Power-to-Gas in a Smart City Context - Influence of Network Restrictions and Possible Solutions using On-site Storage and Model Predictive Controls

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Abstract

Power-to-gas (P2G or PtG) technology can provide energy storage capacity to the energy system by converting excess electrical energy into hydrogen and feeding it into the natural gas network, where it can be stored. However nowadays hydrogen feed-in has to be limited to certain percentages in order to keep the characteristics of the resulting gas mixture (i.e. heating value) within the national standards. For P2G plants in urban areas this can strongly impact the economic viability. This paper investigates the use of on-site storage and model predictive controls (MPC) to ease the negative effect of restrictions in the gas and power grid on the economics of P2G systems. Three different use-cases for P2G in an urban setting are considered: Optimal utilisation of renewable electricity produced within the boundaries of the city, optimised electricity purchase at the spot market and optimal usage of electric network. MPC is compared to an optimised rule-based control approach. Results show that both controls can be used to meet the objectives and operate the power-to-gas plant. However, the MPC approach results in a smoother operation of the plant and significantly improved economic performance in all cases and is recommended. The results indicate the beneficial effects of on-site hydrogen storage on system operation and economics. For the investigated cases a storage capacity around 6 full load hours of the electrolyser was sufficient to improve results significantly.

Keywords: Flexibility, Power-to-Gas-Stations, Model predictive controls, Renewable Energy Management, Urban Energy Systems, Smart Grid, Hydrogen, feed-in, feed-in-restrictions

Contents

1 Introduction and motivation **2**
- 1.1 Past work: The role and potential applications of P2G in the future energy system 2
- 1.2 Contribution of this work 3

2 Models, controls and indicators **3**
- 2.1 System description 4
- 2.2 Simulation set-up 4
- 2.3 Models used 4
  - 2.3.1 Electrolyser model 4
  - 2.3.2 Hydrogen storage model 5
- 2.4 Controls 5
  - 2.4.1 Rule-based controller (RBC) 5
  - 2.4.2 Model predictive controller (MPC) . . . 5
- 2.5 Key performance indicators 6

3 Results **6**
- 3.1 Simulated cases 7
- 3.2 Influence of controls 7
- 3.3 Influence of network restrictions 8
- 3.4 Influence of use-case and storage size 9
- 3.5 Influence of plant-model mismatch 9

4 Conclusion **10**

5 Acknowledgements **10**

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1. Introduction and motivation

For most countries decarbonisation of the energy system requires changes across all energy sectors [1; 2]. In the electric sector the replacement of fossil fired power plants with renewable electricity generation leads to challenges such as balancing the fluctuations of wind and photovoltaic (PV) on different time scales. Storage will be needed to avoid curtailment during periods of high renewable electricity generation [3], to provide base-load electricity using renewable sources [4], and to support a stable operation of the electric grid [5].

Power-to-gas (P2G) systems, based on water electrolysis can convert available renewable electricity and water into hydrogen and oxygen. For this process alkaline water and proton-exchange membrane (PEM) electrolysers are commonly used [6]. The produced hydrogen can be used in different applications, such as industrial processes, mobility or electricity generation using turbines, combustion engines or fuel cells. Furthermore the generated hydrogen can be fed into the natural gas network directly or after a methanisation step. Feeding hydrogen into the natural gas network makes existing natural gas storage caverns accessible for seasonal storage [7–9].

Today's P2G stations show a capacity of several MW_{el} and are mainly located in the proximity of natural gas pipelines, industrial sites and wind farms. However, decentralisation of the energy system might lead to situations where P2G stations will be installed to provide storage (or more precisely flexible shifting of negative residual load from the electric sector to other sectors) in micro-grids, smart energy regions and cities or energy independent neighbourhoods. Decentralised distribution of P2G stations included into urban energy systems may be an alternative to large scale, centralised approaches.

Such a setting is investigated in this presented work, where a P2G unit is part of an urban energy network, shown in Figure 1. The urban energy system consists of a wind array of 7.2 MW, a solar PV array of 2.5 MW, a base-load biomass plant and distributed CHP units located at industrial sites. The P2G unit is located within the city boundaries of Freiburg, Germany and connected to a natural gas line, which supplies a residential area. For this case restrictions in the electric grid and the local gas network have to be considered.

Although the electric network at this site is sufficiently strong to connect the P2G unit, operation during peak load hours is to be reduced to postpone reinforcement of the electric infrastructure. Generally transformer capacity and line capacity can limit the allowed installed capacity or the operation of a P2G unit. When operated in a grid friendly way, P2G can be used to reduce feed-in peaks of PV and Wind or provide ancillary services to the network as shown in [10; 11].

In an urban setting restrictions in the gas network are an important parameter to consider when selecting a site as indicated by the results of [12]. In Germany, the operator of the gas network guarantees a stable quality of the natural gas in his network. Thus a frequent requirement - at least nowadays - is that the amount of hydrogen in the gas network may not exceed 2 vol-% [13–15]. This requirement leads to limitations in the allowed feed-in and thus the economic performance of

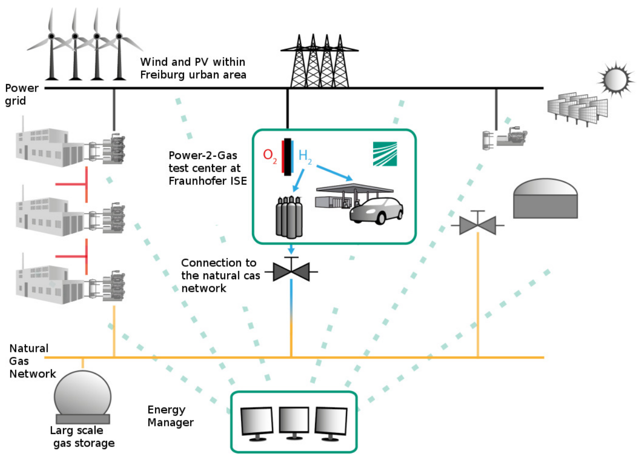


Figure 1: P2G stations as part of an urban energy system as will be demonstrated in the city of Freiburg, Germany.

decentralised P2G stations.

