Competitiveness of Reversible Power-to-Gas Technology

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Abstract

Information on how sustainable competes against conventional technology becomes increasingly valuable for managers. Yet, the measurement of competitiveness remains controversial due to ambiguity in the calibration of unit cost. Here I show that the concept of levelized cost yields a simple and definite criterion for the calculation and the relevant unit cost for different perspectives of a potential investor. Crucial to the calculation is that levelized cost reflects the constant payment required over the life of a capacity to break-even on the initial investment. A timely application is to compare clean to 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 indeed be low enough to compete with fossil-based alternatives. Central to the finding is that the ability to reversibly convert electricity to hydrogen and trade both outputs in the market leads to an effective cross-sectional allocation of sizable joint cost.

Keywords: competitiveness, capacity investment, unit cost, renewable energy, power-to-gas

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1 Introduction

A central obligation of the world economies in the years ahead is to rapidly reduce the emissions of carbon dioxide and other greenhouse gases. The extent and speed of reduction will thereby rely on when sustainable technology becomes cost competitive with respective alternatives based on fossil fuels. An instructive way to measure the competitiveness of a technology is to calculate its unit cost of production (Islegen and Reichelstein, 2011). Yet, this calculation 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 productive capacity over multiple periods. Here I show that the concept of *levelized cost* produces an unit cost that allows to compare the competitiveness of alternative production technologies characterized by different cost structures.

A new technology that could take a central role in a decarbonized economy is reversible Power-to-Gas (PtG). While wind and solar power sources have outpaced early projections in terms of cost reductions and share of power generation (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 also include transportation and manufacturing (Zhou et al., 2016). 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 in industry and transportation that are otherwise difficult to decarbonize (Davis et al., 2018). Here I also show that the levelized cost of electricity and hydrogen production can be low enough for reversible PtG to compete with conventional production from fossil fuels.

The insistent issue of 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 in response have evolved in accounting and economics with different purposes and ways of calculation. A simple concept to gauge the value of capacity 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 focused on (intertemporal) allocation rules to derive, for instance, the relevant unit cost for capacity investments (Rogerson, 2008; Boyabatl et al., 2015), product cost suitable for product pricing (Balachandran and Ramakrishnan, 1996; Pavia, 1995), or efficient transfer prices for decentralized capacity management (Dutta and Reichelstein, 2010; Wei, 2004). The common objective of these concepts is to identify unit cost that provide managers with the right information for their decisions. Information previously neglected yet rapidly growing in importance is how sustainable competes against fossil-based technology.

The guiding principle for measuring competitiveness is that levelized cost reflects 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.[1] This break-even conceptualization stipulates that the aggregation of multi-period cash flows accounts for all capacity-related and operating expenditures required to supply one unit of output or productive capacity. This, in turn, allows to compare production technologies that differ in cost structure across their economic life.[2]

The break-even condition also simplifies the aggregation by providing a definitive criterion for both intertemporal and cross-sectional allocation. In the intertemporal allocation, simply all cash flows required for the delivery of output are discounted and apportioned across both the periods of operation and the productive time or output of the capacity. Cross-sectionally, the break-even criterion imposes that the allocation aligns profitability among the joint products (electricity and hydrogen). In alignment either all or none of the products are profitable for any production quantity, whereby each product would be declared profitable if its unit cost is less than 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 levelized cost concept borrows from the energy literature, which initially introduced the levelized cost of electricity production.[3] This metric captures the constant electricity price required over the life of a power generator to cover all operating expenses, financing cost, and initial project expenses (MIT, 2007). The metric is commonly used in practice to compare the competitiveness of alternative generation technologies and decide upon capacity investments. While the concept has been formalized for a generic production capacity (Reichelstein and Rohlfing-Bastian, 2015), the formulation settings have remained stylized with several simplifying features. Most restrictive 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. 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 is given by what I call the *levelized*

[1] The concept 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, levelized cost examines the cost of delivering a product for a given technology.

