices, as a way to support emerging technologies (e.g. Richstein et al., 2021).

Data availability

Relevant input data and information with regards to time series and capacities are available from the corresponding author upon reasonable request.

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Author contributions

Conceptualization: MB, JM. **Methodology:** MB, JM, CW. **Software, Validation:** JM, MB. **Investigation:** JM, MB. **Data Curation:** JM, MB. **Writing - Original Draft:** MB, JM. **Writing - Review Editing:** MB, JM, CW. **Visualization:** MB, JM.

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Appendix A: Detailed data description

Fuel and CO₂ prices

The fuel prices for natural gas (21.20 €/MWh_{th}), hard coal (9.18 €/MWh_{th}), fuel oil (27.61 €/MWh_{th}) and light oil (33.20 €/MWh_{th}) are computed based on the average future prices for 2022 during the second quarter of the year 2019.

The status-quo CO₂ price (26.00 €/tCO₂) is the rounded average price of the period from April to July 2019. The ambitious price (107.50 €/tCO₂) is interpolated for the year 2025 with the considered CO₂ prices for 2020 and 2030 in the expert reports for CO₂ pricing by order of the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) in 2019. The moderate price (66.75 €/tCO₂) is calculated as the average of the status-quo and the ambitious price.

PtG – conversion rates

The assumptions regarding the conversion rates for PtH₂ and PtM are based on recent studies covering a period from 2009 until 2040. Figure 14 and Figure 15 indicate the range of conversion rates, whereas for the scenario year 2025 the minimum and maximum value are highlighted. In our case study we consider the mean values derived from these bandwidths.

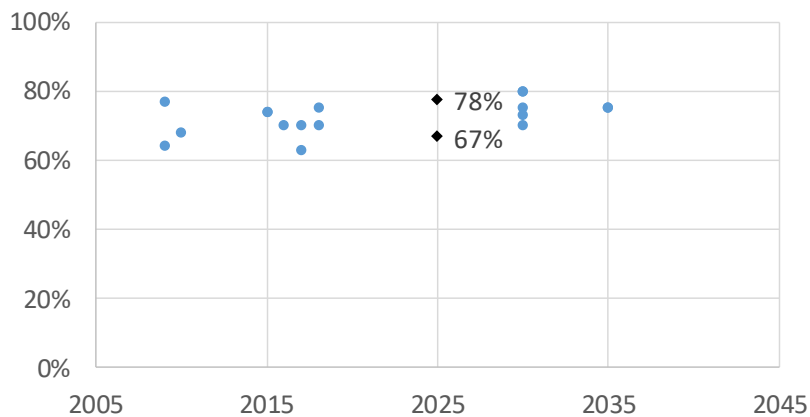


Figure 14: Conversion rate electrolysis (PtH₂)

Sources: (Blanco et al., 2018; Blanco & Faaij, 2018; Buchholz et al., 2014; Clegg et al., 2017; Clegg & Mancarella, 2015; de Boer et al., 2014; Dickinson et al., 2010; FfE, 2017; Götz et al., 2016; Jentsch et al., 2014; Kötter et al., 2015; Moeller et al., 2014; Sterner & Jentsch, 2011; Wietschel et al., 2019)

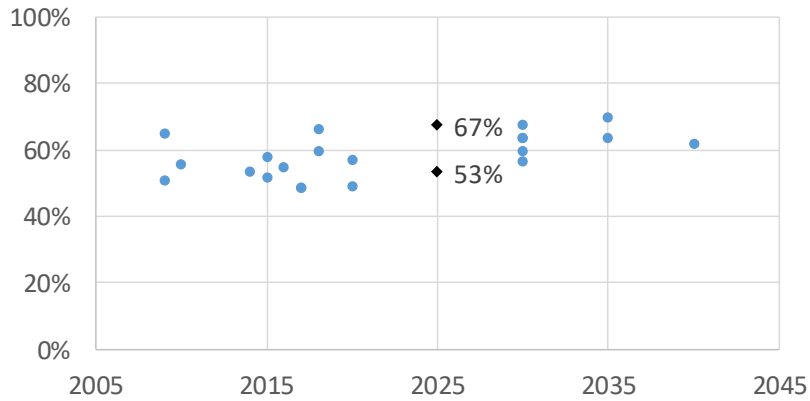


Figure 15: Conversion rate electrolysis + methanation (PtM)

Sources: (Blanco et al., 2018; Blanco & Faaij, 2018; Buchholz et al., 2014; Clegg et al., 2017; Clegg & Mancarella, 2015; de Boer et al., 2014; Dickinson et al., 2010; FfE, 2017; Götz et al., 2016; Jentsch et al., 2014; Kötter et al., 2015; Moeller et al., 2014; Sterner & Jentsch, 2011; Wietschel et al., 2019)

The assumptions for modelling of DSM are based on Langrock et al. (2015).