On-site hydrogen storage can act as a buffer and provide flexibility so that the negative effect of grid restrictions to unit operation can be eased. For this purpose adjusted controls of the P2G unit are needed. This work investigates to what extend network restrictions, storage size and control strategy influence the technical and economic performance of a P2G plant in different use-cases.

The results of this study are used to select a control strategy and a preferred use-case for a real P2G unit located within the city of Freiburg, Germany.

1.1. Past work: The role and potential applications of P2G in the future energy system

Previous studies focus has been on investigating the role of P2G in the future energy system. This was done by using structural optimisation or scenario based simulation approaches.

In [7] a scenario with a 100 % renewables is discussed, where electricity generated by hydrogen provided by P2G contributes up to 10 % to the total supply and is considered an important storage technology in the future power system.

In [4] different scenarios for Germany 2050 are simulated. The authors show that depending on the scenario more than 20 % of all fuels might be produced in a renewable way using P2G. In this scenario, the share of renewables in electricity consumption is more than 75 %.

The ability of P2G-stations to integrate renewable electricity is demonstrated in [5]. This study shows, that for a 85 % renewable energy scenario in Germany, up to 12 GW of P2G could be installed. The authors state that plants should be located close to wind farms for reducing power flows in the transmission grid [16].

The cost optimal structure of a fully renewable energy system of a model region in Germany is investigated in [17]. It is shown that going 100% renewable is possible with and without P2G technology. However including P2G as long term storage significantly reduces levelised cost of energy LCOE of the system. The authors highlight the importance of decentralised solutions for the energy system and sector coupling. Battery storage and power to heat (here only direct electric heating) are seen as viable parts of a storage portfolio.

Study [18] investigates the use of P2G as energy storage in a smart grid context and compares it to other storage technology using an analytical hierarchy process. The study highlights potential benefits of P2G by providing ancillary services, seasonal storage on a large scale and an efficient energy transportation infrastructure with losses around 0.001% per 1000km.

Study [19] puts a focus on integrating P2G in urban energy systems, here highlighting the importance of the heat sector. The authors state the importance of middle and high temperature heat that can be generated by CHP units, gas-boilers and gas driven heat pumps using methanised hydrogen, which in the investigated case can be produced by surplus renewable electricity on city level.

Another stream of studies explores the use of P2G in exemplary applications in the context of providing services to the electric grid. The studies mostly are combined with economic evaluation of the investigated case.

In [3] the combination of P2G with wind and gas power plants is examined. It is shown that curtailment of wind turbines and the need of balancing energy are reduced significantly if P2G is included in the system. However the positive effects in terms of CO_2 reductions are reduced by the use of the gas turbine.

In [11] P2G is used to provide balancing services to the electric grid (in this case primary reserve) in France. The study demonstrates the capability of P2G to provide fast response services to the grid. The importance of the economic boundary conditions are highlighted and difficulties finding an economic use case are reported.

An isolated energy system consisting of electrolyser, hydrogen storage, wind turbine, PV and battery system is investigated in [20]. A high level controller manages the production of hydrogen and its conversion back into electricity according to the availability of renewable electricity and the demand. The study highlights the importance of advanced controls and the potential of such a system to provide flexibility.

In [21] three different use-cases for a 6 MW_{el} P2G unit are investigated: optimised purchase of electricity at EEX spot market, reduction of balancing energy costs and participation in control reserve markets. It is shown that depending on the use-case and full load hours, hydrogen generation costs vary significantly.

The work of [10] shows the potential of a fuel-cell and an electrolyser system to reduce forecast errors for wind farms and the associated need for balancing energy and costs. Provision of secondary operating reserve is studied with respect to different bidding strategies. The study shows an economically interesting use-case but indicates that finding viable business cases for P2G is still critical.

The optimal sizing and operation of an off-grid system of electrolyser and battery to produce hydrogen from photovoltaic electricity is investigated in [22]. Hydrogen is fed into the gas network. MILP is used to obtain the optimal solution. It shows that - for the given assumptions - building a set of small, medium and a large electrolyser and only a small battery is the cost optimal solution.

In [12] sizing and operation of a P2G plant to absorb excess electricity from a wind farm are discussed for an urban setting is demonstrated. The produced hydrogen is fed into the gas network. The study highlights the influence of seasonality of gas flow in the network and the need for on-site hydrogen storage capacity. For the given case a storage capacity of 600kg is recommended for a 4MW_{el} electrolyser unit to overcome restrictions in the gas network.

P2G applications in the energy system have been demonstrated in numerous research projects listed and studied in [23–25]. The individual projects differ by the type of connection to the electric grid (on-grid/off-grid) and the gas network (feed-in/no feed-in), the existence of on-site hydrogen storage and the usage of the generated hydrogen. The majority of projects is located in the proximity of wind farms and PV arrays. Systems are combined with a battery stack used to counterbalance fast fluctuations, on-site hydrogen storage, a gas turbine or a fuel cell. 24 % of the projects listed in [25] are connected to the electric grid.

Reading through the above articles carefully it is found that most presented cases struggle with economics even in using idealised assumptions. As a conclusion this means that solutions (as presented in this work) that have the potential making P2G more economic are needed.

1.2. Contribution of this work

Most previous studies focus on P2G stations on multi MW_{el}-scale, located at ideal spots, where no restrictions in the gas network or the electric grid apply. However, decentralisation of the energy system might lead to situations where P2G stations will be installed in micro-grids or urban energy systems where restrictions apply. Hence, providing solutions for an improved integration of P2G units at this system level is essential. Furthermore it is shown that solutions that improve the economic viability of P2G systems are highly welcomed.

Consequently this work focuses P2G in an urban context where restrictions in the energy networks apply. On-site storage and improved controls are investigated to overcome network restrictions. A linearised model predictive control (MPC) approach, that can be used in other P2G applications (i.e. to keep expensive on-site hydrogen storage to a minimum), is presented and shown to improve economic performance significantly. Different storage capacities are evaluated to provide knowledge on how to best size P2G units in such a setting. Validated models are used and the resulting controls will be deployed on a real unit.

2. Models, controls and indicators

This section presents the models, methods and indicators used for simulation and interpretation of the results.

