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Shared Capacity and Levelized Cost with Application to Power-to-Gas Technology

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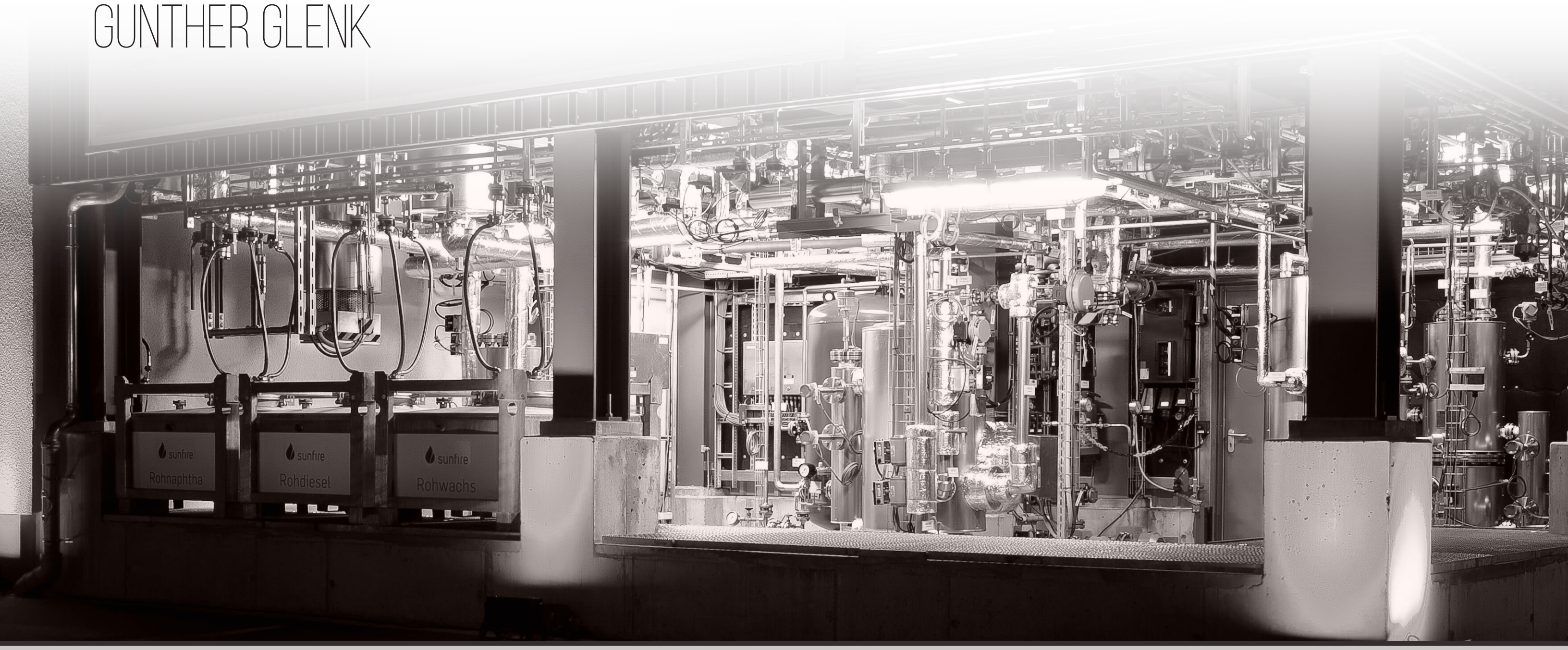

APRIL 2019

CEEPR WP 2019-007

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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Shared Capacity and Levelized Cost with Application to Power-to-Gas Technology

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April 2019 (Update May 2019)

Abstract

Ambiguity in calculating unit cost continues to spur debate on how to account for operating assets in managerial decisions, especially when capacity is shared. Here I show that the concept of levelized cost yields a simple and definite allocation of historic cost and relevant unit cost for different perspectives of a potential investor. Crucial to the allocation is that levelized cost reflects the constant payment required over the life of a capacity to break-even on the initial investment. A common application of the concept is to compare the competitiveness of clean versus fossil energy sources in potential pathways to a decarbonized economy. Contrary to previous work, I find that the levelized cost of new Power-to-Gas technology can be low enough to compete with fossil-based alternatives. Central to this finding is that the ability to reversibly convert electricity to hydrogen and trade both outputs in the market leads to an effective sharing of sizable joint cost.

Keywords: unit cost, capacity investment, product prices, renewable energy, energy storage

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1 Introduction

The cost and value of productive capacity reflects indispensable information for the management of a firm. The information facilitates core decisions on, for instance, capital budgeting and capacity planning (e.g., Boyabatli and Toktay (2011); Göx (2002)) or performance evaluation and organizational control (e.g., Dutta and Reichelstein (2018); Baldenius et al. (2007)). The calculation of unit cost, however, is frequently viewed as inherently ambiguous due to the many ways to apportion the stream of expenditures that is associated to the installation and operation of capacity over multiple periods. When capacity is shared among multiple outputs or respondents, the additional need for cross-sectional allocation makes the calculation even more manifold.

The challenge of calculating unit cost is that the historic cost of a firm's accumulated operating assets is sunk in the short run but decisive for survival in the long run (Pittman, 2009). Concepts responding to this challenge have evolved in the accounting and economics literature in various ways. The simplest concept is to assume that firms have access to a competitive rental market for capacity, in which the rental price reflects the respective unit cost (Carlton and Perloff, 2015). Alternative concepts have developed individual allocation rules to derive, for instance, the periodic economic income (Rogerson, 2008; Baldenius and Reichelstein, 2005), efficient transfer prices for intra-company trade (Dutta and Reichelstein, 2010; Wei, 2004), or product cost suitable for product pricing and profitability analyses (Balachandran and Ramakrishnan, 1996; Pavia, 1995). The underlying objective of these concepts is to identify unit cost that provide the managers of a firm with the right information and incentives for their decisions. Despite the common goal, however, there appears to be no unifying principle for the characterization of relevant unit cost.

Here I propose that unit cost should reflect the constant revenue payment that a potential investor in capacity would have to receive over the life of the asset in order to break-even on the initial investment. This break-even conceptualization simplifies the aggregation of multi-period cash flows and provides a definitive criterion for both intertemporal and cross-sectional allocation. In particular, the criterion stipulates that all capacity-related and operating cash flows required to supply the capacity are discounted and allocated intertemporally across both the periods of operation and the productive time or output of the capacity.[1] The cross-sectional allocation must then align profitability among the joint products. In alignment either all or none of the products are profitable for any production quantity, whereby each product would be declared profitable if

[1]The aggregation is related to the notion of life-cycle costing, which argues that revenues must cover all costs, including the initial R&D, to be profitable in the long run (Horngren et al., 2015). In contrast, the aggregation here examines the cost of delivering a product for a given technology.

its unit cost is exceeded by the selling price. This alignment, I show, can be achieved if and only if the joint costs of capacity are allocated by relative contribution margin, that is, by the share of the total contribution margin that each output is planned to generate.

The break-even criterion for the characterization of unit cost builds upon the concept of *levelized cost*. Introduced in the energy literature, the levelized cost of electricity production represents the *"constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors"* (MIT, 2007). The cost metric is commonly used in the energy sector to compare the cost competitiveness of alternative generation technologies and decide upon capacity investments.[2] While the concept has been formalized for a generic productive capacity (Reichelstein and Rohlfing-Bastian, 2015), the formulation settings have remained stylized with several simplifying features. Most restrictive among them is the assumption that the capacity is dedicated to the delivery of a single product or service.

When capacity is shared, I show that the calculation of levelized cost depends on the perspective that the potential investor takes.[3] With what I term a *capacity perspective* the investor focuses on the supply of productive capacity and seeks to identify the constant rental payment required to break-even. My analysis shows that the relevant unit cost can be given by what I call the *levelized fixed cost (LFC)*, which reflects the average contribution margin per hour of available capacity. Taking a *product perspective*, on the other hand, the investor concentrates on the production of individual outputs and aims to determine the constant prices per unit of output required to break-even when selling each output on the respective market. Here, the relevant unit cost emerges as the levelized cost of an individual product. The necessary and complicating cross-sectional cost allocation can be simplified to just one additional factor in the formulation that adjusts the joint costs of capacity for the share allocated to the output.

In facilitating managerial decisions, the concept of levelized cost shows to yield the relevant unit cost. Most fundamental, I find that the concept identifies the unit cost firms should impute when deciding upon investments in productive capacity. While my analysis confines to decisions whether or not to invest, the concept can also be used for choosing the optimal level of capacity investment (Reichelstein and Rohlfing-Bastian, 2015). The focus of my setting follows from the observation that oftentimes an indicative decision proceeds a quantitative one. Conceptualized as a break-even

[2]A variation of levelized cost has also been used with pharmaceutical R&D (Grabowski and Vernon, 1990).

[3]The possible perspectives are closely related to the organizational structures investigated in the literature on decentralized capacity management; see, for instance, Dutta and Reichelstein (2010, 2018) or Rogerson (2008). As perspectives and structures not always align, it is important to distinguish between them.

price, the levelized cost also identifies the minimum price that an output or service must achieve in the long term and hence the relevant unit cost in a pricing decision. With regard to decentralized capacity management, I find that both the LFC of capacity and the levelized cost of a product can serve as efficient transfer prices depending on the investor perspective and the organizational structure (Karmarkar and Pitbladdo, 1993).

To the broad literature on marginal and full cost, the concept of levelized cost relates in several aspects. Most important to the continuous debate on how to measure marginal cost is that the levelized cost of a product can be interpreted as the long-run marginal cost of a product (Reichelstein and Rohlfing-Bastian, 2015).[4] Against a product's full cost the levelized product cost can be equated to an extended form of full cost that also includes taxes and imputed interest charges on the remaining book value (Reichelstein and Rohlfing-Bastian, 2015). In predicting product prices in the market the concept can provide a sufficient measure under different extents of competition (Reichelstein and Sahoo, 2017; Balakrishnan and Sivaramakrishnan, 2002).

A timely field of application is within sustainable energy. While wind and solar power sources have outpaced early projections in terms of cost reductions and share of power generation (Comello et al., 2018a; Kök et al., 2018), two challenges remain unsolved in the transition to a decarbonized economy. First, renewable energy production relies on intermittent weather conditions and, second, decarbonization efforts must go beyond the power sector, especially, to transportation and manufacturing. A promising solution could be new Power-to-Gas (PtG) technology.[5] By converting and reconverting electricity to hydrogen (Buttler and Spliethoff, 2018), reversible PtG can effectively store electricity at large scale and provide a clean energy carrier to processes that are otherwise difficult to decarbonize.[6] Since both outputs are produced on the same facility and sold separately in the respective markets, reversible PtG presents a shared capacity in the generic sense.

To assess the economic viability of reversible PtG, a potential investor naturally assumes the capacity perspective. Accordingly, a reversible PtG facility breaks-even if and only if the LFC is exceeded by the average contribution margin. As a technology that can store electricity over time, the break-even of reversible PtG is widely thought to rely on the volatility in power prices and the continuous switch between conversion and reconversion.[7] While my analysis confirms this tie, it

[4] For a discussion on long-run marginal cost, see, for instance, Rogerson (2011), Rajan and Reichelstein (2009), Nezlobin et al. (2012), or Friedl and Küpper (2010).

[5] See alternative options, for instance, in Islegen and Reichelstein (2011) or Zhou et al. (2016).

[6] Hydrogen reflects a platform with many applications including fuel for transportation, feedstock in chemical and processing industries, or energy storage for power generation (Davis et al., 2018).

[7] See, for instance, Jülch (2016) for PtG and de Groote (1994) or Dong et al. (2014) in the real-option literature with consistent findings for a generic flexible capacity.

shows that the ability to trade the storage medium (hydrogen) is even more important. Through the market access reversible PtG receives a price for hydrogen and the possibility to generate value from operating in only one direction. As a consequence, reversible PtG will typically break-even when it produces the output with the higher average contribution margin by a large majority.

To measure the competitiveness of electricity and hydrogen, an investor assumes the product perspective, since the levelized cost concept is frequently used to find the cheapest technology for power generation. This requires an insight on the cross-sectional allocation at break-even of the PtG facility. While one may intuitively assume an equal allocation for a storage technology, I find that the economics of reversible PtG divide the sizable joint costs unequally into a large and a small share. The cross-sectional allocation thus becomes the main driver of competitiveness.

Against alternative sources that could complement intermittent renewables, the economics of reversible PtG may unfold as a competitive advantage. Operating in just one direction, conventional power generators based on, say, coal or natural gas are sensitive to rising volatility in power prices and decreasing utilization, which both have followed the shift towards renewables (Wozabal et al., 2016). Other storage technologies like batteries rely, unable to trade their storage medium, on generating value purely from volatile power prices and on covering their costs with the limited amounts of stored electricity (Comello and Reichelstein, 2019). For reversible PtG I find that electricity production is likely to receive only a small share of joint cost so that its levelized cost can be competitive despite high cost for the new technology and hydrogen as a fuel.

