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Economics of Renewable Hydrogen

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Abstract

In light of a warming climate, the transition towards decarbonized energy systems emerges as a central obligation of the world economies. Hydrogen has long been heralded as a potentially crucial element in this transition, but the inability to produce the gas at low cost and emissions has so far withheld a widespread adoption. Recent technological advancements and the sharp decline in the cost of renewable energy suggest improved economics for the production of hydrogen from renewable power through a Power-to-Gas (PtG) process. Here I show that renewable hydrogen is on the verge of being sufficiently cost competitive so as to fulfill the promise of substantially reducing carbon emissions. Hydrogen generated at a PtG facility that sources electricity from both the energy market and a wind energy source is competitive with large-scale industrial hydrogen supply from fossil fuels and could thus reduce some carbon emissions already in the current economic environment. Hydrogen that is produced purely from renewable energy to fully eliminate carbon emissions in the production process requires a price premium today but is projected to become equally competitive if recent market trends continue in the coming years. This conclusion stands in contrast to the current view on PtG and corroborates the potential of the technology. The economics of hydrogen production with PtG are investigated from three perspectives in terms of sustainability, operational synergies, and competitiveness with fossil-based alternatives. The frameworks developed in this thesis reflect relevant tools for corporate investors and policy makers within and beyond the context of renewable energy systems.

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Nomenclature

Abbreviations

AEL	Alkaline electrolysis
ITC	Investment tax credit
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LFC	Levelized fixed cost
LFCH	Levelized fixed cost of hydrogen
NPV	Net present value
PEM	Polymer electrolyte membrane
PP	Production premium
PTC	Production tax credit
PtG	Power-to-Gas
SOC	Solid oxide cell
WACC	Weighted average cost of capital

Symbols

α	Effective corporate income tax rate
β	Adjustment rate of electricity price trend
δ	Markup on market price
Δ	Tax factor
$\epsilon(t)$	Multiplicative deviation factor of generation at time t
η	Conversion rate of Power-to-Gas
γ	Discount factor
Γ	Co-variation coefficient between production and prices
λ	Cost allocation factor
$\mu(t)$	Multiplicative deviation factor of prices at time t
$\phi(t)$	Share of called capacity for frequency control at time t

Symbols

c	Cost of capacity per unit
$CF(t)$	Capacity factor at time t
CFL_i	After-tax cash flow in year i
CFL_i^0	Pre-tax cash flow in year i
$CM(t)$	Contribution margin at time t
CV_h	Conversion value of hydrogen
d_i	Allowable tax depreciation in year i
$D(i)$	LCOE minus adjusted market price in year i
F_i	Fixed operating cost in year i
f	Fixed operating cost per unit
I_i	Taxable income in year i
k	Size of capacity investment
L	Levelization factor
m	Number of hours per year
$p_e(t)$	Electricity price at time t
p_h	Hydrogen price
$p^+(t)$	Price of renewable electricity conversion at time t
$p^b(t)$	Buying price of electricity at time t
$p^{b+}(t)$	Price of purchased electricity conversion at time t
$p^c(t)$	Calling price of frequency control at time t
$p^s(t)$	Selling price of electricity at time t
$p^{sb}(t)$	Standby price of frequency control at time t
$p^m(t)$	Price of open market energy at time t
pp	Levelized production premium
ptc	Levelized production tax credit
r	Cost of capital
SP	System price of capacity
T	Useful life of capacity investment
W_i	Variable operating cost in year i
$w^c(t)$	Variable cost of conversion at time t
w^o	Other variable operating cost
w^r	Variable cost of reconversion
w	Variable operating cost per unit
x^{i-1}	Degradation factor of capacity in year i
$z(t)$	Effective capacity of conversion at time t
z	Effective conversion of renewable energy

1 Introduction

1.1 Motivation

The increasingly tangible effects of climate change have led the world's economies in recent years to intensify their efforts for a transition away from fossil fuels. While the transition is certainly forging ahead, it remains far from clear whether the emission of carbon dioxide and other greenhouse gases will be curtailed sufficiently fast. The critical issue is that the increase in carbon emissions in the world's atmosphere will have to drop fast enough in order to prevent carbon dioxide concentrations to exceed threshold levels that climate scientists have identified as fatal for the stability of the climate.

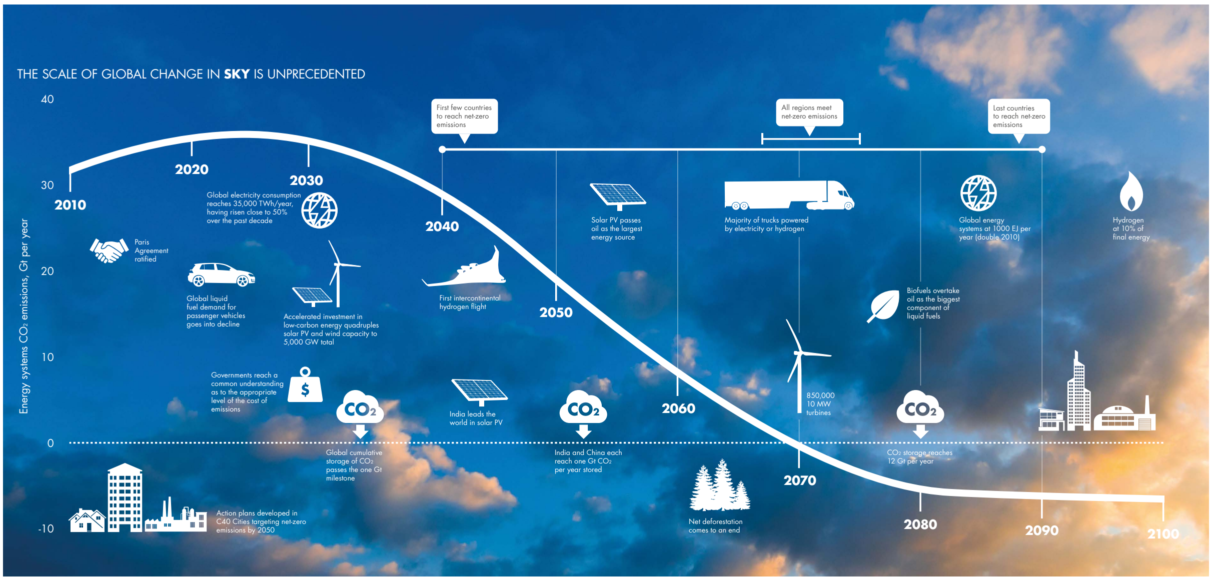

FIGURE 1.1: Decarbonization pathway *Sky* by Shell (2018).

One decarbonization pathway has recently been proposed under the title *Sky* by the oil and gas company Shell (2018). Shown in Figure 1.1, the scenario provides a useful illustration of how a global decarbonization might unfold over the coming decades. When interpreting the scenario, however, two particular aspects should be kept in mind. First, if global emissions follow the trajectory proposed in Sky, the total cumulative emissions by the year 2070, which is the area under the curve in Figure 1.1, would amount to around 1,300 Gigatonnes of carbon dioxide. This amount would dramatically exceed the threshold of 800 Gigatonnes, which some climate scientists have determined as an allowable upper limit. The limit will mitigate with a probability of two thirds the temperature increase on earth to below 2°C relative to pre-industrial levels (IPCC, 2013). Second, the transition towards low-carbon economies must be a path of unprecedented technological innovation. This path will depend not only on the economics of alternative energy solutions but also on the extent of supportive public policies. Governments around the world have introduced various policy measures, such as carbon pricing, direct regulations, and subsidy schemes, in order to trigger innovation in the context of sustainable energy systems. Some of these measures have indeed been essential for driving the commercialization of new low-carbon technologies.[1]

An exceptional push for innovation is the development of renewable energy sources. Due to a range of public subsidies, the market for wind and solar power capacity was able to evolve and, in turn, the costs of renewables to fall precipitously over the recent years. For instance, the price of solar modules has declined from about $4.0 per Watt in 2007 to around $0.35 per Watt by late 2017. Provided the market continues to expand, the price of solar modules is expected to continue the learning curve, shown in Figure 1.2, with reductions of over 20.0% with every doubling of cumulative industry output (Reichelstein and Sahoo, 2017). As a consequence of the cost decline, electricity production at wind and solar power installations is now turning cost competitive with conventional power generation from coal, nuclear, and natural gas in more and more locations. Renewables will undoubtedly serve as the backbone of decarbonization and replace fossil fuels as primary source of energy not only in the power sector but also in heat, transportation, and industrial processes. The switch to wind and solar power, however, entails two critical challenges that have remained unsolved thus far. First, the production of electricity is contingent on highly intermittent natural conditions and, second, modern civilization entails numerous energy services that will be difficult to decarbonize through direct electrification (Davis et al., 2018).

[1]Opportune in time, the Royal Swedish Academy of Science awarded William D. Nordhaus and Paul M. Romer the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2018 for their contributions to the mechanisms of public policy in affecting technological innovation and long-term sustainable economic growth.

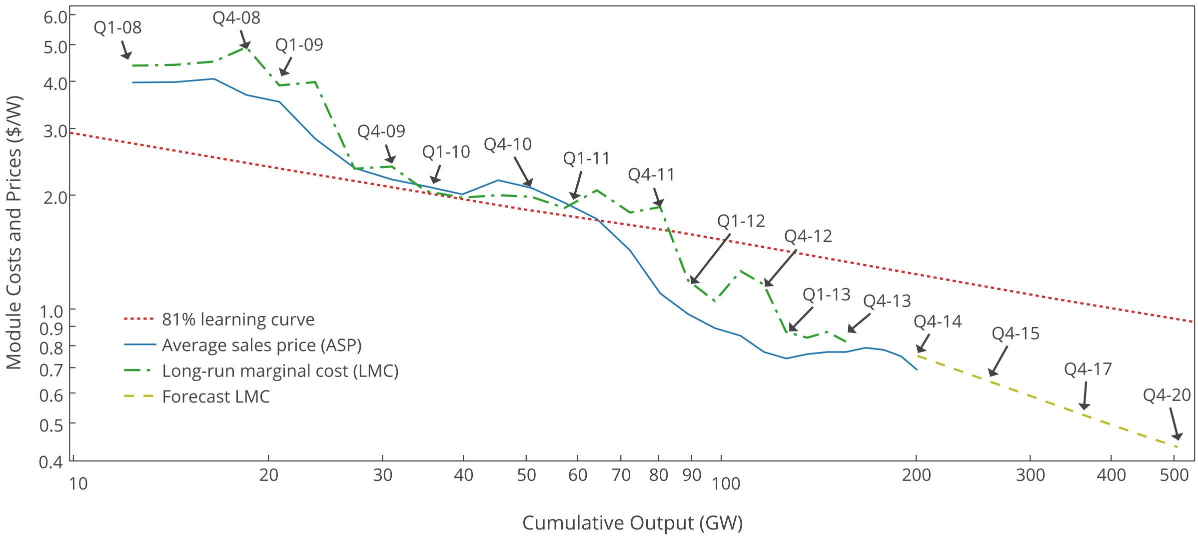

FIGURE 1.2: Cost decline of solar photovoltaic modules.

One promising complement to intermittent renewable power generation is the conversion of surplus electricity to energy storing products like hydrogen. Current industrial supply for hydrogen is derived primarily from a carbon-intensive process based on natural gas (steam reforming) such that hydrogen has remained limited to use cases that specifically require the gas. Hydrogen, however, reflects a platform for a range of applications including fuel for transportation, feedstock in chemical and processing industries, and energy storage for power generation (Jacobson, 2016, Jones, 2012). Hydrogen thus has a considerable potential to reduce carbon emissions in several energy sectors if it is produced from renewable electricity. Clean hydrogen has actually long been heralded as the key to a carbon-free economy, but widespread adoption has so far been withheld by the inability to produce the gas without emissions and at low cost.

Recent market developments and technological advances revitalize the case for hydrogen. As wind and solar power sources increase in share of power generation, the electricity market is more frequently exhibiting periods of surplus electricity (Kök et al., 2018). New Power-to-Gas (PtG) technology enables to generate hydrogen from electricity through water electrolysis, whereby electricity infused in water instantly splits the water molecule into hydrogen and oxygen. The new technology can operate both more dynamically, which allows the combination with intermittent renewable energy, and reversibly, which effectively enables to store energy at large scale (Buttler and Spliethoff, 2018). The better market environment and the technological progress urge to investigate the economic opportunities for renewable hydrogen.

This thesis examines the economics of renewable hydrogen production from electricity with PtG technology. The main objective is to characterize unit cost for the generation of clean hydrogen that is relevant for capacity investment decisions so as to receive a metric that can be used to gauge the competitiveness of renewable hydrogen with fossil-based alternatives in the market. Essential to the analysis is that the production capacity for hydrogen can be put to optimal use in real time in order to incorporate the continuous fluctuations in renewable power generation and electricity prices on the open market. As a result of the fluctuations, the analytical and numerical evaluations of my analyses identify optimal levels of capacity investments of a PtG facility relative to a co-located renewable energy source.

In particular, the thesis explores the question of hydrogen generation with PtG in three separate essays. As illustrated in Figure 1.3, each essay investigates a different technological setting for how a PtG facility interacts with a renewable power source and the external markets for electricity and hydrogen. Each technological setting can deliver a specific value to a potential investor in terms of (1) sustainability, (2) operational synergies, and (3) the competitiveness of outputs with fossil-based alternatives. Economically, each setting poses a distinctive problem to the investor and operator of such productive capacity and, in turn, bears other requirements for a regulatory environment.

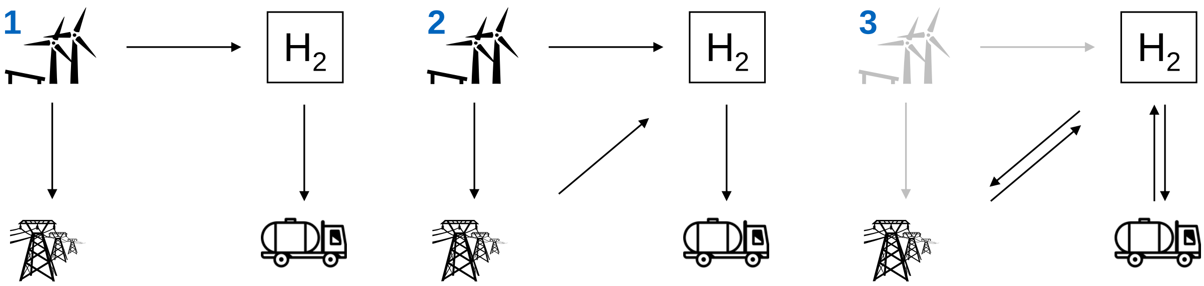

FIGURE 1.3: Illustration of the technological settings.

1.2 Findings

In the first essay, which is on 'The Prospects for Renewable Hydrogen Production,' my co-author Stefan Reichelstein and I examine the economic case for combining an investment in renewable energy with a PtG facility that would sell hydrogen on the external market. To eliminate any carbon emissions, we concentrate on the conversion of electricity obtained purely from a renewable energy source. Since both the electricity price and the renewable power generation fluctuate over time, an investor in such a hybrid energy system obtains a real option for the power source that facilitates the optimization in real time of either selling electricity at the current market price or converting it to hydrogen. Besides the optimized operation, the second main cost driver for hydrogen is that the PtG facility is sized optimally in relation to the available renewable energy capacity.

Renewable hydrogen production is referred to as *economically viable* if an investment in a combined renewable energy and PtG system of optimal capacity sizes has a positive net present value (NPV) and exceeds the NPV of the renewable energy source in a stand-alone setting. The model framework identifies necessary and sufficient conditions for the economic viability and is applicable beyond the case of PtG to general hybrid energy systems. Instrumental to the findings is that the investment conditions can be stated elegantly in terms of average per unit capacity costs and the price premium for converting electricity to hydrogen. The intertemporal fluctuations of renewable power and electricity prices can be accounted for with simple co-variation coefficients.

We then apply the model framework to wind energy and PtG facilities in Germany and Texas, two jurisdictions that have installed substantial amounts of wind power in recent years (IEA, 2017). The numerical evaluations yield that renewable hydrogen turns economically viable if hydrogen is sold at prices of at least 3.23 €/kg in Germany and 3.53 $/kg in Texas. In the current market, these prices are competitive with small- and medium-scale hydrogen supply from fossil fuels but not with large-scale industrial supply. This finding reveals why purely renewable hydrogen production is currently only observable in niche applications (Curtin and Gangi, 2017, U.S. Department of Energy, 2018). Yet, our evaluations project that, within a decade, renewable hydrogen will also become competitive with the lower prices paid for large-scale hydrogen supply, provided the investment cost for wind turbines and PtG facilities continue on their respective recent learning curves. These projections take into account that the public support for wind energy available in the U.S. is scheduled to be phased out in the coming years and that the subsidy in Germany is determined via a competitive auction mechanism.

Our model framework also allows to quantify the impact of policy support measures that could accelerate the convergence process of renewable hydrogen. Most important, we find that the current form of the German subsidy for wind energy imposes a prohibitively large opportunity cost for onsite conversion of renewable power, because the supportive premium is paid only for renewable electricity fed into the grid. By waiving this feed-in requirement for receiving the premium, policy makers could provide critical support to the competitiveness of renewable hydrogen and prepare the ground for the production of synthetic fuels required for energy services that are difficult to decarbonize through electrification. To further accelerate the emergence of renewable hydrogen, regulators could parallel the efforts by the U.S. federal tax code for solar photovoltaic and battery storage installations by introducing rebates or investment tax credits. By incorporating three alternative levels of rebates for the acquisition cost of PtG facilities in our calculations, we find that every increment of 10% accelerates the competitiveness of renewable hydrogen with large-scale fossil hydrogen supply by about 1.5 years. Beyond the conducted analyses, the framework can further be used to estimate the impact of higher fossil fuel prices or higher charges imposed on carbon emissions on the competitive position of industrial hydrogen produced from fossil fuels.

The second essay examines 'Operational Volatility and the Synergistic Value of Vertically Integrated Energy Systems' and is also written in co-authorship with Stefan Reichelstein. When both the renewable energy source and the PtG facility are connected to the external electricity market, as illustrated in Figure 1.3, the economic problem becomes subject to the question of vertical integration. In the first essay, the question of vertical integration does not occur, because renewable hydrogen can only be produced at an integrated facility. Vertical integration has long been a central topic in the literature on the theory of the firm (Williamson, 1975, 1985). With the rising volatility in global market, the topic has recently been increasingly revisited by the operations literature (e.g. Kazaz (2004), Dong et al. (2014), Boyabatli et al. (2017)). In these studies, the benefits of vertical integration arise from operational synergies, while costs stem from the need for additional upfront investments in productive capacity.

In our model of a vertically integrated production system, the upstream unit produces an intermediate production good that can either be sold on the external market or transferred internally to a downstream unit. Benefits from investing in both units stem from imperfections in the market for the intermediate good. Such imperfections occur whenever the selling price attainable by the upstream unit is below the buying price at which the downstream unit could purchase the good in the external market. Internal sourcing of the intermediate production good will create operational synergies, which must be balanced with the cost of additional capacity investments (van Mieghem, 2003, Hekimoglu et al., 2017, Kouvelis et al., 2018).

In application to hydrogen production, the PtG facility reflects the downstream production unit with electricity sourced either from an upstream renewable energy source or the external market. Operational synergies emerge as buying and selling prices of electricity differ and fluctuate intertemporally across hours and seasons of a year. Furthermore, the generation of renewable electricity relies on intermittent natural conditions. While some of the recent studies on production synergies capture volatility by random shocks (Hu et al., 2015, de Véricourt and Gromb, 2018), we capture volatility by foreseeable variations in both the average electricity prices and the average electricity output from the renewable power generator at various points in time.

The main question of the article is whether the investment in a combined renewable energy and PtG production system has *synergistic value*. The condition for such value is that the optimized NPV of the vertically integrated energy system exceeds the sum of the NPVs of both capacities on their own that would trade electricity only on the external market. In this comparison, the NPVs of the stand-alone capacities are bound below by zero due to the option not to invest in the first place. The presence of synergistic value thus demands operational synergies to more than compensate for losses of the individual capacities in stand-alone mode if either or both energy systems have a negative NPV on their own. Similar to the first essay, the operational volatility characterizes optimal levels of capacity investment of both facilities to each other.

Investment conditions for a vertically integrated energy system are simple to identify in a hypothetical stationary environment, in which production output and prices are constant over time. Our analysis shows how such conditions continue to hold for settings of operational volatility. Essential to the extensions is that the intertemporal fluctuations in electricity prices and the renewable power output can be summarized to simple covariance terms that adjust the average price and output parameters used in a stationary condition.

The second part of the article applies the model framework to PtG facilities and wind energy in Germany and Texas. Our numerical evaluations yield that stand-alone wind energy in the current market obtains a negative investment value in Texas but is profitable in Germany, which can be attributed, to a large extent, to the supportive mechanisms for renewable energy. The stand-alone NPV of PtG facilities relies in both jurisdictions on the attainable market price of hydrogen. For higher prices paid in medium-scale supply settings, stand-alone PtG facilities are marginally profitable in both Germany and Texas. Yet, for the lower prices associated with large-scale industrial hydrogen supply, our evaluations indicate a negative NPV for PtG installations.

As the two energy systems typically encounter some synergistic interaction, it would be intuitive that a synergistic value emerges if both wind electricity and hydrogen production are profitable stand-alone. Our evaluations confirm this in the context of Germany and medium-scale hydrogen prices. In contrast, one would not expect a synergistic value to emerge if both subsystems have a negative NPV as operational synergies would have to be sufficiently large to compensate both stand-alone losses. Nevertheless, our calculations yield a synergistic value for the setting of Texas and the lower price paid for large-scale hydrogen supply.

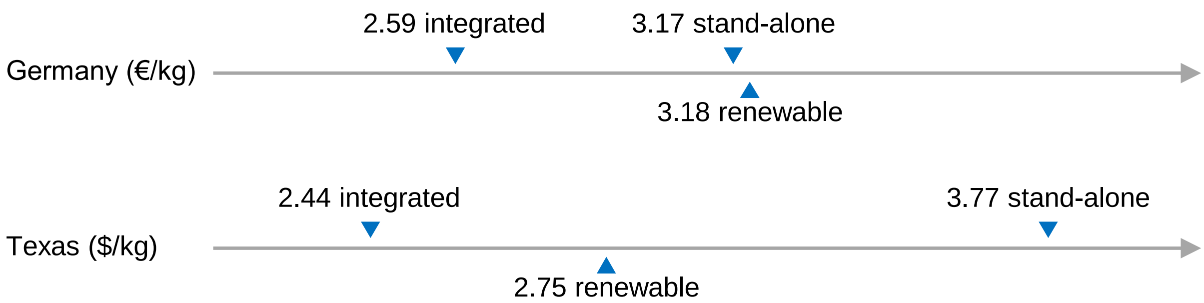

FIGURE 1.4: Comparison of break-even prices for hydrogen production.

To measure the magnitude of synergistic gains from vertical integration we identify the break-even price of hydrogen, shown in Figure 1.4. This price is defined as the lowest downstream (i.e., hydrogen) price required for a vertically integrated system to obtain synergistic value. By construction, the break-even hydrogen price of the vertically integrated system is always lower than the price at which hydrogen production turns profitable on its own. For the setting of Texas and large-scale hydrogen supply, we find that the break-even price of hydrogen for a vertically integrated energy system is about 30% lower than the price that is necessary for a PtG facility to turn viable stand-alone, as illustrated in Figure 1.4. This demonstrates the economic relevance of vertical integration in the context of renewable energy systems.

The third essay examines 'Shared Capacity and Levelized Cost with Application to Power-to-Gas Technology.' Recall that in the transition towards a decarbonized economy, the reliability of energy supply emerges as the crucial challenge, because the rapidly growing share of wind and solar power generation is characterized by weather-dependent intermittency. A promising remedy is new reversible PtG technology that can convert and reconvert electricity to hydrogen in real time (Buttler and Spliethoff, 2018). With this operation, reversible PtG can effectively store energy at large scale and power processes that are difficult to decarbonize through direct electrification (Davis et al., 2018). One objective of the essay is to examine when a reversible PtG facility would be economically viable and both outputs competitive with fossil-based alternatives in the market.