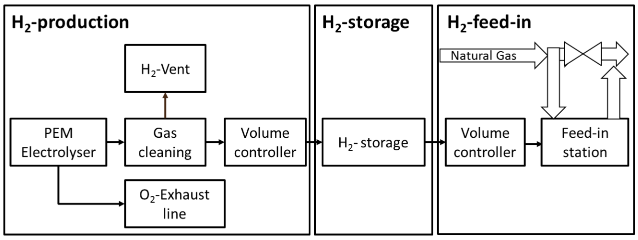


Figure 2: System description of the P2G test site at Fraunhofer ISE in Freiburg.

2.1. System description

The investigated P2G system is shown in Figure 2 and is to be installed at the test site at Fraunhofer ISE, within the city boundaries of Freiburg, Germany. It consists of a PEM-electrolyser stack converting water into hydrogen and oxygen, a gas cleaning unit, on-site hydrogen storage and a feed-in station to the gas network. The P2G unit is connected to the local electric grid and the gas network. The (DC-)electricity for the PEM-electrolyser is provided by a rectifier. A cooling-unit provides constant working conditions for the electrolyser. The feed-in unit connects the P2G station to the natural gas network. Real-time measurements of hydrogen feed-in and the gas-flow through the network make sure that the unit is operating within the gas network restrictions.

A hierarchical control infrastructure is used to operate the P2G unit. A high level controller generates set-points for hydrogen generation and feed-in and a low level controller is in charge of operating the unit according to the set points.

2.2. Simulation set-up

The simulation framework for the P2G unit consists of two components:

1. *P2G unit model*: Detailed models of the electrolyser and the storage are used to calculate the response of the P2G unit towards different control signals and boundary conditions. The models account for system dynamics, unit efficiency, hydrogen production of the electrolyser and storage SOC depending on pressure, environmental temperature and mass of hydrogen stored.

2. *High level controller platform*: A model predictive controller (MPC) and a rule-based controller (RBC) are implemented. Both calculate the operation of the system at each time step and define set-points for hydrogen generation and feed-in. These set-points are transmitted to the lower control level represented by the internal control of the electrolyser. Both high level control approaches make use of a simplified electrolyser model to calculate the control actions. Additionally the current state of the P2G unit, storage content, ambient temperature, electricity price, allowed maximum hydrogen feed-in, state of the electric grid and available renewable electricity are used to calculate the control actions.

The P2G model and controls are explained in the following.

2.3. Models used

The simulation model of the P2G unit consists of the electrolyser model and a model for the hydrogen storage.

2.3.1. Electrolyser model

The relationship between hydrogen production and electricity consumption is shown in Figure 3(a). The data used is taken from field measurements of a PEM electrolyser. It can be seen that hydrogen production needs a certain minimum threshold to begin. In this case, hydrogen production starts at 55 $\mathrm{kW_{el}}$, which corresponds to 18 % of the nominal power. Note that this this value is rather high for the given unit and generally depends on the individual characteristics of the used electrolyser.

The measured flow of hydrogen in terms of standard cubic meters per hour $\dot{q}_{\mathrm{H_2}}$ is converted into a thermal power equivalent $P_{\mathrm{th,H_2}}$ using the *Higher Heating Value* (HHV) for hydrogen:

$$P_{\mathrm{th,H_2}} = \mathrm{HHV} \cdot \dot{q}_{\mathrm{H_2}} \qquad [\mathrm{W}] \quad (1)$$

In this work HHV is set to 12.75 MJ/Nm^3 [26].

Figure 3(a) also shows that the relation between electric power and hydrogen production is mildly non-linear. It is modelled using the following regression model, valid above the minimum operation threshold with $P_{\mathrm{el,ely}}$ representing the electrolyser's electric power demand:

$$\begin{aligned} P_{\mathrm{th,H_2}} = &- 8 \cdot 10^{-7} \cdot P_{\mathrm{el,ely}}^2 \\ &+ P_{\mathrm{el,ely}} - 16.5 \cdot 10^3 \end{aligned} \qquad [\mathrm{W}] \quad (2)$$

For the current study a simplified approach for start-up and shut-down procedures was chosen to represent the dynamic characteristics of the plant, which are non-linear and strongly plant- and manufacturer-specific. Dynamics are modelled by considering three different operation states and corresponding limitations in ramp-rate and minimum run or pause times. The considered states are:

1. *Start mode*: If the power consumption is smaller than the minimum power, the power changing rate is defined by r_{start}, which is smaller than the nominal power changing rate.

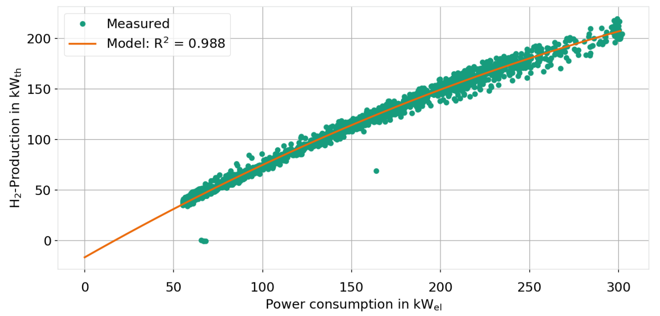
2. *Nominal reaction mode*: Between minimum power consumption and nominal power, the electrolyser can react with r_{nom}.

3. *Shut-down mode*: If the electrolyser is switched off, it reduces its power consumption with a shut-down rate r_{sd}.

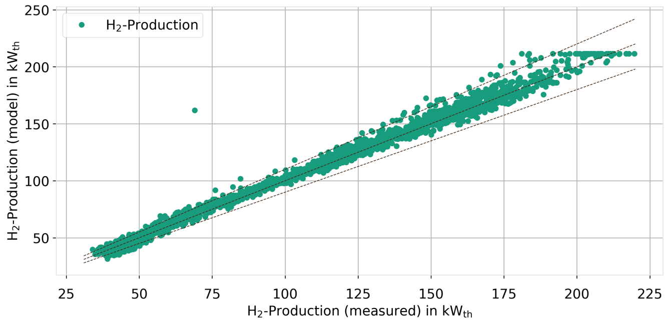
The parameters needed to describe the different power ramps are listed in Table .1 in the Appendix.