Table 2: Assumptions for modelling of DSM. Based on (Langrock et al., 2015)

	Reduction [MW]	Max. duration of reduction [h]	vSTOMIN [MWh]	Increase [MW]	Max. duration of increase [h]	vSTOMAX [MWh]	Costs [Euro/MWh]
ALUMINIUM 1	691.12	16.00	11,057.92	9.48	4.00	37.92	200.00
ALUMINIUM 2	188.68	4.00	754.72	0.00	0.00	0.00	225.00
ALUMINIUM 3	177.02	12.00	2,124.24	15.72	60.00	943.20	60.00
ALUMINIUM 4	3.18	3.00	9.54	3.80	3.00	11.40	200.00
CHLORINE 1	118.19	58.00	6,855.02	30.86	5.00	154.30	83.65
CHLORINE 2	60.50	12.00	726.00	0.00	0.00	0.00	149.45
CHLORINE 3	0.00	0.00	0.00	4.94	24.00	118.56	0.10
CHLORINE 4	120.53	76.00	9,160.28	45.20	1.00	45.20	233.15
CHLORINE 5	68.94	72.00	4,963.68	0.00	0.00	0.00	169.00
CHLORINE 6	100.84	12.00	1,210.08	0.00	0.00	0.00	108.15
ELECTRIC STEEL 1	0.00	0.00	0.00	25.00	1.00	25.00	0.10
ELECTRIC STEEL 2	74.21	1.00	74.21	0.00	0.00	0.00	89.30
ELECTRIC STEEL 3	232.07	8.00	1,856.56	0.00	0.00	0.00	89.30
ELECTRIC STEEL 4	176.11	8.00	1,408.88	0.00	0.00	0.00	127.80
PAPER 1	73.62	1.00	73.62	102.05	8.00	816.40	7.50
PAPER 2	525.00	8.00	4,200.00	0.00	0.00	0.00	200.00
PAPER 3	298.76	48.00	14,340.48	0.00	0.00	0.00	1,000.00
PAPER 4	111.00	72.00	7,992.00	50.95	8.00	407.60	200.00
CEMENT 1	0.20	1.00	0.20	0.10	1.00	0.10	5.70
CEMENT 2	0.22	6.00	1.32	0.11	4.00	0.44	5.70
CEMENT 3	21.58	120.00	2,589.60	10.79	20.00	215.80	5.70

Appendix B: Further figures and results

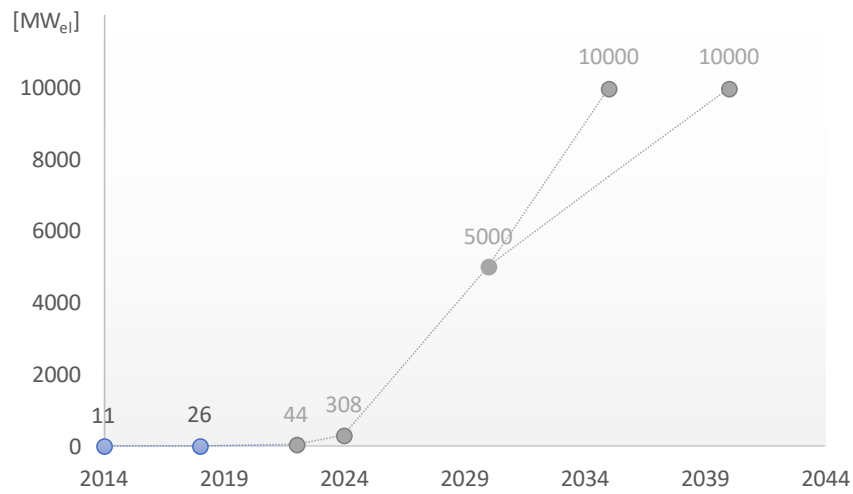


Figure 16: Installed and planned electrolyser capacity in Germany
Sources: BMWi (2020b), DVGW (2020), TÜV SÜD (2020)

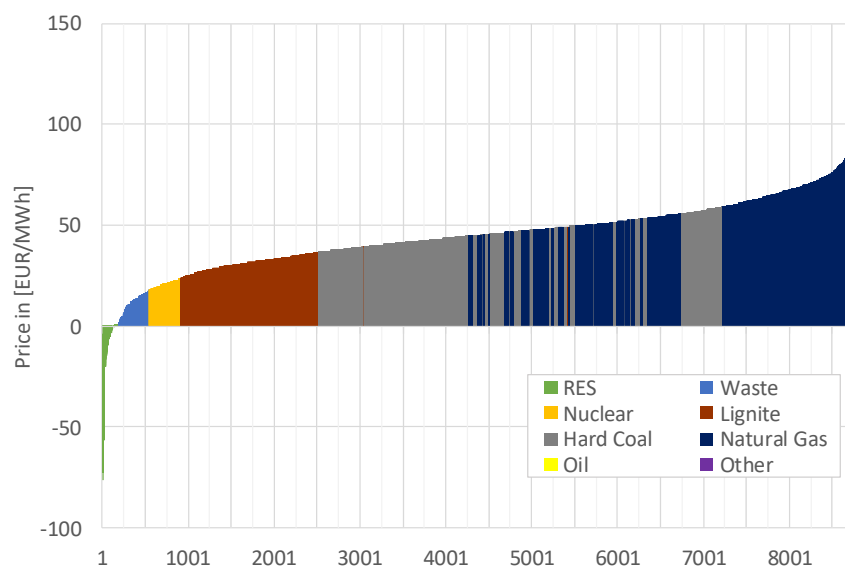


Figure 17: Mirrored price duration curve and estimation of price setting technologies for Germany and the year 2018