Since reversible PtG produces electricity and hydrogen on the same facility, the technology reflects a shared capacity in the generic sense. To deliver products and services, productive capacity typically expenses upfront capacity investments, periodic operating costs, and financing cost. With the many ways to apportion such cash flows over multiple periods, the calculation of unit cost is inherently ambiguous. At the same time, the calculation can be essential for estimating product prices and capacity investment decisions, as arbitrary unit cost may lead to prices being too low for capacity investments to turn out profitable in the long run (Pittman, 2009). The calculation of unit cost is even more obscure when productive capacity is shared among multiple outputs. The second objective of the essay is to develop a theoretical framework for the calculation of relevant unit cost when productive capacity is shared.

The guiding principle of the framework is that unit cost should be equivalent to a constant revenue payment that the investor in capacity needs to receive over the life of the asset in order to break-even on the upfront investment. This criterion simplifies the aggregation of multi-period cash flows to the relevant cost and unit for capacity investment decisions. The criterion builds upon the concept of so-called *levelized product cost*. The metric identifies the constant price per unit of a product that is required to break-even and aggregates a share of the upfront investment with periodic fixed and variable operating costs (MIT, 2007). The cost measure can be interpreted as the long-run marginal cost of a product and thus reflects the relevant unit cost for investments in productive capacity (Reichelstein and Rohlfing-Bastian, 2015). The interpretation has been examined for a range of market conditions, but the concept has remained limited to single-output production environments.

For shared capacity the essay shows that the characterization of relevant unit cost hinges on the perspective of the potential investor. With what I refer to as a *capacity perspective* the investor concentrates on the supply of capacity and the identification of the constant revenue payment per unit of capacity required to break-even. I find that the relevant unit cost reflects the constant contribution margin per hour and can be aggregated to what I call the *levelized fixed cost (LFC)* of shared capacity. The LFC is valuable information for an investor who sells the facility for the production of the output that yields the highest contribution margin over a particular time period (Friedl et al., 2017). The simplification of the guiding principles applies in so far as all capacity and fixed operating costs associated with the supply of capacity are discounted and allocated intertemporally across the availability and average utilization of capacity.

In the alternative scenario of a *product perspective*, the focus resides on the delivery of individual outputs and the identification of the constant product prices per unit required to break-even. Following the original conceptualization, the relevant unit cost is provided by the levelized product cost. The unit cost of each product reflects the constant selling price required to break-even. It can be calculated in a way that it finds the break-even of the capacity without the need to examine the unit cost of other outputs. In contrast to the original concept, the discounted sum of all costs required for the delivery of the outputs must be allocated not only intertemporally but also cross-sectionally among the outputs when capacity is shared. This complication, however, is shown to be simplified in the formulation of individual unit cost to one further factor that adjusts the joint costs of capacity for the share allocated to the output.

Cross-sectional cost allocation is repeatedly considered as arbitrary although it is often necessary to allocate joint costs among outputs (Balakrishnan and Sivaramakrishnan, 2002, Küpper, 2009). My essay shows, in contrast, that the break-even conceptualization of levelized cost provides a unique criterion for allocation as to induce profitability alignment among the jointly generated products. Each product is thereby declared profitable if the price exceeds its unit cost. Accountants in theory and practice have developed a range of rules for cross-sectional allocation of joint cost. My analysis shows that profitability is aligned if only if capacity-related costs are allocated according to the relative contribution margin, that is, by the share of the total contribution margin that each output is planned to generate.

In light of decentralized capacity management, the perspectives of the analysis are closely related to the settings investigated in the literature (see, for instance, Dutta and Reichelstein (2010, 2018), Wei (2004), or Rogerson (2008)). A common setting is that for a firm that has two divisions the managers of both are jointly responsible for the investment in productive capacity. Due to technical expertise the upstream division installs the capacity and produces all outputs, but both divisions sell their outputs separately in the respective markets. The manager of the upstream division, as the supplier of capacity, would naturally take the capacity perspective, while the manager of the downstream division would assume the product perspective. In the conceivable scenario, however, that the upstream division stands in competition with the external market for the delivery of the output, it will take the product perspective to measure its competitiveness. Since perspectives and organizational structures not always align, it is crucial to distinguish between them.

To the broad literature on full cost the levelized cost concept is connected in several regards. First, levelized product cost is equivalent to a product's full cost if that accounts for taxes and imputed interest charges on the remaining book value (Reichelstein and Rohlfing-Bastian, 2015). Second, the cost metric provides a useful measure of full cost for gauging product prices in the market in various settings of competition (Reichelstein and Rohlfing-Bastian, 2015, Banker and Hughes, 1994, Balakrishnan and Sivaramakrishnan, 2002, Göx, 2002). Third, the essay shows that the levelized cost measured identified in both perspectives provide under distinct conditions efficient transfer prices for several conceivable organizational structures.

In application to reversible PtG technology, a potential investor would naturally assume a capacity perspective to examine the economic viability of a facility. Confirming the general insights on shared capacity, the essay finds that a PtG facility breaks-even if and only if the average contribution margin exceeds the LFC. This break-even is commonly perceived to rely on the volatility in electricity prices and the frequent switch between conversion and reconversion, because PtG reflects a technology for storing electricity over time (see, for instance, Jülch (2016) or Steward and Zuboy (2014)). My analysis confirms the value driving effect of volatility but finds in addition that the possibility to trade hydrogen as the storage medium in the market is more important. The market access for reversible PtG issues a price for hydrogen and the ability to derive value from converting electricity to hydrogen without the need to reconvert after power prices have sufficiently fluctuated. For conditions frequently observable in current market environments, my analysis shows that reversible PtG breaks-even if it largely produces the one output that has the higher average price.

To examine the competitiveness of electricity and hydrogen, the investor in reversible PtG would calculate the levelized cost of each product and thus take the product perspective. The most common use of the levelized cost concept is in connection with electricity to identify the cheapest power generation technology to cover a particular load, because it calculates the lowest product price required to break-even MIT (2007). Since the calculation of levelized product cost at shared capacity includes a cross-sectional cost allocation, the measurement of competitiveness must know the allocation of joint costs at break-even of the facility. The analysis shows that the economics of reversible PtG divide the sizable joint costs of capacity into a larger and a smaller share so that the cross-sectional cost allocation becomes a main driver of competitiveness. With the growing share of renewable power generation and the attendant trend of falling power prices, the smaller share of joint costs is allocated to electricity. A reversible PtG facility may thus achieve a competitive levelized cost of electricity even though the new technology and hydrogen as a fuel are relatively expensive.

The economics of reversible PtG reflect a competitive advantage in comparison to alternative energy sources that could deliver electricity during the periods of insufficient renewable power. Conventional power generators based on, for instance, coal, nuclear or natural gas can operate in only one direction. The value of their production is therefore harmed by the shift towards renewables causing both a rise in volatility of the electricity price and a decrease in utilization (Wozabal et al., 2016). Other storage devices like batteries, pumped storage or compressed air cannot trade their storage medium in the market. The value of such technologies hinges on the volatility in electricity prices, which alone must be sufficient to cover the entire costs with the limited amounts of stored electricity.

The final part of the analysis evaluates the case of reversible PtG numerically, for comparability of the results across all three essays, again in Germany and Texas. In the current economic environment, the calculations find that reversible PtG breaks-even only if the average hydrogen price exceeds that of electricity and the facility generates hydrogen for the most part. If a facility is to break-even on mostly power generation, the price of electricity would have to be considerably higher than the current market price to yield a contribution margin that exceeds the cost of capacity. For both outputs, the analysis shows that competitiveness is only achieved in niche applications in Germany and Texas. Hydrogen production, in particular, is competitive with the supply of industrial hydrogen produced from fossil fuels at small- and medium-scale but not with the lower prices paid for supply at large-scale.

Including recent market trends, the calculations project a cost development for reversible PtG that supports the potential of the technology for providing a clean solution to the challenges of intermittency and widespread decarbonization. Similar to the previous essays, the main ingredients for this development are sustained cost reductions, efficiency improvements, and that reversible PtG is combined with a co-located wind energy source to leverage operational synergies. These synergies turn hydrogen production with reversible PtG competitive with large-scale hydrogen supply already in the current environment. The cost of electricity production remains currently above but is projected to fall below the cost of conventional power generation over the coming decade. As shown in Figure 1.5, the effect is particularly clear considering that conventional power generators face a falling utilization when market share shifts towards renewables.

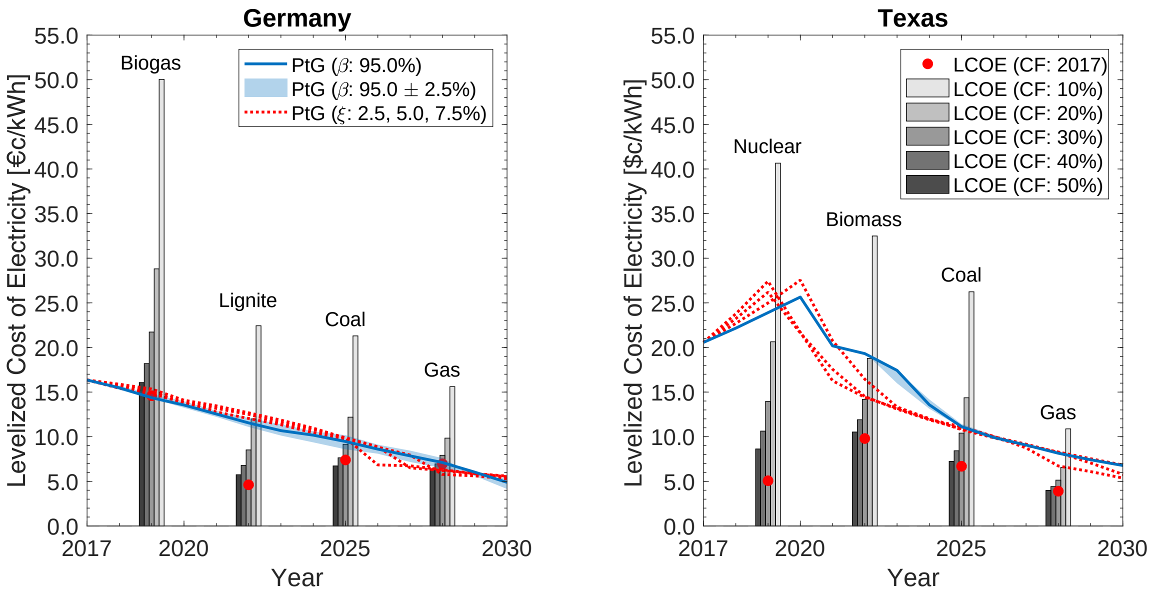

FIGURE 1.5: Projected levelized cost of electricity.

1.3 Contribution

Across all three essays, my analyses conclude that hydrogen produced with PtG will be sufficiently competitive with fossil-based alternatives in order to emerge as a critical element in the transition to a decarbonized economy. Already in the current market, hydrogen can reduce some carbon emissions in a profitable business case. If a PtG facility can be vertically integrated with a co-located renewable energy source, hydrogen production with PtG is cost competitive with large-scale industrial hydrogen supply from fossil fuels. This finding is consistent with current market activity for early deployments of large-scale PtG facilities in connection with refineries and steel production sites; see, for instance, Bloomberg (2017), ITM Power (2018), Voestalpine (2018), GTM (2018). Provided recent market trends continue, the cost of generating hydrogen purely from renewable energy will drop fast enough for renewable hydrogen to also become competitive with industrial-scale supply within the coming decade. This parity will allow applications of renewable hydrogen to fully curtail carbon emissions and is projected to emerge much sooner than many studies suggest, such as the Sky scenario by Shell (2018).

A comparison of the numerical results of the first and the second essay quantifies, in particular, the value of granting a PtG facility that is combined with a renewable energy source access to the electricity market. Figure 1.4 shows that such market access reduces the break-even price for hydrogen production by about 20% in Germany and about 10% in Texas. The reductions are due to the higher utilization of a PtG facility that can purchase additional electricity from the market during periods of low prices and low wind power generation. The price difference is particularly pronounced in Germany, which illustrates the importance of market access for the competitiveness of hydrogen production with PtG. The comparison can also be viewed from the perspective of sustainability. If hydrogen is required to be free of carbon emissions, which are still associated to grid electricity in the current market, hydrogen customers must be willing to pay a premium for hydrogen production to be renewable. Finally, note that the prices for renewable hydrogen shown in Figure 1.4 are lower than the prices in the first article. This is because the calculations in the second article incorporate the most recent cost and operational inputs for wind energy and PtG.

In contrast to the first two essays, the results of the third essay demonstrate the economic relevance of a reversible operation. The break-even price of hydrogen generated with reversible

PtG (essay 3) is currently slightly higher than the break-even price of hydrogen generated with a one-directional PtG facility (essays 1 and 2). The higher prices stem from the higher investment expenditures for the reversible technology. A comparison of the current environment would advocate a one-directional over a reversible PtG facility for the production of hydrogen. However, a contrast of the prospects for both technologies shows that reversible PtG will be able to generate hydrogen at lower cost in the coming years due to considerable cost reductions for reversible electrolyzers and the cost allocation among hydrogen and electricity.

The conclusion of my analyses holds several practical implications for potential investors and policy makers, in particular, when they are focused on the structure of renewable energy systems. Most important, all three essays develop a general framework for evaluating the economics of renewable hydrogen in specific cases. The optimal setup for renewable hydrogen production will vary across geographic regions due to profound differences in the availability of natural resources and country-specific institutions. For regulators, specifically, the frameworks also reflect tools with which to predict a collection of policy measures that can accelerate the adoption of clean energy technologies, like PtG. For instance, recall that waiving the feed-in requirement in Germany for renewable energy to be eligible to the subsidy would provide essential support for the production of renewable hydrogen to be economically viable. As the analyses show, a price on carbon or rebates and investment tax credits for PtG investments are also proven policy mechanisms in the area of renewable energy that could further improve the competitive position of renewable hydrogen.

Beyond the context of energy systems, all three theoretical models lend themselves for assessing issues in industrial settings that share similar characteristics. With regard to the framework in the second essay, one such setting could be the question of vertical integration in the presence of operational volatility. The question arises in a variety of economic environments, for instance, in agriculture where farmers could hedge against volatile crop prices by investing in equipment that processes the crops to products with a fixed price (see the settings, for instance, in McKinnon (1967) and Rolfo (1980)). The third essay applies to all firms that need to make upfront investments in order to deliver their product or service and that require a cost per unit for guiding product prices and capacity investment decisions. Incorrect unit cost, for instance, can lead to prices being set too low for upfront investments to turn out profitable. This issue has recently gained global attention when the 45$^{\text{th}}$ President of the United States, Donald Trump, twittered on March 31, 2018: *"[I]t is reported that the U.S. Post Office will lose $1.50 on average for each package it delivers for Amazon. [...] This Post Office scam must stop. Amazon must pay real costs (and taxes) now!"*

1.4 Literature Context

In comparison to previous studies, all three essays indicate a better economic position for hydrogen and project a faster decarbonization potential of hydrogen than the trajectory outlined in Shell's Sky scenario (Ainscough et al., 2014, Bertuccioli et al., 2014, Felgenhauer and Hamacher, 2015, Jentsch, 2014, Zakeri and Syri, 2015, Shell, 2018). These improvements are in large parts due to the interdisciplinary approach taken in this thesis, as illustrated in Figure 1.6. The three essays study the economic opportunities for renewable hydrogen from PtG at the intersection of technological innovation, business and economic fundamentals as well as public policy. The common research approach is that the articles examine how technological developments together with supportive public policies can incentivize investors, including public and private organizations, to adopt low-carbon hydrogen produced from (renewable) electricity via PtG processes. In particular, given technological possibilities, the analyses explore how specific public policy mechanisms allow investors to optimize the economics of renewable hydrogen so as to attain sufficient returns when replacing traditional carbon-intensive energy sources with low-carbon platforms based on hydrogen.

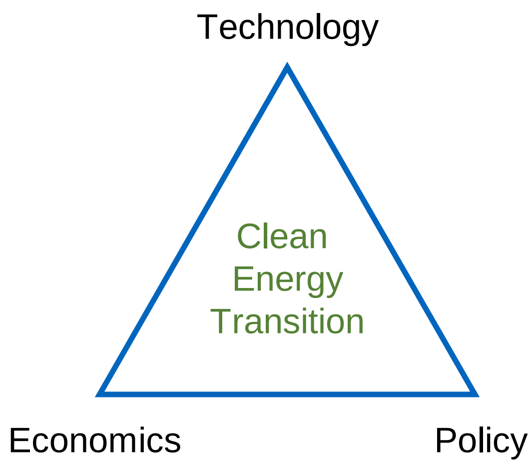

Figure 1.6: Interdisciplinary research approach of thesis.

With regard to the economic optimization, in particular, the improved results can be attributed to three key factors. First, the PtG facility is sized optimally in capacity relative to the renewable energy source, which is of primary importance in capital-intensive investments. Second, if the PtG system sources electricity from both a renewable source and the electricity grid, the facility can achieve higher capacity utilizations than if the facility only converted renewable energy. Third, a PtG facility that operates reversibly entails a cross-sectional allocation of the sizable capacity-related costs to both outputs improving their competitiveness.

The analyses of this thesis focus on hydrogen production from renewable electricity using PtG technology, because electrolyzers are commercially available and can buffer the increasing share of intermittent renewable power generation. There is, however, substantial research on alternative routes for hydrogen production that also avoid the emission of carbon dioxide. The most promising technologies are thermochemical water splitting and artificial photosynthesis, which both directly convert sunlight to hydrogen without the need for intermediary electricity (T-Raissi, 2010). The technologies are still at a stage of research and development, but they present the potential of further improving the economics of renewable hydrogen production due to higher conversion efficiencies.

Instead of converting renewable energy to hydrogen, the challenge of intermittency may also be mitigated by alternative storage technologies. Pumped hydropower, for instance, uses a height difference between two water reservoirs to store energy and has been widely used for decades (Schmidt et al., 2017). In the past, pumped hydropower has been employed much to reduce the ramping cost of large-scale power generators by shifting electricity production from nighttime when demand was relatively low to daytime when demand increased. In order to perfectly compensate the intermittency of renewables, pumped hydropower capacity would have to be expanded considerably. Such expansions, however, are in most countries limited by the available geographic formations and the accompanying changes to the environment.

On a smaller scale, battery storage has grown strongly in behind-the-meter applications in recent years (Burger and Luke, 2017). The growth can be largely attributed to the advantage of batteries that they can be deployed in a modular and distributed fashion (Hoppmann et al., 2014, Fisher and Apt, 2017). With high round-trip efficiencies for charging and discharging, batteries appear well suited to extend, on a regular basis, the power of residential solar photovoltaic installations by a couple of hours after sunset. Yet, with relatively high cost for the energy-storing battery cells, they seem less practical for storing electricity on a larger scale across several days or even seasons of the year (Comello and Reichelstein, 2018). In contrast to that, a chemical storage medium, like hydrogen, is economic to store at large scale, for instance, in underground caverns and pipeline networks (Michalski et al., 2017). Since hydrogen can also be traded in the market, reversible PtG can utilize the benefits of cross-sectional cost allocation to obtain a competitive unit cost for electricity.

Along with renewable power sources and the complementing energy storage facilities, two further areas are likely to play a major role in decarbonizing the world's economy. First, digitalization by means of 'smart meter' technology bears the great potential of widespread pricing of electricity in real time. This will induce more production-oriented consumption and effectively allow more flexibility in balancing demand and supply on the grid. More broadly, digitalization will facilitate the integration of distributed energy systems, such as residential or communal solar installations and behind-the-meter storage, into the grid (Sekaric, 2018). Current research activities are targeted at identifying business models for new digital energy services. Particular examples are demand response services and virtual power plants, which bundle distributed energy sources and offer the aggregated capacity to the general market (Rieger et al., 2016). An important area for research is also the necessary regulatory environment that would facilitate the formation of new digital energy services.

The second area is a market for industrial carbon dioxide. Public debates on carbon concentrations in the atmosphere frequently ignore that the gas by itself is a valuable production input in a range of industrial processes, including oil recovery, carbonation, and fertilizer production. Despite the prospects of climate change, customers of carbon dioxide widely retrieve the gas, in the current market, either from natural underground reservoirs or by burning natural gas. At the same time, the industrial sector, without power generation and transportation, is responsible for roughly 25% of total global emissions in 2016 (IEA, 2018). Prominent examples of carbon intensive manufacturing processes are the production of cement, metals and paper. Current research focuses on technological and policy developments that would create incentives for carbon dioxide to be captured at industrial facilities. The gas could then be traded with companies that require it as an input or sequestered permanently in underground structures. Another part of research addresses the possibilities to capture carbon dioxide from the ambient air. This technology has long been regarded as too expensive due to the low concentrations of carbon dioxide in the atmosphere, but several start-up companies are challenging this conclusion by co-locating their facility with customers of carbon dioxide (Keith et al., 2018). The interest in carbon capture from air stems largely from the fact that it reflects one of the few currently known pathways for achieving negative carbon emissions. From a policy perspective, the development of the technology therefore provides an insurance policy for the case that the impact of the changing climate is more severe and arrives sooner than scientists project. Policy makers around the world could trigger the insurance by increasing the price of carbon, which has so far been zero or at most moderate in nearly all jurisdictions.

For centuries, mankind has been deriving economic value from oil and gas as primary source of energy. Since the leading economies of the world have committed to decarbonize, this self-evident fact is prone to become invalid as almost every industry appears affected by a transition away from fossil fuels. My analyses show that rather than converting gas to electricity as it has been done traditionally, the recent sharp cost declines for renewable energy suggest to convert electricity to gas, like hydrogen. Clean hydrogen can be used in a variety of applications, including options to mitigate the intermittency of renewable power generation and to decarbonize energy services that cannot be powered with renewable electricity directly. Together with alternative low-carbon technologies outlined above, there seems to be sufficient potential for development to remain optimistic that carbon concentrations in the atmosphere will be reduced fast enough so as to avert severe climatic consequences for the world. Some technologies may also reinforce each other with synergistic gains, for instance, from combining hydrogen obtained from surplus renewable electricity with carbon dioxide to create synthetic fuels. However, for the development of these technologies to be fast enough, continued efforts from industry and policy makers are required to drive innovation. Most important is a regulatory environment, in which clean energy technologies can continue their respective cost decline and new digital energy services can evolve. The development of these technologies will chart the exact decarbonization pathway taken in each jurisdiction.

1.5 Structure of Thesis

The remainder of the thesis is structured as follows. Chapter 2 presents the first essay on 'The Prospects for Renewable Hydrogen Production.' Since the essay was prepared for publication in *Nature Energy*, a journal with strict guidelines on the structure of the article, the method section that includes the details of the model framework follows after the conclusion. Chapter 3 proceeds with the essay on 'Operational Volatility and Synergistic Value in Vertically Integrated Energy Systems.' Chapter 4 then provides the article on 'Shared Capacity and Levelized Cost with Application to Power-to-Gas Technology.' Finally, chapter 5 draws the general conclusions, recapitulates the main practical implications, and shows avenues for further research. Supplementary information, such as proofs, input variables, and further results of the numerical evaluations, are provided for each essay in a comprehensive appendix at the end of the thesis.