[2] Against a product's full cost as characterized in accounting textbooks, the levelized cost of a product can be equated to an extended form that also includes taxes and imputed interest charges on the remaining book value (Reichelstein and Rohlfing-Bastian, 2015). For the supply of productive capacity, levelized cost shows to be a suitable metric to calculate the long-run marginal cost of capacity (Reichelstein and Sahoo, 2017; Rogerson, 2011).

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

fixed cost (LFC), which reflects the average contribution margin per hour of capacity available for rent. Taking a *product perspective* instead 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 as I show to just one additional factor in the formulation that adjusts the joint costs of capacity for the share allocated to the output.[4]

The two perspectives facilitate the assessment of reversible PtG technology. To examine the general economics, a potential investor would refrain from the cross-sectional cost allocation and assume the capacity perspective. Accordingly, reversible PtG breaks-even if and only if the LFC is exceeded by the average contribution margin. As a technology that stores electricity over time, the break-even of reversible PtG is commonly thought to rely on the volatility in power prices and the continuous switch between conversion and reconversion (Braff et al., 2016). While my analysis confirms this tie, it shows that the ability to trade the storage medium (hydrogen) in the market is even more important. Through the market access reversible PtG receives the possibility to generate value from operating in only one direction. As a result, reversible PtG breaks-even when it produces the output with the higher average contribution margin by a notable majority.

For the competitiveness of reversible PtG in producing electricity and hydrogen, an investor then assumes the product perspective. This allows to compare the levelized cost of both outputs with those produced using alternative production technologies. When productive capacity is shared, the calculation of levelized cost requires an insight on the cross-sectional allocation at break-even. 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. In particular, I find that electricity production is likely to receive the smaller share and hence that it can be competitive with conventional power generation from coal or natural gas despite relatively high cost for the new technology and hydrogen as a fuel.

Beyond the information of competitiveness, the levelized cost concept shows to be relevant with additional conditions to other managerial decision as well. Most fundamental, I find that the concept identifies the unit cost firms should impute when deciding upon capacity investments.[5]

[4]The perspectives are closely related to the organizational structures investigated in the literature on decentralized capacity management; see, for instance, Dutta and Reichelstein (2010, 2019) or Rogerson (2008). But since perspectives and structures not always align, it is important to distinguish between them.

[5]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 price, the levelized cost also identifies the minimum price that an output or service must achieve in the long term. Lastly 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 (Dutta and Reichelstein, 2019; Karmarkar and Pitbladdo, 1993).

Finally, an empirical evaluation of reversible PtG in Germany and Texas corroborates and extends my so far analytical considerations. 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 illustrates 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, fossil-based power generators over the coming decade.

Compared to previous studies, my empirical analysis finds a better competitive position of reversible PtG. The main ingredient for this is the interdisciplinary approach of techno-economic modeling. This approach reveals that the ability to operate reversibly and trade both outputs leads to an uneven production and an 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; Glenk and Reichelstein, 2019).

In the following, section 2 describes the model setting and the production at reversible PtG. Sections 3 and 4 proceed with the capacity and product perspective respectively. Section 5 contains the empirical evaluation. Section 6 concludes. Proofs are provided in the Appendix and input variables in the Supplementary Information.

2 Model Description

2.1 Productive Technology

My model considers a technology that can produce one or multiple outputs in form of products or services. With an eye on climate change, I focus on new Power-to-Gas (PtG) technology, as the formulations are generic in most aspects.[6] PtG 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.[7]

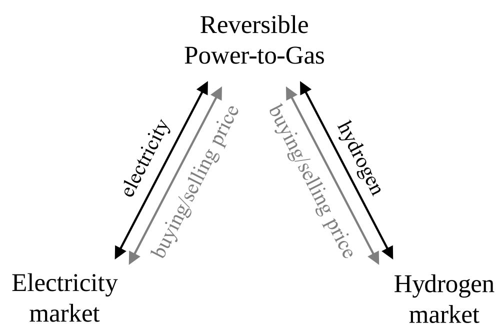

Figure 1: Illustration of reversible Power-to-Gas.