Finally, I seek to assess empirically the economic prospects for reversible PtG in Germany and Texas, two jurisdictions that have exhibited a rapid growth of renewables. For the current market environment, I find that reversible PtG breaks-even only if the average value of hydrogen is above that of electricity and the facility largely produces hydrogen. With regard to the competitiveness I find that electricity and hydrogen are in both jurisdictions only competitive in niche applications. Hydrogen, for instance, is competitive with small- and medium-scale but not with the lower prices paid for large-scale supply of industrial hydrogen produced from fossil fuels.

Incorporating recent market trends, the calculations line out a trajectory for reversible PtG that corroborates its potential in addressing the issues of intermittency and decarbonization. These trends include sustained cost reductions, efficiency improvements, and the vertical integration with a co-located renewable energy source to benefit from operational synergies. Due to these synergies, hydrogen produced with reversible PtG becomes competitive with large-scale hydrogen supply already today. Electricity production remains presently more expensive but is likely to become cheaper than conventional power generators over the coming decade.

Compared to previous studies on PtG, my analysis finds a better competitive position of reversible PtG. The main ingredient for this is that the ability to operate reversibly and trade both outputs leads to an unbalanced production and effective sharing of sizable capacity-related costs (Braff et al., 2016; Jülch, 2016). In addition, the calculations take advantage of synergistic benefits that arise from combining a PtG facility with an optimally sized renewable energy source (Felgenhauer and Hamacher, 2015). Finally, the facility can achieve a higher utilization by converting both renewable and grid electricity rather than only renewable power (Glenk and Reichelstein, 2019).

In the following, section 2 describes the model setting and the production of reversible PtG. Section 3 proceeds with the capacity perspective and section 4 with the product perspective. Section 5 contains the application and numerical evaluation. Section 6 concludes. Proofs are provided in the Appendix and input variables in the Supplementary Information.

2 Model Description

2.1 Shared Capacity

Consider a productive capacity that is shared among multiple outputs each of which is produced separately and sold immediately in the respective market. Examples of such capacity are found in both manufacturing of, for instance, chemicals or mechanical parts, and service-oriented businesses, such as support or postal services. The delivery of products or services causes various cash flows for upfront investment, annual operating expenses, and financing cost for debt and equity investors.

The main concept examined in this paper is the *levelized cost*. Conceptualized for capacity dedicated to a single output, the levelized cost of a product or service calculates a per unit revenue payment that an investor in productive capacity would have to obtain as average minimum over the life of the investment in order to break-even (MIT, 2007). The metric aggregates a share of the initial capacity investment with operating expenses and any tax-related cash flows. To achieve the per unit basis, the aggregation includes an expectation of a production schedule that the capacity would assume past the installation. The central issue of the aggregation is to identify the particular cost and unit that are relevant from the perspective of the investor.

My analysis considers two distinct scenarios of the perspective that an investor in shared capacity can take. In what I call the *capacity perspective*, the investor concentrates on the supply of productive capacity. The issue then is to identify the constant revenue payment per unit of capacity the investor would have to receive in order to break-even when renting the capacity over time for the production of an output. The perspective is naturally assumed by a manager who due to technical expertise is responsible for the initial installation of the capacity and the subsequent utilization by other divisions of the same company.[8]

In the *product perspective*, in contrast, the attention resides on the sale of individual outputs. For a potential investor the critical issue is to identify the constant payment per unit of output required to break-even when selling the outputs in the markets. The perspective would be taken by a manager who is primarily occupied with the marketing of the product. Yet, it may also be taken by the previous manager, who normally assumes a capacity perspective, if the generated output is supplied, for instance, to an internal division and stands in competition with the external market.

The perspectives determine which cost aggregation and unit basis is relevant for the potential investor. A differentiation between them is crucial when capacity is shared, because the value is driven by a portfolio of different outputs. If a capacity generates only a single output, the value of the capacity and the perspective of analysis is dominated by the sale of this output. Both perspectives trigger analyses that an investor can conduct independently from each other.

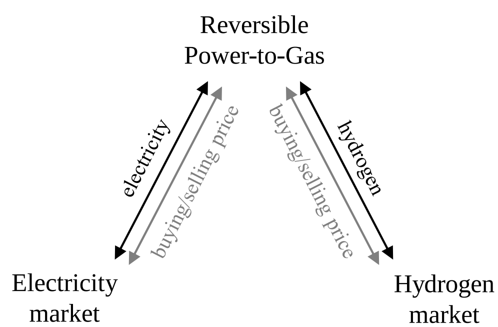

Figure 1: Illustration of reversible Power-to-Gas.

With an eye on the challenges of intermittency and decarbonization, confine attention to a reversible Power-to-Gas (PtG) facility as the subsequent formulations are generic in most aspects. Facilities with a polymer electrolyte membrane (PEM) or solid oxide cell (SOC) electrolyzer permit bi-directional operation and can effectively convert and reconvert electricity to hydrogen (Pellow et al., 2015). In the power-to-gas process, electricity infused in water instantly splits the water molecule into oxygen and hydrogen. In reverse, hydrogen recombines with oxygen producing water and electricity. As illustrated in Figure 1, both outputs are produced on the same capacity and traded separately in the respective markets.[9] Reversible PtG thus represents a shared capacity

[8]This corresponds to the manager of an upstream division in a decentralized organizational structure as studied, for instance, in Dutta and Reichelstein (2010, 2018) and Wei (2004).

[9]Hydrogen trade is currently developing from individual transactions to open markets that compare to those for

in the generic sense and seeks to exploit the volatility of wholesale prices in a business model previously defined as *trading arbitrage* (Baumgarte et al., 2019).

Let SP denote the cost for upfront investment as the system price of reversible PtG per kilowatt (kW) of peak capacity for electricity absorption and desorption.[10] The lifetime of the capacity is given in T years and the time value of money is captured by the discount factor $\gamma = \frac{1}{(1+r)}$, with r as the cost of capital.[11] r should be interpreted as the Weighted Average Cost of Capital (WACC) if the unit cost is to incorporate returns for both equity and debt investors (Ross et al., 2008). Technological availability of the capacity is covered by the degradation factor x^{i-1}, which gives the fraction of the initial capacity that is functioning in year i.

The cost of an investment is affected by corporate income taxes by means of a debt and a depreciation tax shield, because interest payments on debt and depreciation charges reduce the taxable earnings of a firm. The tax shield from debt is already included in the calculation if the cost of capital is interpreted as the WACC. The depreciation tax shield can be accounted for with the definition of a tax factor that is denoted by Δ. The depreciation tax shield and hence the tax factor is a dominant driver of cost if the upfront investment constitutes a large part of overall costs.

The capacity investment typically also triggers a stream of fixed operating costs. Let F_i denote the annual fixed costs per kW of installed capacity. To identify a levelized cost measure, both SP and F_i must be apportioned among the relevant units. The quantity of the units hinges in both perspectives on the anticipated production schedule of the capacity.

2.2 Production Schedule

Given a shared capacity, the decision which output to produce over time is based on the contribution margin that each output would generate within a time period (Friedl et al., 2017). A reversible PtG facility, in particular, seeks to maximize the periodic contribution margins and optimize the use of available capacity in line with the real-time fluctuations in electricity prices.

A reversible PtG facility converts electricity to hydrogen if the conversion price of hydrogen per kilowatt hour (kWh) exceeds the current variable cost of conversion. The conversion price refers to the price per kilogram (kg) of hydrogen at which the PtG facility can sell hydrogen on the market. This price is scaled by the conversion rate of the reversible electrolyzer from electricity to water in kg/kWh. Let p_h denote the price for hydrogen and η^c the conversion rate of the electrolyzer, which

natural gas (Business Insider, 2018; Government of Japan, 2018).

[10]For notational compactness, the model assumes that capacity and fixed operating costs scale linearly with the size of the facility but could be easily extended to consider economies of scale.

[11]A comprehensive lists of all symbols and acronyms is provided in the Appendix.

reflects the amount of hydrogen that can be procured from 1 kWh of electricity.

The variable cost of conversion comprises costs for mainly electricity and other variable consumable inputs like water and reactants for deionizing the water. Let w^o denote the costs of other consumable inputs per kg of hydrogen production, $p_e(t)$ denote the wholesale market price per kWh of electricity at which the PtG facility can sell at time t, and δ_e denote a frequently observable markup for taxes, fees, and levies that arise when electricity is purchased from the market.[12] Time is a continuous variable t ranging from 0 to 8,760 hours per year, which is the common granularity of electricity prices. For simplicity, it is assumed that the intertemporal distribution of prices is constant across years. The variable cost of conversion is thus given by:

$$w^c(t) = p_e(t) + \delta_e + \eta^c \cdot w^o. \tag{1}$$

Regarding hydrogen production, let $CF^c(t)$ denote the capacity factor of hydrogen conversion reflecting the percentage of the capacity that is generating hydrogen at time t. Since bi-directional electrolyzer technologies can ramp swiftly (Ferrero et al., 2015), the facility is set to absorb electricity at full capacity whenever the conversion value of hydrogen exceeds the buying price of electricity and to remain idle otherwise. Using the notation of an indicator function, $CF^c(t)$ is given by:

$$CF^c(t) = \mathbb{1}\{\eta^c \cdot p_h > w^c(t)\}. \tag{2}$$

The contribution margin of hydrogen conversion per kWh at time t is then given by:

$$CM^c(t) = \big(\eta^c \cdot p_h - w^c(t)\big) \cdot CF^c(t). \tag{3}$$

Conversely, the PtG facility generates power through hydrogen reconversion if the price at which electricity can be sold on the market at time t exceeds the variable cost of reconversion. The latter comprises per kWh of electricity output the reconversion rate of the electrolyzer, denoted by η^r (in kWh/kg), multiplied with the market price of hydrogen, p_h, plus a markup for transportation and storage denoted by δ_h. Thus:

$$w^r = \frac{1}{\eta^r} \cdot (p_h + \delta_h). \tag{4}$$

For the quantity of power generation, let $CF^r(t)$ denote the capacity factor of hydrogen reconversion, which reflects the percentage of the capacity that is generating electricity at time t. With

[12] A market-based buying price is necessary for PtG to operate in support of grid stability. The facility absorbs electricity during surplus when prices are low, and generates electricity during shortage when prices are higher.

hydrogen storable in pipelines and caverns, it can be procured in sufficient amounts (Michalski et al., 2017) and the facility is set to generate electricity at full capacity whenever the price for electricity exceeds the variable cost of reconversion and to remain idle otherwise:

$$CF^r(t) = \mathbb{1}\{p_e(t) > w^r\}. \tag{5}$$

The capacity factor of reconversion quantifies the kWh of electricity generated by a PtG facility of 1 kW. The contribution margin of hydrogen reconversion per kWh at time t is given by:

$$CM^r(t) = \big(p_e(t) - w^r\big) \cdot CF^r(t). \tag{6}$$

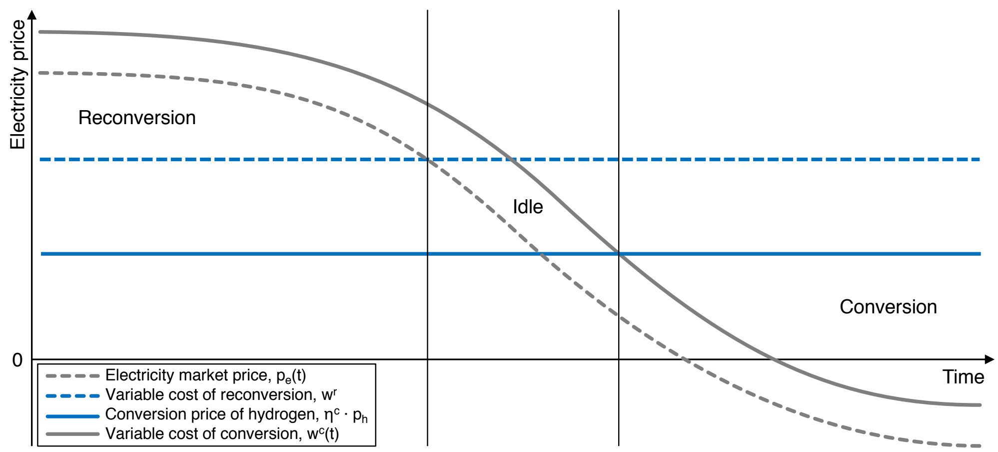

Figure 2: Complementary slackness of reversible Power-to-Gas.

Clearly, at a reversible PtG facility, the decision which output to produce is without trade-off, because the electrolyzer can run in only one direction at any point in time.[13] This technological characteristic manifests economically in the way that out of the two individual contribution margins only one can be positive at a time, as Figure 2 shows.[14] The law of conservation of energy stipulates that the round-trip efficiency of the facility must satisfy that $\eta^c \cdot \eta^r \leq 1$. Consequently, $w^r \geq \eta^c \cdot p_h$, where both values are equal if $\eta^c \cdot \eta^r = 1$ and $\delta_h = 0$. The relation of individual contribution margins is subsequently referred to as the *complementary slackness* of reversible PtG.