2 | The Prospects for Renewable Hydrogen Production

by Gunther Glenk and Stefan Reichelstein[1]

Hydrogen has long been heralded as a potentially critical element in the transition to a decarbonized economy. The recent sharp decline in the cost of renewable energy suggests that the production of hydrogen from renewable power through a Power-to-Gas process might become economically viable. We examine this prospect from the perspective of an investor who seeks to configure a hybrid energy system that optimally combines renewable power with a Power-to-Gas facility. The available capacity can be optimized in real time so as to take advantage of fluctuations in electricity prices and intermittent renewable power generation. Calibrating our model to the current environment in both Germany and Texas, we find that renewable hydrogen is already cost competitive in niche applications (3.23 €/kg) but not yet with industrial-scale supply. This conclusion, however, is projected to change within a decade (2.50 €/kg) provided recent market trends continue in the coming years.

[1]Author Contributions: The authors jointly developed the research question, the model framework and the analytical findings. Gunther Glenk lead the literature review, the data collection and the calculations. Both authors contributed substantially to the writing of the paper.

2.1 Introduction

The production of hydrogen from renewable power has considerable potential to reduce carbon emissions as hydrogen is effectively a platform for a range of applications including fuel for transportation (Jones, 2012, van Renssen, 2013, Goodall, 2017), feedstock in chemical and processing industries (European Power to Gas, 2017), or energy storage for heat and power generation (Jacobson, 2016, Zakeri and Syri, 2015, Evans et al., 2012, Hosseini et al., 2015, Nat, 2016). However, the production of hydrogen through electrolysis, whereby electricity infused in water instantly splits the water molecule into oxygen and hydrogen (Sterner and Stadler, 2014, Hosseini and Wahid, 2016, Holladay et al., 2009), has so far been regarded as too expensive (Davis et al., 2018, Bertuccioli et al., 2014). This paper examines whether the recent precipitous decline in the cost of renewable power creates new economic opportunities for Power-to-Gas (PtG) facilities (Wiser et al., 2016, Comello et al., 2018b).

We examine the economic case for combining an investment in renewable power generation with a PtG facility that would then sell hydrogen in the market place. Essential to our analysis is that the PtG facility is sized optimally in relation to the capacity available for power generation. An investor in such a hybrid energy system effectively acquires a "real option" that allows for real-time optimization by either selling electricity at the current market price or converting it to hydrogen. Such flexibility is valuable in an environment in which both electricity prices and renewable power generation fluctuate over time.

We refer to renewable hydrogen production as *economically viable* if an investment in an optimally chosen combination of renewable energy and PtG capacity has a positive net present value (NPV) and furthermore this value exceeds the NPV of the renewable energy facility on its own. The novel framework applies to general hybrid energy systems and yields necessary and sufficient conditions for their economic viability. These conditions are stated compactly in terms of the average per unit capacity costs and price premium for converting electricity to hydrogen, after including an adjustment factor that accounts for the temporal fluctuations of renewable power generation and electricity prices.

Applying our model to wind parks in Germany and Texas, we find that renewable hydrogen turns economically viable if hydrogen is sold at prices of at least 3.23 €/kg in Germany and

3.53 \$/kg in Texas. In the current environment, these prices are compatible with small- and medium-scale hydrogen supply but not with large-scale industrial sales. Our findings explain that PtG is currently only applied in niche applications (Strategieplattform Power-to-Gas, 2016, Curtin and Gangi, 2017, U.S. Department of Energy, 2018). However, if the acquisition prices for electrolyzers and wind turbines continue on their respective recent learning curves, our findings project that, in about a decade, renewable hydrogen will also become competitive with the lower prices paid for large-scale industrial hydrogen. Our results also delineate how this convergence process could be accelerated through policy support mechanisms such as rebates or investment tax credits.

2.2 Model Framework

Consider a hybrid energy system combining a renewable energy source with a PtG facility (including the electrolyzer, piping, and hydrogen compressor) that converts electricity and water into hydrogen. At each point in time, the electricity that is generated can be sold externally at the current market price or it can be fed to the electrolyzer for conversion to hydrogen. With an eye on reducing carbon emissions, we focus on electricity obtained from a *renewable* power source.

In our continuous time formulation t ranges between 0 and $m = 24 \cdot 365 = 8,760$ hours. The price per kilowatt hour (kWh) at which renewable energy can be sold at time t is denoted by $p_e(t) \geq 0$. Without loss of generality, we normalize the capacity of the renewable energy facility to 1 kilowatt (kW). The capacity factor, $CF(t)$, represents the percentage of the available capacity that is used at time t. Because of the inherent intermittency of renewable power, $CF(t)$ is exogenous, varies with time, and generally satisfies $CF(t) \leq 1$. The variable operating costs of renewable energy production are considered negligible.

The *conversion value* of hydrogen is the selling price of hydrogen minus the variable operating cost (including water and other consumable inputs) multiplied by the conversion rate of the electrolyzer. The price and the variable cost per kilogram (kg) of hydrogen are denoted by p_h and w_h, respectively. We model p_h as time-invariant, because buyers and suppliers typically enter into fixed-price contracts. The conversion rate of the electrolyzer (in kg/kWh) is represented by

η, the amount of hydrogen that can be procured from 1 kWh of electricity. Thus, the conversion value (in \$/kWh) becomes: $CV_h = \eta \cdot (p_h - w_h)$.

The contribution margin of the hybrid energy system can then be expressed as follows: all renewable energy is sold at the market price, and, if the conversion value of hydrogen exceeds the selling price of electricity, the facility earns a *conversion premium* up to the capacity maximum given by $z(t|k_h) \equiv \min\{CF(t), k_h\}$, with k_h denoting the capacity of peak power conversion (in kW). The conversion premium is given by:

$$CP_h(t) \equiv \max\{CV_h - p_e(t), 0\}. \tag{2.1}$$

Accordingly, the optimized contribution margin of the hybrid energy system in \$ for hour t is:

$$CM(t|k_h) = p_e(t) \cdot CF(t) + CP_h(t) \cdot z(t|k_h). \tag{2.2}$$

To determine when renewable hydrogen production is economically viable, we first consider the average annual contribution margin of renewable energy on its own. The average value of all $p_e(t) \cdot CF(t)$ can be expressed as $p_e \cdot CF \cdot \Gamma$, where p_e denotes the average selling price of electricity per kWh, with the average taken across the 8,760 hours of the year, CF denotes the average capacity factor, and Γ represents the co-variation coefficient between intertemporal prices and capacity factors. By construction, $\Gamma = 1$ if either prices or capacity factors are time-invariant and $\Gamma < 1$ if the renewable energy source produces more energy during hours of below-average electricity prices (Reichelstein and Sahoo, 2015, Hirth, 2013, Sensfuß et al., 2008).

On the cost side, we similarly focus on average cost values represented by the Levelized Cost of Electricity (LCOE) and the Levelized Fixed Cost of Hydrogen (LFCH) production (Reichelstein and Sahoo, 2015, Farhat and Reichelstein, 2016). As shown in section 2.7, both of these are standard unit cost measures per kWh that account for the initial system price, any applicable fixed operating costs, corporate income taxes, and the time value of money. Earlier work has shown that renewable energy is cost competitive on its own, that is, an investment in one kW of power generation capacity has a positive net-present value, if and only if $\Gamma \cdot p_e - LCOE > 0$ (Reichelstein and Sahoo, 2015).

The expression for the net present value (NPV) of a hybrid energy system with a renewable energy capacity of $k_e = 1$ kW and a PtG capacity of k_h kW is derived in section 2.7 and will be denoted by $NPV(1, k_h)$. Renewable hydrogen production will be referred to as *economically viable* if the NPV of an optimized hybrid energy system is positive and exceeds the value of $NPV(k_e = 1, k_h = 0)$, provided renewable energy is cost competitive on its own. Formally:

$$NPV(1, k_h^*) > \max\{NPV(1, 0), 0\}, \tag{2.3}$$

for some optimally chosen k_h^*. We subsequently refer to the lowest hydrogen price, p_h, for which the inequality in (2.3) can hold as the *break-even price of hydrogen.* The following two general results identify the economic viability of renewable hydrogen production in terms of the average conversion premium, the levelized fixed cost of hydrogen and the unit profit margin of renewable energy generation.

Finding 1: *If $\Gamma \cdot p_e \geq LCOE$, a necessary and sufficient condition for renewable hydrogen production to be economically viable is that $CP_h > LFCH$.*

Thus, if the renewable energy source is cost competitive on its own, it is optimal to invest in electrolyzer capacity whenever the average hydrogen conversion premium exceeds the levelized fixed cost of hydrogen production.

Finding 2: *If $\Gamma \cdot p_e < LCOE$, a necessary condition for renewable hydrogen production to be economically viable is that:*

$$CP_h > LFCH + (LCOE - \Gamma \cdot p_e) \cdot CF. \tag{2.4}$$

We emphasize that the condition in (2.4) is only necessary for the viability of renewable hydrogen in case $\Gamma \cdot p_e < LCOE$. In section 2.7, we derive a necessary and sufficient condition that applies irrespective of whether the renewable energy source is cost competitive on its own.

2.3 Current Economic Viability of Renewable Hydrogen

The preceding model framework is now applied to wind energy in both Germany and Texas. PtG naturally complements wind energy which tends to reach peak production levels at night when demand from the grid and power prices are relatively low (Engelhorn and Müsgens, 2018, Wozabal et al., 2016). In Texas, operators of wind turbines are eligible for a Production Tax Credit (PTC), a fixed credit per kWh of produced electricity (U.S. Department of Energy, 2016). In contrast, Germany offers a Feed-in Premium per kWh (EEG, 2017). In its current form, this premium is paid only for renewable electricity *fed into the grid* and therefore imposes a prohibitively large opportunity cost for onsite conversion of renewable power. In our calculations below, we assume that the current feed-in requirement will be waived and the same premium be credited as an equivalent Production Premium (PP). Such a policy change would be supportive of the frequently discussed goal of connecting the different energy segments, such as electricity, heat, and transportation. In the *Appendix*, we report the change in the break-even price of hydrogen that would result if the feed-in requirement was maintained in its current form.

The following calculations are based on data inputs from journal articles, industry data, publicly available reports and interviews with industry sources. For the PtG system, we consider a Polymer Electrolyte Membrane (PEM) electrolyzer, which can be ramped up rapidly and attain a near constant efficiency once a small threshold utilization has been reached (Gahleitner, 2013, Buttler and Spliethoff, 2018). Table 2.1 summarizes the main input variables; see the *Appendix* for further detail.

Table 2.1: Main input variables.

	Germany	**Texas**
PtG system price, SP_h	2,287 €/kW	2,009 \$/kW
Conversion rate of PtG, η	0.019 kg/kWh	0.019 kg/kWh
Wind system price, SP_e	1,367 €/kW	1,596 \$/kW
Wind capacity factor, CF	30.27 %	34.61 %
Electricity price, p_e	3.18 €¢/kWh	2.55 \$¢/kWh
Subsidy: PP or PTC	6.16 €¢/kWh	2.30 \$¢/kWh
Cost of capital (WACC), r	4.00 %	6.00 %

To assess the economic viability of renewable hydrogen, we first determine the break-even hydrogen price, that is, the lowest p_h at which (2.3) will be met. This break-even value can then be compared to observed transaction prices for hydrogen, keeping in mind that wind energy in combination with PtG can frequently be installed onsite or adjacent to a hydrogen buying site. The transaction prices for hydrogen currently comprise three segments that vary primarily with scale (volume) and purity: large-scale supply between 1.5–2.5 €/kg, medium-scale between 3.0–4.0 €/kg, and small-scale above 4.0 €/kg (Michaelis et al. (2014), corroborated through interviews with industry experts).

Table 2.2: Current economics of renewable hydrogen production.

	Germany	**Texas**
Break-even price of hydrogen	3.23 €/kg	3.53 $/kg
Co-variation coefficient	0.88	0.89
Levelized cost of electricity	5.36 €¢/kWh	5.02 $¢/kWh
Levelized production premium	4.73 €¢/kWh	0.00 $¢/kWh
Levelized production tax credit	0.00 €¢/kWh	1.99 $¢/kWh
Wind energy profit margin	0.65 €¢/kWh	-0.27 $¢/kWh
Conversion premium	2.85 €¢/kWh	4.23 $¢/kWh
Levelized fixed cost of hydrogen	2.54 €¢/kWh	2.47 $¢/kWh
Optimal PtG capacity	0.01 kW	0.29 kW

Based on recent data inputs, our findings yield break-even prices of 3.23 €/kg in Germany and 3.53 $/kg in Texas (Table 2.2) making renewable hydrogen production cost competitive with small- and medium-scale but not with large-scale fossil hydrogen supply. In Germany, wind energy is cost competitive on its own so that the NPV of the hybrid energy system must only marginally improve upon the stand-alone value of wind energy (Finding 1). At the break-even price for hydrogen, the corresponding optimal PtG capacity is small (our calculations proceed in increments of 0.01 kW or 1.0% of the normalized wind capacity). In Texas, wind energy is not competitive with current wholesale prices on its own (IRENA, 2018). Consistent with Finding 2, we therefore find that in order for a hybrid energy system to be viable, the PtG facility must also compensate for the stand-alone loss of the wind power source. This will happen at a higher break-even price and a correspondingly larger optimal PtG capacity of 0.29 kW.

In comparison to earlier studies, we obtain lower break-even prices in large part because our calculations are based on PtG facilities that are sized optimally (U.S. Department of Energy, 2018, Ainscough et al., 2014, Bertuccioli et al., 2014, Felgenhauer and Hamacher, 2015, Shaner et al., 2016, Mohsin et al., 2018). For alternative hydrogen prices that exceed the break-even value, Figure 2.1 shows the optimal size of the PtG facility in relation to a wind facility with a capacity of 1.0 kW. Consistent with our model framework, each assumed hydrogen price triggers a unique maximizing capacity choice, k_h^*.

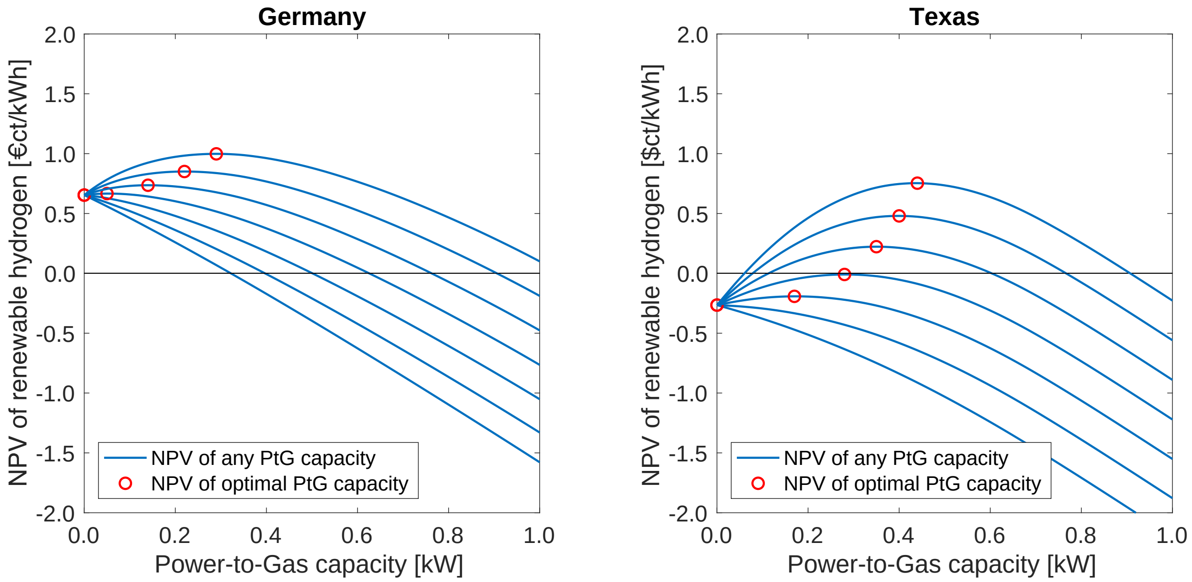

FIGURE 2.1: **Optimal Power-to-Gas capacity size and corresponding hourly profit margin.** Given a normalized wind energy capacity of 1.0 kW, the figure shows the optimized PtG capacity for alternative hydrogen prices ranging from 2.0 to 5.0 €/$ per kg (blue lines). The red circles mark the optimal PtG capacity size for alternative hydrogen price. Circles at 0.0 kW reflect that no PtG capacity should be installed.

2.4 Prospects for Renewable Hydrogen

Recent historical data strongly suggest continued declines in the following variables: (i) the system price of electrolyzers (Schmidt et al., 2017, Saba et al., 2018), (ii) the system price of wind turbines (Wiser et al., 2016), and (iii) the wholesale market price of electricity. At the same time, the capacity factor of wind turbines is likely to increase further (Wiser et al., 2016, Staffell and Pfenninger, 2016). Our projections for the system prices of electrolyzers are based on hand-collected data from manufacturers, operators of PtG plants, articles in peer-reviewed journals, and technical reports. Covering the years 2003 - 2016, we ran a univariate regression for a constant elasticity functional form of the type: $SP_h(i) = SP_h(0) \cdot \lambda^i$, where i refers to years. For PEM, our data set comprises $N = 70$ observations. The regression provides an estimate for the annual price decline of 4.77%, that is, $\lambda = 0.9523$, with a 95% confidence interval of $\pm 1.88\%$; see Figure 2.2 and section 2.7 for further details.

The acquisition price of wind turbines is projected to decline at an annual rate of 4.0%, while the capacity factor is forecast to increase annually at a rate of 0.7% (Wiser et al., 2016). To project the LCOE of wind energy in future years, we take into consideration that in Texas the PTC

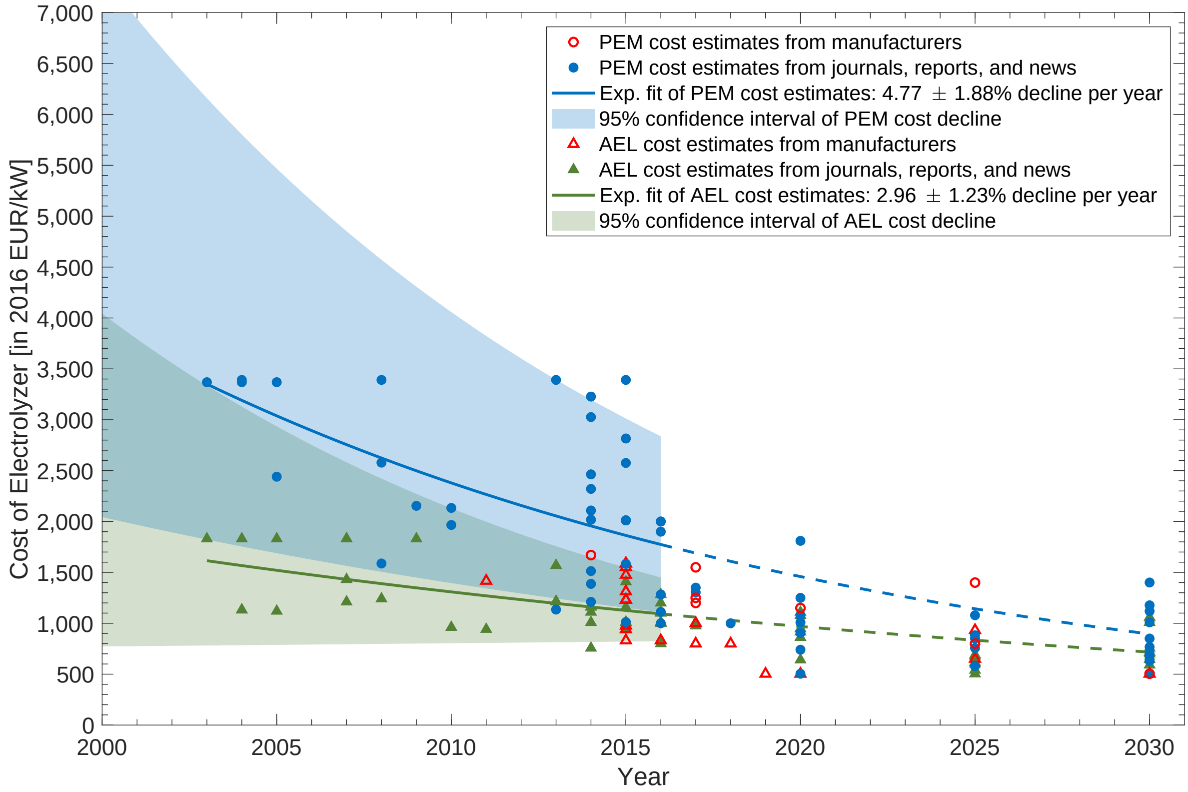

FIGURE 2.2: **Cost of electrolyzer technologies for Power-to-Gas application.** Data are from multiple sources for Alkaline Electrolysis (AEL) and Polymer Electrolyte Membrane (PEM) electrolysis (see section 2.7 for details).

is scheduled to be phased-down linearly from its initial value to zero in annual increments of 20.0% (U.S. Department of Energy, 2016). Regarding the wholesale price of electricity in future years, we assume that wind power will become an effective price trend setter, as suggested by several recent studies (Ketterer, 2014, Paraschiv et al., 2014, Woo et al., 2011). Accordingly, the difference between the LCOE in year i, $LCOE(i)$, and the adjusted average wholesale price, $\Gamma \cdot p_e(i)$, is assumed to decline 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 $D(0) \equiv LCOE(0) - \Gamma \cdot p_e(0)$.

Beginning in 2017, Germany will replace the traditional fixed feed-in premium by a variable premium the magnitude of which is determined through a competitive auction mechanism (EEG, 2017). Thus, in year i we expect the competitive price premium to emerge as $PP(i) = LCOE(i) - \Gamma \cdot p_e(i)$. Regarding the anticipated future wholesale electricity prices, $p_e(i)$, we again make the assumption that over time the levelized cost of wind power will effectively set the average wholesale price such that the price premium goes to zero at a constant rate with $PP(i) = D(0) \cdot \beta^i$.

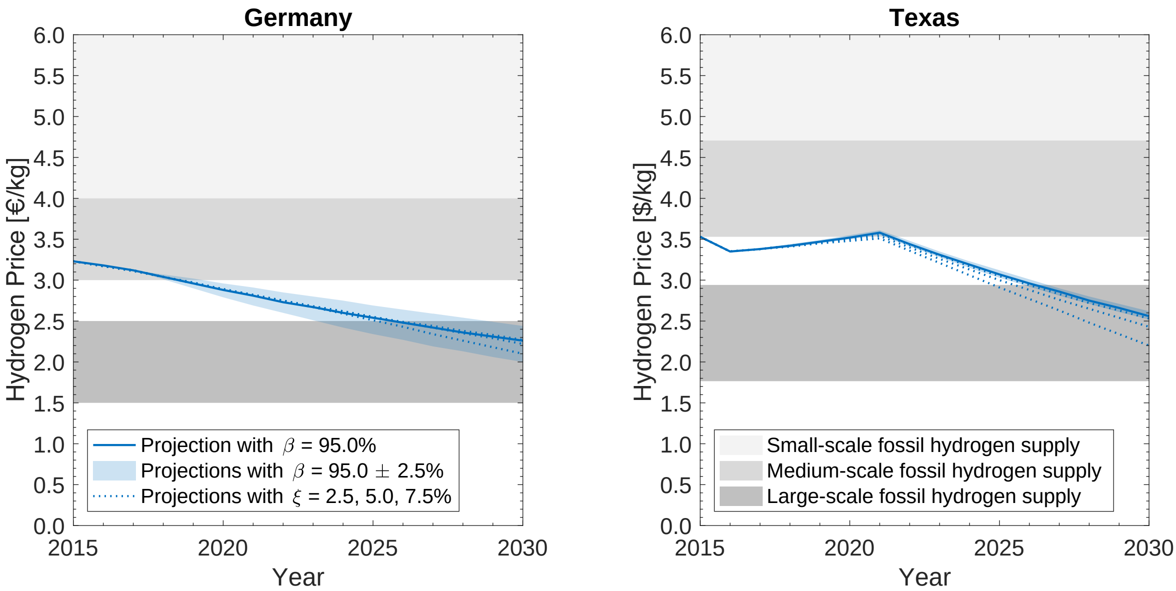

FIGURE 2.3: **Prospects for renewable hydrogen production.** The break-even price of renewable hydrogen for Germany and Texas relative to the benchmark prices for conventional hydrogen supply.