Figure 18: Sensitivity analysis – Generation and import for Germany in 2025 (Cons: consumption of flexibilities)

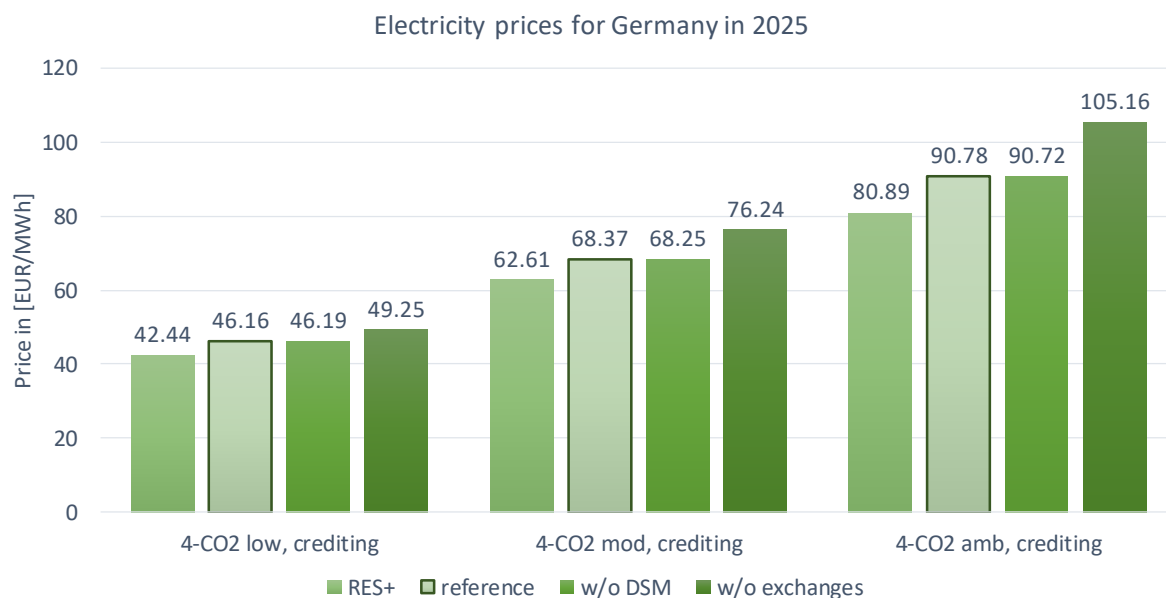


Figure 19: Sensitivity analysis – electricity prices

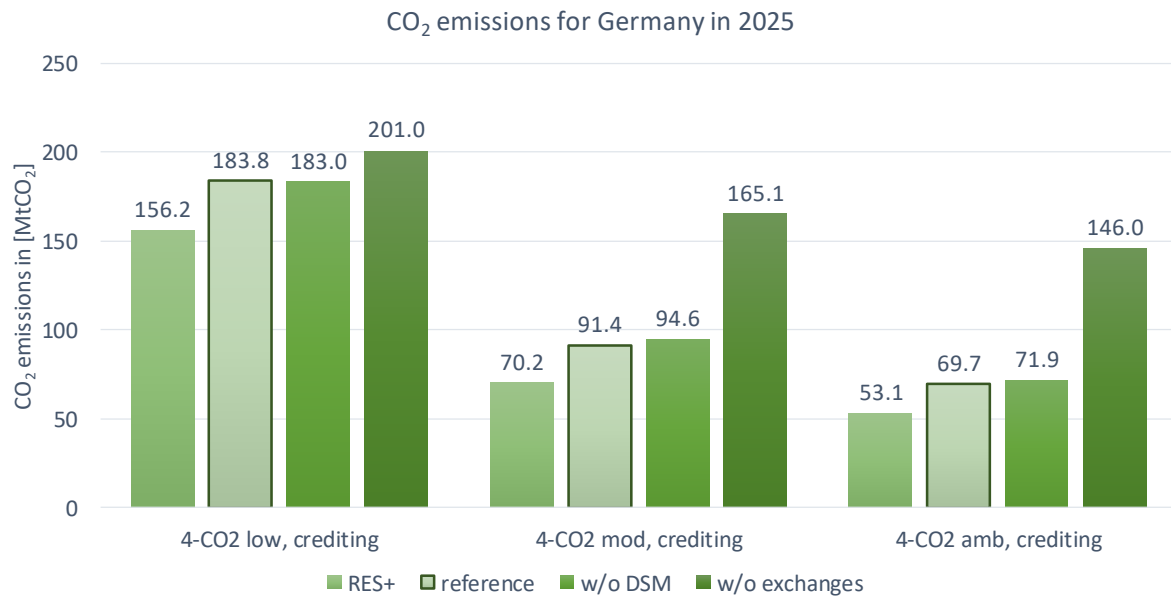


Figure 20: Sensitivity analysis – CO₂ emissions

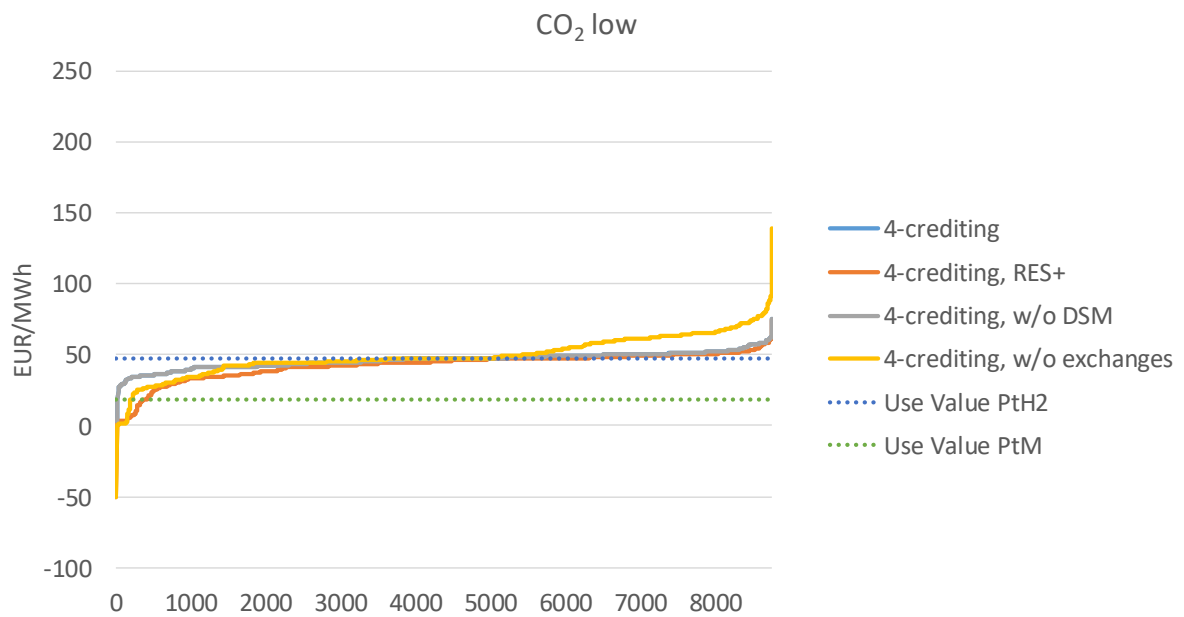


Figure 21: Sensitivity analysis – price duration curves CO₂ low

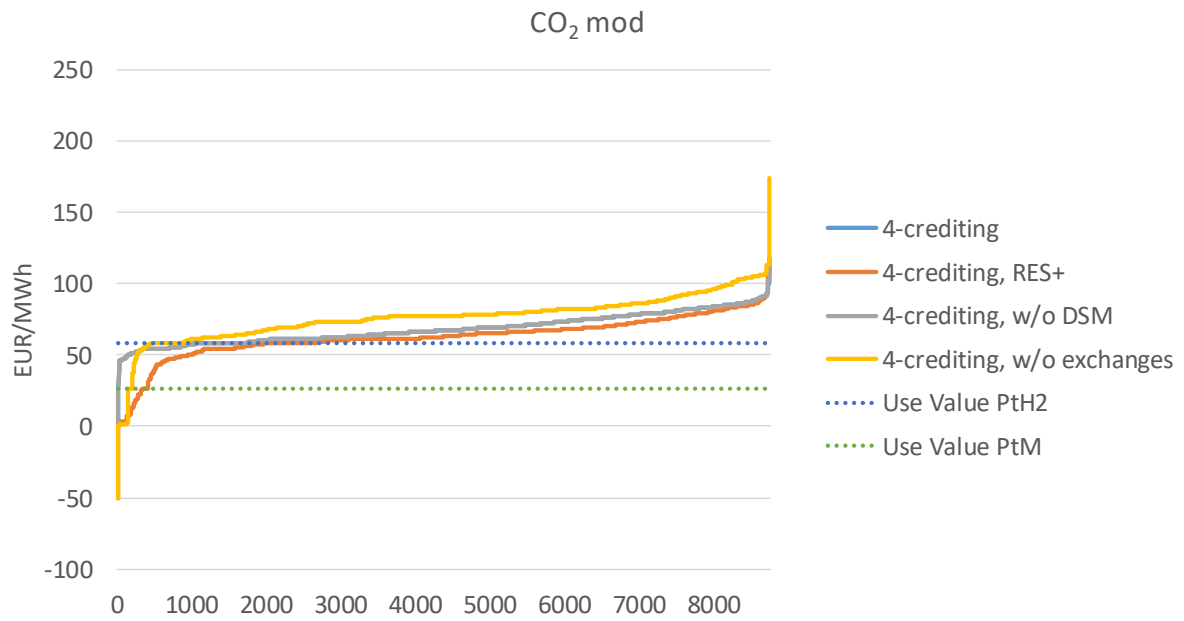


Figure 22: Sensitivity analysis – price duration curves CO₂ mod

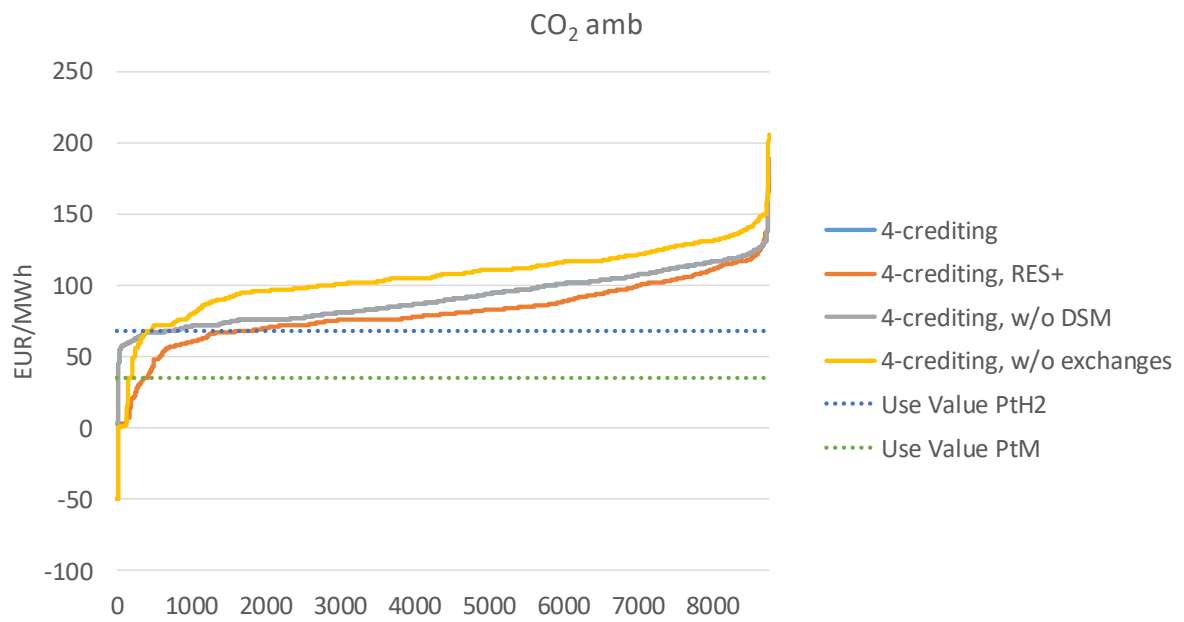


Figure 23: Sensitivity analysis – price duration curves CO₂ amb

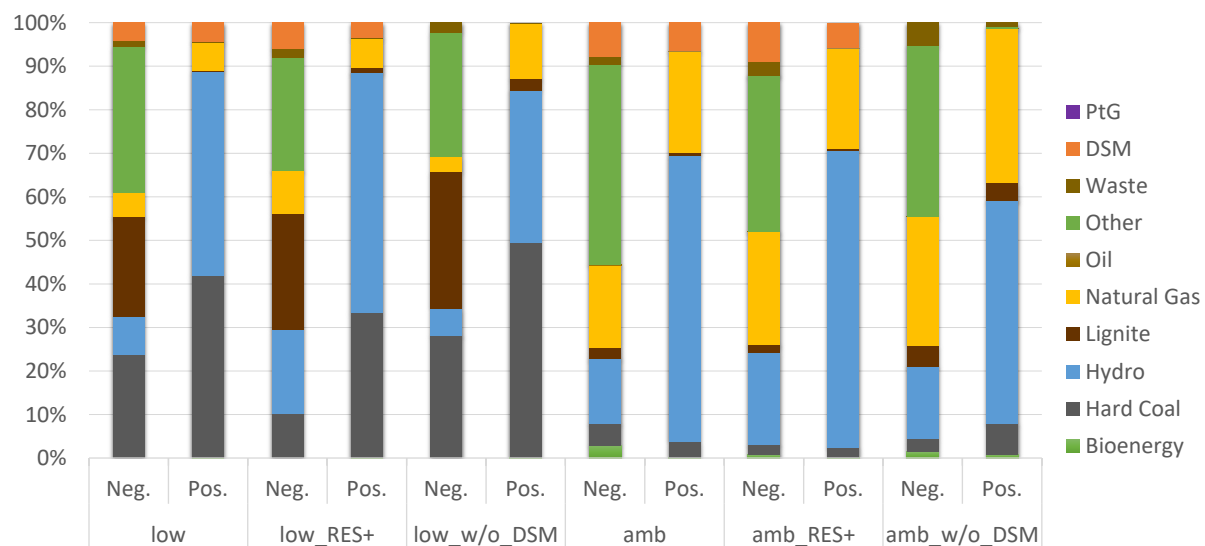


Figure 24: Average provision of spinning reserves per technology for scenario family with CO₂ crediting (4-CO₂, crediting)