In addition to the production of either output, the reversible PtG facility may also turn idle if both contribution margins are negative or zero because $p_e(t) \leq w^r$ while $w^c(t) \geq \eta^c \cdot p_h$. The

[13]If a capacity produces multiple outputs simultaneously, the capacity factors can be set to the share of the capacity dedicated to the production of the respective output instead of to a binary value.

[14]Note that wholesale electricity markets increasingly exhibit negative prices as a result of surplus energy being unloaded on the grid at certain hours.

downtime results from markups and variable costs paid, and a round-trip efficiency of less than one, which together open up an efficiency gap, in which electricity prices are lost. The idle time grows with the size of this gap and the distribution of electricity prices.

If the facility produces only a single output, for instance, in a hypothetical stationary environment where prices are constant, the contribution margin of the facility is equivalent to one of the individual contribution margins without time dependence. With the flexibility to switch production in accordance to real-time price fluctuations, the periodic contribution margin of a reversible PtG facility per kWh results from aggregating the individual contribution margins to:

$$CM(t) = \big(\eta^c \cdot p_h - w^c(t)\big) \cdot CF^c(t) + \big(p_e(t) - w^r\big) \cdot CF^r(t). \tag{7}$$

The formulation shows that a shared capacity will generate the output that delivers the highest contribution margin at a point in time. A reversible PtG facility, in particular, will switch between electricity and hydrogen production in line with the continuous fluctuations in electricity prices.

3 Capacity Perspective

Let us first investigate the scenario in which the potential investor takes the capacity perspective. Here the investor focuses on the supply of productive capacity that will be rented subsequently for the production of several outputs. The analysis in this section thus seeks, in general, to identify the relevant unit cost for the supply of shared capacity and, in particular, to examine for reversible PtG when a facility would be economically viable.

Which unit cost is relevant for an investor with a capacity perspective is revealed as the information that is essential when supplying productive capacity. As shown above, a capacity generates for a certain time the output that yields the highest contribution margin. The contribution margin is necessary to be positive to trigger production in the short run, but to generate value in the long run it must also suffice to cover the cost of consuming productive capacity. Essential information for the capacity perspective is therefore the minimum contribution margin per hour that the capacity has to receive on average in order to break-even. The relevant unit cost thus aggregates a share of the upfront capacity investment with annual fixed operating expenses and any tax-related cash flows to a metric that I will refer to as the *levelized fixed cost* (LFC) per hour of shared capacity.[15]

The upfront investment, SP, and fixed operating cost, F_i, are inherently a joint cost shared

[15] In contrast, the levelized fixed cost of hydrogen characterized by Glenk and Reichelstein (2019) is a cost per kWh of electricity converted to hydrogen rather than a cost of an average hour of production.

among the hours of production in subsequent periods. To obtain the cost per hour, the joint cost must be allocated across both the availability and average utilization of the capacity. The availability of capacity can be captured by the levelization factor L. With $m = 24 \cdot 365 = 8,760$ hours per year, let $L = m \cdot \sum_{i=1}^{T} \gamma^i \cdot x^{i-1}$ express the discounted number of hours that the capacity is available over its lifetime.

The average capacity utilization of the productive capacity is given by the average of hourly capacity factors of the individual outputs. Let CF denote the average capacity factor that is a unitless scalar and given by:

$$CF \equiv \frac{1}{m} \int_0^m \big(CF^c(t) + CF^r(t)\big)dt. \tag{8}$$

For a reversible PtG facility, the capacity factor is driven by the degree of overlap of the efficiency gap with electricity prices and the complementary slackness ensures that $CF \leq 1$.[16] The capacity and fixed operating costs per hour are given by:

$$c \equiv \frac{SP}{CF \cdot L}, \text{ and } \qquad f \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{CF \cdot L}. \tag{9}$$

With regard to taxes, let d_i denote the allowable tax depreciation charge in year i and note that the assumed lifetime for tax purposes is usually shorter than the economic lifetime such that $d_i = 0$ in those years. With α as the effective corporate income tax rate, the tax factor is given by:

$$\Delta = \frac{1 - \alpha \cdot \sum_{i=1}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{10}$$

Δ is increasing and convex in the tax rate α, meaning it is greater than 1 in the absence of tax credits and is bound above by $1/(1-\alpha)$. Considering the time value of money, an accelerated tax depreciation schedule reduces Δ; for instance, if the tax code was to allow for a full depreciation in the first year ($d_0 = 1$ and $d_i = 0$ for $i > 0$), $\Delta = 1$.

Definition 1. *The levelized fixed cost of a reversible PtG facility is given by:*

$$LFC \equiv f + \Delta \cdot c. \tag{11}$$

To examine whether the expression in (11) satisfies the break-even requirement provided at the

[16] This entails the implicit assumption that the PtG facility can be maintained when it is idle.

beginning of this section, the LFC can be compared to the average contribution margin per hour that would be earned if a reversible PtG capacity is supplied for the production of electricity and hydrogen. The average contribution margin results from time-averaging the periodic contribution margin, which requires to account for covariances between output and prices, because the capacity factors vary by construction with the real-time fluctuations in the attainable contribution margins.

Building upon the formulation by Reichelstein and Sahoo (2015), let $\epsilon^c(t)$ denote the multiplicative deviation factor of $CF^c(t)$ from the average value $CF^c = \frac{1}{m}\int_0^m CF^c(t)dt$, and by $\mu^c(t)$ the deviation of $w^c(t)$ from the average w^c:

$$\epsilon^c(t) \equiv \frac{CF^c(t)}{CF^c}, \text{ and } \mu^c(t) \equiv \frac{w^c(t)}{w^c}, \text{ with} \tag{12}$$

$$\frac{1}{m}\int_0^m \epsilon^c(t) = \frac{1}{m}\int_0^m \mu^c(t) = 1. \tag{13}$$

The co-variation coefficient denoted by Γ^c captures the variation between hydrogen conversion and variable cost of conversion. The factor equals zero if the PtG facility fails to capture any electricity prices for conversion to hydrogen and equals one if it captures all electricity prices. Formally:

$$\Gamma^c = \frac{1}{m}\int_0^m \epsilon^c(t) \cdot \mu^c(t)dt. \tag{14}$$

Similarly, let $\epsilon^r(t)$ denote the multiplicative deviation of $CF^r(t)$ from the average CF^r and by $\mu^r(t)$ the deviation by which $p_e(t)$ differs from the average p_e:

$$\epsilon^r(t) \equiv \frac{CF^r(t)}{CF^r}, \text{ and } \mu^r(t) \equiv \frac{p_e(t)}{p_e}, \text{ with} \tag{15}$$

$$\frac{1}{m}\int_0^m \epsilon^r(t) = \frac{1}{m}\int_0^m \mu^r(t) = 1. \tag{16}$$

Let Γ^r denote the co-variation coefficient between hydrogen reconversion and the electricity price. Γ^r equals one if the PtG facility reconverts hydrogen to electricity during all hours. For hydrogen prices that allow the PtG facility to capture only higher electricity prices, Γ^r increases until the facility fails to capture any electricity prices for reconversion. The factor is given by:

$$\Gamma^r = \frac{1}{m}\int_0^m \epsilon^r(t) \cdot \mu^r(t)dt. \tag{17}$$

The average contribution margin per hour of a reversible PtG facility is given by:

$$CM = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{18}$$

The expression describes the margin earned by a reversible PtG facility in an average hour of operation given a particular mix of generated products. The margin results as the sum of individual contribution margins weighted by the average capacity factors. For later use, the individual margins can further be aggregated to the average contribution margins of conversion and reconversion:

$$CM^c = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c, \text{ and } CM^r = (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{19}$$

Proposition 1. *A reversible PtG facility breaks-even on the initial investment if and only if:*[17]

$$(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r \geq LFC \cdot CF. \tag{20}$$

Proposition 1 shows that a reversible PtG facility breaks-even if the average contribution margin exceeds the levelized fixed cost multiplied with the average capacity factor. LFC thus reflects the relevant unit cost for an investment in shared capacity if the investor assumes the capacity perspective. The proof of Proposition 1 shows that the expression directly results from stating the net present value (NPV) in terms of per hour costs and revenues. $LFC \cdot CF$ will subsequently be referred to as the *capacity-related costs.* If the facility produces only one output, Proposition 1 can be easily transformed into the break-even condition of a dedicated capacity and is consistent with previous findings (Reichelstein and Rohlfing-Bastian, 2015).

In light of the supply of capacity, note that the LFC aligns under certain conditions with the notion of full cost transfer pricing, as studied, for instance, in Dutta and Reichelstein (2018) or Baldenius and Reichelstein (2006). Suppose the supplier of capacity is a central unit that owns the productive capacity and rents it to internal divisions, which are each responsible for the production of one output. A key question then is at what transfer price the capacity should be rented so as to set the right investment incentives for the central unit. Proposition 1 shows that the central unit should set the hourly rental price to LFC. Note, however, that this ignores typical issues like double marginalization or diverse time preferences of managers.

In addition to the mere condition, a potential investor would also be interested in the necessary circumstances for the facility to break-even. As it is widely understood for energy storage tech-

[17] Proofs of the formal claims are shown in the Appendix.

nology, the value of reversible PtG increases with the volatility in electricity prices.[18] Section 2.2 shows that the production of reversible PtG hinges on the spread between the price of electricity and hydrogen. As the amount of volatility grows, the spread at the point of (re)conversion and hence the value of production increases.

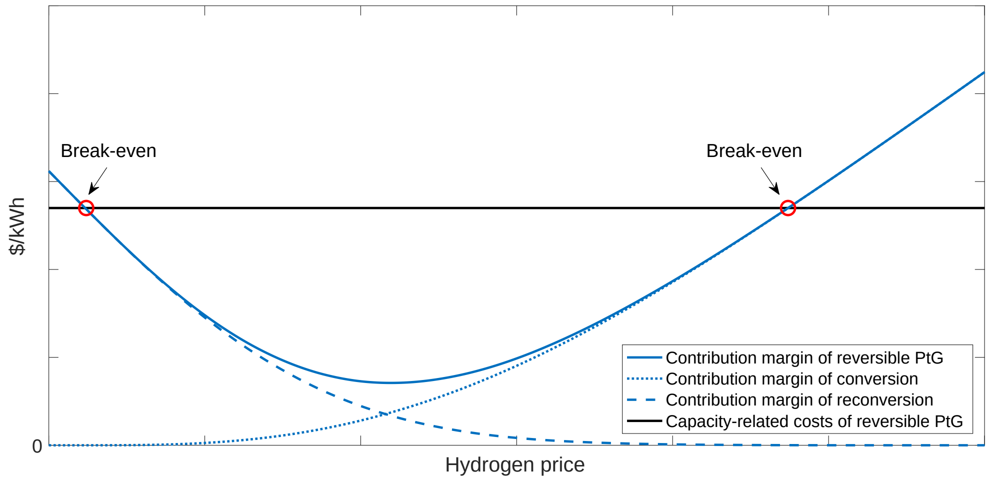

Figure 3: Economics of reversible Power-to-Gas.

Less immediate is how the economics of reversible PtG also depend on the ability to trade hydrogen as the storage medium in the market. Suppose p_e has a distribution as commonly observable in current wholesale markets.[19] Let CM then be viewed in dependence of p_h:

$$CM(p_h) = \big(\eta^c \cdot p_h - w^c \cdot \Gamma^c(p_h)\big) \cdot CF^c(p_h) + \big(p_e \cdot \Gamma^r(p_h) - w^r(p_h)\big) \cdot CF^r(p_h). \tag{21}$$

As Figure 3 illustrates, the contribution margin of conversion is increasing in p_h, while the contribution margin of reconversion is decreasing in p_h. As the sum of both parts, $CM(p_h)$ obtains a U-shaped form. The minimum of $CM(p_h)$ indicates the constellation of electricity and hydrogen prices with the least potential for arbitrage through (re)conversion. The capacity-related costs are independent of p_h and intersect the average contribution margin above the minimum, provided the costs are *sizable* in the sense that $LFC \cdot CF > \text{argmin}\{CM(p_h)\}$ as is applicable at the current stage of technological development (Buttler and Spliethoff, 2018).

Proposition 2. *Suppose $p_e(t)$ is given as observable in electricity markets and capacity-related costs are sizable. In dependence of p_h, a reversible PtG facility obtains two break-even points in one of which $CM^c(p_h) > CM^r(p_h)$ and in the other one $CM^r(p_h) > CM^c(p_h)$.*

[18]This also aligns the option value of flexible production capacity (van Mieghem, 1998; Fine and Freund, 1990).
[19]Approximating distribution functions are, for instance, Normal, Weibull, or Rayleigh.