Reversible PtG technology stands in competition with alternative production technologies of comparable output. For electricity, that is conventional power generation from, say, coal or natural gas. For hydrogen, that is mainly steam methane reforming based on natural gas. The delivery of outputs causes for all production methods various technology-specific cash flows for upfront investment, annual operating expenses, and financing cost for debt and equity investors.

The potential investor of a firm in a competitive or monopolistic market decides for a particular production technology based on how it compares in competitiveness with the alternatives. Competitiveness hereby refers to the total assets and resources required over the economic life of a productive capacity to deliver one unit of output. An instructive measure for such technological competitiveness can be the unit cost of productive operation that aggregates per unit of output a share of total input. Critical to the calculation is, however, how to aggregate the relevant share of

[6]Reversible PtG represents a shared capacity in the generic sense and seeks to exploit the volatility of wholesale prices in a business model for energy storage previously defined as *trading arbitrage* (Baumgarte et al., 2019).

[7]Hydrogen trade is developing from individual transactions to an open market that compares to that for natural gas with service providers for transmission and storage (Business Insider, 2018; Government of Japan, 2018).

the various cash flows that occur over multiple periods.

My analysis considers two distinct scenarios of the perspective that an investor in productive technology may take. In what I call the *capacity perspective*, the investor concentrates on the supply of one unit of capacity. The issue then is to identify the relevant unit cost for renting the capacity over time. 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 relevant unit cost for selling outputs in the market.

The two perspectives determine which cost aggregation and unit basis is relevant for the potential investor. The differentiation between them is crucial when capacity is shared among multiple outputs, because the value is driven by a portfolio of outputs that may differ in variable operating cost and unit of measurement. 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.

The perspectives relate to the organizational structures of decentralized capacity management but overlap only in distinct settings. For instance, the capacity perspective is naturally assumed by the manager of an upstream unit who due to technical expertise is responsible for the initial installation of capacity and the subsequent utilization by downstream divisions of the same company.[8] The product perspective would be taken by a downstream manager who is primarily occupied with the marketing of a product. Yet, it may also be taken by the manager, who previously assumed a capacity perspective, if the generated output stands in competition with the external market.

To capture the cost structure, let v denote the upfront cash expenditure for reversible PtG per kilowatt (kW) of peak capacity for electricity absorption and desorption. While reversible PtG reflects a long-run constant returns to scale technology, the model can be extended by non-linearity. 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.[9] 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 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

[8]See, for instance, Dutta and Reichelstein (2010, 2019) and Wei (2004).
[9]A comprehensive lists of all symbols and acronyms is provided in the Appendix.

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.

Capacity investments typically also trigger a stream of fixed operating costs. Let F_i denote the annual fixed costs per kW of installed capacity. To identify unit cost both v and F_i must be apportioned among the relevant and anticipated units of production. The quantity of units thereby relies on time variations in selling prices and variable operating costs that both drive the utilization of capacity.

2.2 Capacity Utilization

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.

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.[10] 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 conversion reflecting the percentage of the capacity used for hydrogen generation at time t. Since bi-directional electrolyzer

[10] 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.

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:

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

Let $CF^r(t)$ denote the capacity factor of reconversion that reflects the percentage of the capacity used for power generation at time t. With 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 measures the kWh of electricity generated over time by a PtG facility of 1 kW. The contribution margin of hydrogen reconversion per kWh at time t is given by:

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

Clearly, the decision which output to produce is without trade-off, because the electrolyzer can run in only one direction at any point in time.[11] 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.[12] The law of conservation of energy stipulates that the round-trip

[11] 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.

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

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 referred to as the *complementary slackness* of reversible PtG.