Appendix C: Sensitivity analyses

In this section, we analyse further sensitivities that consider a higher share of renewables and interactions with other flexibility options, such as DSM and cross-border exchanges.

Impact of higher RES share. In general, a higher penetration of variable RESs leads other things being equal to lower electricity prices due to the merit-order effect (see Figure 19 in Appendix B). Consequently, the increased number of hours with electricity prices lower than the use values for PtM and PtH₂ leads to more utilisation hours of both PtG technologies in all CO₂ price scenarios (see Figure 25 and Figure 26). Especially PtH₂ benefits with more than 750 additional utilisation hours, although PtM usage is also extended from 15 to 287 utilisation hours in the case of the ambitious CO₂ price level for a 30% increase in renewable generation. As a result, the contribution margins for PtH₂, as well as for PtM, rise significantly (see Figure 27 and Figure 28). While PtM is still not profitable under the considered scenario in 2025, for PtH₂, contributions margins exceed annual investment costs under all CO₂ price scenarios, indicating clear investment incentives (see Figure 27).

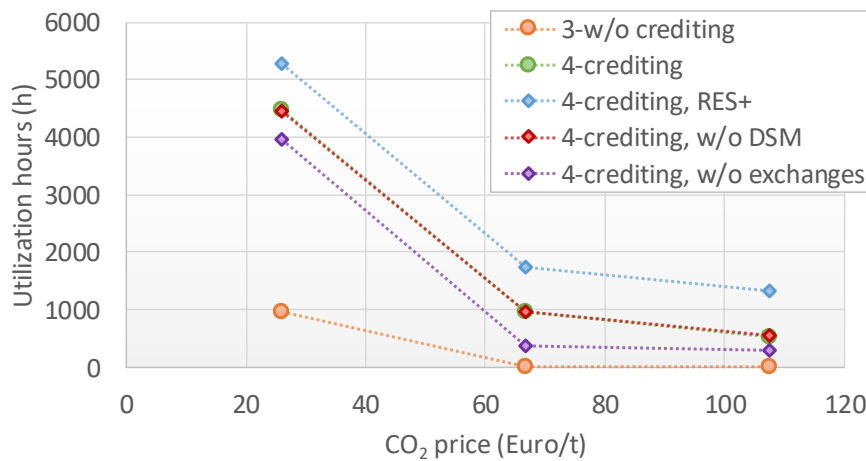


Figure 25: Utilisation hours per year of PtH₂ (sensitivities)

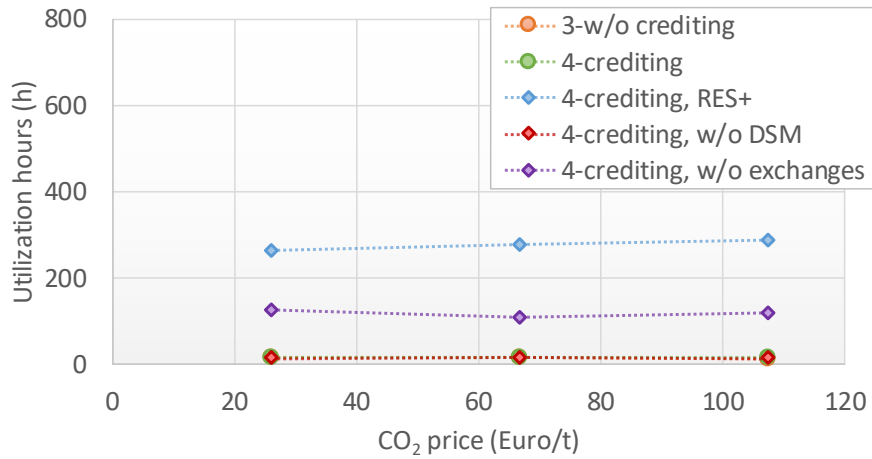


Figure 26: Utilization hours per year of PtM (sensitivities)

Interactions with other flexibility options. Just like for PtG, the utilisation of DSM is determined by electricity prices and corresponding opportunity costs. As discussed in Section 4.2.1, the utilisation of DSM (shift of electricity consumption) is driven by the provision of balancing reserves. Following this, a sensitivity without DSM was computed. However, as shown in Figure 25 and Figure 26, ignoring DSM does not impact PtG usage, as the electricity consumption of electrolyzers is mainly balanced with the additional utilisation of pumped storage plants (see Figure 18 in Appendix B). The negligible impact on the utilisation of PtG translates into barely visible differences in the contribution margins (see Figure 27 and Figure 28).