The validation results for the used regression shown in Figure 3(a) and 3(b) show an R2 of over 0.98 and a relative error mostly below 10% indicating a good quality of the used fit.

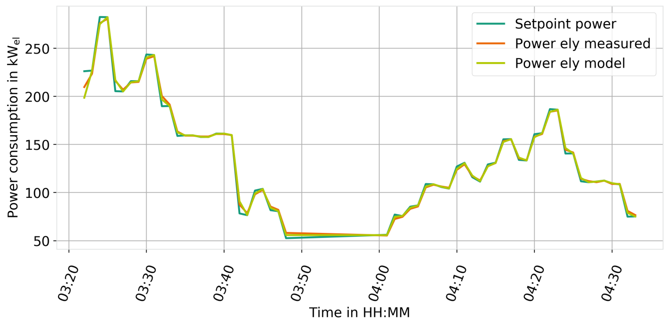
Figure 3(c) compares the dynamic behaviour of the electrolyser model with measured data, following varying power set-points. The sequence demonstrates that the system dynamics of the simulation model correspond well to the real unit.



(a) Modelled and measured relationship between electrical power and hydrogen production.



(b) Comparison of measured and simulated hydrogen production. Dashed lines represent the 10 % deviation corridor.



(c) Exemplary sequence to show the dynamic behaviour of modelled and simulated electrolysis mode.

Figure 3: Modelling and validation of the electrolyser.

This model was scaled to a factor of 2 for this study (see Table .1 in the Appendix) and is going to be used in further simulations.

2.3.2. *Hydrogen storage model*

The temperature of the hydrogen in the storage influences the maximum storage capacity as storage pressure has to be kept within the design conditions. The temperature of the hydrogen in the storage is calculated using an non-stationary energy balance for the tank. The change of the temperature is dependent on the thermal mass of the storage construction, the current hydrogen content in the storage and temperature of the surrounding. Given the temperature of hydrogen and the storage content and volume, the pressure is calculated using the Van-der-Waals Equation [27].

2.4. *Controls*

Two different control strategies are implemented. Both set the current hydrogen production considering electricity and gas prices, the availability of renewable electricity and network restrictions into the calculation of the controls. The control strategies use a simplified model of the P2G plant for calculating the control decisions.

2.4.1. *Rule-based controller (RBC)*

The rule-based controller (RBC) calculates the control decision based on thresholds. If a certain threshold according to Table .1 is undercut (EPEX-price, grid load) or exceeded (renewable energy feed-in), hydrogen production is started. The hydrogen content W in the storage for the next time step $t+1$, given the current set-point $P_{\text{el,ely}}$ and feed-in $P_{\text{th,feed}}$ is calculated to:

$$W_{t+1} = (\eta_{\text{ely}} \cdot P_{\text{el,t}} - P_{\text{th,feed,t}}) \cdot \Delta t + W_t \quad [\text{J}] \quad (3)$$

To determine the maximum allowed hydrogen production, Equation 3 is transformed to:

$$P_{\text{el,max,t}} = \frac{W_{\max} - W_t - P_{\text{th,feed,t}} \cdot \Delta t}{\eta_{\text{ely}} \cdot \Delta t} \quad [\text{W}] \quad (4)$$

Correspondingly, the maximum possible gas feed-in is set in Equation 5 using the minimum storage content as a lower boundary

$$P_{\text{th,feed,max,t}} = \frac{W_t - W_{\min} + \eta_{\text{ely}} \cdot P_{\text{el,set,t}} \cdot \Delta t}{\Delta t} [\text{W}] \quad (5)$$

2.4.2. *Model predictive controller (MPC)*

The second implemented control approach is a model predictive controller (MPC). Based on a system model, the measurements of the actual storage content (system states) and predictions about the costs and gas flow in the network (boundaries) are used. The MPC calculates the set-point trajectory over the entire prediction horizon using linear optimisation. The set-values are power consumption of the electrolyser $P_{\text{el,ely}}$ and gas feed-in $P_{\text{th,feed}}$. For each time-step the relevant part of the optimisation result is transmitted to the P2G unit as set-point.

The objective is to minimise a cost function l for every optimisation step k within the prediction horizon N_p, which is defined as follows:

$$l(k, P_{\text{el,k}}, P_{\text{th,feed,k}}) = c_{\text{el,k}} \cdot P_{\text{el,k}} - c_{\text{gas,k}} \cdot P_{\text{th,feed,k}} \quad \text{[EUR]} \quad (6)$$

with $c_{\text{el,k}}$ and $c_{\text{gas,k}}$ representing the electricity and gas prices in timestap k respectively. The optimization horizon is is set to a time window of 24 h or 24 time steps ($N_p = 24$) for time intervals of 60 min. The overall cost function is

$$\min_{P_{\text{el}}, P_{\text{th,feed}}} J(k, P_{\text{el}}, P_{\text{th,feed}}) = \sum_{k=0}^{N_p-1} l(k, P_{\text{el,k}}, P_{\text{th,feed,k}}) \quad (7)$$

Gas prices are assumed constant throughout the 24h time window. This might not be entirely true but compared to price fluctuations of the electricity market this is considered an acceptable assumption. Therefore the key parameter to be changed are the costs of electricity $c_{\text{el,k}}$ depending on the consumed power. So, the model-predictive-control optimises Equation 6 with respect to $P_{\text{el,ely}}$ and delivers an operation schedule to the internal control of the electrolyser for the next N time steps [28]. This schedule is updated every time step using updated predictive data and the current system state.