Proposition 2 shows that the ability to trade hydrogen in the respective market is a main driver of profitability for reversible PtG, because a facility will typically break-even when it produces the output with the higher average price and hence contribution margin by a large majority. Through the market access reversible PtG receives a price for hydrogen and the possibility to draw value from the spread between the average price of electricity and hydrogen. A reversible PtG facility can therefore generate value by operating in just one direction and selling the generated output in the market without the need for reconversion.

Relative to alternative energy sources, the reversible operation and ability to trade the storage medium provides an economic advantage for reversible PtG. Conventional power generators operating in only one direction, such as coal- or gas-fired power plants, suffer from the increase in volatility in electricity prices that resulted from the growth renewable energy sources due to an increased ramping and a decreased utilization (Wozabal et al., 2016). Storage technologies like batteries, pumped hydro, or compressed air cannot trade their storage medium and must compete for the volatility of electricity prices. Furthermore, without the ability to utilize the market they are limited in the duration of power supply.

4 Product Perspective

Contrary to the case examined thus far, where the potential investor takes the capacity perspective and focuses on the supply of productive capacity, let us now consider the alternative scenario that the investor takes the product perspective. Here the potential investor focuses on the production and sale of individual outputs. The analysis in this section thus seeks to identify the relevant unit cost when selling the outputs in the market. For a reversible PtG facility, this section also seeks to examine the competitiveness of both generated outputs.

A product manager responsible for the installation decides to invest in capacity if the selling price of an output is sufficiently large. The price is necessary to exceed the variable operating costs to justify production in the short run, but to generate value in the long run it must also exceed the capacity-related costs of production. Essential information for an investment decision is therefore the minimum selling price per unit of output that the capacity has to receive on average in order to break-even on the investment. The relevant unit cost thus aggregates a share of the upfront capacity investment with fixed and variable operating expenses and tax-related cash flows to the levelized cost of an individual product.

As before, the upfront investment, SP, and the annual fixed costs, F_i, represent joint costs.

Only here the joint costs must be apportioned among the units of output produced in subsequent periods rather than the hours of production. Since both SP and F_i are given in cost per kW of peak capacity, the production volume of an output can be given implicitly as the utilization of the available capacity dedicated to the output. The availability is captured by the levelization factor L. The utilization of capacity dedicated to one output is measured by the average capacity factor of the output, that is, CF^c for conversion and CF^r for reconversion.

In the case of hydrogen production, the capacity and fixed operating costs per unit of electricity conversion to hydrogen result from aggregating all capacity and fixed operating costs over the lifetime of the facility and distributing them among the production volume:

$$c^c \equiv \frac{SP}{CF^c \cdot L}, \text{ and} \qquad\qquad f^c \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{CF^c \cdot L}. \tag{22}$$

The formulation for electricity production is entirely symmetric. Let c^r and f^r denote the unit capacity and fixed operating costs respectively.

The variable operating costs per unit comprise the time-averaged variable costs of conversion and reconversion denoted by w^c and w^r. Recall that the variable costs of conversion fluctuate in real time with the production and are thus adjusted with the co-variation coefficient Γ^c. With regard to taxes, the expression of the tax factor provided in the previous section remains applicable.

Note at this point that the expressions in (22) distribute the capacity-related costs only intertemporally across periods and production volume. When a productive capacity is shared by multiple outputs, the identification of relevant cost per unit of output requires to allocate the joint costs also cross-sectionally among the outputs.

As discussed, the cost per unit of an output is relevant for an investor with the product perspective when it reflects the constant selling price required for the capacity to break-even. The complication, however, is that the break-even evaluation occurs on the level of the product rather than of the capacity. A product would be declared as profitable if its unit cost is exceeded by the average price, while a capacity is profitable if its entire costs are exceeded by its entire revenues. If a capacity generates only a single product, this product carries the entire cost of capacity and the profitability of the product and the capacity naturally align. With multiple outputs, the alignment hinges on the cross-sectional allocation of joint costs.

For the unit cost of a product generated with shared capacity to reflect the break-even price of the capacity, profitability evaluations on a product and capacity level must align. A cross-sectional allocation rule is thus said to induce *profitability alignment* if it yields unit costs of individual products such that either all or none of the products are profitable for any production schedule. On the contrary, profitability is not aligned if one product is profitable while the others are not for some combination of output production. As a consequence of the alignment among products, the profitability of the entire productive capacity is equally aligned with each product.

Proposition 3. *Profitability alignment is given if and only if capacity-related costs are allocated cross-sectionally by relative contribution margin, that is, according to the share of the total average contribution margin that each product is planned to generate. For reversible PtG, let λ^c and λ^r denote the cost allocation factors for conversion and reconversion given by:*

$$\lambda^c \equiv \frac{CM^c}{CM}, \text{ and } \lambda^r \equiv \frac{CM^r}{CM}. \tag{23}$$

The proposition becomes intuitive for reversible PtG when taking the capacity perspective. Consider for necessity that if a share of the average contribution margin generated by an arbitrary quantity of one output exceeds the same share of capacity-related costs (say, $\lambda^c \cdot CM > \lambda^c \cdot LFC \cdot CF$), it follows that the residual share of the average contribution margin also exceeds the residual share of the capacity-related costs ($(1-\lambda^c) \cdot CM > (1-\lambda^c) \cdot LFC \cdot CF$). Consequently, the total average contribution margin exceeds the total capacity-related costs and the entire facility is profitable ($CM > LFC \cdot CF$). For sufficiency consider that the facility is profitable if the total average contribution margin exceeds the total capacity-related costs. If the capacity-related costs are then allocated to both outputs by their relative contribution margin, both outputs would also be profitable in an individual inspection.

Against alternative allocation rules, the relative contribution margin also shows as necessary and sufficient for the profitability alignment. Traditional allocation rules, such as activity-based costing, may align profitability for some but not all production schedules. In contrast, an allocation by relative contribution margin aligns profitability for all production schedules. Yet, an allocation by relative contribution margin requires an assumption of the production schedule.[20] Allocations by *net realizable sales value* or *constant gross margin*, as characterized in Horngren et al. (2015), may yield equivalent results to an allocation by relative contribution margin depending on the level of inventory in a particular period. Rather than on a period-by-period basis, the relative contribution margin is intended to allocate costs for an entire investment cycle.

[20]The focus of this analysis is not on product pricing but on the identification of unit cost relevant for capacity investments. Product prices are treated as exogenous, which prevents a problem of circularity.

Definition 2. *Suppose a reversible PtG facility produces both outputs:*

i) *The levelized cost of electricity is given by:*

$$LCOE \equiv w^r + \lambda^r \cdot (f^r + \Delta \cdot c^r). \tag{24}$$

ii) *The levelized cost of hydrogen is given by:*[21]

$$LCOH \equiv \frac{1}{\eta^c} \cdot \big(w^c \cdot \Gamma^c + \lambda^c \cdot (f^c + \Delta \cdot c^c)\big). \tag{25}$$

Definition 2 shows that the levelized product cost at shared capacity can, like the initial formalization for dedicated capacity (e.g., Reichelstein and Rohlfing-Bastian (2015)), also be stated as the sum of three cost components: unit variable operating cost, unit fixed operating cost, and unit capacity cost adjusted by the tax factor. The only addition to the formulation is the cost allocation factor that adjusts the capacity-related costs for the share allocated to the output.

To control that the expressions in Definition 2 satisfy the break-even requirement, both cost metrics can be compared to the average selling prices of both outputs. As derived The average price for electricity is denoted by p_e and for hydrogen by p_h. Recall also that the electricity price fluctuates in real time with the production and is adjusted with the co-variation coefficient Γ^r.

Proposition 4. *Suppose a reversible PtG facility produces both outputs and the cross-sectional cost allocation is subject to profitability alignment. A reversible PtG facility breaks-even on the initial investment if and only if* $p_e \cdot \Gamma^r \geq LCOE$ *and* $p_h \geq LCOH$.

The proposition shows that a reversible PtG facility breaks-even if the average selling prices exceed the levelized cost of individual products. LCOE and LCOH each represent the relevant unit cost for an investment in a reversible PtG facility if the investor assumes the product perspective. The proof of the proposition shows that the expressions result from stating the NPV of the capacity in terms of per unit costs and revenues of both outputs. If the PtG facility produces only one output, Proposition 4 reduces to the break-even condition of that output, which is equivalent to that of a dedicated capacity as found, for instance, in Reichelstein and Rohlfing-Bastian (2015).

In relation to literature on decentralized capacity management, note that the levelized cost of individual products aligns under certain conditions with the notion of full cost transfer pricing, as

[21] While similar in spirit, the $LCOH$ characterized in Farhat and Reichelstein (2016) is determined for a capacity that is dedicated to the production of hydrogen from natural gas via steam reforming.

studied, for instance, in Dutta and Reichelstein (2010), Wei (2004), or Rogerson (2008). Suppose the ownership of the PtG facility is shared by two divisions, whereby each is responsible for the marketing of one output and the investment decision. The main issue then is to align the decision of both divisional managers. Proposition 4 shows that if both managers decide based on levelized cost, their decision would indeed be aligned. This sketched-out scenario, however, abstracts from problems that commonly arise in such settings, such as differing time preferences of managers, transparency of information, and the hold-up problem.

Another task for a potential investor in reversible PtG is to examine the competitiveness of both outputs with substitutes in the market. Since electricity is a homogeneous good, a key objective in the setup of energy markets is to find the power generation technology that can serve a given demand at lowest cost. With the transition towards intermittent renewables, in particular, the goal is to identify the cheapest technology to cover the residual load during hours of insufficient wind and solar power. A metric the energy sector has been widely using for such comparisons is the levelized cost of electricity (MIT, 2007) as it it quantifies, as the break-even price, the competitiveness of a production technology in delivering the output.

Since the levelized cost of electricity or hydrogen from reversible PtG is contingent on the cross-sectional cost allocation, measuring the competitiveness requires an insight on the output-specific contribution margins at break-even of the facility. As Proposition 2 shows, a reversible PtG facility breaks-even under conditions observable in current markets when the contribution margin of one output exceeds the contribution margin of the other output.

Corollary to Proposition 2 and 3. *Suppose capacity-related costs are sizable and allocated by relative contribution margin. The cross-sectional cost allocation at break-even of a reversible PtG facility is unbalanced in the sense that* $\lambda^c \neq \lambda^r$.

The corollary shows that the cross-sectional cost allocation presents a main driver of unit costs and hence the competitiveness of electricity and hydrogen, because it divides the joint costs into a larger and a smaller share. Then, which output of a reversible PtG facility can enjoy the smaller share? With the shift to renewable power and the attendant trend of falling power prices, a reversible PtG facility will likely produce hydrogen most of the time and only occasionally switch to electricity as weather conditions become adverse for renewables and power prices rise. Hydrogen will receive the larger and electricity the smaller share of joint costs. This stands in contrast to recent studies, which account the entire capacity-related costs to the production of electricity (Braff et al., 2016; Jülch, 2016). My analysis shows, in contrast, that $\lambda^r = 1$ only if the facility exclusively generates electricity, which may be the case in a hypothetical stationary environment or in the unlikely scenario that electricity prices never fall below the conversion price of hydrogen.

The unbalanced cost allocation reflects a competitive advantage for reversible PtG relative to alternative energy sources. Dedicated to the production of only one output, conventional power plants exhibit a falling utilization and hence increasing unit cost as market share shifts towards renewables. Similarly, alternative storage technologies like batteries must cover their entire cost with power generation. Reversible PtG, on the contrary, may be competitive in electricity production because of the favorable cost allocation between electricity and hydrogen even though hydrogen as a fuel and the new technology entail higher cost.

5 Reversible Power-to-Gas in Germany and Texas

This final section seeks to evaluate empirically the economic prospects for reversible PtG in solving the issues of intermittency and decarbonization. The framework is applied to Germany and Texas, which both have deployed considerable amounts of renewable energy in recent years and are increasingly exposed to the issue of intermittency (IEA, 2017). To get a full picture of the prospects, the section assesses the case of reversible PtG first in the current economic environment and then how it will likely unfold in the coming years if recent market trends continue.

The calculations base on data inputs from journal articles, industry data, publicly available reports, and interviews with industry sources. The main input variables and results are provided in the following subsections. A comprehensive overview is provided in the Supplementary Information.

5.1 Current Economic Environment

The evaluations of the current environment employ the most recent data available. Moreover, they assume the capacity perspective to explore the economics of reversible PtG and the product perspective for the competitiveness of electricity and hydrogen with alternatives in the market.