Our assumptions regarding the dynamics of the price of wind turbines, their capacity factors, the price of electrolyzers and wholesale electricity prices yield a trajectory of break-even prices for hydrogen through 2030 (Figure 2.3). The central finding is that renewable hydrogen is projected to become cost competitive with large-scale fossil hydrogen supply within the next decade. The solid line assumes an adjustment rate of $\beta = 0.95$, while the shaded areas represent slower and faster adjustment rates in the range of 0.975 and 0.925, respectively. The dotted lines quantify the potential impact of a higher variance in the distribution of electricity prices. Specifically, we allow for the wholesale price of electricity, $p_e(t)$, to increase by an additional ξ% per year during those hours for which $p_e(t)$ is above the average value p_e. To keep the mean average price for year i unchanged, $p_e(t)$ is reduced by an offsetting percentage during the hours of below-average prices. In the chart for Texas, the "hump" for all four break-even price lines in 2020 reflects the anticipated phase-out of the production tax credit for wind power in the United States.

2.5 Policy Implications

We recall that our findings for Germany presume a modification of the rule for granting a price premium to renewable energy. By waiving the requirement that renewable energy be fed into the grid in order to be eligible for the price premium, policy makers would lend critical support to the economic viability of hydrogen produced from renewable sources. Alternative policy tools for accelerating the emergence of renewable hydrogen production include a straight rebate or an investment tax credit (ITC) for investments in electrolyzers. Such support mechanisms would parallel the efforts by the United States federal tax code for solar photovoltaic and battery storage installations, or the California SGIP program for rebates in connection with battery storage. In the context of our analysis, Figure 2.4 quantifies the impact of three alternative levels of rebates granted on the acquisition cost of electrolyzers. For every rebate increment of 10%, the break-even prices for renewable hydrogen are shown to accelerate the competitiveness with large-scale fossil hydrogen supply by about 1.5 years.

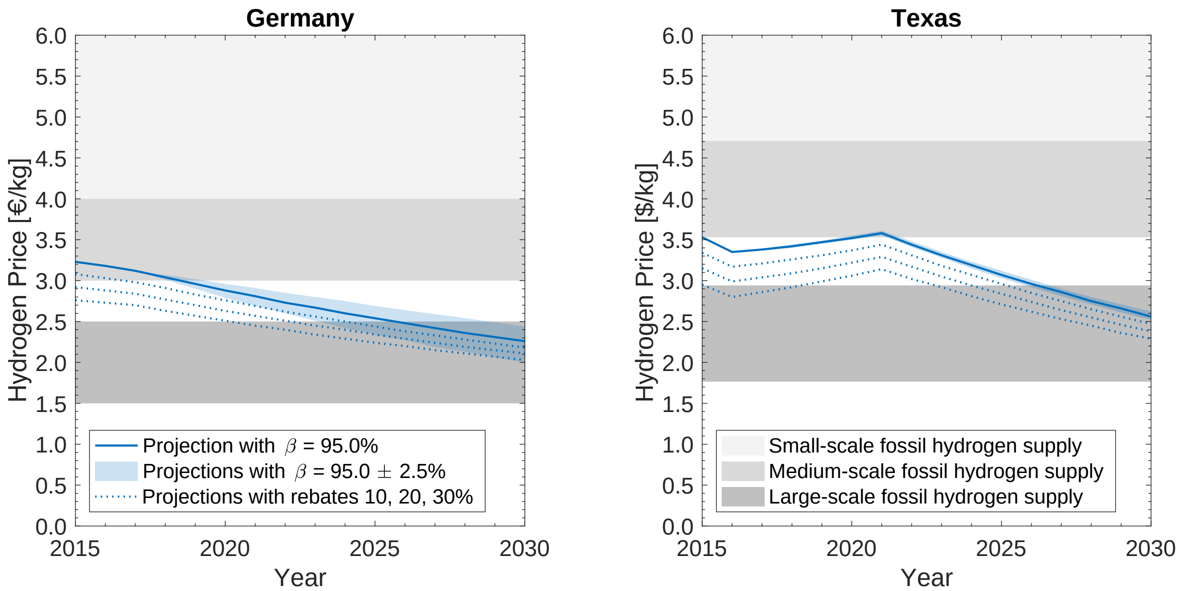

FIGURE 2.4: **Prospects for renewable hydrogen production with rebates.** The impact of rebates on the break-even price of renewable hydrogen in Germany and Texas

As one might expect, greater fluctuations in the distribution of wholesale energy prices and a partial rebate on the acquisition cost of electrolyzers would reinforce each other in accelerating the cost competitiveness of renewable hydrogen. For instance, a 20% rebate combined with a higher variance factor of $\xi = 5.0\%$ would imply that in Texas the break-even price for hydrogen could reach the price level of industrial sale as early as 2023.

Finally, we note that the preceding framework can readily be used to gauge the impact of higher fossil fuel prices or the impact of higher charges placed on carbon emissions. Since industrial hydrogen is currently produced from hydrocarbon fuels, policy makers can quantify the impact of higher costs associated with fossil fuel prices on the competitive position of renewable hydrogen.

2.6 Conclusion

While renewable hydrogen has considerable potential to reduce carbon emissions, it has thus far been regarded as too expensive. We have analyzed the economic prospects for renewable hydrogen through the lens of a potential corporate investor. The investor would optimally choose the size of the renewable power source in relation to the PtG facility while taking advantage of real-time fluctuations in electricity prices and intermittent renewable power generation. Calibrating the model to the current market environment in Germany and Texas, we find that renewable hydrogen is already cost competitive in niche applications and is projected to become competitive with industrial scale supply within a decade if recent market trends continue and current policy support mechanisms are maintained.

In future extensions of this line of work, it would be insightful to consider hybrid energy systems such that the PtG facility can also source electricity from the external electricity market. While the hydrogen produced would then be no longer “renewable" due to the carbon emissions associated with grid electricity, such systems would achieve higher capacity utilization and thereby potentially result in substantially lower break-even prices for hydrogen. An alternative extension of our framework could view hydrogen as a form of electricity storage. Since recent electrolyzer technologies can operate reversibly, hydrogen conversion and reconversion of intermittent renewable electricity may effectively compete with dispatchable power plants and other storage systems such as batteries.

2.7 Methods

Economic Model

We first derive the levelized cost expressions for the levelized cost of electricity (LCOE) and the net present value (NPV) of a renewable energy source only. The LCOE aggregates all costs over the lifetime of a power facility to deliver one unit of electricity output (Reichelstein and Sahoo, 2015). Assuming that the variable operating costs of the renewable energy facility are negligible, $LCOE$ can be expressed as:

$$LCOE = f_e + \Delta \cdot c_e, \tag{2.5}$$

where the subscript e reflects electricity generation, f denotes the levelized fixed operating cost per kWh, c the levelized capacity cost of the facility per kWh, and Δ the tax factor covering the impact of income taxes and the depreciation tax shield. To obtain the levelized capacity cost per kWh, the system price per kW denoted by SP_e is divided by the discounted number of kWh that the facility produces over its useful life:

$$c_e = \frac{SP_e}{CF \cdot L}, \tag{2.6}$$

where $L \equiv m \cdot \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i$ denotes the *levelization factor* that expresses the total discounted number of hours that the system produces over its lifetime. T represents the economic lifetime of the facility in years, x the system degradation factor so that x^{i-1} quantifies the percentage of the initial capacity that is still operating in year i, and γ the discount factor based on the cost of capital r with $\gamma = \frac{1}{(1+r)}$. The cost of capital should be interpreted as the weighted average cost of capital (WACC) if the project is financed through both equity and debt (Islegen et al., 2011). For technical reasons, we assume that $CF(t) > 0$ for all t and that the function $CF(t)$ assumes any value in the interval $[0, 1]$ at most finitely many times. These assumptions appear descriptive for the average capacity factor of wind turbines.

Similarly, the levelized fixed operating cost per kWh is the total discounted fixed costs that incur over the lifetime divided by the levelization and capacity factor:

$$f_e = \frac{\sum_{i=1}^{T} F_{ei} \cdot \gamma^i}{CF \cdot L}. \tag{2.7}$$

Completing the LCOE, we include corporate taxes and the depreciation tax shield, which result from depreciation charges for tax purposes reducing taxable income. Since we interpret the cost of capital as the weighted average cost of capital, the tax shield associated with debt is already accounted for. Let d_i be the allowable tax depreciation rate in year i and α the effective corporate income tax rate. Since the tax lifetime of renewable energy sources is often shorter than their actual economic lifetime, the tax depreciation rate is zero ($d_i = 0$) for the remaining years. The tax factor is then given by:

$$\Delta = \frac{1 - \alpha \cdot \sum_{i=1}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{2.8}$$

As for revenues, the inherent intermittency of the renewable source and the continuous fluctuations in electricity prices demand to account for covariances between renewable power generation and market prices. Let $\epsilon(t)$ denote the multiplicative deviation of $CF(t)$ from its average value CF and $\mu(t)$ the multiplicative deviation of $p_e(t)$ from the average selling price, p_e:

$$\epsilon(t) = \frac{CF(t)}{CF} \text{ and } \mu(t) = \frac{p_e(t)}{p_e}. \tag{2.9}$$

By definition:

$$\frac{1}{m}\int_0^m \epsilon(t) = \frac{1}{m}\int_0^m \mu(t) = 1. \tag{2.10}$$

The co-variation coefficient then captures the variation between output and price:

$$\Gamma = \frac{1}{m}\int_0^m \epsilon(t) \cdot \mu(t) dt. \tag{2.11}$$

The co-variation coefficient is non-negative and zero only if the renewable energy source generates electricity exclusively at times when prices are zero. Clearly, the economics of a renewable energy source improve if it generates more power during peak prices and thus increases the co-variation coefficient. In terms of after-tax cash flows, the NPV of a renewable source on its own can be stated as:

$$NPV = (1 - \alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE) \cdot CF. \tag{2.12}$$

As stated in the main body of the paper, the United States federal government provides a Production Tax Credit (PTC) for wind energy, which is a fixed credit per kWh of produced electricity. Since the duration of the PTC is limited to 10 years, and therefore shorter than the lifetime of the wind power plant, we need to levelize the stream of the PTC payments for the first 10 years:

$$ptc = PTC \cdot \frac{\sum_{i=1}^{10} x^{i-1} \cdot \gamma^i}{(1-\alpha) \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i}. \tag{2.13}$$

For Texas, the PTC adjusted net present value of a wind power facility can therefore be expressed as: $(1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE + ptc) \cdot CF$.

In Germany, wind energy is eligible to the Production Premium (PP), which is accounted for as additional revenue and is therefore subject to taxation. Since the duration of the PP is limited to 20 years, and therefore shorter than the lifetime of the wind power plant, we levelize the stream of the PP payments for the first 20 years:

$$pp = \frac{\sum_{i=1}^{20} PP_i \cdot x^{i-1} \cdot \gamma^i}{\sum_{i=1}^{T} x^{i-1} \cdot \gamma^i}. \tag{2.14}$$

For Germany, the PP adjusted net present value of a wind power facility can therefore be expressed as: $(1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE + pp) \cdot CF$.

For the hydrogen subsystem, we construct the levelized fixed cost of hydrogen (LFCH) as the life-cycle capacity and fixed operating costs per kWh of electricity absorption of a PtG plant (Farhat and Reichelstein, 2016). With subscript h for hydrogen, the LFCH is given by:

$$LFCH = f_h + \Delta \cdot c_h. \tag{2.15}$$

We recall that the capacity factor of the PtG plant equals one. The levelized cost elements then are the capacity cost per kW and fixed operating cost per kW divided by the lifetime aggregate output of the PtG plant:

$$c_h = \frac{SP_h}{L}, \qquad f_h = \frac{\sum_{i=1}^{T} F_{hi} \cdot \gamma^i}{L}. \tag{2.16}$$

On the revenue side, we denote by $\delta(t)$ the deviation of the hourly conversion premium from the mean value so that $CP_h \cdot \delta(t) \equiv CP_h(t)$ and the mean of $\delta(\cdot)$ equals one. The average contribution margin of a hybrid energy system with capacities $(k_e = 1, k_h)$ then becomes:

$$CM(k_h) \equiv \frac{1}{m} \int_0^m CM(t|k_h)\, dt \equiv \Gamma \cdot p_e \cdot CF + CP_h \cdot z(k_h), \tag{2.17}$$

where

$$z(k_h) \equiv \frac{1}{m} \int_0^m z(t|k_h) \cdot \delta(t)\, dt.$$

The function $z(\cdot)$ is increasing and concave such that $z(k_h) \leq k_h$ and $z'(0) = 1$. To see that, note that the partial derivative of $z(1, k_h)$ with respect to k_h is given by:

$$\frac{\partial}{\partial k_h} z(1, k_h) = \frac{1}{m} \int_{\{t|k_h \leq CF(t)\}} \delta(t) dt. \tag{2.18}$$

Clearly, $\frac{\partial}{\partial k_h} z(1, k_h)$ is decreasing in k_h with $\lim\limits_{k_h \to 0} \frac{\partial}{\partial k_h} z(1, k_h) = 1$ and $\lim\limits_{k_h \to 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$. Consequently, $NPV(1, \cdot)$ is a single-peaked function of k_h (see Figure 2.1). The overall net-present value of a hybrid energy system can be expressed as:

$$NPV(1, k_h) = (1 - \alpha) \cdot L \cdot \left[CM(k_h) - LCOE \cdot CF - LFCH \cdot k_h \right]. \tag{2.19}$$

Given $k_e = 1.0$ kW, the optimal k_h^* is the maximizer of $CP_h \cdot z(k_h) - LFCH \cdot k_h$. The properties of $z(\cdot)$, imply that $0 \leq k_h^* \leq 1$. In summary, renewable hydrogen production is economically viable if and only if:

$$(\Gamma \cdot p_e - LCOE) \cdot CF + CP_h \cdot z(k_h^*) - LFCH \cdot k_h^* \geq \max\{(\Gamma \cdot p_e - LCOE) \cdot CF, 0\}. \tag{2.20}$$

The inequality in (2.20) combined with the properties of $z(\cdot)$ yield the necessary and sufficient conditions identified in Findings 1 and 2, depending on whether renewable energy is cost competitive on its own. See the *Appendix* for proofs.

Cost Review of Electrolyzer Technologies

We gathered cost estimates from manufacturers, operators of PtG plants, scientific articles in peer-reviewed journals, and frequently cited gray literature including reports by agencies, consultancies, and industry analysts. Cost estimates from industry were collected in individual interviews with 16 of 28 contacted companies. Scientific articles were found by searching the data bases Web of Science, Scopus, Sciencedirect, and Google Scholar using the keyword "Power-to-Gas cost", and the gray literature by searching the web with Google's search engine using the same keyword. The keyword "electrolyzer cost" was discarded because it yielded cost estimates for individual electrolyzer stacks rather than full PtG systems. For both searches, we reviewed the top 100 search entries. The cost review and the entire data set is documented in an Excel file available in the online version of the published article.

We searched and interviewed for cost estimates for electrolyzer systems, in contrast to individual cells or entire PtG plants. The three main electrolyzer technologies we focused on were: alkaline electrolysis (AEL), polymer electrolyte membrane electrolysis (PEM), and solid oxide cells (SOC). With the literature review, we retrieved 146 sources, which we filtered by the method used in the article for achieving the cost estimates. We excluded sources without clear cost data (41) and sources referencing other articles (36). These latter references were traced back to the original source and if the original was new, it was added to the pool. We also excluded sources without clear references or method (14). As a result, we were left with 55 sources with original data from industry or an original review of multiple sources. The literature provides 131 unique data points: 59 for AEL, 62 for PEM, and 10 for SOC. The interviews of manufacturers and operators yielded 35 data points: 21 for AEL, 8 for PEM, and 6 for SOC. This sums to 166 data points: 80 for AEL, 70 for PEM, and 16 for SOC. The few data points for SOC correspond to the novelty of the technology so that we excluded it from further analysis.

For all data points, we converted cost ranges (if given) with the arithmetic mean of the highest and the lowest points in the range. Cost estimates in other currencies than Euro were converted using the average exchange rate of the respective year from the European Central Bank. Historic cost estimates were adjusted for inflation using the HCPI of the Euro Zone as provided by the European Central Bank (see the sheet "Adjustment Factors" of the Excel file). Finally, all data points were winsorized with an $\alpha = 5.0\%$.

We estimate the annual cost decline with an exponential regression of system prices from 2003 to 2016 in the form of $SP_h(i) = SP_h(0) \cdot \lambda^i$, where i denotes the year. We base the cost declines on time rather than cumulative industry output due to scarce data on the latter. The regression for PEM is based on $N = 70$ unique estimates and yields an average cost decline of $\lambda = 4.77\%$ with a 95% confidence interval of $\pm 1.88\%$ and an *adj.* $R^2 = 0.34$. The regression for AEL is based on $N = 80$ unique estimates and yields an average cost decline of $\lambda = 2.96\%$ with a 95% confidence interval of $\pm 1.23\%$ and an *adj.* $R^2 = 0.24$. Linear models give similar *adj.* R^2 values, but an exponential relationship especially for PEM is to be expected. The declining uncertainty was quantified with an affine regression of the falling standard deviation from 2003 to 2016.

3 | Operational Volatility and Synergistic Value in Vertically Integrated Energy Systems

by Gunther Glenk and Stefan Reichelstein[1]

This paper examines the conditions under which synergistic effects emerge in vertically integrated energy systems when the subsystems are subject to operational volatility in terms of price and output fluctuations. We develop a framework for capturing the link between operational volatility, optimally sized capacity investments and the presence of synergistic values. The front part of our analysis develops a model that provides necessary and sufficient conditions for the value (NPV) of the integrated system to exceed the sum of the two optimized subsystems on their own. In this comparison, zero is always a lower bound for the optimized NPV of the stand-alone entities because of the option not to invest in capacity. We then calibrate the model in the context of systems that combine wind energy with Power-to-Gas (PtG) facilities for hydrogen production both in Germany and Texas. Depending on the attainable market prices for hydrogen in different market segments, we find that synergistic values emerge in select scenarios. In the context of Texas, it turns out that neither electricity production from wind power nor hydrogen production from PtG facilities will be profitable on its own in the current market environment. Yet, provided the capacity of the two subsystems is sized optimally in relative terms, the attendant synergistic gain from a vertically integrated system more than compensates for the stand-alone losses of the subsystems.

[1]Author Contributions: The authors jointly developed the research question, the model framework and the analytical findings. Gunther Glenk lead the literature review, the data collection and the calculations. Both authors contributed substantially to the writing of the paper.

3.1 Introduction

The boundaries of the firm and the costs and benefits of vertical integration have long been central issues in the theory of the firm (Williamson, 1975, 1985). Much of the literature in economics has approached these issues from an incentive and management control perspective; see, for instance, Grossman and Hart (1986), Melumad et al. (1995), and Gilbert and Riordan (1995). Our approach in this paper is in line with recent perspectives in the operations literature, e.g. Kazaz (2004), Dong et al. (2014), and Boyabatli et al. (2017). In these studies, the benefits of vertically integrated production systems generally stem from operational synergies, while costs arise from the need for additional upfront investments in productive capacity.

In our model of a vertically integrated production system, the downstream unit requires an intermediate production input that can be sourced from the external market or alternatively from an upstream unit. Benefits from investing in both units arise because of imperfections in the market for the intermediate input, that is, the selling price attainable by the upstream unit will at times be below the buying price that the downstream division would have to pay in the external market. Internal sourcing of the intermediate input will therefore result in operational synergies, which must be traded off against the attendant cost of additional capacity investments (van Mieghem, 2003, Hekimoglu et al., 2017, Kouvelis et al., 2018).

Our study is partially motivated by the rapidly changing economics of renewable energy. As has been widely reported, the cost of generating electricity at wind and solar photovoltaic installations has been falling dramatically, a trend that has been accompanied by a corresponding increase in the share of renewable power. Yet, the intermittent nature of wind and solar photovoltaics presents new challenges in balancing electricity supply and demand in real-time. One potential remedy is to divert surplus energy from renewable power sources to the production of energy storing products like hydrogen.[2] The gas is produced from electricity via Power-to-Gas (PtG), a process encompassing water electrolysis whereby electricity infused in water instantly splits the water molecule into oxygen and hydrogen.[3] In the context of our vertical integration analysis, the PtG facility represents the downstream production unit with electricity sourced either from the open market or from an upstream renewable energy source.

[2]See, for instance, Zhou et al. (2016).

[3]Hydrogen is sold as a commodity that is used in multiple applications including fuel for transportation, feedstock in chemical and processing industries, or energy storage for power generation.

For an integrated PtG and renewable energy facility, operational synergies will arise from electricity prices (buying and selling) that fluctuate across the hours of the day and the seasons of the year. In addition, the renewable energy source generates electricity output that is subject to intermittency. In contrast to some of the recent work on production synergies, we capture volatility not by random shocks, but by predictable variations in both the average electricity prices and the average electricity output from the renewable power source at different points in time (Hu et al., 2015, de Véricourt and Gromb, 2018).

Our main question in this study is whether investment in a facility that combines renewable energy with PtG production has *synergistic value*. Our criterion for such synergies is that the net present value (NPV) of the vertically integrated system exceeds the sum of the optimized NPVs of the two stand-alone facilities that would buy or sell electricity only on the external market. In this comparison, zero will always be a lower bound for the optimized NPV of the stand-alone entities because of the option not to invest in capacity in the first place. If either or both energy systems have negative NPVs on their own, the presence of a synergistic value must entail operational synergies that more than compensate for the cost of capacity investments, which would be excessive if the individual systems were to operate in stand-alone mode.[4] In the presence of such synergistic values, our analysis also characterizes the relative optimal size of the two capacity investments.

The conditions for a synergistic value are straightforward to identify in a hypothetical stationary environment where electricity prices and output do not vary over time. Our analysis demonstrates how these conditions extend to production environments that are subject to operational volatility. In essence, the main comparisons involve time-averaged cost, price and output levels, with the latter two averages adjusted by covariance terms that reflect the extent to which intertemporal variations in prices correlate with variations in output from the renewable power source.

[4]Our results are consistent with the perspective in the real option literature where the value of a flexible system must exceed the value of a rigid system in order to justify investment in the flexible system, e.g. Kogut and Kulatilaka (1994), van Mieghem (1998), Trigeorgis (1993). In these studies output is assumed to be fully dispatchable. By including exogenous output fluctuations, our study is partly in the spirit of the hedging literature. McKinnon (1967) and Rolfo (1980) showed that farmers can obtain effective hedge by selling a share of their crops on the futures market instead of selling everything on the spot market. The analogy with our setting is that, instead of hedging with a price future, farmers could also invest in equipment that turns the crops into products with a guaranteed fixed price.

The back-end of this paper applies our modeling framework to PtG facilities that could be co-located with wind parks. We provide a numerical evaluation for vertically integrated energy systems in both Germany and Texas, two jurisdictions that have installed substantial amounts of wind power in recent years. On a stand-alone basis, wind parks are currently unprofitable in Texas, though they entail positive NPVs in Germany, in large part due to public subsidies for renewable energy. The stand-alone value of investments in PtG facilities depends on the attainable market price of hydrogen. For medium-scale supply settings, hydrogen sales prices tend to be relatively high, making stand-alone PtG facilities marginally profitable in both Germany and Texas. In contrast, such facilities entail negative NPVs in both jurisdictions relative to the lower prices associated with industrial-scale hydrogen supply arrangements.

Since the two subsystems generally experience some gains from synergy, one would expect a synergistic value to emerge if both wind power and hydrogen production are profitable on their own. We confirm this for the setting of Germany and medium-scale hydrogen supply. Conversely, it may intuitively appear difficult for the synergistic effect to be sufficiently large so as to outweigh stand-alone losses if those occur in both subsystems. Yet, we identify such a synergistic value in the context of Texas when hydrogen can only be sold at low prices in the context of industrial-scale supply and thus neither wind power nor hydrogen production is viable by itself.