To promote the use of renewable energy or penalise the operation in hours of high load in the electric distribution grid the price in the MPC algorithm is modified in those cases to:

$$c_{\text{el,k}} = -m \cdot \text{x}_{\text{k}} + c_0 \quad \text{[EUR/MWh]} \quad (8)$$

where x(t)_{k} is a dynamic weighting factor. m and c_0 are tuning parameters.

c_0 is calculated using the average efficiency of the electrolyseur η_{ely} and the gas price. It represents the highest price for electricity, where operation of the electrolyser is still profitable, which corresponds to the thresholds used in the RBC. At this exact price, revenues from selling gas exceed the costs for electricity purchase.

$$c_0 = c_{\text{gas}} \cdot \eta_{\text{ely}} \quad \text{[EUR/MWh]} \quad (9)$$

To optimise operation for the best usage of renewable electricity the price is adjusted by $\text{x(t)}_{\text{RE,k}}$ using:

$$\text{x}_{\text{RE,k}} = \frac{P_{\text{RE,k}} - P_{\text{RE,nom,k}}}{P_0} \quad \text{[-]} \quad (10)$$

To optimise operation towards avoiding high loads in the electric grid the price is adjusted $\text{x(t)}_{\text{GL,k}}$ using:

$$\text{x}_{\text{GL,k}} = \frac{P_{\text{GL,nom,k}} - P_{\text{GL,k}}}{P_0} \quad \text{[-]} \quad (11)$$

To obtain a physically correct and technically feasible solution the optimal control problem is subject to a number of constraints.

The energy content of the storage $W_{\text{sto,k}}$ at each optimisation step k is calculated recursively by:

$$W_{\text{sto,k+1}} = (\eta_{\text{ely}} \cdot P_{\text{el,k}} - P_{\text{th,feed,k}}) \cdot \Delta t + W_{\text{sto,k}} \quad \text{[J]} \quad (12)$$

The maximum and minimum storable energy, defined as $W_{\text{sto,min,k}}$ and $W_{\text{sto,max,k}}$ is checked by:

$$W_{\text{sto,min,k}} \leq W_{\text{sto,k}} \leq W_{\text{sto,max,k}} \quad \text{[J]} \quad (13)$$

The maximum allowed hydrogen feed-in at the gas network $P_{\text{th,grid,max}}$ has to be respected at any time:

$$0 \leq P_{\text{th,feed,k}} \leq P_{\text{th,grid,max,k}} \quad \text{[W]} \quad (14)$$

The operational limits of the electrolyser $P_{\text{el,ely,max}}$ have to be respected and electricity consumption must not violate the restrictions present in the electric network $P_{\text{el,grid,max,k}}$:

$$0 \leq P_{\text{el,ely,k}} \leq \min(P_{\text{el,ely,max}}, P_{\text{el,grid,max,k}}) \quad \text{[W]} \quad (15)$$

2.5. *Key performance indicators*

A set of key performance indicators (KPIs) is used to compare the controller performance for each use-case. Those are:

- Contribution margin (CM): Calculated as the difference between the revenues achieved by selling of H_2-gas and the costs for buying electricity. Further maintenance and operating costs as well as investment costs are not considered.

- Full load hours (FLH): Full load hours are used to evaluate the run-time of the unit.

- Hydrogen feed-in: The amount of hydrogen that was fed-in in the gas network. Depends on the consumed power and the full load hours.

- Self-consumption: The share of locally generated renewable electricity that is consumed for hydrogen generation. An increasing self-consumption decreases the electricity surcharges paid if there is a direct connection of the P2G plant to the renewable power generation plants.

- Relative control error: The deviation between the set-point transferred to the P2G unit and the realised power consumption is used to evaluate controller performance.

$$err = \frac{\sum_{k=1}^{N} |P_{\text{el,ely,set},k} - P_{\text{el,ely},k}|}{\sum_{k=1}^{N} P_{\text{el,ely},k}} \quad \text{[-]} \quad (16)$$

3. Results

This section presents the simulation results of the P2G unit in different use-cases.

3.1. Simulated cases

The unit investigated in this study is located within the city boundaries of Freiburg, Germany, connected to the electric grid and the local gas network. Within the city of Freiburg a 7.2 MW wind park and a 2.5 MW PV array are present and it is possible for the unit to purchase electricity from the spot market. Hence operation of the P2G unit is investigated for three different use-cases, that have been identified relevant when integrating P2G into an urban energy system. Those are referred to as:

1. Reference: Neither electricity prices, nor renewable feed-in, nor limitations in the electric grid are taken into account. The electrolyser operates whenever the network restrictions allow it. To reduce the number of starts a dead-band control approach with respect to the storage content is applied. The maximum possible amount of hydrogen is fed into the gas network.

2. Electricity price: Time variable electricity prices based on the EPEX day ahead price for electricity are used for the optimisation. Neither usage of renewable electricity, nor limitations in the electric grid are taken into account. Hourly electricity prices are obtained from EPEX day-ahead [29], shown in Figure 4(b).

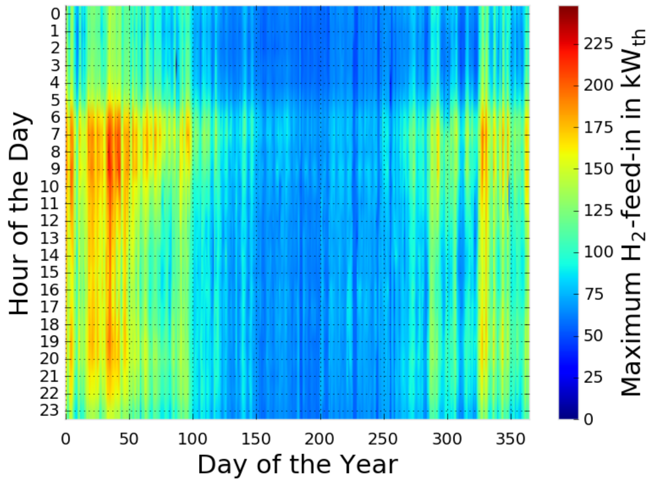
3. Renewable energy: No electricity prices are considered for the optimisation, but renewable electricity from a local wind farm and a PV plant is used. Renewable electricity generation data of the 7.2 MW wind park and the 2.5 MW PV array data is provided by the local distribution grid operator. Operational target is to maximise the use of renewables.

4. High grid load: Neither electricity prices nor renewable feed-in is considered for the optimisation, but presence of limitations in the electric grid during hours of high load are taken into account. Data for the load of the electric distribution is obtained from the local distribution grid operator [30].