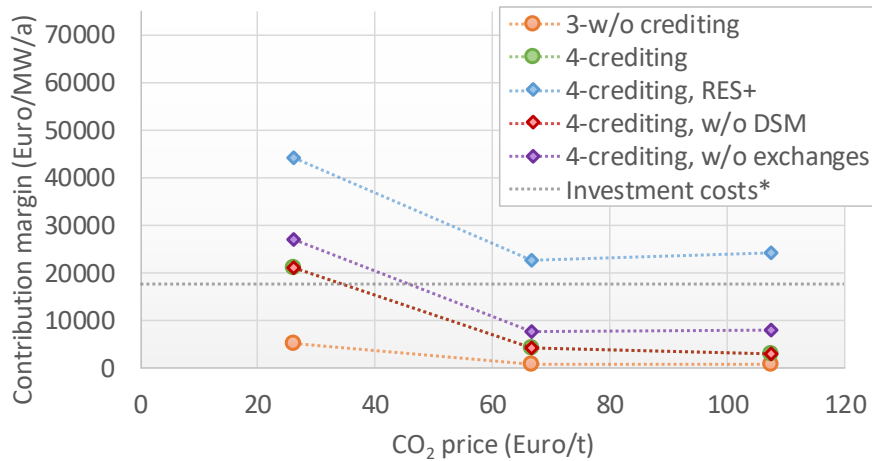


Figure 27: Contribution margins of PtH₂ (sensitivities)

* Minimum annual investment costs for alkaline electrolysis in China 2019, Source: IRENA (2019)

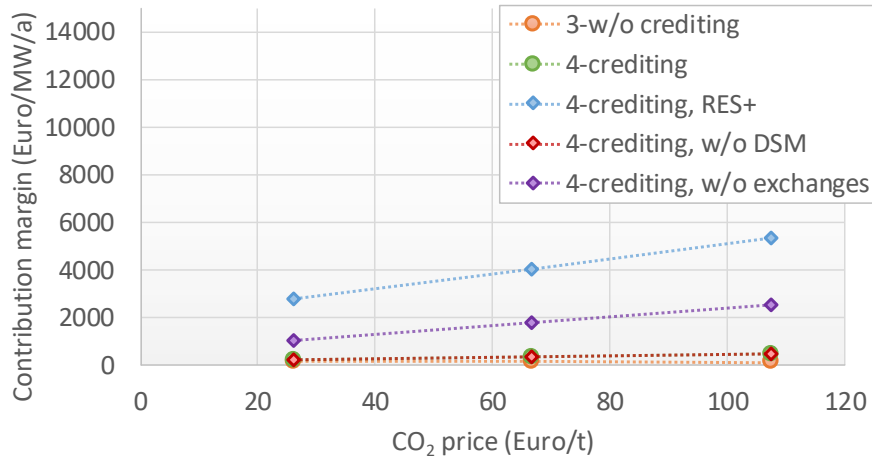


Figure 28: Contribution margins of PtM (sensitivities)

Impact of cross-border exchanges. Besides DSM, cross-border capacities between countries can serve to compensate for imbalances between electricity demand and supply. A sensitivity without cross-border capacities was calculated to estimate the influence of import and export possibilities on the utilisation and profitability of PtG facilities. The resulting prices are more volatile (higher standard deviation) because the number of hours with extreme electricity prices increases. During these hours, electricity exchanges with other countries are prevented, which leads to a steeper price duration curve impacting the operation of PtG (see e.g. Figure 21 in Appendix B). The higher number of hours with low electricity prices at the end of the price duration curve caused by missing export possibilities leads to an increase in PtM utilisation (see Figure 26). PtH₂ has a higher use value than PtM. Therefore, the higher average price level caused by the missing import possibilities overcompensates the effect of the increasing number of low prices for PtH₂, resulting in decreasing PtH₂ utilisation (see Figure 25). However, for both PtM and PtH₂, the contribution margins increase due to the lower procurement costs on average (see Figure 27 and Figure 28).