To sell electricity, the PtG facility participates in both jurisdictions in the day-ahead wholesale market. In 2017, wholesale prices averaged to 3.46 €¢/kWh in Germany and 2.44 $¢/kWh in Texas. For buying electricity, a PtG facility in Germany is eligible for the wholesale market price plus, as a producer of industry gases, a relatively small markup for taxes, fees and levies. In Texas, the facility draws on the time-invariant industrial rate offered by Austin Energy. To still reflect the balance of power supply and demand in the market, the calculations use the wholesale market price plus the average difference between the industrial rate and the market price as markup. Since the facility has a grid connection, it can also provide frequency control to the grid and help to balance supply and demand by rapidly absorbing electricity when the market is in excess. These revenues integrated with the prices at which the facility can buy electricity yield average buying prices of 3.93 €¢/kWh in Germany and 5.39 $¢/kWh in Texas.

Hydrogen prices are determined by the calculations as the lowest price required to break-even. These prices can then be compared to observable transaction prices for hydrogen supply, considering that a reversible PtG facility can be installed onsite or adjacent to a hydrogen customer. Current supply for hydrogen is derived by and large from fossil fuels in carbon intensive processes (Kothari et al., 2008). Note that the co-location with a hydrogen customer enables the PtG facility to sell hydrogen to the customer at the same price at which the facility or customer can buy from the market. The markup factor for transportation and storage, δ_h, can thus be considered to be zero.[22]

For capacity-related costs, the analysis assumes a SOC electrolyzer, which is the most flexible technology for reversible operation (Buttler and Spliethoff, 2018). Recent cost data for reversible PtG facilities found in a systematic review yield average system prices of 3,695 €/kW in Germany and 3,302 $/kW in Texas with an estimated annual fixed operating cost of 4.0% of the initial investment. Both the data and the description of the cost review is provided in the Supplementary Information. The conversion rate, η^c, is found to be 0.025 kg/kWh and the round-trip efficiency amounts to 45%, which gives a reconversion rate of 17.74 kWh/kg (SunFire GmbH, 2018).

Table 1: Economics of reversible Power-to-Gas.

	Germany	**Texas**
Average contribution margin, CM	4.7630 €¢/kWh	4.1596 $¢/kWh
Contribution margin of conversion, CM^c	4.7630 €¢/kWh	4.1591 $¢/kWh
Contribution margin of reconversion, CM^r	0.0000 €¢/kWh	0.0005 $¢/kWh
Levelized fixed cost, LFC	4.8880 €¢/kWh	4.1921 $¢/kWh
Average capacity factor, CF	97.4429%	99.2237%

Based on these data inputs, the numerical evaluations return results for the economics of reversible PtG as summarized in Table 1. In both jurisdictions, a reversible PtG facility breaks-even when (almost) exclusively producing hydrogen. The calculations do not return a break-even point on the electricity side, because the system price of the PtG facility is so large that the hydrogen price would have to be negative for the low wholesale price of electricity to generate a sufficient contribution margin. That the facilities produce so little electricity, or in Germany even no electricity at all, is due to the fact that at the break-even prices of hydrogen the variable costs of reconversion

[22]The effect of higher values for δ_h is shown in the Supplementary Information.

(almost) always exceed the electricity prices in the market.

The results for the competitiveness of electricity and hydrogen are summarized in Table 2. For hydrogen, the facility in Germany breaks-even at a price of 3.51 €/kg and in Texas at 3.85 \$/kg. Observable transaction prices for hydrogen supply cluster in three segments that vary primarily with scale (volume) and purity: large-scale supply between 1.5–2.5 €/kg (1.8–2.9 \$/kg), medium-scale between 3.0–4.0 €/kg (3.5–4.7 \$/kg), and small-scale above 4.0 €/kg (4.7 \$/kg) (Glenk and Reichelstein, 2019). The break-even prices thus make hydrogen from reversible PtG competitive with small- and medium-scale but not with large-scale industrial hydrogen supply. Note that hydrogen gets allocated essentially the entire capacity-related costs.

Table 2: Levelized cost of electricity and hydrogen from reversible Power-to-Gas.

	Germany	**Texas**
Hydrogen		
Variable cost of conversion, w^c	4.19 €¢/kWh	5.62 \$¢/kWh
Co-variation coefficient, Γ^c	0.96	0.99
Cost allocation factor, λ^c	100.00%	99.99%
Fixed and capacity costs	4.71 €¢/kWh	4.14 \$¢/kWh
Levelized cost of hydrogen, *LCOH*	3.51 €/kg	3.85 \$/kg
Electricity		
Variable cost of reconversion, w^r	19.78 €¢/kWh	21.70 \$¢/kWh
Cost allocation factor, λ^r	0.00 %	0.01%
Fixed and capacity costs	- €¢/kWh	363.68 \$¢/kWh
Levelized cost of electricity, *LCOE*	- €¢/kWh	25.70 \$¢/kWh

For electricity, the applicable unit cost for the facility in Germany would equal the variable cost of reconversion of 19.78 €¢/kWh if it was to generate a marginal kWh. In Texas, the LCOE amounts to 25.70 \$¢/kWh with variable cost of reconversion of 21.70 \$¢/kWh. The remarkably high number for fixed and capacity costs is due to the small capacity factor of reconversion and is mitigated in the expression of the levelized cost by a similarly small cost allocation. In comparison, the cost of conventional power generation varies in each jurisdiction by production technology.[23] In Germany, the LCOE of lignite is around 4.61 €¢/kWh, of natural gas around 6.96 €¢/kWh, of coal around 7.40 €¢/kWh, and of biogas around 14.59 €¢/kWh. In Texas, natural gas is at 3.89 \$¢/kWh, nuclear at 5.07 \$¢/kWh, coal at 6.68 \$¢/kWh, and biomass at 9.80 \$¢/kWh.[24] Electricity from reversible PtG is thus far more costly even though the allocated share of joint costs is small.

[23] Since alternative storage technologies, most prominently batteries, are limited in discharge duration and cost estimates vary considerably due to inconsistent methodology, they are omitted in the comparison.

[24] The numbers result from own calculations with data for Germany largely retrieved from Fraunhofer ISE (2018) and for Texas from Comello et al. (2018b), ABB (2018), and OpenEI (2018) (see a detailed overview in the Supplementary Information). Natural gas is assumed to be utilized in both jurisdictions in combined cycle gas turbines. Nuclear energy was omitted for Germany, because the government declared a phase-out until 2022.

5.2 Prospects for Competitiveness

Recent market developments suggest ongoing improvements in the economic opportunities for reversible PtG. This subsection integrates these trends to identify a trajectory of the competitiveness for hydrogen and electricity in future years. The projections focus on the product perspective to evaluate the potential for reversible PtG against alternative energy sources in the market.

The most important trend is the combination of the reversible PtG facility with a co-located renewable energy source of optimal relative size to a vertically integrated energy system. Such an integration gains operational synergies that stem from imperfections (e.g. taxes, fees, and levies) widely observed in market environments (Dong et al., 2014). In the presence of imperfections, the price at which the PtG facility can buy electricity from the market is generally above the price at which a the renewable source can sell electricity to the market.

Through the integration, the break-even calculations are subject to yield a synergistic value, that is, that the integrated system exceeds in value (NPV) both facilities stand-alone. The lower bound in the comparison is the stand-alone break-even of a facility because of the option not to invest (Glenk and Reichelstein, 2018). For renewable energy that sells its electricity on the wholesale market, previous work has identified the break-even condition as: $p_e \cdot \Gamma > LCOE$. Similar to the notation in this paper, p_e denotes the average electricity price, Γ the co-variation coefficient for the joint fluctuations in electricity prices and renewable generation, and $LCOE$ the levelized cost of electricity as calculated for a dedicated capacity (Reichelstein and Sahoo, 2015).

A suitable renewable source is wind energy as it reaches peak production levels at night when electricity demand and prices are relatively low (Engelhorn and Müsgens, 2018). System prices for wind turbines currently average in Germany to 1,180 €/kW and in Texas to 1,566 \$/kW (Fraunhofer IWES, 2017; ABB, 2018). Average capacity factors data at hand amount to 30.33 % in Germany and 44.39 % in Texas. Going forward, the system prices are expected to decline at an annual rate of 4.0%, while the average capacity factors increase at 0.7% per year (Wiser et al., 2016).

Another trend is the drift in electricity prices that results from the growing share of renewable energy sources. Wind energy is expected to obtain in Germany and Texas the leading role in directing future electricity prices in the market (Ketterer, 2014; Paraschiv et al., 2014). The calculations thus assume that the difference between the LCOE of wind energy in year i, $LCOE(i)$, and the adjusted average selling price, $\Gamma \cdot p_e(i)$, declines to zero at a constant adjustment rate such that:

$$LCOE(i) - \Gamma \cdot p_e(i) = D(0) \cdot \beta^i,$$

where $\beta < 1$ denotes the adjustment rate and $D(0) = \max\{LCOE(0) - \Gamma \cdot p_e(0), 0\}$.

Note in this context that wind energy is eligible for public subsidies in both jurisdictions. Wind energy in the U.S. receives a federal Production Tax Credit (PTC), which is a fixed amount per kWh of electricity (U.S. Department of Energy, 2016). Germany supports wind energy with a guaranteed minimum price per kWh that results from a competitive auction system. Specifically, the government pays the difference between a successful bid and the actual revenue obtained from wind energy in the market place (EEG, 2017). I refer to this difference as the Production Premium (PP).[25] Since the PP is effectively determined through a competitive auction mechanism, an auction in year i should yield a premium of $PP(i) = D(i)$. In Texas, the calculations anticipate the scheduled phase-out of the PTC by 20.0% per year (U.S. Department of Energy, 2016).

For PtG, the development of system prices follows findings from the own review with input from manufacturers, peer-reviewed articles, and technical reports. Covering data from 2003 to 2017 ($N = 20$), the annual decline rate results from a univariate regression for a constant elasticity functional form of the type: $SP_h(i) = SP_h(0) \cdot \beta^i$, where i refers to years. The regression provides an estimate for the annual price decline of 11.45 %, that is, $\beta = 0.8855$ (see the Supplementary Information for details).[26] The cost review also revealed that the round-trip efficiency is expected to increase from 45.0% to around 50.0% due to improvements for reconversion until 2030, which translates into an annual growth rate of 0.81%.

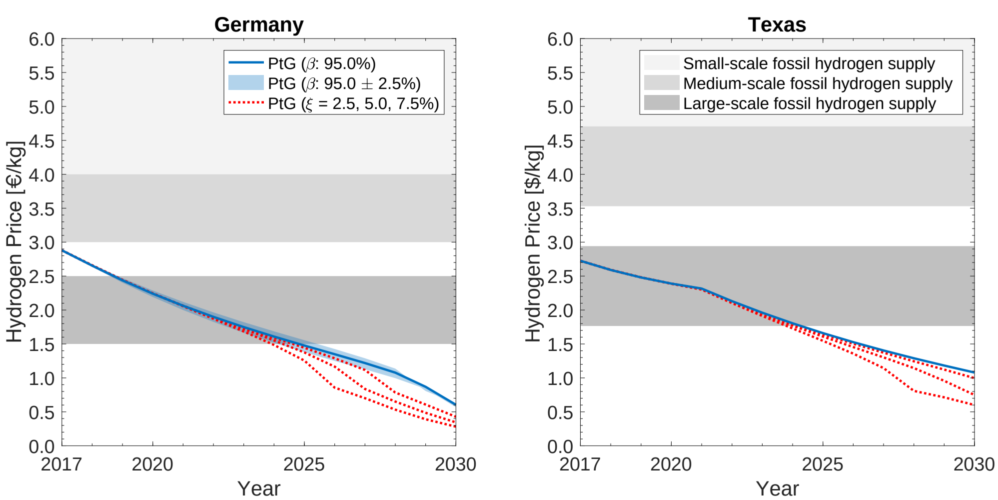

Figure 4: Prospects for the competitiveness of hydrogen.

[25] In the current form, the premium is only granted for wind energy fed into the grid. Considering the public ambitions to connect energy sectors, the calculations assume that the premium could also be granted for renewable electricity that is directly converted to hydrogen.

[26] The uncertainty from the relatively small sample size may be mitigated by the independence of data sources.

Based on these trends, the calculations identify a trajectory of the LCOH from a vertically integrated, reversible PtG system through 2030. As shown in Figure 4, hydrogen is projected to become widely cost competitive with industrial-scale hydrogen supply in the coming decade. The values shown by the solid line assume an adjustment rate of $\beta = 0.95$ and the shaded area outlines slower and faster adjustment rates of 0.975 and 0.925, respectively. The dotted lines incorporate the possibility of increased volatility in the selling price of electricity (see, for instance, Wozabal et al. (2016)). Operationally, $p_e(t)$ is thereby assumed to increase by $\xi\%$ whenever $p_e(t)$ is above the average p_e and to decrease otherwise by a corresponding percentage to keep the average p_e for year i unchanged. The lines represent the effect of ξ for values of 2.5, 5.0 and 7.5%.