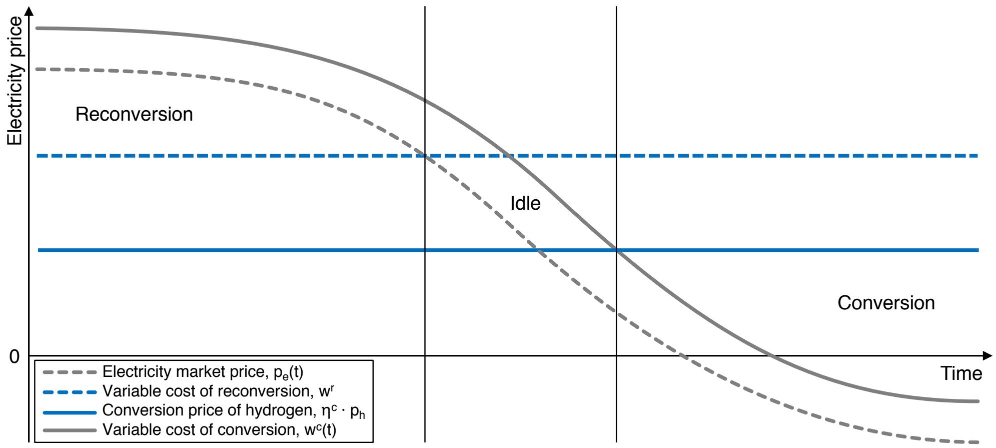

Figure 2: Complementary slackness of reversible Power-to-Gas.

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 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 the utilization of a shared capacity follows the time variations in prices and variable operating costs. A reversible PtG facility, in particular, switches between electricity and hydrogen production in line with the continuous fluctuations in electricity prices.

3 Capacity Perspective

Let us first investigate the scenario of the capacity perspective. Here the potential investor focuses on the supply of one unit of productive capacity. The analysis in this section thus seeks to identify the relevant unit cost when renting productive technology over time. The section also seeks to examine the general economics of reversible PtG.

Unit cost relevant to measure the competitiveness in a capacity perspective have to account for all assets and resources required to supply one unit of capacity at a particular point in time. Assuming variable operating costs are born by the client renting the capacity, then the unit cost reflects a constant contribution margin per hour of capacity available for rent. 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. The relevant unit cost should thus reflect the constant contribution margin per hour required to break-even on the initial investment. The metric aggregates a share of the upfront investment with annual fixed operating expenses and any tax-related cash flows. Borrowing from the energy literature, I refer to this cost metric as the *levelized fixed cost* (LFC) per hour of capacity.[13]

The upfront investment, v, and fixed operating cost, F_i, are inherently a joint cost shared 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 capacity. The availability can be captured by the levelization factor L. With $m = 8,760$ 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 utilization 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 $CF \leq 1$.[14] The capacity

[13]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.

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

and fixed operating costs per hour are given by:

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

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 reversible PtG is given by:*

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

Previous accounting literature, including Rogerson (2008) and (Rajan and Reichelstein, 2009) identifies the relevant unit cost for renting capacity for one period of time as the user cost of capital. This cost is calculated by annuitizing the unit cost of capacity v, that is, dividing v by $\sum_{i=1}^{T} \gamma^i$, the present value of a \$1 annuity over T periods. While this formulation compares with the formulation of c in equation (9), note that the LFC also accounts for fixed operating cost, tax-related expenses, and the degradation of capacity. The inclusion of these components may be critical for a rental business to break-even on the initial investment.

The industrial organization literature also uses the rental price of one unit of capacity to gauge the marginal cost of capital (Carlton and Perloff, 2015). The assumption of a competitive rental market for capacity allows to model productive capacity as a consumable input, like labor and raw materials, and circumvent the issue of an appropriate allocation of joint cost. According to the literature, one unit of capacity would trade in equilibrium at a price of $(r + \hat{d}) \cdot v$, where $\hat{d}$ denotes the economic depreciation. Provided that assets are infinitely lived ($T = \infty$), the economic depreciation rate is equated with the 'survival' factor of capacity ($\hat{d} = 1 - x$), and the capacity degradation follows a geometric pattern ($x_i = x^{i-1}$), then it can be readily verified that the marginal cost of capital corresponds to the definition of c in equation (9).[15]

To examine whether the LFC indeed satisfies the break-even requirement from the beginning of this section, the metric 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. This requires to account for covariances between output and prices, since 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

[15]The mathematical derivation makes use of the geometric series that $\sum_{i=1}^{\infty} x^{i-1} \cdot \gamma^i = (1 - x + r)^{-1}$.