An instructive metric for measuring the gains from vertical integration is what we term the *break-even price* of hydrogen for a vertically integrated energy system. The break-even price is defined as the lowest downstream (i.e., hydrogen) price at which the vertically integrated system achieves a synergistic value. By construction, the break-even hydrogen price of the vertically integrated system is always lower than the price at which hydrogen production turns profitable on its own. In the context of Texas and industrial-scale hydrogen supply, we find that the break-even price of hydrogen for a vertically integrated energy system is about 30% lower than the critical price at which hydrogen would become viable on its own. This difference illustrates the relative magnitude of the synergistic gains in that particular context.

The final part of our analysis seeks to project likely improvements in the economics of combined energy systems that integrate wind power with hydrogen production. Several factors are likely to contribute to more robust synergistic values in the future. These include sustained price reductions for both wind turbines and PtG facilities as well as greater operational volatility in terms of fluctuating market prices for electricity. The latter trend is mainly a consequence of the trend towards time-of-use pricing. Overall, our projections indicate that even relative to the benchmark of the low hydrogen prices associated with large-scale industrial supply, synergistic value for the integrated systems will widely emerge in both Texas and Germany within a decade. These projections take into account that the public support for wind energy, e.g., the production tax credit available in the United States, is scheduled to be phased out in the coming years.

For the specific application of wind power combined with hydrogen production, our numerical assessments point to a more favorable cost structure than other recent studies (Ainscough et al., 2014, Bertuccioli et al., 2014, Felgenhauer and Hamacher, 2015, Glenk and Reichelstein, 2019). We attribute this to the fact that our calculations are based on subsystems that have been sized optimally, an aspect that is of first-order importance when capacity investments account for a large share of overall production costs. In addition, our calculations take advantage of higher capacity utilization that results when both renewable and grid electricity are converted to hydrogen. Finally, our calculations reflect the most recent cost and operational inputs for wind energy and PtG.

The remainder of the paper is organized as follows. Section 3.2 develops the model framework for the identification of synergistic value in vertically integrated energy systems under conditions of operational volatility. Section 3.3 applies the model framework to PtG and wind energy. We first provide an assessment based on most recent data and then project likely changes in synergistic values for the coming decade. Section 3.4 concludes the paper. Supplemental materials such as proofs and data sources are provided in the *Appendix*.

3.2 Model Framework

In our model framework, a vertically integrated production system comprises two interacting subsystems. The upstream subsystem generates an intermediate production input that can be sold externally or transferred to the downstream production subsystem. While our model is generic in most aspects, we focus for concreteness on a renewable energy source, like wind or solar power, that is combined with a Power-to-Gas (PtG) facility producing hydrogen. The setting in Figure 3.1 comprises four building blocks: the renewable energy source, a PtG facility (including the electrolyzer, piping and hydrogen compressor), the external electricity market, and the market for hydrogen.

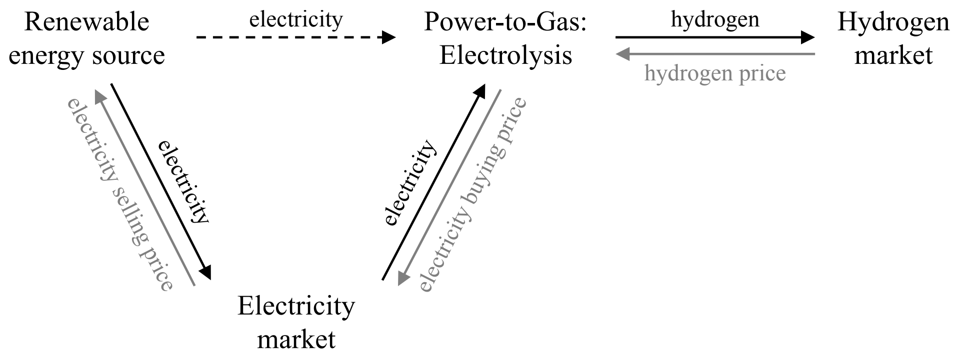

Figure 3.1: Illustration of a vertically integrated energy system.

In a mode of stand-alone operation, the renewable energy source can generate electricity that is sold on the open market at time-varying prices. The PtG facility can buy electricity from the open market to produce hydrogen which is sold at a time-invariant price. Integration of the two subsystems enables the transfer of in-house generated electricity to the electrolyzer to convert water to hydrogen. Our perspective is that of an investor who seeks to maximize the net present value, potentially through vertical integration of two subsystems whose relative capacity sizes are chosen optimally. For simplicity, our model views the investor and the operator of the facilities as one and the same party.

3.2.1 Contribution Margins

Combining a renewable energy source and a PtG plant in a vertically integrated energy system may yield a positive synergistic value due to real-time fluctuations in electricity prices. For a given capacity investment, an integrated system will seek to maximize the periodic contribution margin earned by optimizing the use of the available capacity in real time. The key variables in this optimization are the amount of power the renewable system produces at a particular point in time and the corresponding prices at which electricity can be bought and sold externally.

Let $p^s(t)$ denote the selling price per kilowatt hour (kWh) at which renewable energy can be sold on the open market at time t. For modeling purposes, we view time as a continuous variable t ranging from 0 to 8,760 hours. The magnitude and intertemporal distribution of prices are assumed to be constant across the T years of the facility. We denote by k_e the peak capacity in kilowatt (kW) of the renewable energy source and by $CF(t)$ the capacity factor at time t. The capacity factor is a scalar between 0 and 1 reflecting the actual percentage of the maximum power the system can generate.[5] Thus, $CF(t) \cdot k_e$ represents the actual amount of power generated at time t, corresponding an investment in k_e kW of peak capacity.

Let $p^b(t)$ denote the price per kWh that would have to be paid for electricity procured on the open market at time t. During hours when electricity trades at a positive price, we posit the *no-arbitrage* condition that $p^b(t) \geq p^s(t)$. This condition is descriptive of most electricity markets. Furthermore, wholesale electricity markets increasingly exhibit patterns where at certain hours surplus electricity is unloaded on the grid and therefore prices become negative. Our analysis assumes that the renewable energy subsystem can be idled at no cost, as is generally possible for both wind and solar electricity generation. Instead of an explicit option to curtail production whenever prices turn negative, we specify equivalently that renewable power is always produced at full capacity but can be disposed off at no charge ($p^s(t) = 0$), whenever the buying prices turn negative. Formally, we assume:

$$p^s(t) \begin{cases} \leq p^b(t) & \text{if } p^b(t) \geq 0, \\ = 0 & \text{if } p^b(t) < 0. \end{cases} \tag{3.1}$$

Given supply of electricity from either the external market or the internal renewable source, the *conversion value* per kilogram (kg) of hydrogen produced is the selling price of hydrogen minus the variable operating costs. These costs include water and other variable consumable inputs like those used to deionize the water. We denote by p_h the hydrogen price per kg and by w_h the variable operating cost per kg of hydrogen produced. The conversion rate of the electrolyzer (in kg/kWh) is represented by the parameter η, reflecting the amount of hydrogen that can be produced from 1 kWh of electricity. Accordingly, the conversion value of hydrogen is given by:

$$CV_h = \eta \cdot (p_h - w_h). \tag{3.2}$$

For a stand-alone PtG system based entirely on electricity purchased on the open market, the contribution margin obtained at time t would therefore be:

$$CM(t|k_h) = [CV_h - p^b(t)] \cdot k_h, \tag{3.3}$$

[5]For technical reasons, we assume that $CF(t) > 0$ and that each value in the range of the function $CF(\cdot)$ is assumed at most finitely many times. These assumptions appear descriptive for wind turbines, the setting we examine in Section 4 below.

if the electrolyzer of the PtG system has the capacity to absorb k_h kW of power at any point in time.

To formalize the contribution margin that can be attained from a vertically integrated energy system, we distinguish four different phases in terms of electricity prices and the conversion value of hydrogen. In Phase 1 of the diagram in Figure 3.2, both the buying and the selling electricity price exceed the conversion value of hydrogen: $p^b(t) \geq p^s(t) \geq CV_h \geq 0$. As a consequence, the plant operator will keep the electrolyzer idle. Since the variable operating cost of the renewable energy source is negligible, the entire electricity generation capacity will be fully exhausted and the contribution margin of the vertically integrated energy system is equal to:

$$CM_1(t|k_e) = p^s(t) \cdot CF(t) \cdot k_e. \tag{3.4}$$

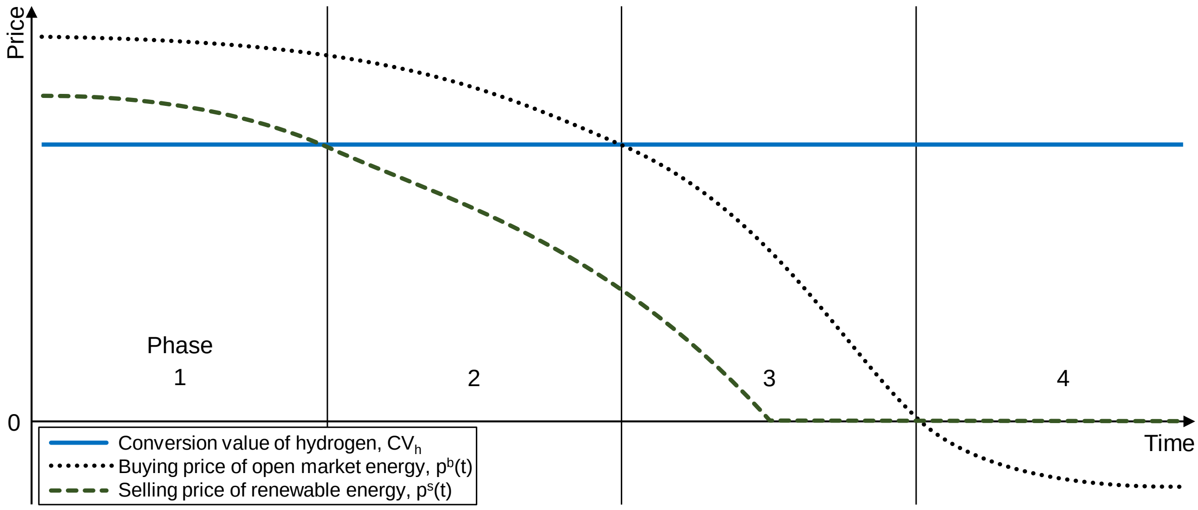

FIGURE 3.2: Phase diagram.

In Phase 2, the buying price exceeds the conversion value of hydrogen, which, in turn, exceeds the selling price: $p^b(t) \geq CV_h > p^s(t) \geq 0$. It is then preferable to convert the generated renewable energy, without further purchases from the external electricity market. Since the electrolyzer of the PtG plant can absorb renewable electricity up to its peak capacity, k_h, we introduce the notation $z(t|k_e, k_h)$ to capture the *effective conversion capacity* at time t. This scalar is the minimum of the capacity factor of the renewable energy source and the peak capacity of the PtG plant, and represents the kW of electricity that the electrolyzer can receive and absorb internally from the renewable source at time t:

$$z(t|k_e, k_h) \equiv \min\{CF(t) \cdot k_e, k_h\}. \tag{3.5}$$

For most electrolyzers, the switching costs associated with ramping up or down the PtG facility can be considered negligible. The contribution margin of the integrated system in Phase 2 is the contribution margin of renewable energy plus the associated conversion premium:

$$CM_2(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e + [CV_h - p^s(t)] \cdot z(t|k_e, k_h). \tag{3.6}$$

In Phase 3, both electricity prices are non-negative and less than the conversion value of hydrogen: $CV_h > p^b(t) \geq p^s(t) \geq 0$. It is then optimal to convert the generated renewable energy and buy electricity from the market to fully utilize the remaining PtG capacity. The attainable contribution margin is then the sum of both stand-alone energy systems plus the conversion premium of renewable energy:

$$\begin{aligned} CM_3(t|k_e, k_h) = {} & p^s(t) \cdot CF(t) \cdot k_e \\ & + [CV_h - p^s(t)] \cdot z(t|k_e, k_h) \\ & + [CV_h - p^b(t)] \cdot [k_h - z(t|k_e, k_h)]. \end{aligned} \tag{3.7}$$

Finally, in Phase 4, the buying price is negative and thus $CV_h \geq p^s(t) = 0 > p^b(t)$. The facility will then idle the renewable energy source and exhaust the electrolyzer capacity with negatively priced electricity from the market. Accordingly, the contribution margin in that scenario equals:

$$CM_4(t|k_h) = [CV_h - p^b(t)] \cdot k_h. \tag{3.8}$$

In a stationary environment where prices and output are constant, the contribution margin of a vertically integrated energy system equals one of the four phases without time dependence. With operational volatility, the optimized contribution margin of a vertically integrated energy system can be synthesized as follows.[6]

[6] Proofs are shown in the Appendix.

Lemma 1. *The optimized contribution margin of a vertically integrated energy system at time t is:*

$$\begin{aligned} CM(t|k_e, k_h) = \ & p^s(t) \cdot CF(t) \cdot k_e \\ & + [p^{b+}(t) - p^b(t)] \cdot k_h \\ & + [p^+(t) - p^s(t)] \cdot z(t|k_e, k_h), \end{aligned} \tag{3.9}$$

where $p^{b+}(t) \equiv \max\{p^b(t), CV_h\}$ *and* $p^+(t) \equiv \max\{\min\{p^b(t), CV_h\}, p^s(t)\}$.

Lemma 1 shows that the contribution margin of a vertically integrated energy system can be expressed as the sum of the contribution margins of the two stand-alone energy systems plus a third term that captures the economic interaction of the two subsystems. The term $p^{b+}(t) - p^b(t) = \max\{CV_h - p^b(t), 0\}$ will be referred to as the conversion premium of hydrogen. It reflects the option for the stand-alone PtG system to idle the electrolyzer at times when the buying price of electricity exceeds the conversion value of hydrogen. The final term of (3.9) reflects potential synergies, that is, the benefit of consuming the intermediate input internally. We refer to $p^+(t) - p^s(t) = \max\{\min\{p^b(t), CV_h\} - p^s(t), 0\}$ as the *price premium* of a vertically integrated energy system at time t. As one would expect, this premium is zero if $p^b(t) = p^s(t)$ for all t. Our analysis in the following subsections shows that a positive price premium, that is, $p^+(t) - p^s(t) > 0$, is necessary but generally not sufficient for a vertically integrated system to generate a net present value that exceeds the sum of the optimized values of the two stand-alone systems.

3.2.2 Net Present Values

A vertically integrated energy system yields cash inflows in the form of optimized contribution margins. Such a system will create value if the discounted sum of the cash inflows collectively covers the initial cash outflow for capacity investments plus the subsequent periodic operating costs, including corporate income taxes. To identify the potential of synergistic value in vertically integrated systems, it will prove useful to express the overall net present value in terms of unit costs and revenues. Specifically, we rely on the definition of the *Levelized Cost of Electricity*

(LCOE), a common unit cost measure for stand-alone electricity generation systems; see, for instance, Islegen et al. (2011).[7]

The LCOE aggregates all costs occurring over the lifetime of a power plant to deliver one unit of electricity output. The LCOE of a one kW facility can be given by:

$$LCOE = w_e + f_e + \Delta \cdot c_e, \tag{3.10}$$

with subscript e for electricity, w as the variable operating cost per kWh, f as the levelized fixed operating cost per kWh, c as the levelized capacity cost of the facility per kWh, and Δ as the tax factor covering the impact of income taxes and the depreciation tax shield. Since the variable operating cost for wind and solar power is negligible, we set $w_e = 0$. The following parameters determine the LCOE: system price, SP_e, of the generation capacity (in \$ per kW), fixed operating cost in year i, F_{ei} (in \$ per kW), discount factor, γ, with the cost of capital r such that $\gamma = \frac{1}{1+r}$ (scalar), useful economic life, T (in years), and system degradation factor in year i, x^{i-1} (scalar).

The granularity of electricity prices is typically one hour. We denote by $m = 24 \cdot 365 = 8,760$ the number of hours per year. The discount factor γ is based on an underlying cost of capital (interest rate) r. This cost of capital should be interpreted as the weighted average cost of capital (WACC) if the project is financed through both equity and debt (Islegen et al., 2011). The scalar x, with $0 < x < 1$, denotes the system degradation factor, so that x^{i-1} represents the fraction of the initial capacity that is still operating in year i. For notational simplicity, we assume that prices and all operational parameters, except for the system degradation factor, are identical across years. The usual definition of the LCOE ignores the hourly fluctuation in capacity utilization and instead uses an average capacity factor, CF, that is the average of all hourly capacity factors: $CF = \frac{1}{m} \int_0^m CF(t)dt$.

To obtain the levelized capacity cost per kWh, the system price per kW is divided by the total discounted number of kWh that the system produces over its useful life:

$$c_e = \frac{SP_e}{CF \cdot L}. \tag{3.11}$$

[7] As shown in Reichelstein and Rohlfing-Bastian (2015), this cost measure is also the relevant unit cost for optimal capacity investment decisions in the presence of future random shocks to demand.

We refer to $L \equiv m \cdot \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i$ as the *levelization factor* which expresses the discounted number of hours that are available from the facility over its entire lifetime.

Similar to the levelized cost of capacity, we define the levelized fixed operating cost per kWh as the total discounted fixed costs that incur over the lifetime of the facility divided by the levelization factor adjusted by the capacity factor.

$$f_e = \frac{\sum_{i=1}^{T} F_{ei} \cdot \gamma^i}{CF \cdot L}. \tag{3.12}$$

To complete the formulation of the LCOE, we include corporate taxes and the depreciation tax shield. Depreciation charges for tax purposes and interest payments on debt reduce taxable earnings. The effect of the debt tax shield is already accounted for, provided the cost of capital, r, is viewed as a weighted average cost of capital. Let d_i denote the allowable tax depreciation rate in year i and α the effective corporate income tax rate. The useful life of renewable power plants for tax purposes is usually shorter than their useful economic life. Therefore, the tax depreciation charges are set to zero ($d_i = 0$) for the remaining years. The tax factor is then given by:

$$\Delta = \frac{1 - \alpha \cdot \sum_{i=1}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{3.13}$$

It is readily verified that Δ is increasing and convex in the tax rate α. Δ exceeds one in the absence of tax credits and is bound above by $1/(1-\alpha)$. Because of the time value of money, an accelerated tax depreciation schedule reduces Δ. If the tax code allows a full depreciation immediately (meaning $d_0 = 1$ and $d_i = 0$ for $i > 0$), the tax factor equals one.

Some countries, such as the United States, grant subsidies in form of a tax credit for renewable energy production. For wind power, this takes the form of a Production Tax Credit (PTC) per kWh of electricity produced (U.S. Department of Energy, 2016) as:

$$ptc = \frac{\sum_{i=1}^{T} PTC_i \cdot x^{i-1} \cdot \gamma^i}{(1-\alpha) \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i}, \tag{3.14}$$

where PTC_i denotes the tax credit of year i. Since the duration of the PTC is generally shorter than the useful life of wind turbines, we set $PTC_i = 0$ for the remaining years. The credit adds to the after-tax cash flow and is therefore divided by $(1-\alpha)$. Overall, the LCOE in the presence of production tax credits can be expressed as $LCOE = w_e + f_e + \Delta \cdot c_e - ptc$.

On the revenue side, we need to account for the fact that the capacity factor, $CF(t)$ and the attainable revenue at time t, $p^s(t)$ vary in real time. Accordingly, we denote by $\epsilon(t)$ the multiplicative deviation of $CF(t)$ from its average value CF and by $\mu(t)$ the multiplicative deviation of $p^s(t)$ from the average selling price, p^s:

$$\epsilon(t) = \frac{CF(t)}{CF} \text{ and } \mu(t) = \frac{p^s(t)}{p^s}. \tag{3.15}$$

By definition:

$$\frac{1}{m}\int_0^m \epsilon(t) = \frac{1}{m}\int_0^m \mu(t) = 1. \tag{3.16}$$

In the terminology of Reichelstein and Sahoo (2015), the *co-variation coefficient* captures the variation between output and price:

$$\Gamma^s = \frac{1}{m}\int_0^m \epsilon(t) \cdot \mu(t)dt. \tag{3.17}$$

Clearly, the co-variation coefficient is non-negative and zero only if the renewable energy source generates electricity exclusively at times when prices are zero. For a dispatchable energy source, i.e. when $CF(t) \equiv CF$, $\Gamma^s = 1$. Similarly, $\Gamma^s = 1$ if $p^s(t) \equiv p^s$. Intuitively, the economics of a renewable energy source improve if it generates more power during peak prices and thus increases the co-variation coefficient.

The stand-alone NPV of an intermittent electricity generation system is then given by:

$$NPV(k_e) = (1-\alpha) \cdot L \cdot (\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e. \tag{3.18}$$

We refer to $\Gamma^s \cdot p^s - LCOE$ as the profit margin per kWh for the renewable energy source.[8]

[8]We could assign the after-tax factor $(1-\alpha)$ to the unit profit margin, but for reasons of notational parsimony we keep this term separate.

According to (3.18), a renewable electricity generation system is cost competitive (yields a positive NPV) in an environment with time varying prices if the average sales price adjusted by the co-variation coefficient exceeds the levelized cost of electricity.

For the hydrogen subsystem, our definition of the conversion value of hydrogen, CV_h, already incorporates the variable operating costs of converting electricity and water into hydrogen. For investment purposes, the additional relevant cost then is the *Levelized Fixed Cost of Hydrogen (LFCH)*. On a life-cycle basis, it captures the capacity and fixed operating costs per kWh required to absorb electricity at the PtG plant (Farhat and Reichelstein, 2016). With subscript h for hydrogen, we proceed analogously to the levelized cost of electricity to define the LFCH as:

$$LFCH = f_h + \Delta \cdot c_h, \tag{3.19}$$

where:[9]

$$c_h = \frac{SP_h}{L}, \qquad f_h = \frac{\sum_{i=1}^{T} F_{hi} \cdot \gamma^i}{L}. \tag{3.20}$$

To express the NPV of a power-to-gas facility, we introduce the *average conversion premium*:

$$p^{b+} - p^b \equiv \frac{1}{m} \int_0^m [p^{b+}(t) - p^b(t)]dt.$$

The NPV of a stand-alone PtG facility can then be stated as:

$$NPV(k_h) = (1 - \alpha) \cdot L \cdot (p^{b+} - p^b - LFCH) \cdot k_h, \tag{3.21}$$

with $p^{b+} - p^b - LFCH$ representing the unit profit margin of PtG.

Similar to the covariance between output and price for the renewable electricity subsystem, we need to account for the co-variance between hydrogen output and the price premium, $p^+(t) - p^s(t)$ of a vertically integrated energy system. Let $\mu^+(t)$ denote the multiplicative deviation factor of the price premium of the integrated energy system from the average premium of an integrated

[9] This entails the implicit assumption that the PtG facility can be maintained when it is idle and hence the capacity factor equals one.

energy system, $p^+ - p^s$ at time t:

$$\mu^+(t) = \frac{p^+(t) - p^s(t)}{p^+ - p^s}. \tag{3.22}$$

As before, the multiplicative deviation factor reflects a normalization so that $\frac{1}{m}\int\limits_0^m \mu^+(t) = 1$. Finally, we denote by $z(k_e, k_h)$:

$$z(k_e, k_h) \equiv \frac{1}{m} \int\limits_0^m z(t|k_e, k_h) \cdot \mu^+(t)dt. \tag{3.23}$$

Lemma 2. *The NPV of a vertically integrated energy system of size* (k_e, k_h) *is given by:*

$$\begin{aligned} NPV(k_e, k_h) = \ & (1-\alpha) \cdot L \cdot [(\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e \\ & + (p^{b+} - p^b - LFCH) \cdot k_h \\ & + (p^+ - p^s) \cdot z(k_e, k_h)]. \end{aligned} \tag{3.24}$$

An immediate consequence of Lemma 2 is that if both stand-alone systems are profitable on their own, a vertically integrated energy system will generate synergies if $p^+ > p^s$. On the other hand, if either one or both of the stand-alone systems exhibit a negative NPV, then the "synergistic" third term in (3.24) would have to compensate for the losses associated with the stand-alone system. Formally, a vertically integrated energy system is said to have *synergistic value* if for some combination (k_e, k_h):

$$NPV(k_e, k_h) > \max\{NPV(k_e, 0), 0\} + \max\{NPV(0, k_h), 0\}. \tag{3.25}$$

Clearly, if the inequality in (3.25) is met for some (k_e, k_h), no upper bound restricts the attainable net present value in the context of our model since the function $NPV(k_e, k_h)$ is homogeneous of degree 1, that is, for any $\theta > 0$, $NPV(\theta \cdot k_e, \theta \cdot k_h) = \theta \cdot NPV(k_e, k_h)$.