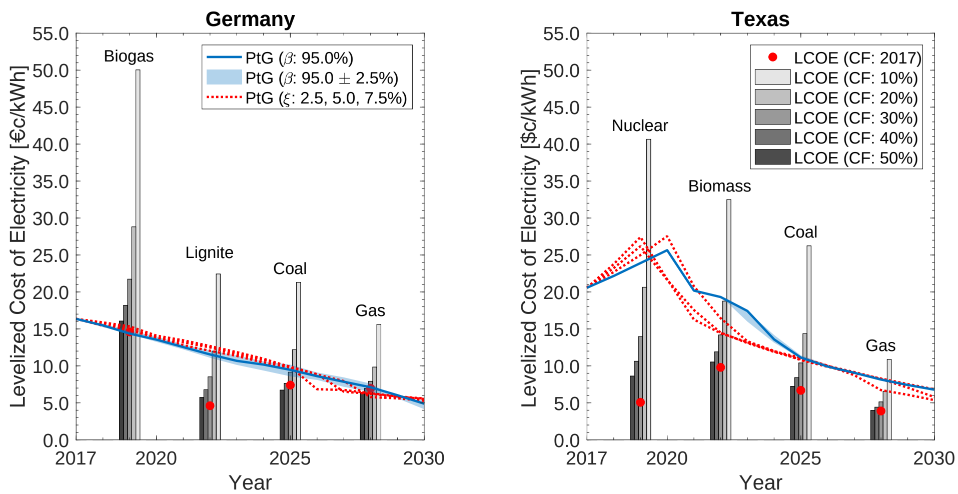

Figure 5: Prospects for the competitiveness of electricity.

Conversely, Figure 5 shows the trajectory of the LCOE through 2030. Electricity from vertically integrated, reversible PtG is projected to also become competitive with the levelized cost of conventional power generation. The competitiveness will emerge, in particular, given that the rising market share of renewables will cause the utilization of conventional generators to fall. Figure 5 illustrates the effect of falling utilizations on the LCOE of conventionals for a range of capacity factors from 50 to 10% in increments of 10%.[27] The "hump" in Texas is due to the phase-out of the PTC. The reduction is more pronounced for electricity than for hydrogen production because the rising selling prices induce a higher cost allocation to reconversion in the respective years.

The prospects suggest that reversible PtG will be sufficiently competitive with fossil-based alternatives so as to become a serious solution to the issues of intermittency and decarbonization.

[27]Conventional generators may also face the unfavorable trends of, for instance, increased ramping, higher prices on carbon emissions, requirements for carbon capture, and higher prices for fossil fuels.

That this conclusion is more positive in comparison to previous studies is due to several factors. Most important is that the ability to operate reversibly and to trade both outputs leads to the production of largely one output and an unbalanced allocation of the sizable capacity-related costs (Braff et al., 2016; Zakeri and Syri, 2015). In addition, the vertical integration with a renewable energy source benefits from operational synergies and from combining the two subsystems at optimal relative size, which is a dominant driver in capital-intensive investments (Felgenhauer and Hamacher, 2015). Furthermore, the conversion of both grid and renewable energy compared to only one yields a higher utilization (Glenk and Reichelstein, 2019). Finally, the calculations include the favorable trends in the costs and prices of wind energy and PtG.

6 Conclusion

The valuation of productive capacity continues to drive a controversial debate in accounting and economics due to considerable leeway associated to the intertemporal and cross-sectional allocation in the calculation of relevant unit cost. This paper has proposed a principle for the definite characterization of unit cost when productive capacity is shared among multiple outputs. Building upon the concept of levelized cost, relevant unit cost should be calibrated as the constant payment required over the life of a capacity to break-even on the investment. Essential for the calibration is that the relevance depends on the two perspectives that an investor can assume. With a capacity perspective the relevant cost reflects the constant contribution margin required for supplying productive capacity and can be aggregated to the levelized fixed cost of capacity. With a product perspective, in contrast, the relevant cost equals the constant price required for selling a product and is calculated by the levelized cost of a product.

Able to reversibly convert electricity to hydrogen, new Power-to-Gas technology could complement wind and solar energy sources in the transition to a low-carbon economy and address the outstanding issues of industrial decarbonization and intermittent power generation. Interpretable as shared capacity, the analysis of the technology is facilitated by both perspectives: the capacity perspective for the economic viability and the product perspective for the competitiveness of both outputs with fossil-based alternatives in the market. An empirical evaluation of Germany and Texas shows that a facility in the current economic environment is only viable and both outputs competitive with prices paid in niche applications. Integrating recent market trends, however, the calculations project that both outputs will likely become competitive with the lower prices paid in large-scale applications over the coming decade.

The paper suggests several avenues for future research. In respect of the economic theory, the analysis has confined to the generalization of levelized cost to shared capacity. Subsequent work could continue the generalization, for instance, in how the concept compares to various measures of full cost. With regard to sustainable energy systems, it would be instructive to develop a methodology with which to compare reversible PtG to battery storage installations. Both technologies may effectively compete in a race for complementing the rising share of intermittent renewable energy.

Appendix

List of Symbols and Acronyms

α	Effective corporate income tax rate	LFC	Levelized fixed cost
β	Adjustment rate of electricity price trend	LCOH	Levelized cost of hydrogen
c	Cost of capacity per unit or hour	m	Number of hours per year
$CF(t)$	Capacity factor at time t	$\mu(t)$	Deviation factor of prices
CFL_i^0	Pre-tax cash flow in year i	NPV	Net present value
CFL_i	After-tax cash flow in year i	$p_e(t)$	Electricity price at time t
$CM(t)$	Contribution margin at time t	p_h	Hydrogen price
Δ	Tax factor	PP	Production premium
δ	Markup on market price	PEM	Polymer electrolyte membrane
d_i	Allowable tax depreciation in year i	PTC	Production tax credit
$D(i)$	LCOE minus adjusted price in year i	ptc	Levelized production tax credit
$\epsilon(t)$	Deviation factor of generation	PtG	Power-to-Gas
η	Conversion rate of Power-to-Gas	r	Cost of capital
f	Fixed operating cost per unit or hour	SOC	Solid Oxide Cell
F_i	Fixed operating cost in year i	SP	System price of capacity
γ	Discount factor	T	Useful life of capacity investment
Γ	Co-variation coefficient	w	Variable operating cost per unit or hour
I_i	Taxable income in year i	WACC	Weighted average cost of capital
kg	Kilogram	$w^c(t)$	Variable cost of conversion at time t
kW	Kilowatt	w^r	Variable cost of reconversion
kWh	Kilowatt hour	w^o	Other variable operating cost
L	Levelization factor	W_i	Variable operating cost in year i
λ	Cost allocation factor	x^{i-1}	Degradation factor of capacity in year i
LCOE	Levelized cost of electricity		

Proof of Proposition 1

The NPV is given by the present value of future operating cash flows less the initial investment:

$$NPV = \sum_{i=1}^{T} CFL_i \cdot \gamma^i - SP, \tag{26}$$

with CFL_i as the after-tax cash flow in year i. It equals the annual pre-tax cash flow, CFL_i^o, minus the corporate income taxes given by the tax rate, α, multiplied with the taxable income, I_i:

$$CFL_i = CFL_i^o - \alpha \cdot I_i. \tag{27}$$

The annual pre-tax operating cash flow equals the contribution margin less fixed operating costs:

$$CFL_i^o = x^{i-1} \int_0^m CM(t)dt - F_i. \tag{28}$$

The firm's taxable income in year i is then given by the pre-tax cash flow less depreciation:

$$I_i = CFL_i^o - SP \cdot d_i. \tag{29}$$

Combining the expressions in (27), (28), and (29), the net present value becomes:

$$NPV = (1-\alpha) \cdot \left[\sum_{i=1}^{T} \gamma^i \cdot \left(x^{i-1} \int_0^m CM(t)dt - F_i \right) \right] - (1 - \alpha \sum_{i=1}^{T} d_i \cdot \gamma^i) \cdot SP. \tag{30}$$

With the definition of the tax factor the expression for the NPV reduces to:

$$NPV = (1-\alpha) \cdot \left[\sum_{i=1}^{T} \gamma^i \cdot \left(x^{i-1} \int_0^m CM(t)dt - F_i \right) - \Delta \cdot SP \right]. \tag{31}$$

It is convenient to pull out the levelization factor $L = m \cdot \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i$:

$$NPV = (1-\alpha) \cdot L \cdot \left[\frac{1}{m} \int_0^m CM(t)dt - \frac{\sum_{i=1}^{T} \gamma^i \cdot F_i}{L} - \Delta \cdot \frac{SP}{L} \right]. \tag{32}$$

The body of the paper introduced the levelized fixed cost as $LFC = f + \Delta \cdot c$. Thus:

$$NPV = (1-\alpha) \cdot L \cdot \left[\frac{1}{m} \int_0^m CM(t)dt - LFC \cdot CF \right]. \tag{33}$$

The average contribution margin is given by time-averaging the periodic contribution margin:

$$CM = \frac{1}{m} \int_0^m CM(t)dt = \frac{1}{m} \int_0^m \left[\left(\eta^c \cdot p_h - w^c(t) \right) \cdot CF^c(t) + \left(p_e(t) - w^r \right) \cdot CF^r(t) \right] dt. \tag{34}$$

Substituting the multiplicative deviation factors allows to re-arrange to:

$$CM = \big[\eta^c \cdot p_h - w^c \cdot \frac{1}{m}\int\limits_0^m \epsilon^c(t) \cdot \mu^c(t)dt\big] \cdot CF^c + \big[p_e \cdot \frac{1}{m}\int\limits_0^m \epsilon^r(t) \cdot \mu^r(t)dt - w^r\big] \cdot CF^r. \tag{35}$$

The definitions of the co-variation coefficients of conversion and reconversion given in the main body then transform the average contribution margin to:

$$CM = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{36}$$

Inserting the expression for the average contribution margin into the NPV allows to reduce to:

$$NPV = (1-\alpha) \cdot L \cdot \big[(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r - LFC \cdot CF\big]. \tag{37}$$

A reversible PtG facility breaks-even if and only if it yields a non-negative NPV. Thus:

$$(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r \geq LFC \cdot CF. \tag{38}$$

■

Proof of Proposition 2 and the Corollary to Proposition 2

To examine the behavior of the average contribution margin as function of the hydrogen price, assume first that $p_e(t) = p_e$ for all t and that $p_e > \frac{1}{\eta^r}\delta_h \geq 0$. Since the average contribution margin of reversible PtG is the sum of both output-specific contribution margins, examine first the behavior of both components. The average contribution margin of conversion is then given by:

$$CM^c(p_h) = \eta^c \cdot p_h \cdot CF^c(p_h) - w^c \cdot CF^c(p_h), \tag{39}$$

where

$$CF^c = \begin{cases} 1 & \text{if } \eta^c \cdot p_h > w^c, \\ 0 & \text{otherwise.} \end{cases} \tag{40}$$

Clearly, there exists a $p_h^+ \geq 0$, at which $\eta^c \cdot p_h^+ = w^c$. For $p_h < p_h^+$, $CM^c(p_h) = 0$ and for $p_h > p_h^+$, $CM^c(p_h) = \eta^c \cdot p_h - w^c$. For $p_h > p_h^+$, $CM^c(p_h)$ is continuously increasing in p_h with $\frac{\partial}{\partial p_h} CM^c(p_h) = \eta^c$.

On the other side, the average contribution margin of reconversion is given by:

$$CM^r(p_h) = p_e \cdot CF^r(p_h) - \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot CF^r(p_h), \tag{41}$$

where

$$CF^r = \begin{cases} 1 & \text{if } p_e > \frac{1}{\eta^r} \cdot (p_h + \delta_h), \\ 0 & \text{otherwise.} \end{cases} \tag{42}$$

Clearly, there exists a $p_h^- \geq 0$, at which $p_e = \frac{1}{\eta^r} \cdot (p_h^- + \delta_h)$. For $p_h > p_h^-$, $CM^r(p_h) = 0$ and for $p_h < p_h^-$, $CM^r(p_h) = p_e - \frac{1}{\eta^r} \cdot (p_h + \delta_h)$. For $p_h < p_h^-$, $CM^r(p_h)$ is continuously decreasing in p_h with $\frac{\partial}{\partial p_h} CM^r(p_h) = -\frac{1}{\eta^r}$.

As the sum of both individual contribution margins, $CM(p_h)$ is continuously decreasing for $p_h < p_h^-$ and continuously increasing in p_h for $p_h > p_h^+$, and equals zero for $p_h \in [p_h^-, p_h^+]$. In the range, $p_h^+ \geq p_h^-$ considering that $\frac{1}{\eta^r} \cdot (p_h + \delta_h) \geq \eta^c \cdot p_h$ and $w^c \geq p_e$.