Nomenclature

Indices and Sets:

T, t	Hour
A, a	Area
R, r, \bar{r}	Region
i	Unit group
u	Unit
$I^{DISPATCH}$	Set of dispatchable units (subset of I^{ELEC})
I^{ONLINE}	Set of unit groups with minimum stable operation limit for power production
T^{SPOT}	Time steps (day-ahead) where trading is possible
$I^{STORAGE}$	Set of storages with loading capacity
I^{ELEC}	Set of power producing unit groups
Z, z	Control zone for control reserve
I^{PtG}	Set of Power-to-gas facilities
I^{DSM}	Set of DSM options

Parameters:

c_t^{gas}	Natural gas price in hour t in €/MWh
$\xi_t^{PtG,use}$	Use value for power-to-gas utilisation in hour t in €/MWh
η_{PtG}	Conversion efficiency of power-to-gas [-]
$c_t^{CO_2}$	CO ₂ price in hour t in €/t CO ₂
$f_{gas}^{CO_2-factor}$	CO ₂ emission factor of natural gas in t CO ₂ /MWh
$c_u^{O\&M}$	Operation and maintenance cost for unit u in €/MWh
η_u	Efficiency of unit u [-]
c_t^{fuel}	Price for a specific fuel for unit u in hour t in €/MWh
$f_{fuel}^{CO_2-factor}$	CO ₂ emission factor of a specific fuel in t CO ₂ /MWh
$c_{a,t}^{fuel}$	Fuel costs in hour t in area a in
$c_{a,i}^{O\&M}$	Operation and maintenance cost for unit group i in €/MWh
$c_{a,i}^{STARTUP}$	Start-up cost for unit i in area a in €/MW
$\delta_{\bar{r},r}$	Loss factor for power exchanges from region \bar{r} to region r
δ_i^{STAND}	Standstill losses of storage group i (e.g. self-discharge for batteries, evaporation for pumped storages, or cooling down of intermediate thermal storages for DSM)
$d_{r,t}^{ELEC}$	Electricity demand in region r in hour t in MW
$\eta_i^{UNLOADEFF}$	Unload efficiency for unit group i in area a
$\eta_i^{LOADEFF}$	Load efficiency for unit group i in area a
$w_{a,i}^{MAX}$	Maximum load capacity of unit group i in area a
η_i	Efficiency of unit group i [-]
$sp_{a,i}^{STORAGE}$	Shadow price of storage i in area a in €/MWh
$d_{r,t}^{ELEC}$	Electricity demand in region r in hour t in MW
$p_{r,t}^{RES}$	Renewable electricity feed-in (before curtailment) in region r in hour t in MW
$d_{z,t}^{ANC}$	Demand for control reserve in control zone z in hour t in MW
$v_{a,i}^{PtG,MAX}$	Maximum storage capacity of power-to-gas unit group i in area a in MWh
$v_{a,i}^{PtG,MIN}$	Minimum storage capacity of power-to-gas unit group i in area a in MWh
$v_{a,i}^{STO,MAX}$	Maximum storage capacity of storage unit group i in area a in MWh
$v_{a,i}^{STO,MIN}$	Minimum storage capacity of storage unit group i in area a in MWh

c^{DSM} Costs of shifting load of DSM unit group in €/MWh

Variables:

λ_t^{el}	Electricity price in hour t in €/MWh
$P_{a,i,t}^{DA}$	Electricity generation of unit i in area a in hour t in MW
$P_{a,i,t}^{PtG}$	Extraction of synthetic gas from the gas network produced by power-to-gas unit group i in area in hour t
$P_{a,i,t}^{STARTUP}$	Started generation capacity of unit i in area a in hour t in MW
$P_{r,t}^{RESCURT,DA}$	Curtailement of renewable infeed in MWh
$P_{r,\bar{r},t}^{TRANS,DA}$	Power exchange from region \bar{r} to region r in hour t in MW
$P_{t,a,i}^{ANC,+}$	Reserved capacity for positive control reserve provided in generation mode of unit group i in area a in hour t in MW
$P_{a,i,t}^{ANC,-}$	Reserved capacity for negative control reserve provided in generation mode of unit group i in area a in hour t in MW
π_t	Contribution margin in hour t in €/MW
$Sp_{a,i}^{STORAGE}$	Shadow price of storage unit i in area a
$V_{a,i,t}^{STORAGE}$	Filling level of storage unit group i in area a in hour t in MWh
$V_{a,i,T}^{STORAGE}$	Filling level of storage unit i in area a in the last time step T of the planning horizon in MWh
$V_{t,a,i}^{PtG}$	Filling level of power-to-gas unit group i in area a in hour t in MWh
V_{obj}	System cost (value of the objective function) in €
$W_{t,a,i}^{DA}$	Electricity consumption of unit group i in area a in hour t in MW
$W_{t,a,i}^{ANC,-}$	Reserved capacity for negative control reserve provided in consumption mode of unit group i in area a in hour t in MW
$W_{t,a,i}^{ANC,+}$	Reserved capacity for positive control reserve provided in consumption mode of unit group i in area a in hour t in MW

Abbreviations:

cf.	Confer (compare)
CO ₂	Carbon dioxide
e.g.	Exemplī grātiā (for example)
et al.	Et alii (and others)
ETS	Emissions Trading Scheme
EU	European Union
GAMS	General Algebraic Modelling System
GW	Gigawatt
max	Maximum
Min	Minimum
RES	Renewable energy source
TYNDP	Ten Year Network Development Plan
w/	With
w/o	Without