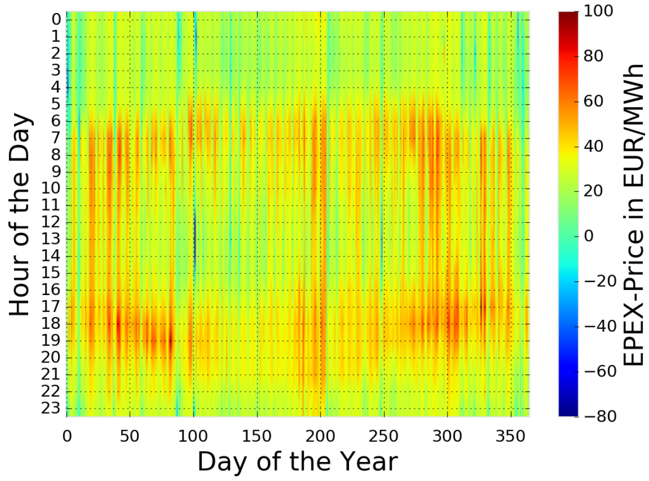
Each use-case is simulated for five different hydrogen storage capacities, the rule-based controller and the MPC. The simulation parameters are listed in Table .1 at the end of this article. The maximum allowed amount of hydrogen feed-in to the natural gas network is based on measured data of the year 2015 provided by the gas network operator and is shown in Figure 4(a).

3.2. Influence of controls

To illustrate the operation of the model predictive controller Figure 5 shows an exemplary sequence of 48 hours for operation of the P2G plant during winter and summer for the Electricity Price use-case. In both cases the storage is charged during the low price periods and discharged during the following hours to be at the minimum pressure needed for feed-in. Comparing the summer and winter sequence three things can be observed 1) Prices and maximum allowed feed-in are higher in the winter sequence, 2) Higher maximum allowed feed-in leads to a longer operation of the electrolyser during low price periods in

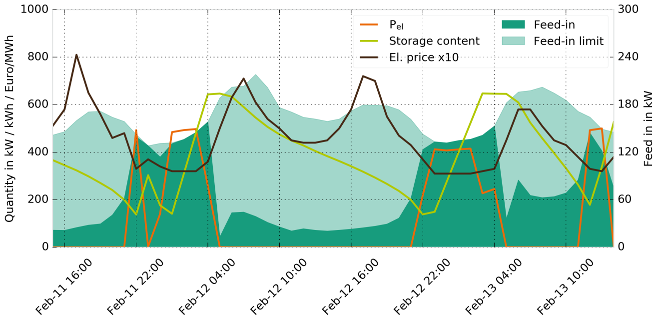


(a) Maximum allowed H_2-Feed-in

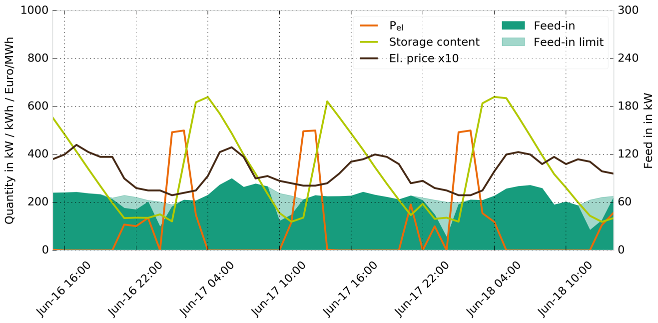


(b) Electricity price

Figure 4: Time series of maximum hydrogen feed-in and electricity price used as input data.



(a) Winter



(b) Summer

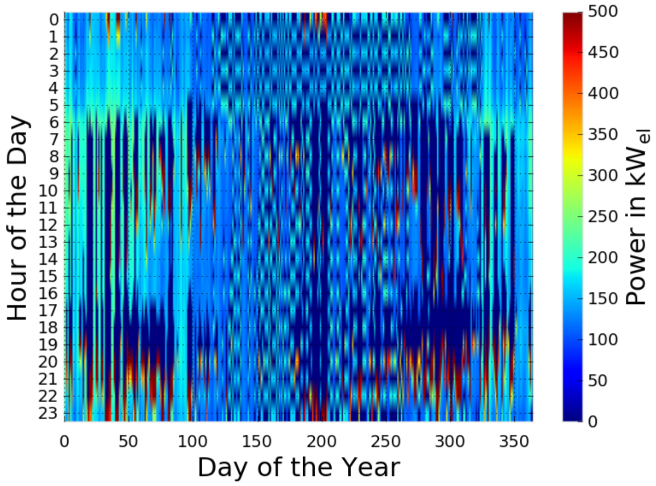
Figure 5: Exemplary sequence for operation of the P2G unit in the price use-case.

winter than in summer 3) During summer time feed-in is close to maximum allowed feed-in for most of the time.

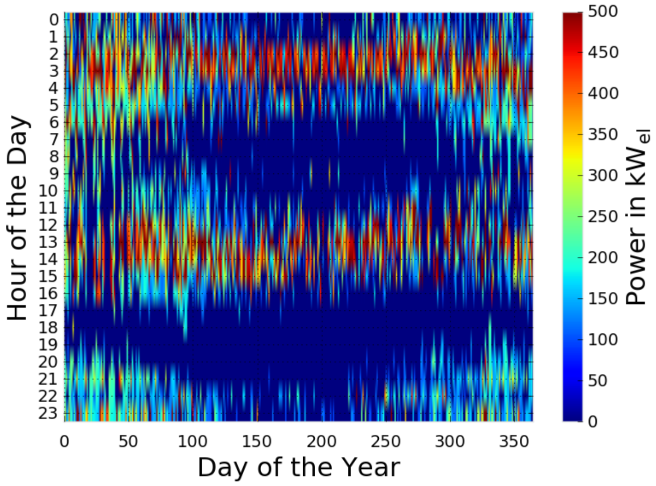
To highlight the difference between the RBC and MPC operation of the P2G unit, the operation of the electrolyser over the whole year is shown in Figure 6 for the case of variable electricity prices. It can be seen that both controls respond differently to the prevailing electricity prices.