3.2.3 Synergistic Value

A vertically integrated energy system may exhibit synergistic value in one of four alternative scenarios: (i) both energy systems are cost competitive on their own, (ii) the renewable energy source is cost competitive, but the stand-alone PtG facility is not, (iii) the renewable energy source is not cost competitive on its own, while the stand-alone PtG plant is, and finally, (iv) neither energy system is cost competitive on its own. The assessment of a synergistic value is straightforward in the first scenario since the argument then hinges entirely on the average price premium.

Proposition 1. *If both stand-alone energy systems are cost competitive on their own, a vertically integrated energy system has synergistic value if and only if for some* $t \in [0, 8760]$*:*

$$\min\{p^b(t), CV_h\} > p^s(t). \tag{3.26}$$

Clearly, the inequality in (3.26) can only hold during time intervals that correspond to Phases 2 and 3 in the diagram illustrated in Figure 3.2. We note that by definition $p^+ \geq p^s$. Therefore, when both stand-alone systems are profitable on their own, a synergistic value hinges entirely on $p^+ - p^s > 0$. This inequality will hold unless for *all* t: $\min\{p^b(t), CV_h\} \leq p^s(t)$.[10] We note that in a hypothetical stationary environment, where prices and output generation are time-invariant, there will always be a synergistic value if both stand-alone systems are profitable on their own because $CV_h > p^b > p^s$. We next turn to the two mixed cases in terms of cost competitiveness of the stand alone systems.

Proposition 2. *Suppose the intermittent renewable energy source is cost competitive* ($\Gamma^s \cdot p^s - LCOE \geq 0$)*, while the stand-alone PtG plant is not* ($p^{b+} - p^b - LFCH < 0$)*.*

i) *A vertically integrated energy system then has synergistic value if and only if:*

$$p^+ - p^s > LFCH - (p^{b+} - p^b). \tag{3.27}$$

[10] Our argument here assumes implicitly that the functions $p^b(\cdot)$ and $p^s(\cdot)$ are continuous functions.

ii) *If the vertically integrated energy system has synergistic value, then for any given* k_e*,* $NPV(k_e, \cdot)$ *is a single-peaked function of* k_h*.*

The condition identified in the first part of Proposition 2 states that the average price premium associated with a vertically integrated system must exceed the negative profit margin associated with the PtG system. Part (ii) states that if there is synergistic value, that is (3.27) holds, the NPV is, for any given k_e, increasing in k_h up to some cut-off point. To characterize this point, let $k_e = 1$, without loss of generality. Differentiating the expression for $NPV(1, k_h)$ in k_h, we note that this partial derivative is zero at the unique point $k_h^*(k_e = 1)$ given as the solution to the equation:

$$\frac{\partial}{\partial k_h} z(1, k_h^*(1)) \cdot (p^+ - p^s) = LFCH - (p^{b+} - p^b). \tag{3.28}$$

The partial derivative of $z(1, k_h)$ with respect to k_h is given by:

$$\frac{\partial}{\partial k_h} z(1, k_h) = \frac{1}{m} \int\limits_{\{t | k_h \leq CF(t)\}} \mu^+(t) dt. \tag{3.29}$$

Clearly, $\frac{\partial}{\partial k_h} z(1, k_h)$ is decreasing in k_h with $\lim\limits_{k_h \to 0} \frac{\partial}{\partial k_h} z(1, k_h) = 1$ and $\lim\limits_{k_h \to 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$. Thus, $NPV(1, \cdot)$ is a single-peaked function of k_h. Furthermore, the fact that $NPV(k_e, k_h)$ is homogeneous of degree 1 implies that the conditional maximizer of k_h for any given k_e is linear, that is $k_h^*(\cdot)$ is a linear function of k_e. Figure 3.3 illustrates these relationships for Scenario 2.

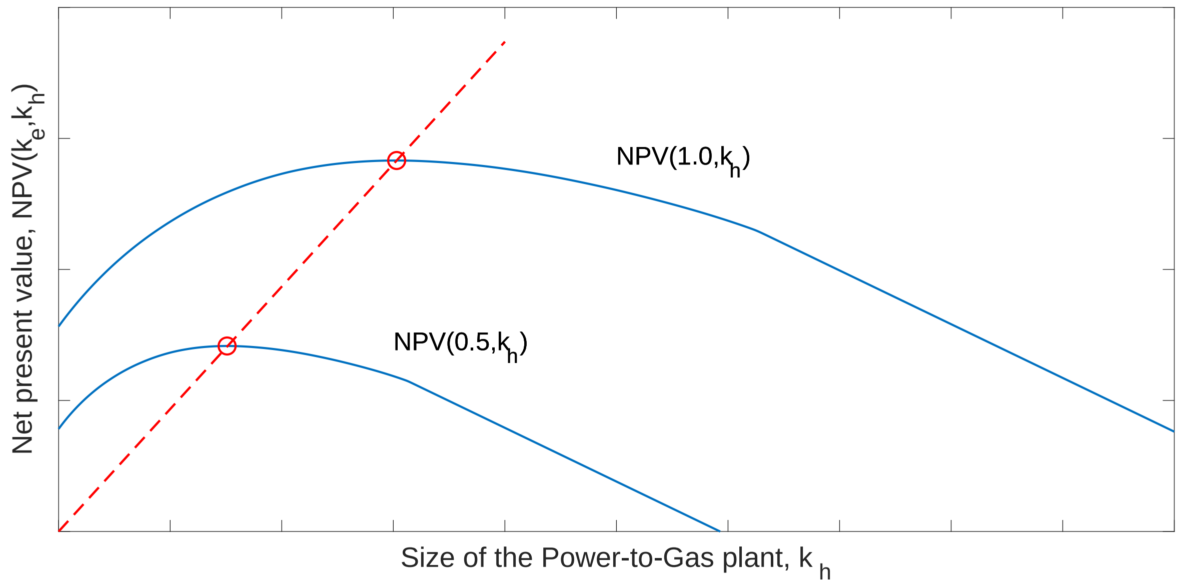

FIGURE 3.3: Linearity of the size of the optimal PtG facility.

In a hypothetical stationary environment, the necessary and sufficient condition in part i) of Proposition 2 simplifies to $CV_h - p^s > LFCH$, provided the underlying parameter values satisfy $CV_h > p^b > p^s$. It will then be optimal to size the PtG facility such that $k_h \leq CF \cdot k_e$ and all renewable energy will be consumed internally.

When the stand-alone PtG facility is cost competitive, but the renewable energy source is not (Scenario 3), we obtain a result that mirrors the one in Proposition 2. Similar to the co-variation factor Γ^s, we denote by Γ^+ the co-variation coefficient between the capacity factors and the real-time price premia of the vertically integrated energy system:

$$\Gamma^+ = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu^+(t) dt. \tag{3.30}$$

Proposition 3. *Suppose the stand-alone PtG plant is cost competitive ($p^{b+} - p^b - LFCH \geq 0$), but the intermittent renewable energy source is not ($\Gamma^s \cdot p^s - LCOE < 0$).*

i) *A vertically integrated energy system then has synergistic value if and only if:*

$$\Gamma^+ \cdot (p^+ - p^s) > LCOE - \Gamma^s \cdot p^s. \tag{3.31}$$

ii) *If the vertically integrated energy system has synergistic value, then for any given k_h, $NPV(\cdot, k_h)$ is a single-peaked function of k_e.*

In this scenario, the emergence of synergies hinges on the condition that the price premium, adjusted by the co-variation factor Γ^+, exceeds the profit margin loss associated with an investment in one kW of renewable energy. Holding the size of the electrolyzer fixed at $k_h = 1$, we obtain the corresponding optimal size of $k_e^*(1)$ as the unique solution to the equation:

$$\frac{\partial}{\partial k_e} z(k_e^*(1), 1) \cdot (p^+ - p^s) \cdot \Gamma^+ = LCOE - \Gamma^s \cdot p^s. \tag{3.32}$$

where:

$$\frac{\partial}{\partial k_e} z(k_e, 1) = \frac{1}{m} \int_{\{t | CF(t) \cdot k_e < 1\}} \mu^+(t) \cdot CF(t) dt. \tag{3.33}$$

As in Scenario 2, the uniqueness of $k_e^*(1)$ follows from the fact that $\frac{\partial}{\partial k_e} z(k_e, 1)$ is decreasing in k_e such that $\lim_{k_e \to 0} \frac{\partial}{\partial k_e} z(k_e, 1) = CF \cdot \Gamma^+$ and $\lim_{k_e \to \infty} \frac{\partial}{\partial k_e} z(k_e, 1) = 0$. In a stationary environment, the condition for a synergistic value in Proposition 3 simplifies to $\max\{p^b, CV_h\} > LCOE$. If this condition is met, it would be optimal to size the renewable energy source such that $CF \cdot k_e \leq k_h$ and therefore all renewable energy is consumed internally.

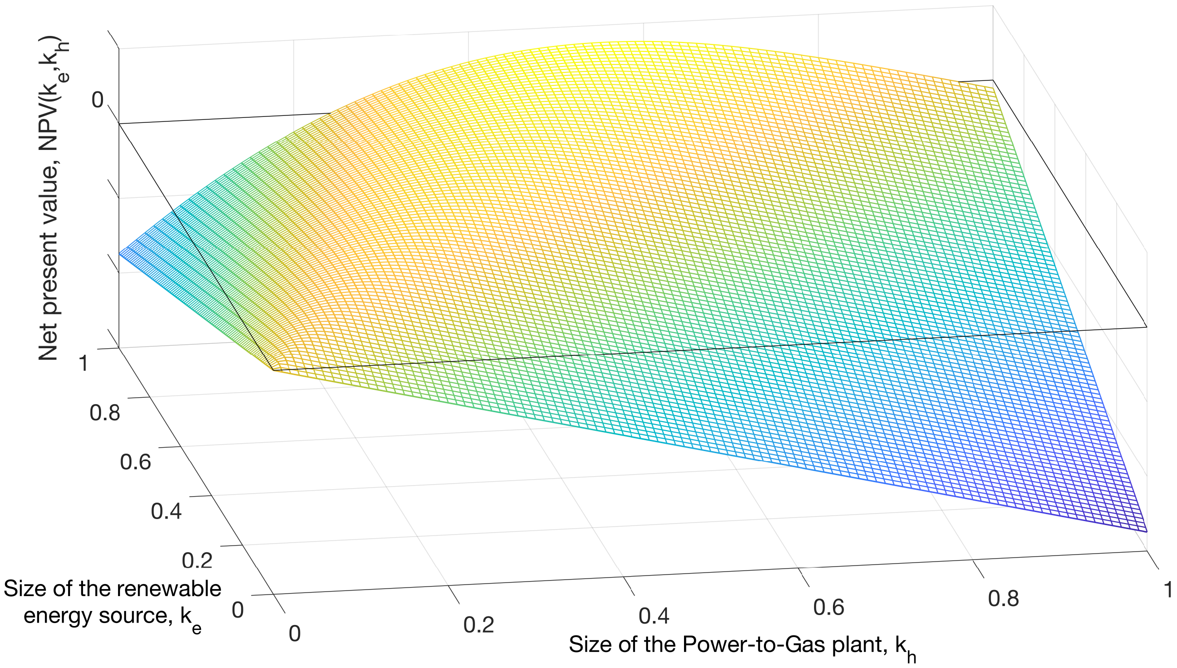

FIGURE 3.4: Synergistic value for no cost competitive stand-alone energy system.

If neither stand-alone subsystem is cost competitive on its own, an investor might still be willing to acquire a combination of the two subsystems provided the synergistic value more than compensates for the losses associated with the two stand-alone systems. Figure 3.4 illustrates this possibility. Without loss of generality, we again anchor the size of the two subsystems, such that $k_e = 1$ and k_h is chosen optimally at $k_h^*(k_e = 1)$. Given our characterization of the NPV of a vertically integrated energy system, the corresponding $k_h^*(1)$ is the value of k_h that maximizes:

$$(p^+ - p^s) \cdot z(1, k_h) + (p^{b+} - p^b - LFCH) \cdot k_h.$$

As argued in connection with Proposition 2, $k_h^*(1) > 0$ if and only if $p^+ - p^s > LFCH - (p^{b+} - p^b)$.

Proposition 4. *Suppose neither the stand-alone PtG plant nor the intermittent renewable energy source is cost competitive* ($p^{b+} - p^b - LFCH < 0$ *and* $\Gamma^s \cdot p^s - LCOE < 0$)*.*

i) *A necessary and sufficient condition for a vertically integrated energy system to have synergistic value is that:*

$$(p^+ - p^s) \cdot z(1, k_h^*(1)) + (p^{b+} - p^b - LFCH) \cdot k_h^*(1) + (\Gamma^s \cdot p^s - LCOE) \cdot CF > 0. \quad (3.34)$$

ii) *If the vertically integrated energy system has synergistic value, then* $NPV(k_e, \cdot)$ *is a single-peaked function of* k_h*, such that* $NPV(k_e, \cdot)$ *is increasing in* k_h *if* $k_h \leq k_h^*(k_e)$ *and decreasing in* k_h *if* $k_h \geq k_h^*(k_e)$*. Correspondingly,* $NPV(\cdot, k_h)$ *is a single-peaked function of* k_e*, such that* $NPV(\cdot, k_h)$ *is increasing in* k_e *if* $k_e \leq k_e^*(k_h)$ *and decreasing in* k_e *if* $k_e \geq k_e^*(k_h)$*.*

While the necessary and sufficient condition for synergies identified in (3.34) is stated in terms of the endogenous optimal value k_h^*, we can state the following weaker necessary condition in terms of the average price premia, the levelized fixed cost of hydrogen and the unit profit margin of the renewable energy source.

Corollary to Proposition 4. *If neither the stand-alone PtG plant nor the intermittent renewable energy source is cost competitive, a necessary condition for a vertically integrated energy system to have synergistic value is that:*

$$p^+ - p^s + p^{b+} - p^b - LFCH + (\Gamma^s \cdot p^s - LCOE) \cdot CF > 0. \quad (3.35)$$

In contrast to the necessary and sufficient condition in (3.34), the preceding (3.35) is only necessary because both k_h^* and $z(1, k_h^*(1))$ are less than one. In a hypothetical stationary environment with constant prices and output, the inequality in (3.35) simplifies to $CV_h > LFCH + LCOE$. Thus, the synergistic value of the vertically integrated system hinges entirely on its levelized cost and the conversion value of hydrogen. The corresponding optimal size for PtG will again satisfy $k_h \leq CF \cdot k_e$, so that hydrogen is produced only from internally generated renewable electricity.

3.3 Application: Wind Energy and Power-to-Gas

3.3.1 Stand-alone Wind Energy

We now apply the preceding model framework to vertically integrated energy systems that combine wind power with PtG. Our numerical analysis focuses on Germany and Texas, two jurisdictions that have deployed considerable amounts of wind power in recent years. Wind energy naturally complements PtG as wind power tends to reach peak production levels at night when demand from the grid and electricity prices are relatively low (Reichelstein and Sahoo, 2015, Wozabal et al., 2016). We base our calculations on data inputs from journal articles, industry data, publicly available reports and interviews with industry sources (see the *Appendix* for a comprehensive list).

Wind energy is eligible for a federal Production Tax Credit (PTC) in the United States. This subsidy is a fixed amount per kWh of electricity (U.S. Department of Energy, 2016). As shown in Section 2, the PTC can be levelized and then effectively subtracted from the LCOE. Beginning in 2017, Germany replaced its traditional fixed feed-in premium for wind energy with a competitive auction system in which successful bidders are guaranteed a minimum price per kWh, with the government paying the difference between the successful bid and the actual revenue obtained from wind energy in the market place (EEG, 2017). We refer to this difference as the Production Premium (PP).[11]

Table 3.1 summarizes the calculation of the unit profit margin for wind energy in both jurisdictions.[12] The LCOE of wind energy amounts to 4.83 €¢/kWh in Germany. The substantially lower LCOE 2.41 \$¢/kWh in Texas reflects the impact of the PTC and, to a smaller extent, a higher capacity factor. The average selling prices of electricity amount to 3.46 €¢/kWh and 2.44 \$¢/kWh, respectively, with corresponding co-variation coefficients are 0.87 and 0.93, indicating that prices tend to be below their average values during periods of above average wind output. We interpret the procurement auctions in Germany as competitive and therefore the profit margins are zero by construction. That means, we infer the production premium (PP)

[11] In its current form, this premium is only granted for wind energy fed into the grid. Our subsequent calculations assume that this premium could also be granted for renewable electricity that is converted to hydrogen, i.e., the renewable energy is effectively stored.

[12] The profit margin in Germany is given by $\Gamma^s \cdot p^s + PP - LCOE$ and in Texas by $\Gamma^s \cdot p^s - LCOE$. Recall that the LCOE in Texas includes the PTC reduction.

as the difference between the winning bids and the observed selling prices adjusted with the co-variation coefficients. The estimates we obtain are corroborated by the observation that the range of observed winning bids (guaranteed selling prices) in 2017 was between 3.82 and 5.71 €¢/kWh and our independent LCOE estimate is just about in the middle of that range. Relating these observations back to our model framework, the question of synergistic value for a vertically integrated system will fall into the domain of either Proposition 1 or 2 in Germany, and either Proposition 3 or 4 in Texas, depending on the profitability of stand-alone hydrogen production.

Table 3.1: Profit margins for wind energy.

	Germany	**Texas**
Input variables		
System price, SP_e	1,180 €/kW	1,566 \$/kW
Capacity factor, CF	30.33 %	44.39 %
Levelized PP or PTC	1.81 €¢/kWh	1.31 \$¢/kWh
Cost of capital (WACC), r	4.00 %	6.00 %
Profit margins		
Levelized cost of electricity, $LCOE$	4.83 €¢/kWh	2.42 \$¢/kWh
Selling price of electricity, p^s	3.46 €¢/kWh	2.44 \$¢/kWh
Co-variation coefficient, Γ^s	0.87	0.93
Profit margin	0.00 €¢/kWh	-0.15 \$¢/kWh

3.3.2 Stand-alone Power-to-Gas

As a producer of industry gases, a PtG facility in Germany is eligible to purchase electricity at the wholesale market price plus a relatively small markup for taxes, fees and levies. For Texas, we use the industrial rate offered by Austin Energy. Because of its grid connection, the PtG facility can also provide frequency control to the grid by rapidly absorbing excess electricity to balance supply and demand. Integrating these revenues from frequency control with the price at which the facility can purchase electricity, the buying price of electricity averages to 3.93 €¢/kWh in Germany and 5.39 $¢/kWh in Texas (see the *Appendix* for details).

A PtG facility could be installed onsite or adjacent to a hydrogen customer.[13] The observed market prices for hydrogen are clustered in three segments that vary primarily with scale (volume) and purity. In Germany, prices for large-scale supply amount on average to 2.0 €/kg, for medium-scale to about 3.5 €/kg, and for small-scale to at least 4.0 €/kg. In Texas, large-scale

[13] Our calculations are based on a Polymer Electrolyte Membrane (PEM) electrolyzer, which is the most flexible electrolyzer technology in terms of ramping delays (Gahleitner, 2013).

hydrogen supply is priced at about 2.5 $/kg, while medium- and small-scale are priced at about 4.0 $/kg or above 4.5 $/kg, respectively (Glenk and Reichelstein, 2019).

Table 3.2 summarizes the calculation of the unit profit margin for PtG in both jurisdictions. The LFCH of PtG amounts to 2.36 €¢/kWh in Germany and 2.22 $¢/kWh in Texas. For medium-scale supply, the conversion premium of hydrogen amounts to 2.93 €¢/kWh in Germany and 2.67 $¢/kWh in Texas, with corresponding profit margins of 0.57 €¢/kWh and 0.44 $¢/kWh, respectively. For large-scale hydrogen supply, the conversion premium equals 1.12 €¢/kWh in Germany and 0.54 $¢/kWh in Texas and the corresponding profit margins are -1.24 €¢/kWh and -1.69 $¢/kWh respectively. In terms of our model, we thus have the scenarios of Proposition 1 or 3 in Germany depending on the scale of hydrogen supply, while the setting in Texas corresponds to either Proposition 2 or 4.

TABLE 3.2: Profit margins for Power-to-Gas.

	Germany	**Texas**
Input variables		
System price, SP_h	2,074 €/kW	1,822 $/kW
Conversion rate, η	0.019 kg/kWh	0.019 kg/kWh
Buying price of electricity, p^b	3.93 €¢/kWh	5.39 $¢/kWh
Medium-scale hydrogen price, p_h	3.50 €/kg	4.00 $/kg
Large-scale hydrogen price, p_h	2.00 €/kg	2.50 $/kg
Profit margins		
Levelized fixed cost of hydrogen, $LFCH$	2.36 €¢/kWh	2.22 $¢/kWh
Medium-scale conversion premium, $p^{b+} - p^b$	2.93 €¢/kWh	2.67 $¢/kWh
Medium-scale profit margin	0.57 €¢/kWh	0.44 $¢/kWh
Large-scale conversion premium, $p^{b+} - p^b$	1.12 €¢/kWh	0.54 $¢/kWh
Large-scale profit margin	-1.24 €¢/kWh	-1.69 $¢/kWh

3.3.3 Vertical Integration of Wind Energy and Power-to-Gas

Given the hydrogen market prices for medium- and large-scale supply shown in Table 3.2 in Texas and Germany, our analysis covers the four possible scenarios that can arise in terms of the stand-alone profitability of the two subsystems. Figure 3.5 indicates the presence of a synergistic value for the vertically integrated PtG system. As one might expect, there is a synergistic value in Germany relative to the scenario of high hydrogen prices in the medium-scale supply segment. Since both subsystems are profitable on their own in that scenario, the low threshold for the presence of a synergistic value, that is, a conversion premium that is positive rather than zero (Proposition 1), is indeed met.

In the setting of low hydrogen prices (large-scale supply) in Germany, PtG exhibits a highly negative profit margin of -1.24 €¢/kWh on its own. The synergistic price premium, $p^+ - p^s$, at 0.42 €¢/kWh is insufficient to compensate for the PtG losses, and thus there is no synergistic value. Arguably, the most surprising finding occurs for the scenario of low hydrogen prices in Texas. Despite the negative profit margins of the two stand-alone subsystems, we find that for a wind power capacity normalized to 1 kW the corresponding optimal size of the PtG facility is $k_h^* = 0.27$ kW and $z(1, k_h^*) = 0.24$. The profit margin of PtG multiplied with k_h^* then amounts to -0.46 $¢/kWh and the profit margin of wind energy multiplied with the average capacity factor to -0.07 $¢/kWh. Yet, the price premium, $p^+ - p^s$, at 2.24 $¢/kWh delivers a sufficiently strong synergistic effect which more than compensates for the two stand-alone losses (Proposition 4).