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 reversible PtG 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. *An investment in reversible PtG breaks-even if and only if:*[16]

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

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 to measure the competitiveness of a shared technology if the investor assumes the capacity perspective. LFC also reflects the relevant unit cost for deciding upon the capacity investment. The proof of Proposition 1 shows that the expression 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).

If capacity management was decentralized, such as in Dutta and Reichelstein (2019), note that the LFC aligns with the notion of full cost transfer pricing. Suppose the supplier of capacity is a central unit that installs and maintains the productive capacity and rents it to decentral 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.

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

Proposition 1 shows that the central unit should set the transfer price to LFC, provided that variable operating costs are born by the decentral divisions and that taxes can be ignored for intra-company trade (i.e., $\Delta = 1$). In this setting, LFC can even be verified to achieve *strong goal congruence* in the sense that it induces managers to make efficient production and investment decisions despite a time horizon that is shorter than that of the firm's owners (Dutta and Reichelstein, 2019). Crucial conditions for this result are that the managers are free to renegotiate the initial capacity utilization, that capacity assets are depreciated by the annuity rule, and that the performance of the managers of the decentral divisions as profit centers are measured by the divisional profit while the performance of the manager of the central unit as investment center is measured by residual income. While the LFC explicitly accounts for fixed operating costs, the formulation of the efficient transfer price in Dutta and Reichelstein (2019) can be assumed to include such charges in the cost of capacity.

In addition to the mere break-even, a potential investor would also be interested in its sensitivity. As it is widely thought for energy storage technology, the value of reversible PtG increases with the volatility in electricity prices.[17] 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.

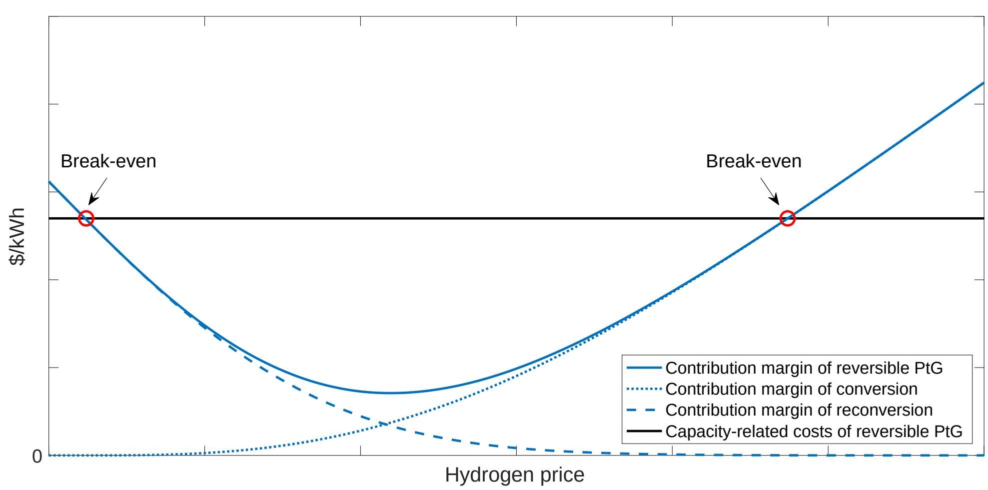

Figure 3: Economics of reversible Power-to-Gas.

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 $p_e(t)$ has a distribution as commonly observable in current wholesale markets. Approximating distribution functions are, for instance,

[17]This also aligns the option value of flexible production capacity (van Mieghem, 1998; Fine and Freund, 1990).