Using the RBC the P2G unit operates when prices are below the threshold. This results in frequent part load operations as storage capacity and restrictions in the gas network limit possible hydrogen generation. Additionally RBC leads to frequent on-off-switching of the plant during summer. This leads to the on-off pattern in electric consumption seen in Figure 6(a). In case of an almost fully charged storage and restrictions in the gas network, the minimum electrolyser power can not be met and power is set to zero at this time step. The electrolyser is started the next time-step when it is technically possible. This process continues as long as gas network restrictions are strict and hydrogen production is economically viable. On-off cycling as observed by the RBC is not favourable as frequent cold start-ups might lead to ageing of the device and add unwanted fluctuations to the local electric grid. Further improvements to overcome this problem for a RBC have to be made.

In contrast to the RBC the MPC operates the P2G unit predominately in the early morning and during noon hours where prices are lowest. On-off-Cycling is reduced by using the hydrogen storage in an optimised way. The MPC detects and exploits minima in price and operates the plant more frequently at



(a) RBC



(b) MPC

Figure 6: Operation of the electrolyser for every hour of the year in the price use-case for the rule-based controller (RBC) and the model predictive controller (MPC).

its nominal capacity and the present restrictions in the gas and electricity network. However the overall amount of produced hydrogen is higher if RBC is used. A reason for this is the mismatch between plant and model discussed in Section 3.5.

With RBC, relative control errors can be avoided completely, but lead to frequent start-stop processes as the state of charge is high on average. MPC shows a more continuous operation consisting of mainly two start-stop sequences during a day.

Controller performance has been discussed in this Section using the findings of the price use-case. With respect to controller performance the other use-cases show similar results. However, operating hours within the day and annual values are changed depending on the use-case.

3.3. Influence of network restrictions

Figure 7 shows the influence of the network restrictions on selected KPIs for a storage of two full load hours. The pre-

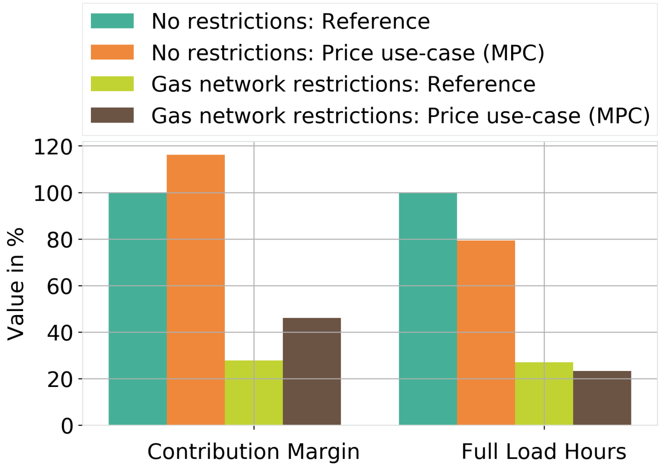


Figure 7: Influence of restrictions in the gas network on selected KPIs. Values are shown as relative numbers compared to the reference case without network restrictions. For simplicity Contribution Margin (CM) only considers electricity purchase and hydrogen sale.

sented numbers are annual values, calculated for the reference case and the variable electricity price use-case. It can be seen that contribution margin is reduced by almost 65 % in the reference and more than 60 % in the price use-case, due to restrictions in the gas network. Full load hours are reduced by more than 65 % when restrictions are applied. The negative effects of the restrictions in the gas network are clearly visible.

If MPC is used the effects of network restrictions can be decreased. Although FLH are reduced by factor 4 when restrictions are applied the overall margin in the price use-case is only 55 % smaller in the MPC case, whereas in the reference case it is reduced proportionally. This highlights the ability of the MPC to operate the P2G when it is most profitable while taking into account the restrictions and the limited capacity of the on-site hydrogen storage.

3.4. Influence of use-case and storage size

The annual results for the restricted use-cases are depicted in Figure 8. It shows that controls and storage capacity both influence the results. The larger the storage the better the performance of the MPC scheme.

Full load hours of the plant are depending on the available storage capacity, as with larger storage capacity more hydrogen can be stored up during times when incentives are high and released to the gas network whenever possible.

In the reference use-case, the electrolyser is merely controlled to produce hydrogen whenever possible. This leads to a match of feed-in and the gas network restriction and represents the maximum possible hydrogen production for the P2G unit at this location. As it is shown the overall amount of produced hydrogen does not necessarily result in higher revenues and contribution margins.

Besides the price use-case, the grid load use-case provides considerable revenues that are comparable to the price use-case. This is due to a good correlation of load in the electric grid and spot market prices. In the reference case, revenues are the lowest. The main improvement by using a MPC therefore lies in reducing costs for the storage and a higher overall revenue.

Only a small fraction of the available renewables could be used on average, which can be seen in self-consumption rates which do not exceed 10 percent. This is due to the high ratio of installed renewable power (approx. 10 MW) and nominal power of the electrolyser (0.5 MW) plus the prevailing network restrictions. Higher self-consumption can be achieved either by increasing the nominal power of the site itself, or by less tight gas network restrictions. Additionally, self-consumption could not be increased if MPC was used compared to scenarios with a RB-controller. However, using the MPC the P2G unit is operated during time periods where incentive maxima occur and thus the need for storage can be interpreted as highest. This could be interpreted as a more system friendly operation.

Power consumption during times with a grid load above $P_{\mathrm{GL,nom}}$ could be avoided completely, if the GL-use-case is used. In the renewable use-case, this parameter is significantly high, which is due to a good correlation of PV-feed-in and grid load.

The overall control error was decreasing with increasing storage size, if MPC was used. For RBC the error was insignificant. Increasing storages led to decreased control errors, which is due to simplifications in the optimal control model, which are discussed in the following.

3.5. Influence of plant-model mismatch

The results show that applying MPC improves both revenue and performance of the electrolyser itself. Still, effects of plant-model mismatch between the detailed system and the optimal control model could be observed. They significantly contribute to the relative control error (see Figure 8).

In the detailed model a minimum hydrogen production rate is needed for the electrolyser to operate, leading to hybrid system characteristics. This is true for the feed-in-plant as well. Nonetheless this is neglected in the optimal control model to avoid mixed-integer characteristics. Values below the minimum operation rate that result as a set-point from the optimisation are set to 0 in a post-processing step, leading to a control error particularly in times with low gas flow in the network. It shows that when storage is added to the system the control error is reduced significantly. In this case the P2G unit is operated more frequently at high loads when economic conditions are good, which not only decreases the relative error but also decreases the cumulated energy consumption for MPC.