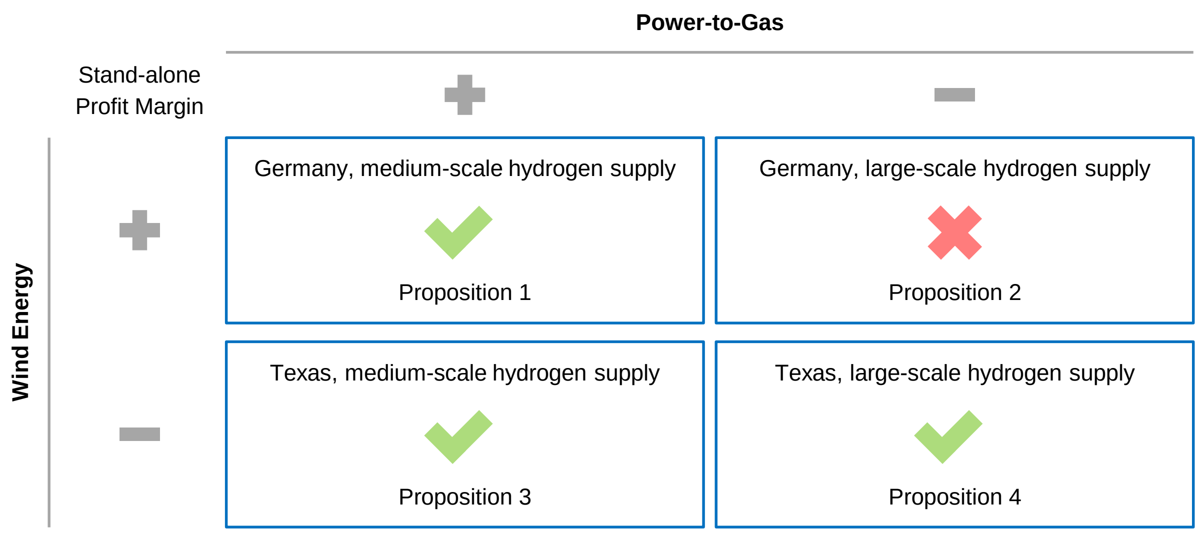

FIGURE 3.5: Synergistic value of vertically integrated wind energy and PtG system.

Another approach for quantifying the synergistic value of an integrated wind energy and PtG system is obtained by calculating the *break-even price* of hydrogen. In stand-alone production mode, this is the lowest price at which the PtG system breaks even, i.e., the price p_h for which $p^{b+} - p^b - LFCH = 0$. In contrast, for a vertically integrated system the break-even price of hydrogen is the lowest value of p_h such that the inequality in (3.25) holds as an equality. Figure 3.6 shows by how much the break-even price falls as a consequence of integrating the two energy systems.[14] This drop is particularly pronounced in Texas where the difference between the two break-even prices is \$1.33 per kg, reflecting the significant price premium in Texas that

[14]We note in passing that the numbers reported in Figure 3.6 are consistent with our claims above where the medium-scale supply price of hydrogen in Texas was benchmarked at 4.00 \$/kg (3.50 €/kg in Germany), while the large-scale supply prices were set at 2.50 \$/kg in Texas and 2.00 €/kg in Germany.

yields a synergistic value even if both subsystems are unprofitable on their own. More broadly, the break-even values reported in Figure 3.6 are consistent with current market activity for early deployments of large-scale PtG facilities in connection with refineries and steel plants; see, for instance, Bloomberg (2017), ITM Power (2018), Voestalpine (2018), GTM (2018).

Break-even analysis can also quantify the value of giving the vertically integrated energy system access to buying electricity from the open market. Cutting off that supply branch would effectively yield a measure for the cost of renewable hydrogen, i.e., hydrogen produced exclusively from wind energy.[15] Figure 3.6 reports the break-even prices for renewable hydrogen as "renewable" prices. By construction, these prices must be higher than those of the vertically integrated system. The price difference is relatively large for Germany, indicating that access to the open electricity market is particularly important there for the economics of hydrogen production.

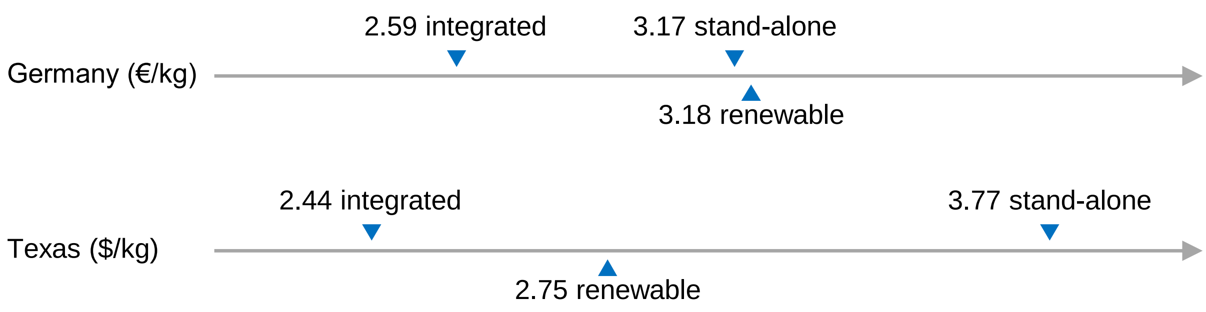

FIGURE 3.6: Break-even prices for hydrogen production.

To conclude this section, we solve for the optimal (relative) size of the PtG capacity for a given wind power facility the size of which has been normalized to 1 kW. The blue lines in Figure 3.7 display the NPV of the vertically integrated system as a function of the size of the PtG facility for alternative hydrogen prices ranging from 1.0 to 4.0 € or \$ per kg. Red circles mark the optimal PtG capacity size for a particular hydrogen price. Circles at 0.0 kW indicate that no PtG capacity should be installed, while a red circle at 1.0 kW indicates that PtG is cost competitive on its own. As shown in Section 3.3, the NPV is a single-peaked function of k_h for any hydrogen price.

In comparison to other recent studies on the economics of hydrogen, our results point to generally lower hydrogen prices (Ainscough et al., 2014, Bertuccioli et al., 2014, Felgenhauer and

[15] This is the perspective taken in Glenk and Reichelstein (2019). We note that the question of a synergistic value cannot be posed in such a context since, by construction, hydrogen can only be produced at an integrated facility.

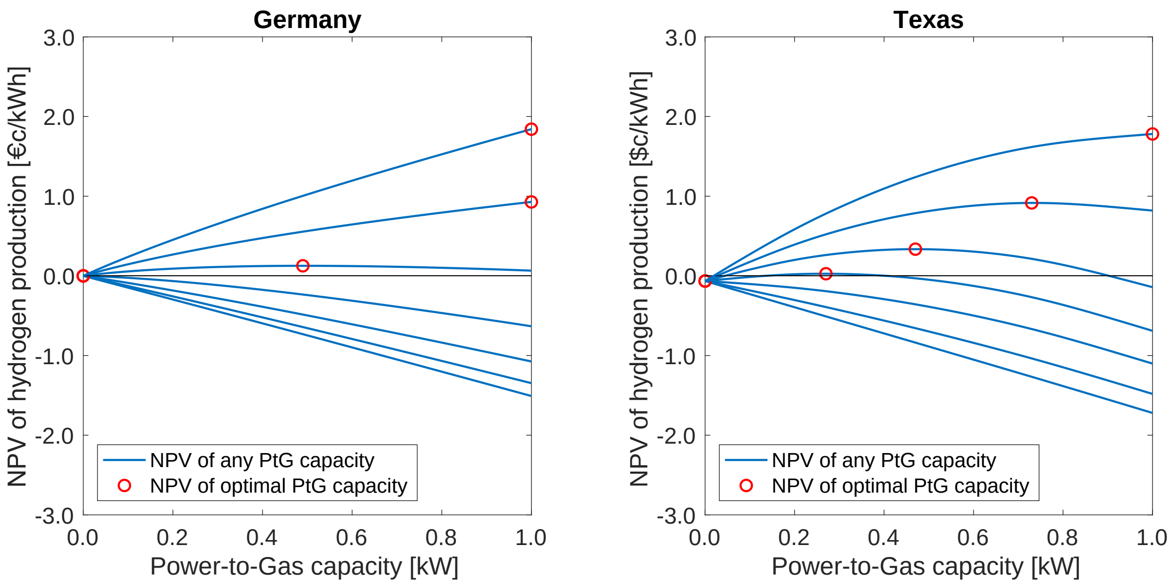

Figure 3.7: Optimal Power-to-Gas capacity size.

Hamacher, 2015). We attribute this discrepancy to several factors. Most importantly, our calculations are based on vertically integrated energy systems that are sized optimally for highly capital-intensive capacity investments. In addition, our vertically integrated PtG facility is assumed to be connected to the grid and therefore obtains higher capacity utilization by converting renewable and grid electricity than it could achieve if it was to convert only renewable energy (Glenk and Reichelstein, 2019). Finally, our calculations are based on most recent data reflecting the rapidly falling cost of producing wind energy as well as recent changes in the acquisition cost of electrolyzers.

3.3.4 Prospects for Synergistic Value

The preceding numerical findings provide a snapshot of the economics of wind energy combined with PtG based on recent data points. Going forward, multiple trends appear to be underway that suggest further improvements in the economics of such vertically integrated energy systems. In this subsection, we integrate these trends to identify a trajectory of break-even prices for hydrogen in future years. The break-even hydrogen prices for a vertically integrated system reported in Figure 3.6 are the starting points of this trajectory.

Regarding the cost structure of wind energy, we follow Wiser et al. (2016) who project that the system prices for wind turbines will decline at a rate of 4.0% per year. At the same time, these authors project an increase in the average capacity factor at an annual rate of 0.7% per year. For the acquisition cost of electrolyzers, we rely on the regression results of Glenk and Reichelstein (2019), yielding an annual 4.77% decrease in the system price of PEM electrolyzers.

Our projections also assume that wind power in Germany and Texas will have a "driving role" in future changes of the selling prices of electricity in the wholesale market (Ketterer, 2014, Paraschiv et al., 2014, Woo et al., 2011). Specifically, the difference between the LCOE in year i, $LCOE(i)$, and the adjusted average selling price, $\Gamma \cdot p^s(i)$, is assumed to decline to zero at a constant adjustment rate such that:

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

where $\beta < 1$ denotes the adjustment rate and $D(0) \equiv \max\{LCOE(0) - \Gamma \cdot p^s(0), 0\}$. Since in Germany the production premium is determined through a competitive auction mechanism, we expect the auction in year i to yield a premium of $PP(i) = D(i)$. In Texas, our calculations anticipate the scheduled phase-out of the PTC by 20.0% per year (U.S. Department of Energy, 2016) which will by itself raise the $LCOE(i)$ for those years.

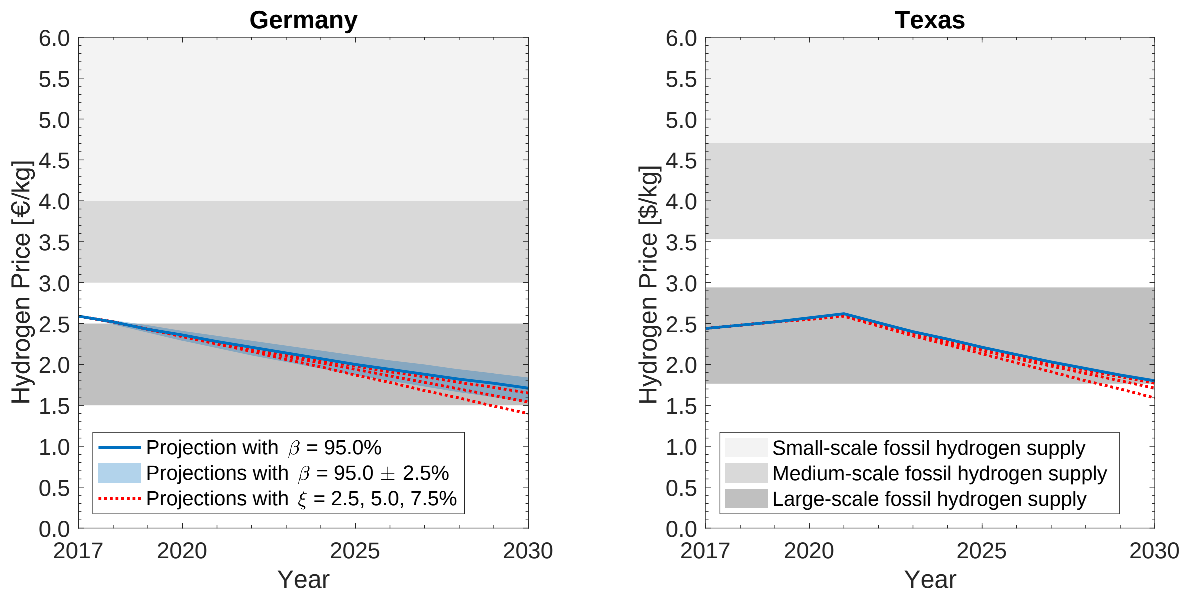

FIGURE 3.8: Trajectory of future hydrogen break-even prices.

Figure 3.8 shows the trajectory of break-even prices for hydrogen from a vertically integrated wind power and PtG system through 2030. Such hydrogen is projected to become widely cost competitive with industrial-scale hydrogen supply, that is currently produced from fossil fuels, in the coming decade. The values shown by the solid line in Figure 3.8 assume an adjustment rate of $\beta = 0.95$. The “hump” in the findings for Texas reflects the scheduled phase-out of the production tax credit. The values covered by the areas shaded in blue color illustrate the impact of slower and faster adjustment rates ranging from 0.975 to 0.925.

Finally, we seek to capture the idea that further increases in renewable energy are likely to increase the variance in daily and seasonal electricity prices. As noted in Section 2, higher operational volatility will generally tend to accentuate the synergistic value of a vertically integrated system. We incorporate the possibility of increased volatility in the selling price of electricity by assuming that $p^s(t)$ increases by $\xi\%$ whenever $p^s(t)$ exceeds the average p^s and to decrease $p^s(t)$ by a corresponding percentage at all other times so that p^s remains unchanged. The dotted red lines represent the effect of ξ values set equal to 2.5, 5.0 and 7.5%, respectively.

3.4 Conclusion

This paper has examined the synergistic value of vertically integrated production systems. Synergies arise because of market imperfections for an intermediate input (electricity in our context) and because of operational volatility in the form of temporal fluctuations in output and prices. While vertically integrated systems will generally experience some synergistic benefit, we attribute a synergistic value only if a negative net present value for one or both of the stand-alone systems is more than outweighed for by the synergistic effect. In the context of an energy system that combines renewable energy with hydrogen production, we derive necessary and sufficient conditions for the presence of the synergistic value. These conditions can be stated in terms of lifecycle unit costs and average prices adjusted for covariance terms that capture the extent to which price premia and output fluctuations are aligned across the hours of a typical year.

We rely on recent production price and cost data to assess the magnitude of synergistic effects in both Texas and Germany. Our empirical focus is on Power-to-Gas facilities that can draw electricity either from the grid or internally from wind turbines. The policy support for renewable energy in Germany ensures that wind power is cost competitive on its own. We find that the emergence of a synergistic value in Germany hinges on the market price of hydrogen being above some break-even value which is currently below the price paid for medium-scale transactions, but above that obtained for transactions of industrial scale.

Owing to the low wholesale prices of electricity in Texas, we find that, on its own wind energy is currently not cost competitive despite the production tax credit available to renewable energy in the United States. Nevertheless, we conclude that the synergies between the two subsystems are sufficiently strong in Texas so that a vertically integrated energy system can create value, despite the fact that Power-to-Gas facilities will also not be viable on their own.

While our numerical analysis is based on the most recent available data, several factors suggest a trend towards more favorable economics for vertically integrated systems in the future. We build our forecast based on the combination of projected reductions in system prices for both wind turbines and electrolyzers as well as a general trend towards more volatility in electricity prices.

Our paper suggests several promising avenues for future research. With regard to the modeling part, it would be instructive to add stochastic shocks to prices and output. Such shocks are likely to increase the call option value of capacity investments, but it remains an open question whether additional volatility in the form of random shocks will lead to synergistic values for a broader range of circumstances. We also note that our framework has viewed hydrogen as a final product. An alternative and promising avenue is to view hydrogen also as a form of electricity storage. Provided the electrolyzer can also run in the “reverse direction”, hydrogen production coupled with reconversion to electricity may effectively compete with battery storage for electricity supply systems characterized by intermittent generation patterns.

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

by Gunther Glenk

The calculation of unit cost that can be used for estimating capacity investment decisions is frequently ambiguous due to the many ways to apportion applicable cash flows connected to the delivery of products. This paper studies the identification of relevant unit cost when productive capacity is shared among multiple outputs. Building upon the concept of levelized product cost, I find that unit cost should reflect a constant revenue payment required to break-even on the initial investment. This payment, which is shown to depend on the perspective that an investor can assume, determines the aggregation of upfront capacity expenditures with periodic operating expenses to the relevant cost and unit. I apply the framework to examine new Power-to-Gas technology, which could become a central enabler of the transition towards a sustainable economy by reversibly converting electricity to hydrogen. Contrary to the common belief that fossil fuels are indispensable, my analysis shows that reversible Power-to-Gas will be sufficiently competitive with alternative fossil-based energy sources so as to provide a clean solution to the challenges of intermittent renewable electricity and widespread industrial decarbonization.

4.1 Introduction

The delivery of products and services typically causes a stream of expenditures for upfront capacity investments, periodic operating expenses, and financing cost for debt and equity investors. Because of the need to apportion such cash flows over multiple periods, the calculation of unit cost is inherently ambiguous even though it is instructive for deciding product prices and capacity investments. Incorrectly calculated unit cost at the outset, for instance, can lead to prices being set too low for upfront investments to turn out profitable in the long run.[1] When productive capacity is shared among multiple outputs or respondents, the task of calculating unit cost becomes even more complex. One objective of this paper is to propose a theoretical framework for the characterization of relevant unit cost when productive capacity is shared.

The central thought of the framework is that unit cost should reflect a constant revenue payment that the potential investor in productive capacity would have to receive over the life of the asset in order to break-even on the initial investment. This guideline is shown to simplify the aggregation of multi-period cash flows and to deliver unit cost relevant for capacity investment decisions. My criterion for unit cost builds upon the concept of *levelized product cost*. This metric is defined as the constant product price required to break-even and aggregates per unit of output a share of the expenditures for the upfront capacity investment with annual fixed and variable operating expenses (MIT, 2007).[2] The levelized cost measure has been shown to represent the long-run marginal cost of a product and hence the relevant unit cost firms should impute for investments in productive capacity (Reichelstein and Rohlfing-Bastian, 2015).[3] While this representation has been shown to hold for various market conditions characterized by price volatility and competition, the concept has so far remained limited to capacity that is dedicated to the delivery of a single output.

This paper shows that with shared capacity the calculation of relevant unit cost depends on the perspective that the potential investor takes. My interpretation of a *capacity perspective* is

[1]The issue drew global attention when Donald Trump twittered on March 31, 2018: *"[I]t is reported that the U.S. Post Office will lose $1.50 on average for each package it delivers for Amazon. [...] This Post Office scam must stop. Amazon must pay real costs (and taxes) now!"*. For a general discussion, see Pittman (2009).

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

[3]For a discussion on long-run marginal cost, see, for instance, Rogerson (2008, 2011), Rajan and Reichelstein (2009), Nezlobin et al. (2012), or Friedl and Küpper (2010).

that the investor focuses on the supply of productive capacity and seeks to identify the constant revenue payment per unit of capacity required to break-even. In this scenario, my analysis shows that the relevant unit cost is given by what I refer to as the *levelized fixed cost (LFC)*. This cost measure reflects the constant contribution margin per hour that the investor would have to receive in order to break-even. The LFC is an essential information for an investment decision considering that the supplier of capacity will sell the facility for the production of output that yields the highest contribution margin over the particular time period (Friedl et al., 2017). The calculation of the unit cost is simplified in so far as all capacity and fixed operating cash flows required to supply the capacity are discounted and allocated intertemporally across the periods of operation and the operating time of the 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 the outputs on the respective markets. The relevant unit cost emerges as the levelized cost of an individual product. In line with the initial definition of levelized product cost, this cost measure represents the constant selling price of an output that the investor has to receive to break-even on the investment. The unit cost of each output can thereby be conceptualized in a way that it determines the break-even of the entire capacity without assessing the unit cost of other outputs generated on the capacity. Contrary to the initial approach with dedicated capacity is that when capacity is shared, the discounted sum of all cash flows required to deliver the outputs must be allocated not only intertemporally but also cross-sectionally among the outputs. Yet, the paper shows that this complication can be simplified in the formulation of an individual unit cost to one additional factor that adjusts the joint costs of capacity for the share allocated to the output.

The two perspectives of the analysis are closely related to the settings investigated in the literature on decentralized capacity management.[4] In the typical setting, the divisional managers of a firm with two divisions are responsible for the initial investment in productive capacity. Both divisions sell a product each in separate markets, whereby the upstream division installs the productive capacity and produces the outputs for both divisions due to technical expertise. As the supplier of capacity, the upstream division would naturally assume the capacity perspective, while the downstream division would take the product perspective. However, the

[4]See, for instance, Dutta and Reichelstein (2010, 2018), Wei (2004), or Rogerson (2008)

perspectives and organizational structures are not always aligned so that it is important to distinguish between them. For instance, the upstream division will prefer to assume the product perspective if it stands in competition with the external market for the delivery of the output to the downstream division.

Cross-sectional allocation rules are widely viewed as arbitrary even though it is often indispensable to allocate joint costs among outputs (Balakrishnan and Sivaramakrishnan, 2002, Küpper, 2009).[5] In contrast, the break-even conceptualization of the unit cost yields a definitive criterion for allocation, namely to align the profitability among the joint products. In the 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 exceeded by the selling price. While accountants have developed a variety of allocation rules based on, for instance, labor costs, machine hours, or sales dollars, my analysis shows that the alignment 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 concept of levelized cost is also related to the broad literature on full cost in several aspects. Most general, levelized product cost has been shown to equal an extended form of a product's full cost that also includes taxes and imputed interest charges on the remaining book value (Reichelstein and Rohlfing-Bastian, 2015). Furthermore, the concept has been shown to provide a sufficient measure of full cost for predicting product prices in the market under different extents of competition (Reichelstein and Rohlfing-Bastian, 2015, Banker and Hughes, 1994, Balakrishnan and Sivaramakrishnan, 2002, Göx, 2002). Finally, the analysis in this paper shows that under certain conditions both the levelized fixed cost and levelized cost of a product would serve as efficient transfer prices depending on the investor perspective and the organizational structure.[6]

An important field of application for the framework is the context of sustainable energy systems. While wind and solar power sources have outpaced early projections in terms of cost reductions and share of power generation (Comello et al., 2018b, Kök et al., 2018), two challenges remain unsolved in the transition to a decarbonized economy. First, the production of electricity depends on intermittent weather conditions and, second, decarbonization measures must include other sectors, especially, transportation and industrial processes. A promising solution could be

[5]Consequently, allocation rules are increasingly tied to specific purposes; see, for instance, Balachandran and Ramakrishnan (1996), Pavia (1995), or Ray and Goldmanis (2012).

[6]See, for instance, Baldenius and Reichelstein (2005), Karmarkar and Pitbladdo (1993), or Pfeiffer et al. (2011).

new Power-to-Gas (PtG) technology.[7] 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 (hydrogen) to processes that are otherwise difficult to decarbonize (Davis et al., 2018).[8] Since both outputs are produced on the same facility and sold separately in the respective markets, a reversible PtG facility presents a shared capacity in terms of the theoretical framework. The second objective of this paper is to assess when a reversible PtG facility would be economically viable and both electricity and hydrogen competitive with fossil-based alternatives in the market.

For the economic viability, a potential investor would naturally assume the capacity perspective. In line with the general results above, I find that 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.[9] While my analysis confirms this tie, it 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 conversion without the need to reconvert after prices have changed sufficiently. As a consequence, I find that for conditions frequently observed in current markets reversible PtG will break-even when it largely produces the one output that has the higher average price.