Normal, Weibull, or Rayleigh. 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, the total contribution margin of reversible PtG is U-shaped and obtains at least one and a maximum of two break-even points in one of which $CM^c(p_h) > CM^r(p_h)$ and in the other one $CM^r(p_h) > CM^c(p_h)$.*

Proposition 2 shows that a reversible PtG facility will break-even when it produces the output with the higher average contribution margin by a significant majority. These economics stem from the ability to trade hydrogen in the market. 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. Reversible PtG can thus generate value by operating in just one direction without the need for reconversion.

Relative to alternative energy sources, the reversible operation and ability to trade the storage medium provides a competitive 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 (Comello and Reichelstein, 2019).

4 Product Perspective

Contrary to the case examined thus far, where the potential investor takes the capacity perspective, let us now consider the alternative scenario of 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 for measuring the competitiveness of a technology in producing a specific output. For reversible PtG, in particular, this section seeks to examine its competitiveness in generating electricity and hydrogen.

Unit cost relevant to measure the competitiveness in a product perspective would have to account for all assets and resources required to deliver one unit of product. As variable operating cost are now born by the operator of capacity, the unit cost reflect a constant selling price per unit of output. The selling 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. The relevant unit cost should thus reflect the constant selling price per unit of output required to break-even on the initial investment. The cost metric aggregates a share of the upfront investment with fixed and variable operating expenses and tax-related cash flows. I refer to this metric as the levelized cost of an individual product.

As before, the upfront investment, v, 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 v 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:

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

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 equation (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 when it reflects the constant selling price required for the capacity to break-even. The complication only 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 the average price exceeds its unit cost, while a capacity is profitable if its entire revenues exceed its entire costs. 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, by 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.[18] 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.

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:*

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

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.[19]

In comparison to the traditional accounting full cost of a product, such as conceptualized in Horngren et al. (2015), the levelized cost of a product reflects an extended form that also includes

[18]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.

[19]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 methane reforming.

taxes and imputed interest charges for capital. Suppose, for instance, the firm employs straight-line depreciation and forget about degradation and capacity utilization for the moment. The capacity component of the traditional full cost measure then amounts to $\frac{v}{T}$, which is clearly less than $\frac{v}{\sum_{i=1}^{T}\gamma^i}$, since $T > \sum_{i=1}^{T}\gamma^i$ for any $\gamma < 1$ (Reichelstein and Rohlfing-Bastian, 2015).

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 achieves profitability alignment. The 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 to measure the competitiveness of technology in producing a particular output. Both metrics also reflect the relevant unit cost for an investment in shared capacity. 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 case capacity management is decentralized again but in a setting where two divisions share the ownership, Proposition 4 shows that if the divisional managers base the capacity investment decision on levelized cost, their decision would be aligned. Yet, in contrast to many decentralization settings where managers only have access to their own information, the criterion of profitability alignment requires full transparency, in particular, on each division's contribution margin. A possible alternative to a specified cross-sectional allocation rule could thus be to let the divisional managers negotiate the sharing of capacity-related cost as shown in Dutta and Reichelstein (2019).

In examining the competitiveness of reversible PtG technology, note that 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).

The levelized cost of electricity or hydrogen is contingent on the cross-sectional cost allocation by relative contribution margin. Measuring the competitiveness thus requires an insight on the output-specific contribution margins at break-even of the facility. As Proposition 2 shows, reversible PtG 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. *Suppose capacity-related costs are sizable and allocated by relative contribution margin. The cross-sectional cost allocation at break-even of reversible PtG is uneven in the sense that either $\lambda^c > \lambda^r$ or $\lambda^c < \lambda^r$.*

The corollary shows that the cross-sectional cost allocation presents a main driver of unit costs, 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 uneven cost allocation reflects a clear 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 competitiveness of 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 capture the prospects of the new technology, 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.[20]

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

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

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 (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.