A further source for mismatch are differences in system dynamics, particularly the possible ramping rates and cold start-up time for the detailed system model. Dynamic inaccuracies, that occur when set-points are changed, are small compared to those resulting from ignoring the hybrid system characteristics. One reason for this is that the optimal control problem is solved on an hourly base and hence set-points are only changed in this interval.

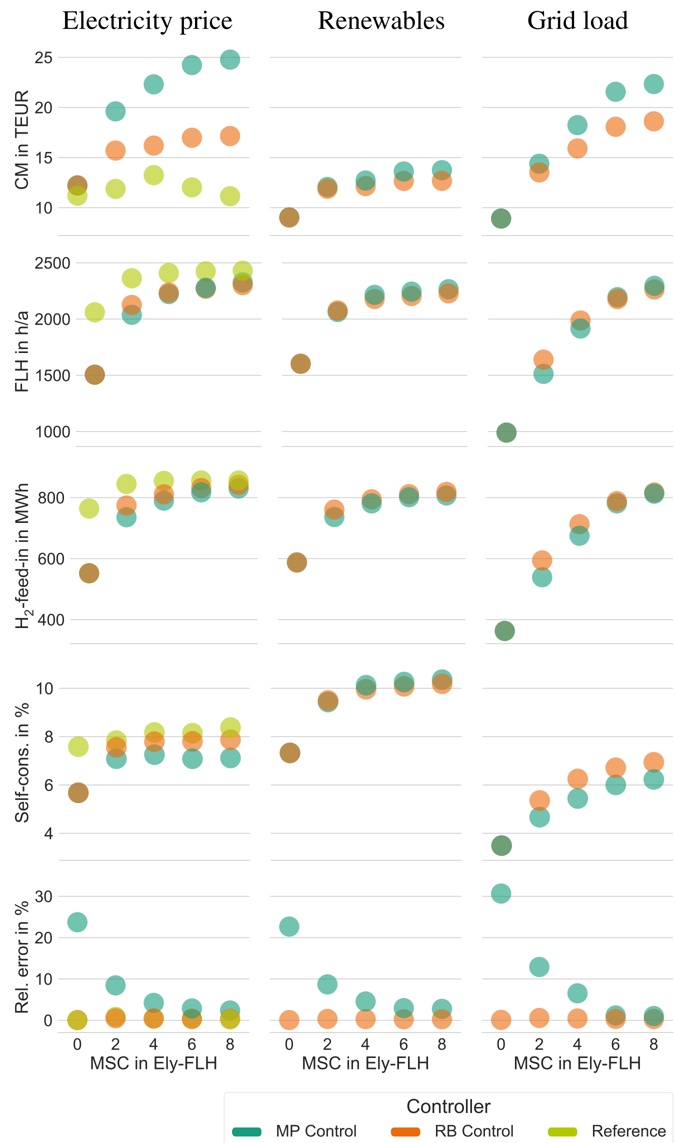


Figure 8: Sensitivity analysis of controls (coloured dots), storage size (x-axis) and use-case (columns) for different KPIs (rows). Storage capacities (MSC) are represented in full load hours (FLH) of the electrolyser.

4. Conclusion

This work investigated the effect of restrictions in the gas network and the electric grid on a power-to-gas station located in an urban area. Adjusted controls and on-site hydrogen storage were tested in a simulation study as a solution to at least partially compensate network restrictions. Three potential use-cases were considered: 1) Maximisation of renewable electricity use, 2) optimised operation at the electric spot market, 3) optimised operation to reduce high load in the electric grid. A model predictive and a rule-based control were used to optimise the operation of the power-to-gas plant.

Imposing gas network restrictions led to a reduction of hydrogen production by more than 65 %. Simultaneously, annual contribution margin was reduced likewise. Hence selection of the location of the P2G unit has to be done with respect to those restrictions.

If restrictions apply, local storage should be added. Increasing the capacity of the on-site storage improved the performance of the P2G unit in all cases. However, it could not fully extinguish the negative effects of network restrictions. For the investigated cases most positive effects can be yielded with a storage capacity of about 6 full load hours of the electrolysis unit.

For an improved operation of the P2G unit and on-site storage, model predictive controls (MPC) are recommended. By applying MPC as control strategy, revenue could be significantly increased in all cases. Results show that, depending on the use-case, using MPC instead of RBC leads to 31 % higher annual contribution margin and up to 48 % less cold start cycles of the plant. Furthermore full-load-hours were increased as well which is important for CAPEX-intensive plants like electrolysers.

Although this approach compensated the effects of gas grid restrictions at least partially it was not possible to reach the original level of contribution margin and full load hours for unrestricted feed-in. Reduction of restrictions is still deemed the best approach even if that approach might be impossible in many urban settings.

Apart from P2G the chose control approach might improve the use of electrolysers in other sectors (i.e. on-site supply of industry or mobility) where restrictions from the demand side apply, as well.

The presented control strategy will be implemented in the P2G unit on the test site at Fraunhofer ISE Freiburg.

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Model parameters

Description	Variable	Value	Unit
Nom. RE feed-in power	$P_{\text{RE,nom}}$	0.0	MW
Nom. high grid load	$P_{\text{GL,nom}}$	200.0	MW
Scaling factor power	P_0	1	MW
Nom. EPEX-price	c_0	37.5	€/MWh
Gas price	c_{gas}	60.0	€/MWh
Efficiency factor ely	η_{ely}	70.0	%
Scaling factor	m	1.0	€/MWh
Power start rate	r_{start}	$+5.0$	kW/s
Power nominal rate	r_{nom}	$\pm$ 6.7	kW/s
Power shut down rate	r_{sd}	-13.3	kW/s
Min. set-point Power	$P_{\text{el,ely,min}}$	110.0	kW
Nominal power	$P_{\text{el,ely,nom}}$	500.0	kW

Table .1: Model parameters used in the simulation study.

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