Let $p_e(t)$ now be a continuous function of time with $p_e = \int_0^m p_e(t)dt > \frac{1}{\eta^r}\delta_h \geq 0$. The average contribution margin of conversion is then given by:

$$CM^c(p_h) = \eta^c \cdot p_h \cdot CF^c(p_h) - \frac{1}{m} \int_0^m w^c(t) \cdot CF^c(t|p_h)dt. \tag{43}$$

$CM^c(p_h)$ is continuously increasing in p_h with the partial derivative with respect to p_h given by:

$$\frac{\partial}{\partial p_h} CM^c(p_h) = \eta^c \cdot p_h \cdot \frac{\partial}{\partial p_h} CF^c(p_h) + \eta^c \cdot CF^c(p_h) - \frac{\partial}{\partial p_h} \left(\frac{1}{m} \int_0^m w^c(t) \cdot CF^c(t|p_h)dt \right) \geq 0. \tag{44}$$

$\frac{\partial}{\partial p_h} CM^c(p_h) \geq 0$, because the facility only converts electricity to hydrogen if $\eta^c \cdot p_h > w^c(t)$. The partial derivatives of the components are given by:

$$\frac{\partial}{\partial p_h} CF^c(p_h) = \frac{1}{m} \int_{\{t|\eta^c \cdot p_h > w^c(t)\}} 1 \; dt, \text{ and} \tag{45}$$

$$\frac{\partial}{\partial p_h} \left(\frac{1}{m} \int_0^m w^c(t) \cdot CF^c(t|p_h)dt \right) = \frac{1}{m} \int_{\{t|\eta^c \cdot p_h > w^c(t)\}} w^c(t)dt. \tag{46}$$

On the other side, the average contribution margin of reconversion is given by:

$$CM^r(p_h) = \frac{1}{m} \int_0^m p_e(t) \cdot CF^r(t|p_h)dt - \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot CF^r(p_h). \tag{47}$$

$CM^r(p_h)$ is continuously decreasing in p_h with the partial derivative with respect to p_h given by:

$$\begin{aligned}\frac{\partial}{\partial p_h} CM^r(p_h) = & \frac{\partial}{\partial p_h}\left(\frac{1}{m}\int_0^m p_e(t)\cdot CF^r(t|p_h)dt\right) \\ & -\frac{1}{\eta^r}\cdot(p_h+\delta_h)\cdot\frac{\partial}{\partial p_h}CF^r(p_h) - \frac{1}{\eta^r}\cdot CF^r(p_h) \leq 0.\end{aligned} \tag{48}$$

$\frac{\partial}{\partial p_h} CM^r(p_h) \leq 0$, because the facility only reconverts hydrogen to electricity if $p_e(t) > \frac{1}{\eta^c}\cdot(p_h+\delta_h)$. The partial derivatives of the components are given by:

$$\frac{\partial}{\partial p_h} CF^r(p_h) = \frac{1}{m}\int_{\{t|p_e(t)>w^r(t|p_h)\}} 1\ dt, \text{ and} \tag{49}$$

$$\frac{\partial}{\partial p_h}\left(\frac{1}{m}\int_0^m p_e(t)\cdot CF^r(t|p_h)dt\right) = \frac{1}{m}\int_{\{t|p_e(t)>w^r(t|p_h)\}} p_e(t)dt. \tag{50}$$

Since $CM(p_h) = CM^c(p_h) + CM^r(p_h)$, $CM(p_h)$ is continuous in p_h and has a p_h^* at which $CM^r(p_h^*) = CM^c(p_h^*)$. Since $\frac{\partial}{\partial p_h}CM^r(p_h) \leq 0$ and $\frac{\partial}{\partial p_h}CM^c(p_h) \geq 0$, $CM^r(p_h)$ dominates $CM^c(p_h)$ and $\frac{\partial}{\partial p_h}CM(p_h) < 0$ for $p_h < p_h^*$, while $CM^c(p_h)$ dominates $CM^r(p_h)$ and $\frac{\partial}{\partial p_h}CM(p_h) > 0$ for $p_h > p_h^*$.

If $LFC \cdot CF > CM(p_h^*)$, a reversible PtG facility obtains two break-even points. In one point $CM^c(p_h) > CM^r(p_h)$ and in the other point $CM^r(p_h) > CM^c(p_h)$. The Corollary to Proposition 2 follows immediately. ■

Proof of Proposition 3

Assume for simplicity a capacity perspective. For sufficiency, both outputs are profitable if the facility is profitable and the capacity-related costs are allocated according to Proposition 2:

$$CM - LFC \cdot CF > 0, \tag{51}$$

$$(\lambda^c + \lambda^r)\cdot CM - (\lambda^c + \lambda^r)\cdot LFC \cdot CF > 0, \tag{52}$$

$$\lambda^c \cdot (CM - LFC\cdot CF) + \lambda^r \cdot (CM - LFC \cdot CF) > 0. \tag{53}$$

For necessity, both outputs and the facility are profitable when an arbitrary quantity of one output is profitable only if capacity-related costs are allocated by Proposition 2. Suppose:

$$\lambda^c \cdot (CM - LFC \cdot CF) > 0, \tag{54}$$

it follows that:

$$\lambda^r \cdot (CM - LFC \cdot CF) = (1 - \lambda^c) \cdot (CM - LFC \cdot CF) > 0, \text{ and} \tag{55}$$

$$CM - LFC \cdot CF > 0. \tag{56}$$

On the contrary, suppose costs are allocated with arbitrary factors β^c and β^r, and $CM^c - \beta^c \cdot LFC \cdot CF > 0$. It remains unclear whether $CM^r - \beta^r \cdot LFC \cdot CF > 0$ and $CM - LFC \cdot CF > 0$. ■

Proof of Proposition 4

The claim follows from re-arranging the NPV expression of reversible PtG. Multiplying LFC with CF and inserting the sum of the allocation factors, which equals one by definition, gives:

$$NPV = (1 - \alpha) \cdot L \cdot \left[CM - (\lambda^c + \lambda^r) \cdot \left(\frac{\sum_{i=1}^{T} \gamma^i \cdot F_i}{L} - \Delta \cdot \frac{SP}{L} \right) \right]. \tag{57}$$

Moving the fixed operating and capacity cost into the brackets for conversion and reconversion and substituting for the definition of the levelized fixed operating and capacity cost yields:

$$\begin{aligned} NPV = (1 - \alpha) \cdot L \cdot \Big[& CF^c \cdot \Big(\eta^c \cdot p_h - w^c \cdot \Gamma^c - \lambda^c \cdot (f^c + \Delta \cdot c^c) \Big) \\ & + CF^r \cdot \Big(p_e \cdot \Gamma^r - w^r - \lambda^r \cdot (f^r + \Delta \cdot c^r) \Big) \Big]. \end{aligned} \tag{58}$$

Aggregating the cost of reconversion gives the levelized cost of hydrogen from reversible PtG as:

$$LCOH = \frac{1}{\eta^c} \cdot \big(w^c \cdot \Gamma^c + \lambda^c \cdot (f^c + \Delta \cdot c^c) \big). \tag{59}$$

Aggregating the cost of conversion gives the levelized cost of electricity from reversible PtG as:

$$LCOE = w^r + \lambda^r \cdot (f^r + \Delta \cdot c^r). \tag{60}$$

Inserting the expressions of the levelized costs into the NPV gives:

$$NPV = (1 - \alpha) \cdot L \cdot \Big[CF^c \cdot \eta^c \cdot \Big(p_h - LCOH \Big) + CF^r \cdot \Big(p_e \cdot \Gamma^r - LCOE) \Big) \Big]. \tag{61}$$

A reversible PtG facility breaks-even if and only if it yields a non-negative NPV. Thus:

$$p_h \geq LCOH, \text{ and } p_e \cdot \Gamma^r \geq LCOE. \tag{62}$$

■

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Supplementary Information to: Shared Capacity and Levelized Cost with Application to Power-to-Gas Technology

Levelized cost of wind energy

The stand-alone NPV of a renewable energy source can be expressed as the average selling price adjusted by the co-variation coefficient minus the LCOE:

$$NPV = (1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE) \cdot CF_e, \tag{A1}$$

whereby Γ measures the covariance between renewable generation and electricity prices.

Wind power in the U.S. is eligible to a Production Tax Credit (PTC) per kWh of electricity produced (U.S. Department of Energy, 2016). The duration of the PTC is limited to 10 years and therefore shorter than the lifetime of the wind power plant. It is therefore necessary to levelize the stream of the PTC payments for the first 10 years:

$$ptc \equiv PTC \cdot \frac{\sum_{i=1}^{10} x^{i-1} \cdot \gamma^i}{(1-\alpha) \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i}. \tag{A2}$$

The PTC adjusted NPV of wind energy can be expressed as: $(1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE + ptc) \cdot CF_e$.

Wind power in Germany can receive a Production Premium (PP) if granted in the competitive auctions as the difference between the market price adjusted by the co-variation coefficient and the LCOE. By construction, the premium reflects a levelized term that adds to the revenue side. The PP adjusted NPV of wind energy can be expressed as: $(1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE + PP) \cdot CF_e$.

Cost Review of Solid Oxide Cell Electrolyzers

The cost review builds upon the review conducted by Glenk and Reichelstein (2019). In particular, I repeated the review with a focus on Solid Oxide Cell (SOC) electrolyzers and on articles published after the initial review. The repetition yielded 4 new data points, which sums with 16 initial data points to 20 data points. The cost review is documented in an Excel file available online.

Cost estimates given in ranges were converted with the arithmetic mean of the highest and the lowest point. The common currency is Euro and all data points in other currencies were converted using the average exchange rate of the respective year as provided by the European Central Bank. Regarding inflation, all historic cost estimates were adjusted using the HCPI of the Euro Zone as provided by the European Central Bank. Cost estimates were winsorized with an $\alpha = 5.0\%$.

The cost decline was estimated with an exponential regression of system prices from 2003 to 2017 in the form of $SP_h(i) = SP_h(0) \cdot \lambda^i$, where i denotes the year. The decline was based on time instead of cumulative industry output due to the technology novelty and hence scarcity of data. The regression is based on $N = 20$ unique estimates and yields an average decline of $\lambda = 11.45\%$ with a 95% confidence interval of ± 34.00 percentage points and an *adj.* $R^2 = 0.11$. Linear models give similar *adj.* R^2 values, but an exponential relationship is to be expected. Declining uncertainty was quantified with an affine regression of the falling standard deviation from 2003 to 2017.

Structures of Electricity Buying Prices

The markups on the electricity price in Germany comprises of the following parameters:

Price	Unit	Value	Source
Trading cost	€¢/kWh	1.0000	Industry experts
Transmission charge	€¢/kWh	0.0000	EnWG (2005, §118 (6))
Concession charge	€¢/kWh	0.1100	KAV (1992, §2 (3) 1.)
EEG-Levy	€¢/kWh	0.1000	EEG (2014, §64 with A.4)
CHP markup	€¢/kWh	0.0830	KWKG (2016, §9 (7))
§19 StromNEV levy	€¢/kWh	0.0510	StromNEV (2016, §19 (2))
Offshore liability levy	€¢/kWh	0.0270	EnWG (2005, §17f)
Levy for interruptible loads	€¢/kWh	0.0000	AbLaV (2012, §18)
Electricity tax	€¢/kWh	0.0000	StromStG (2016, §9a (1) 1.)

In Texas, buying prices base on the industrial rate ”Primary <3MW” by Austin Energy (2014) without time-of-use prices since they have been suspended for new customers. Water electrolysis is exempted from state and local sales tax (Texas Tax Code, 2016, §2.151.317 (a) (6)).