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,

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

the cost of conventional power generation varies in each jurisdiction by production technology.[21] 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.[22] Electricity from reversible PtG is thus far more costly even though the allocated share of joint costs is small.

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 for the competitiveness of reversible PtG technology against alternative energy sources in the market. The projections employ the product perspective to evaluate the change in levelized product costs in future years.

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 investment value, that is, that the integrated system exceeds in value (NPV) both facilities stand-alone. The

[21]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.

[22]The numbers result from own calculations with data for Germany largely retrieved from Fraunhofer ISE (2018) and for Texas from Comello et al. (2018), 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.

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).[23] 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 include 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

[23] 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.

from manufacturers, peer-reviewed articles, and technical reports. With 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: $v(i) = v(0) \cdot \beta^i$, 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).[24] 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%.

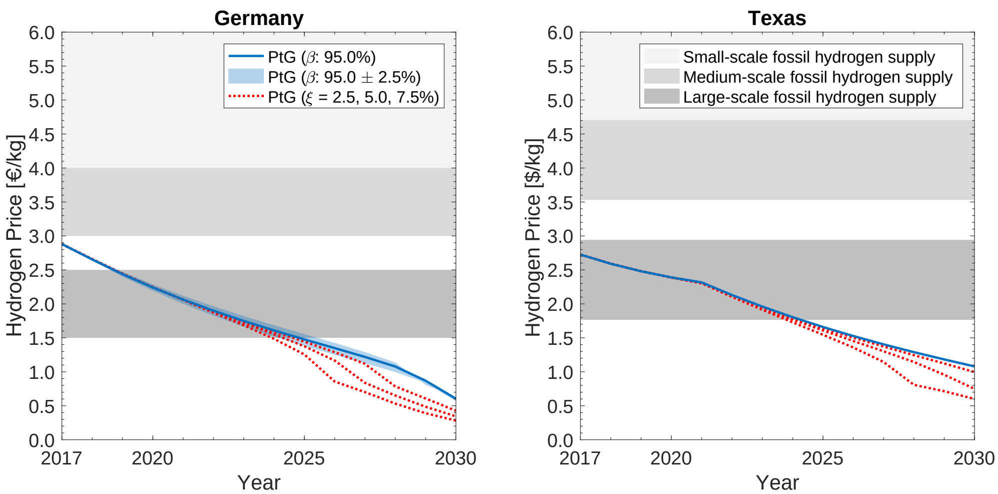

Figure 4: Prospects for the competitiveness of hydrogen.

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 ξ% 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%.

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

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

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%.[25] 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.

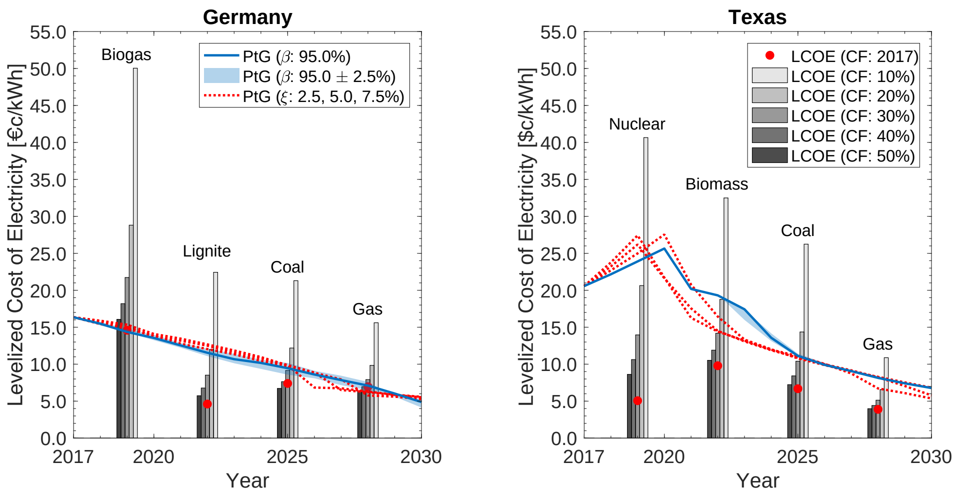

Figure 5: Prospects for the competitiveness of electricity.