A PtG facility offering frequency control can provide ”regulation down”, as it is called in Texas, and the equivalent ”negative Sekundärregelleistung” in Germany (ERCOT, 2017; Regelleistung.net, 2017). In both jurisdictions, frequency control is compensated with a capacity price per kW that the facility is in standby. In Germany, the facility is also paid a price per kWh of energy absorption. Since both compensations reflect negative buying prices, assume that the facility always offers regulation energy. The buying price for open market energy can then be expressed as the weighted average of the energy price for frequency control and the market price:

$$p^b(t) = \phi(t) \cdot p^c(t) + (1 - \phi(t)) \cdot (p_e(t) + \delta_e), \tag{A3}$$

where $p^c(t)$ denotes the price for calling energy per kWh and $\phi(t)$ the share of called capacity in hour t. The capacity price adds directly to the revenue side. Since the price is paid per kW, divide it by the hours of standby to receive a price per kWh. With p^{sb} denoting the standby price:

$$NPV = (1 - \alpha) \cdot L \cdot \left[(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r - LFC \cdot CF - p^{sb}\right]. \tag{A4}$$

Input Variables

	Germany	Texas	Source
General			
Economic lifetime, T	30 years	30 years	Michalski et al. (2017)
Corporate income tax rate, α	35.00 %	21.00 %	German and U.S. Tax Code
Degradation rate, x_i	0.80 %	0.80 %	Deutsche WindGuard (2013),Fraunhofer ISE (2013)
Depreciation rate, d_i	16y linear	100 % Bonus	Bundesfinanzhof (2011); U.S. Congress (2017)
Cost of capital (WACC), r	4.00 %	6.00 %	Fraunhofer ISI (2016); Moné et al. (2015)
Power-to-Gas			
Conversion rate, η^c	0.025 kg/kWh	0.025 kg/kWh	SunFire GmbH (2018b)
Reconversion rate, η^r	17.74 kWh/kg	17.74 kWh/kg	SunFire GmbH (2018a)
Variable cost of conversion, w^c	4.19 €¢/kWh	5.62 $¢/kWh	See description below
Fixed operating cost, F_i	147.80 €/kW	132.08 $/kW	Own review, see description
Acquisition cost, SP	3,695 €/kW	3,302 $/kW	Own review, see description
Wind energy			
Capacity factor, CF	30.33 %	44.39 %	Own data and ABB (2018)
Variable operating cost, w	0.00 €/kWh	0.00 $/kWh	Negligible cost, ABB (2018)
Fixed operating cost, F	38.00 €/kW	21.70 $/kW	Wallasch et al. (2016); ABB (2018)
Acquisition cost, SP	1,180 €/kW	1,566 $/kW	Fraunhofer IWES (2017); ABB (2018)

Cost of Conventional Power Generation

Germany	Natural Gas	Lignite	Source
Economic lifetime, T	30 years	30 years	Fraunhofer ISE (2018)
Acquisition cost, SP	950 €/kW	3,000 €/kW	Fraunhofer ISE (2018)
Capacity factor, CF	39.95%	60.50%	Agentur für Erneuerbare Energien (2013)
Degradation rate, d_i	0.40%	0.40%	Comello et al. (2018)
Fixed operating cost, F_i	22.00 €/kW	120.00 €/kW	Fraunhofer ISE (2018)
Variable operating cost, W_i	0.35 €¢/kWh	0.00 €¢/kWh	Fraunhofer ISE (2018)
Fuel cost	3.50 €¢/kWh	7.58 €¢/kWh	Fraunhofer ISE (2018)
Carbon dioxide emissions cost	5.76 €/t	5.76 €/t	`www.eex.com`
Emissions performance	0.39 kg/kWh	0.00 kg/kWh	Umweltbundesamt (2017)
Cost of capital (WACC), r	5.00%	5.00%	Fraunhofer ISI (2016); Moné et al. (2015)
Corporate income tax rate, α	35.00%	35.00%	German Tax Code
Depreciation rate, d_i	20y linear	20y linear	Bundesfinanzministerium (2018)

Germany	Lignite	Coal	Source
Economic lifetime, T	40 years	40 years	Fraunhofer ISE (2018)
Acquisition cost, SP	1,900 €/kW	1,650 €/kW	Fraunhofer ISE (2018)
Capacity factor, CF	68.49%	42.24%	Agentur für Erneuerbare Energien (2013)
Degradation rate, d_i	0.40%	0.40%	Comello et al. (2018)
Fixed operating cost, F_i	36.00 €/kW	32.00 €/kW	Fraunhofer ISE (2018)
Variable operating cost, W_i	0.50 €¢/kWh	0.50 €¢/kWh	Fraunhofer ISE (2018)
Fuel cost	0.40 €¢/kWh	2.09 €¢/kWh	Fraunhofer ISE (2018)
Carbon dioxide emissions cost	5.76 €/t	5.76 €/t	`www.eex.com`
Emissions performance	1.15 kg/kWh	0.86 kg/kWh	Umweltbundesamt (2017)
Cost of capital (WACC), r	5.00%	5.00%	Fraunhofer ISI (2016); Moné et al. (2015)
Corporate income tax rate, α	35.00%	35.00%	German Tax Code
Depreciation rate, d_i	25y linear	25y linear	Bundesfinanzministerium (2018)

Texas	**Natural Gas**	**Coal**	**Source**
Economic lifetime, T	30 years	40 years	Comello et al. (2018)
Acquisition cost, SP	808 \$/kW	2,429 \$/kW	Comello et al. (2018)
Production tax credit, PTC	0.00 \$¢/kWh	0.00 \$¢/kWh	Comello et al. (2018)
Capacity factor, CF	52.77%	56.57%	Comello et al. (2018)
Degradation rate, d_i	0.40%	0.40%	Comello et al. (2018)
Fixed operating cost, F_i	12.59 \$/kW	33.52 \$/kW	Comello et al. (2018)
Variable operating cost, W_i	0.07 \$¢/kWh	0.16 \$¢/kWh	Comello et al. (2018)
Fuel cost	2.19 \$¢/kWh	2.33 \$¢/kWh	Comello et al. (2018)
Carbon dioxide emissions cost	0.00 \$/t	0.00 \$/t	Comello et al. (2018)
Emissions performance	0.36 kg/kWh	0.81 kg/kWh	Comello et al. (2018)
Cost of capital (WACC), r	6.00%	6.00%	Fraunhofer ISI (2016); Moné et al. (2015)
Corporate income tax rate, α	21.00%	21.00%	U.S. IRS (2018)
Depreciation rate, d_i	100% Bonus	100% Bonus	U.S. Tax Code

Texas	**Nuclear**	**Biomass**	**Source**
Economic lifetime, T	50 years	30 years	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Acquisition cost, SP	4,122 \$/kW	2,695 \$/kW	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Capacity factor, CF	90.06%	57.70%	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Degradation rate, d_i	0.40%	0.40%	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Fixed operating cost, F_i	65.42 \$/kW	31.23 \$/kW	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Variable operating cost, W_i	0.08 \$¢/kWh	0.12 \$¢/kWh	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Fuel cost	0.54 \$¢/kWh	4.92 \$¢/kWh	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Carbon dioxide emissions cost	0.00 \$/t	0.00 \$/t	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Emissions performance	0.00 kg/kWh	0.00 kg/kWh	OpenEI (2018); ABB (2018); IEA (2015); NETL (2012)
Cost of capital (WACC), r	6.00%	6.00%	Fraunhofer ISI (2016); Moné et al. (2015)
Corporate income tax rate, α	21.00%	21.00%	U.S. IRS (2018)
Depreciation rate, d_i	100% Bonus	100% Bonus	U.S. Tax Code

Results

Stand-alone Power-to-Gas	**Germany**	**Texas**
Variable cost of conversion	4.19 €¢/kWh	5.62 \$¢/kWh
Co-variation coefficient of conversion	0.96	0.99
Capacity factor of conversion	97.443%	99.212%
Variable cost of reconversion	19.78 €¢/kWh	21.70 \$¢/kWh
Co-variation coefficient of reconversion	0.00	10.51
Capacity factor of reconversion	0.000%	0.011%
Contribution margin	4.763 €¢/kWh	4.160 \$¢/kWh
Fixed operating cost	1.91 €¢/kWh	1.66 \$¢/kWh
Capacity Cost	2.76 €¢/kWh	3.02 \$¢/kWh
Tax factor	1.1463	1.0150
Levelized fixed cost	5.081 €¢/kWh	4.72 \$¢/kWh
Capacity factor	97.443%	99.223%
Frequency control stand-by price	-0.19 €¢/kWh	-0.54 \$¢/kWh
Cost allocation for conversion	100.00%	99.99%
Levelized cost of hydrogen	3.51 €/kg	3.85 \$/kg
Cost allocation for reconversion	0.00%	0.01%
Levelized cost of electricity	- €¢/kWh	25.70 \$¢/kWh

Vertically integrated Power-to-Gas	Germany	Texas
Capacity size of Power-to-Gas	0.01 kW	0.20
Variable cost of conversion	2.87 €¢/kWh	2.77 $¢/kWh
Capacity factor of conversion	96.827%	98.170%
Variable cost of reconversion	16.29 €¢/kWh	15.39 $¢/kWh
Co-variation coefficient of reconversion	6.05	8.42
Capacity factor of reconversion	0.011%	0.034%
Contribution margin	4.320 €¢/kWh	4.076 $¢/kWh
Fixed operating cost	1.44 €¢/kWh	1.26 $¢/kWh
Capacity Cost	2.78 €¢/kWh	3.05 $¢/kWh
Tax factor	1.1463	1.0150
Levelized fixed cost	4.632 €¢/kWh	4.35 $¢/kWh
Capacity factor	96.838%	98.204%
Frequency control stand-by price	-0.19 €¢/kWh	-0.54 $¢/kWh
Cost allocation for conversion	99.99%	99.96%
Renewable unit loss for conversion	0.00	2.26
Levelized cost of hydrogen	2.89 €/kg	2.73 $/kg
Cost allocation for reconversion	0.0001%	0.04%
Renewable unit loss for reconversion	0.00	6.48
Levelized cost of electricity	16.35 €¢/kWh	20.57 $¢/kWh

Stand-alone wind energy	Germany	Texas
Fixed operating cost	1.58 €¢/kWh	0.48 $¢/kWh
Capacity Cost	2.84 €¢/kWh	3.20 $¢/kWh
Tax factor	1.1463	1.0150
Levelized PP or PTC	1.81 €¢/kWh	1.31 $¢/kWh
Levelized cost of electricity	4.83 €¢/kWh	3.73 $¢/kWh
Selling price	3.46 €¢/kWh	2.44 $¢/kWh
Co-Variation coefficient	0.87	0.93
Profit margin	0.00 €¢/kWh	-0.15 $¢/kWh

Levelized cost of conventional power generation

Germany	Natural Gas	Biogas	Lignite	Coal
Variable operating cost, w	4.08 €¢/kWh	7.57 €¢/kWh	1.56 €¢/kWh	3.08 €¢/kWh
Fixed operating cost, f	0.66 €¢/kWh	2.37 €¢/kWh	0.64 €¢/kWh	0.92 €¢/kWh
Capacity Cost, c	1.85 €¢/kWh	3.86 €¢/kWh	2.75 €¢/kWh	2.75 €¢/kWh
Tax factor, Δ	1.2029	1.2029	1.2349	1.2349
Levelized cost of electricity, $LCOE$	6.96 €¢/kWh	14.59 €¢/kWh	4.61 €¢/kWh	7.40 €¢/kWh

Texas	Natural Gas	Coal	Nuclear	Biomass
Variable operating cost, w	2.26 $¢/kWh	2.49 $¢/kWh	0.62 $¢/kWh	5.04 $¢/kWh
Fixed operating cost, f	0.28 $¢/kWh	0.71 $¢/kWh	0.65 $¢/kWh	0.65 $¢/kWh
Capacity Cost, c	1.33 $¢/kWh	3.43 $¢/kWh	4.05 $¢/kWh	4.05 $¢/kWh
Tax factor, Δ	1.0150	1.0150	1.0150	1.0150
Levelized cost of electricity, $LCOE$	3.89 $¢/kWh	6.68 $¢/kWh	5.07 $¢/kWh	9.80 $¢/kWh

Sensitivity for a markup for transportation and storage of hydrogen
The calculation assumes that a reversible PtG facility can be installed onsite or adjacent to a hydrogen customer and that the markup factor δ_h is effectively zero. This may underestimate the cost of supply once the price of production becomes less than that. Figure A1 quantifies the impact of three markup levels that compare in size to hydrogen supply through pipelines (Kothari et al., 2008). The figure shows that every increment of 20 ¢/kg increases the cost of electricity in Germany by about 1.5 €¢/kWh and in Texas by about 2.5 $¢/kWh, but the conclusion that reversible PtG becomes cost competitive with conventional power generation continues to hold. The declines in Texas are more edgy because the outlying electricity prices cause a larger allocation of capacity-related costs. The trajectory of levelized cost of hydrogen production is largely unaffected.

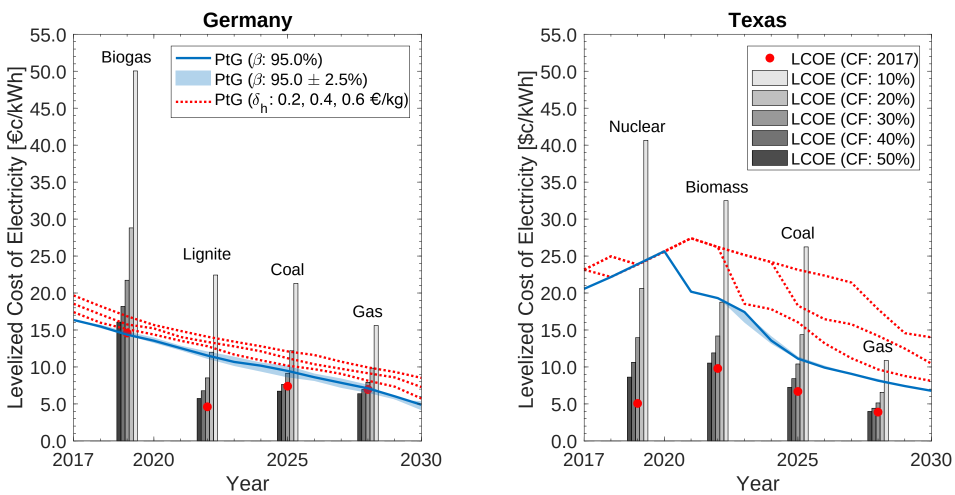

Figure A1: Prospects for the competitiveness of electricity with hydrogen markups.

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