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. 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 uneven 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.

With regard to implications for policy makers, who increasingly notice the societal pressure to act upon their climate promises, recall that the promising results base on the supportive subsidies for renewable energy sources in place to evolve as planned. Yet, the diffusion of PtG could further be accelerated if the technology is included in support schemes for renewables. Suitable schemes could

[25]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.

be the investment tax credit as provided for solar power in the United States or the rebate paid for battery installations in Germany. In addition, policy makers can use the preceding framework to estimate the impact of higher prices for fossil fuels or carbon emissions.

The perspective of this analysis has confined to the view of an individual firm, but the framework can also lend itself to regulators of a monopolistic setting or a market with atomistic competition. The concept of levelized cost gives the average market price a firm must achieve in order to survive in the long run, including an appropriate return for investors. This return may either be determined through a long-run market equilibrium in competition or through a rate-of-return regulation in a monopolistic setting (Reichelstein and Rohlfing-Bastian, 2015; Nezlobin et al., 2012).

6 Conclusion

The competitiveness of sustainable versus fossil-based technology becomes an increasingly important information for the managers of a firm. The measurement in form of unit cost, however, continues to drive a controversial debate in accounting and economics due to considerable leeway associated to the intertemporal and cross-sectional allocation of multi-period cash flows. This paper has proposed a principle for the definite characterization of unit cost when productive technology is shared among multiple outputs. Based on 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 measure the competitiveness of productive technology shared among multiple outputs. Subsequent work could continue the generalization in how the concept works for alternative managerial decisions. 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	T	Useful life of capacity investment
γ	Discount factor	v	Upfront capacity expenditure
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:

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

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:

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

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

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

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

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

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

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

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:

$$CM = \left[\eta^c \cdot p_h - w^c \cdot \frac{1}{m}\int_0^m \epsilon^c(t) \cdot \mu^c(t)dt\right] \cdot CF^c + \left[p_e \cdot \frac{1}{m}\int_0^m \epsilon^r(t) \cdot \mu^r(t)dt - w^r\right] \cdot CF^r. \quad (35)$$

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

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

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

$$NPV = (1-\alpha) \cdot L \cdot \left[(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r - LFC \cdot CF\right]. \quad (37)$$

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

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

■

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:

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

where

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

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:

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

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 $p_e = \int\limits_0^m p_e(t)dt > \frac{1}{\eta^r}\delta_h \geq 0$. The average contribution margin of conversion is then given by:

$$CM^c(p_h) = \eta^c \cdot p_h \cdot CF^c(p_h) - \frac{1}{m} \int\limits_0^m w^c(t) \cdot CF^c(t|p_h)dt. \tag{43}$$

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

$$\frac{\partial}{\partial p_h} CM^c(p_h) = \eta^c \cdot p_h \cdot \frac{\partial}{\partial p_h} CF^c(p_h) + \eta^c \cdot CF^c(p_h) - \frac{\partial}{\partial p_h} \left(\frac{1}{m} \int\limits_0^m w^c(t) \cdot CF^c(t|p_h)dt \right) \geq 0. \tag{44}$$

$\frac{\partial}{\partial p_h} CM^c(p_h) \geq 0$, 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:

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

$$\frac{\partial}{\partial p_h} \left(\frac{1}{m} \int\limits_0^m w^c(t) \cdot CF^c(t|p_h)dt \right) = \frac{1}{m} \int\limits_{\{t|\eta^c \cdot p_h > w^c(t)\}} w^c(t)dt. \tag{46}$$

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

$$CM^r(p_h) = \frac{1}{m} \int\limits_0^m p_e(t) \cdot CF^r(t|p_h)dt - \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot CF^r(p_h). \tag{47}$$

$CM^r(p_h)$ 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:

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

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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