For the competitiveness, an investor would assume the product perspective as it yields a useful metric in form of the levelized product cost. Since levelized cost identifies the lowest price required to break-even, the concept is widely used in the energy sector to find the cheapest power generation technology to serve a particular load that results from, say, insufficient renewable production (MIT, 2007).[10] Due to the need to allocate joint costs cross-sectionally, measuring the competitiveness of outputs generated with reversible PtG requires an insight on the allocation at break-even of the facility. Here my analysis shows that the cost allocation emerges as a main driver of competitiveness as the economics of reversible PtG divide the sizable joint costs into a large and a small share. With the shift to renewable energy, I find that the small share will be

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

[8]Hydrogen reflects a platform with many applications including fuel for transportation, feedstock in chemical and processing industries, or energy storage for power generation (Jacobson, 2016, Jones, 2012).

[9]See, for instance, Jülch (2016) or Steward and Zuboy (2014) for studies on PtG and de Groote (1994) or Dong et al. (2014) in the real-option literature for consistent findings for the value of an option to switch.

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

allocated to electricity which enables a competitive levelized cost despite high cost for the new technology and hydrogen as a fuel.

In comparison to alternative energy sources that could complement intermittent renewables, the economics of reversible PtG unfold as a competitive advantage. Operating in only one direction, conventional power generators based on, say, coal or natural gas are sensitive to a rise in volatility of the electricity price as well as to a decrease in utilization, which both have followed the shift towards renewables (Wozabal et al., 2016). Alternative storage technologies like batteries rely, unable to trade their storage medium in the market, on generating value purely from volatile power prices and on covering their costs only with the limited amounts of stored electricity.

The final part of the paper seeks to assess the economic prospects for reversible PtG in Germany and Texas, two jurisdictions that have exhibited a rapid growth of renewables (IEA, 2017). Given the current market environment, the numerical evaluations yield that reversible PtG breaks-even only if the average price of hydrogen is above that of electricity and the facility largely produces hydrogen. To break-even on electricity production, the price of hydrogen would have to be negative to generate a contribution margin at the current electricity price that exceeds the high cost of capacity. With regard to the competitiveness, the calculations show 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 promising potential for solving the challenges of intermittency and decarbonization. These trends include sustained cost reductions, efficiency improvements, and that reversible PtG is integrated vertically with a co-located wind energy source to benefit from operational synergies. Due to these synergies, hydrogen produced with reversible PtG becomes competitive with large-scale industrial hydrogen supply already in the current market. 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 sharing of sizable capacity-related costs among the outputs (Braff et al., 2016, Jülch, 2016, Steward and Zuboy, 2014, Glenk and Reichelstein, 2018). In addition, the calculations take advantage of synergistic benefits that arise from combining a PtG facility with an optimally sized wind energy source (Bertuccioli et al., 2014, 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).

The remainder of the paper is organized as follows. Section 4.2 describes the model setting and the production at a reversible PtG facility. Section 4.3 proceeds with the capacity perspective and section 4.4 with the product perspective. Section 4.5 applies the framework to reversible PtG in Germany and Texas and section 4.6 concludes the paper. Proofs and input variables for the numerical evaluation are provided in the *Appendix*.

4.2 Model Description

4.2.1 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 for the output. Applicable examples of such capacity is found in both traditional manufacturing of, for instance, chemicals or mechanical parts, and service-oriented businesses, such as support services or postal delivery. In order to deliver its products or services, the capacity causes various cash flows for upfront investment, annual operating expenses, and financing cost. A firm would thus seek to apportion these cash flows so as to obtain unit cost relevant for the capacity investment decision.

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 selling the capacity for a certain time period 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.[11]

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 the perspectives is crucial for shared capacity, because the value is driven by a portfolio of outputs each of which can have distinct characteristics. 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.

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 (Buttler and Spliethoff, 2018, Pellow et al., 2015).[12] 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 4.1, both outputs are produced on the same capacity and traded separately in the respective markets

[11] 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).

[12] The model framework focuses for clarity on a stand-alone operation of the PtG facility sourcing electricity unrestrictedly from the grid. The numerical evaluation in section 4.5 will also explore the impact of combining the PtG facility with a co-located renewable energy source.

so that reversible PtG represents a shared capacity in the generic sense.[13] In addition to the general question, a potential investor in reversible PtG seeks to examine when a facility would be economically viable and electricity and hydrogen competitive in the market.

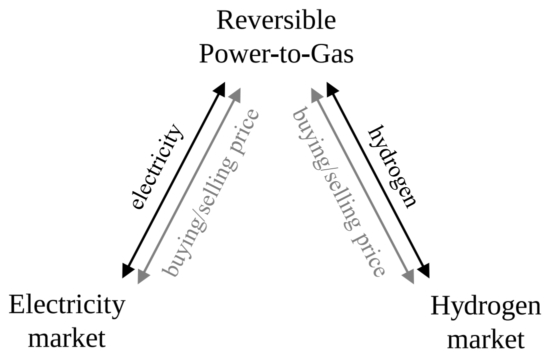

FIGURE 4.1: Illustration of reversible Power-to-Gas.

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.[14] 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.[15] 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

[13]Hydrogen trade is currently developing from individual transactions to open markets that compare to those for natural gas; see, for instance, in France and Japan (Business Insider, 2018, Government of Japan, 2018).

[14]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.

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

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.

4.2.2 Production Schedule

Given a shared capacity, the decision which output to produce at a particular point in time is based on the contribution margin that each output would generate within the 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 accordance with the real-time fluctuations in electricity prices.[16]

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 generated hydrogen on the market. This price is scaled by the conversion rate of the reversible electrolyzer from electricity to water in kg/kWh.[17] Let p_h denote the price for hydrogen and η^c the conversion rate of the electrolyzer, which 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.[18] 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:

$$w^c(t) = p_e(t) + \delta_e + \eta^c \cdot w^o. \tag{4.1}$$

[16] In contrast to previous work, demand uncertainty is captured by predictable price variations rather than random shocks (Banker and Hughes, 1994, Göx, 2002, Boyabatli and Toktay, 2011).

[17] This entails the approximation that the conversion rate remains constant across the utilization of the electrolyzer, which is a permissible assumption for the considered technologies (Buttler and Spliethoff, 2018).

[18] 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.

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 (Gahleitner, 2013, 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:

$$CF^c(t) = \begin{cases} 1 & \text{if } \eta^c \cdot p_h > w^c(t), \\ 0 & \text{otherwise.} \end{cases} \tag{4.2}$$

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

$$CM^c(t) = \big(\eta^c \cdot p_h - w^c(t)\big) \cdot CF^c(t). \tag{4.3}$$

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 variable cost of reconversion per kWh of electricity output comprises the reconversion rate of the electrolyzer multiplied with the market price of hydrogen, p_h, plus a markup for transportation and storage denoted by δ_h. The reconversion rate of the reversible electrolyzer (in kWh/kg) is denoted by η^r and represents the amount of electricity that can be extracted from 1 kg of hydrogen. The variable cost of reconversion is given by:

$$w^r = \frac{1}{\eta^r} \cdot (p_h + \delta_h). \tag{4.4}$$

For the quantity of electricity 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 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:

$$CF^r(t) = \begin{cases} 1 & \text{if } p_e(t) > w^r, \\ 0 & \text{otherwise.} \end{cases} \tag{4.5}$$

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:

$$CM^r(t) = \big(p_e(t) - w^r\big) \cdot CF^r(t). \tag{4.6}$$

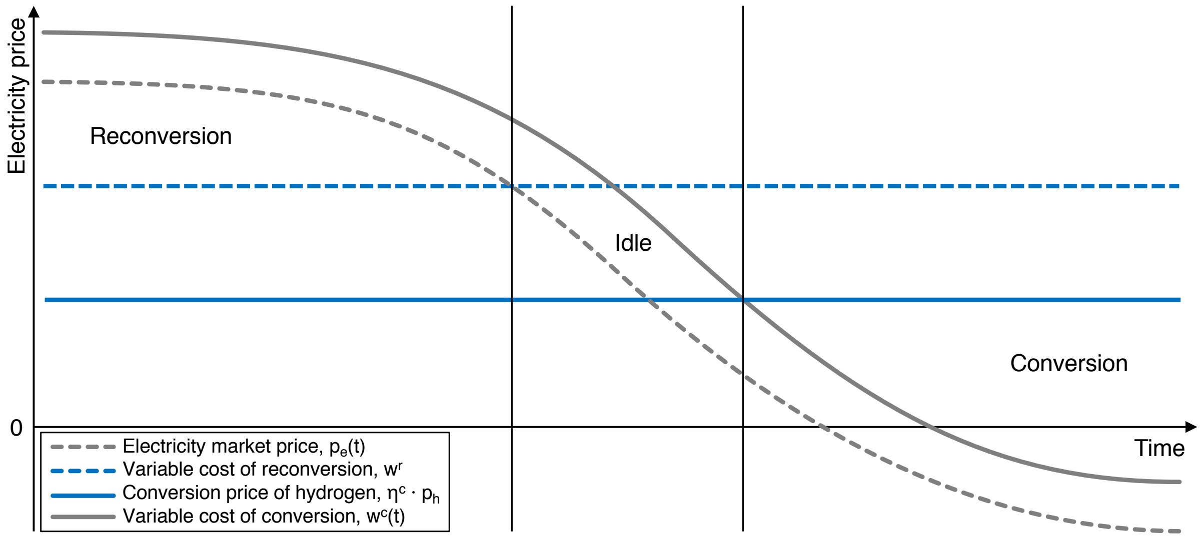

FIGURE 4.2: Complementary slackness of reversible Power-to-Gas.

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.[19] 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 4.2 shows.[20] 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 downtime results from markups and variable costs paid, and a round-trip efficiency of less than one, which together open up an efficiency gap between the thresholds of conversion and

[19] 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.

[20] Note that wholesale electricity markets increasingly exhibit negative prices as a result of surplus energy being unloaded on the grid at certain hours; see, for instance, Bloomberg (2016) and EPEX SPOT (2018).

reconversion, in which electricity prices are lost. The idle time grows with the frequency that the continuously fluctuating electricity prices fall into this gap.

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:

$$CM(t) = \big(\eta^c \cdot p_h - w^c(t)\big) \cdot CF^c(t) + \big(p_e(t) - w^r\big) \cdot CF^r(t). \tag{4.7}$$

The formulation shows that a shared capacity will generate the output that delivers the highest contribution margin at a certain 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. The periodic contribution margin is modeled such that it equals the contribution margin of the generated output that is activated through the binary values of the capacity factors.

4.3 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 subsequently sold for the production of several outputs. The analysis in this section thus seeks to identify in general the relevant unit cost for the supply of shared capacity and to examine for reversible PtG, in particular, 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.[21]

The upfront investment, SP, 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 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:

$$CF \equiv \frac{1}{m} \int_0^m \big(CF^c(t) + CF^r(t)\big)dt. \tag{4.8}$$

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 $CF \leq 1$.[22] The capacity and fixed operating costs per hour are given by:

$$c \equiv \frac{SP}{CF \cdot L}, \text{ and} \qquad f \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{CF \cdot L}. \tag{4.9}$$

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:

$$\Delta = \frac{1 - \alpha \cdot \sum_{i=1}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{4.10}$$

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

[21] 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.

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

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:*

$$LFC \equiv f + \Delta \cdot c. \tag{4.11}$$

To examine whether the expression in (4.11) satisfies the break-even requirement provided at the 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 $CF^c = \frac{1}{m}\int\limits_0^m CF^c(t)dt$, and by $\mu^c(t)$ the deviation of $w^c(t)$ from the average w^c:

$$\epsilon^c(t) \equiv \frac{CF^c(t)}{CF^c}, \text{ and } \mu^c(t) \equiv \frac{w^c(t)}{w^c}, \text{ with} \tag{4.12}$$

$$\frac{1}{m}\int\limits_0^m \epsilon^c(t) = \frac{1}{m}\int\limits_0^m \mu^c(t) = 1. \tag{4.13}$$

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:

$$\Gamma^c = \frac{1}{m}\int\limits_0^m \epsilon^c(t) \cdot \mu^c(t)dt. \tag{4.14}$$

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:

$$\epsilon^r(t) \equiv \frac{CF^r(t)}{CF^r}, \text{ and } \mu^r(t) \equiv \frac{p_e(t)}{p_e}, \text{ with} \tag{4.15}$$

$$\frac{1}{m}\int_0^m \epsilon^r(t) = \frac{1}{m}\int_0^m \mu^r(t) = 1. \tag{4.16}$$

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:

$$\Gamma^r = \frac{1}{m}\int_0^m \epsilon^r(t) \cdot \mu^r(t) dt. \tag{4.17}$$

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

$$CM = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{4.18}$$

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:

$$CM^c = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c, \text{ and} \tag{4.19}$$

$$CM^r = (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{4.20}$$

Proposition 1. *A reversible PtG facility breaks-even on the initial investment if and only if:*[23]

$$(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r \geq LFC \cdot CF. \tag{4.21}$$

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

Proposition 1 shows that a reversible PtG facility breaks-even if the average contribution margin exceeds the levelized fixed cost per hour 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.[24] The average capacity factor of the facility and the average capacity factor of the generated output are equivalent and cancel out. The variable operating cost on the left-hand-side moves to the right-hand-side and sums with the LFC to the levelized cost of the product. In line with the previous work, the facility breaks-even if the average product price exceeds the levelized product cost.

With regard to literature on 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), Pfeiffer et al. (2011), 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 without further research this only holds in the simplified scenario without typical issues, like double marginalization or diverse time preferences of managers.

In addition to the mere condition, a potential investor concerned with the economic viability of reversible PtG would also be interested in the necessary circumstances for the facility to break-even. As it is widely understood for energy storage technology and consistent with earlier findings for flexible production capacity, the value of reversible PtG increases with the volatility in electricity prices.[25] In section 4.2.2, it can be readily seen 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.

[24] See, for instance, Reichelstein and Rohlfing-Bastian (2015).

[25] Kogut and Kulatilaka (1994), van Mieghem (1998), and Fine and Freund (1990), for instance, examine the value of an option to switch.

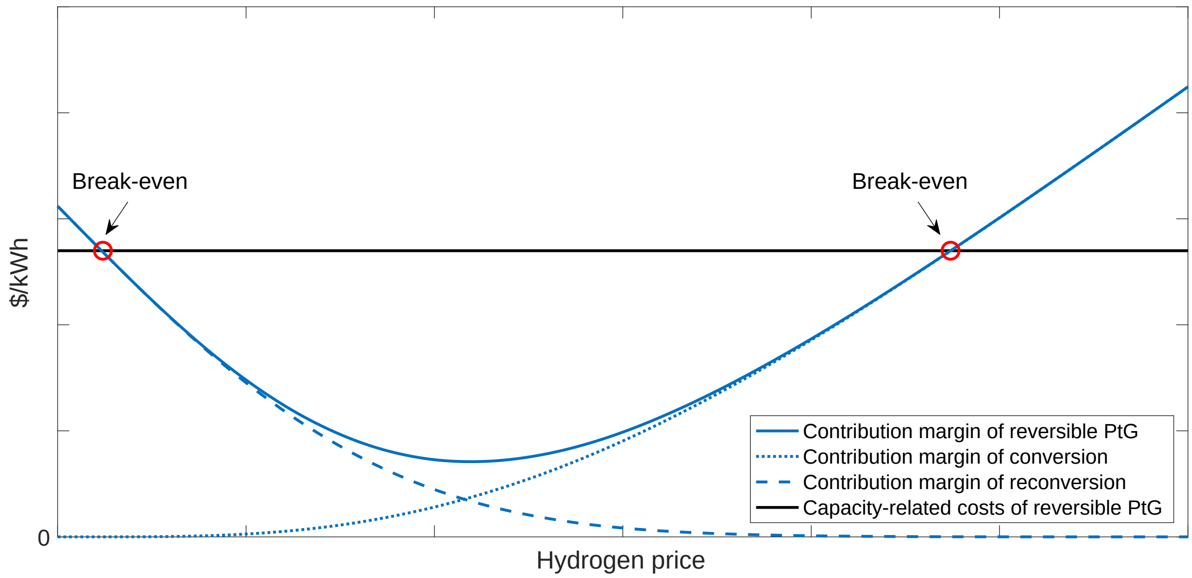

FIGURE 4.3: Economics of reversible Power-to-Gas.

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.[26] Let CM then be viewed in dependence of p_h:

$$CM(p_h) = \big(\eta^c \cdot p_h - w^c \cdot \Gamma^c(p_h)\big) \cdot CF^c(p_h) + \big(p_e \cdot \Gamma^r(p_h) - w^r(p_h)\big) \cdot CF^r(p_h). \tag{4.22}$$

As Figure 4.3 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 which reveals where the majority of electricity and hydrogen prices fall into the efficiency gap of the facility. 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 is given with a common distribution 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 $CM^r(p_h) > CM^c(p_h)$.*

[26]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. Through the market access reversible PtG receives a price for hydrogen and the possibility to also draw value from the spread between the average price of electricity and hydrogen. Therefore, a reversible PtG facility can generate value by operating in just one direction and selling the generated output in the market without the need for reconversion. Proposition 2 shows that a reversible PtG facility that is able to trade both outputs in the market breaks-even when it largely produces the output with the higher average price and hence contribution margin.

Relative to alternative energy sources for complementing the intermittency of renewables, the reversible operation and the 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 in wind and solar energy sources due to an increased ramping and a decreased utilization (Wozabal et al., 2016). Alternative storage technologies like batteries, pumped hydro, or compressed air cannot trade their storage medium and must compete for the volatility of electricity prices for which a volatility-flattening market saturation may emerge at some point. Furthermore, they are limited in the duration of power supply as they are unable to utilize the market as an extensive storage capacity.

4.4 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.

The unit cost relevant for an investor with a product perspective is that which is a useful information for the investment decision. 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 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 in subsequent periods rather than among the hours of production. Since both SP and F_i are given in cost per kW of peak production capacity, the production volume of an output can be given implicitly as the utilization of the available peak capacity dedicated to the output. The availability of peak capacity is captured by the levelization factor L. The average 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:

$$c^c \equiv \frac{SP}{CF^c \cdot L}, \text{ and} \qquad f^c \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{CF^c \cdot L}. \tag{4.23}$$

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 (4.23) 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.

Accountants in theory and practice have developed a range of rules for cross-sectional allocation of joint cost. A prominent example is activity-based costing, where costs are allocated based on activities performed (Cooper and Kaplan, 1988). More traditional cost systems employ volume-driven allocation bases, such as labor costs, machines hours, or sales dollars. Even though cross-sectional allocation is widely used in practice, the selection of a specific rule is frequently argued to be arbitrary (Datar and Gupta, 1994, Thomas, 1974). Yet, approaching the selection from the purpose of the unit cost yields a unique criterion for allocation.

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 aligns. 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, the profitability evaluation on the level of the product must align with that of the capacity. 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:*

$$\lambda^c \equiv \frac{CM^c}{CM}, \text{ and } \lambda^r \equiv \frac{CM^r}{CM}. \tag{4.24}$$

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, which equals the share of the other output, 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.

In relation to alternative allocation bases, the relative contribution margin also shows as necessary and sufficient for the criterion of profitability alignment. Traditional allocation bases, for instance, may align profitability for some but not all production schedules. Note, however, that an allocation by relative contribution margin requires an assumption of the production schedule.[27] 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:*

$$LCOE \equiv w^r + \lambda^r \cdot (f^r + \Delta \cdot c^r). \tag{4.25}$$

ii) *The levelized cost of hydrogen is given by:*[28]

$$LCOH \equiv \frac{1}{\eta^c} \cdot \big(w^c \cdot \Gamma^c + \lambda^c \cdot (f^c + \Delta \cdot c^c)\big). \tag{4.26}$$

[27] 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.

[28] 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.

Definition 2 shows that the levelized product cost at shared capacity can, like the initial formalization for dedicated capacity (see, for instance, Reichelstein and Yorston (2013)), 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 essential addition to the formulation is the cost allocation factor that adjusts the fixed operating and capacity costs for the share of the contribution margin earned with 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 electricity and hydrogen. As derived in the previous section, 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 thus adjusted with the co-variation coefficient Γ^r.

Proposition 4. *Suppose a reversible PtG facility produces both outputs and capacity-related costs are allocated by relative contribution margin. 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 shared 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 Yorston (2013).

With an eye on previous work, note that the levelized cost of individual products aligns under certain conditions with the notion of full cost transfer pricing for decentralized capacity management, as 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. If the division managers are to make the investment decision, the main issue is to align the decision of both managers. Proposition 4 shows that if both managers make the decision based on the levelized cost per unit of product with capacity-related costs allocated by relative contribution margin, their decision would indeed be aligned. This sketched-out scenario, however, abstracts from problems that commonly arise in decentralized investment decisions, 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). By identifying the lowest product price a capacity has to receive on average to break-even, the levelized cost of a product also quantifies 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. *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 of joint costs? With the shift to intermittent renewable power and the attendant trend of falling power prices, a reversible PtG facility produces hydrogen for the majority of the time and only occasionally switches to electricity generation as weather conditions become adverse for renewables and power prices rise. Hydrogen thus receives the larger and electricity the smaller share of joint costs. This stands in contrast to recent studies on the competitiveness of PtG, which account the entire capacity-related costs to the production of electricity (i.e. $\lambda^r = 1$) (Braff et al., 2016, Jülch, 2016, Steward and Zuboy, 2014). The analysis shows, however, 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 in addition to the benefits above. 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 still entail higher cost.

4.5 Reversible Power-to-Gas in Germany and Texas

This final section seeks to evaluate numerically 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 including references is provided in the *Appendix*.

4.5.1 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, as a producer of industry gases, eligible for the wholesale market price plus a relatively small markup for taxes, fees and levies. In Texas, the facility draws on the fixed 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. Integrating these revenues with the prices at which the facility can buy electricity, yields 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.[29]

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 *Appendix*.

[29] The effect of higher values for δ_h is shown in the *Appendix*.

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, 2018b).

TABLE 4.1: 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 4.1. 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.

TABLE 4.2: 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 results for the competitiveness of electricity and hydrogen are summarized in Table 4.2. 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, the cost of conventional power generation varies in each jurisdiction by production technology.[30] 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.[31] Electricity from reversible PtG is thus far more costly even though the allocated share of joint costs is small and reversible PtG achieves to produce some electricity in Texas.

4.5.2 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 to solve the issues of intermittency and decarbonization 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 (Kazaz, 2004, Dong et al., 2014). In the presence of

[30] 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.

[31] The numbers result from own calculations with data for Germany largely retrieved from Fraunhofer ISE (2018) and for Texas from Comello et al. (2018a), ABB (2018), and OpenEI (2018) (see a detailed overview in the *Appendix*). 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.

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.[32]

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 energy source is wind energy as it reaches peak production levels at night when demand from the grid and electricity prices are relatively low (Reichelstein and Sahoo, 2015, Engelhorn and Müsgens, 2018). At present, system prices for wind turbines average in Germany to 1,180 €/kW and in Texas to 1,566 \$/kW (Fraunhofer IWES, 2017, ABB, 2018). The average capacity factors of the wind energy 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 $D(0) = \max\{LCOE(0) - \Gamma \cdot p_e(0), 0\}$.

[32] In addition to the economic benefit, a reversible PtG facility also improves on its carbon footprint with emissions associated to grid electricity and better reflects a form of clean energy storage. Since the PtG facility has market access for selling electricity, the analysis neglects the possibility to restrict the PtG facility completely from purchasing electricity from the market to cut all carbon emissions (Glenk and Reichelstein, 2019).

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).[33] 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 for the new SOC technology with input from manufacturers, articles in peer-reviewed journals, 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 *Appendix* for details).[34] 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%.

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 4.4, 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%.

[33] 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.

[34] Even if the novelty of the technology entails some uncertainty as to the speed of the cost decline, the fact that the trajectory results from independent data points reinforces the magnitude of it.

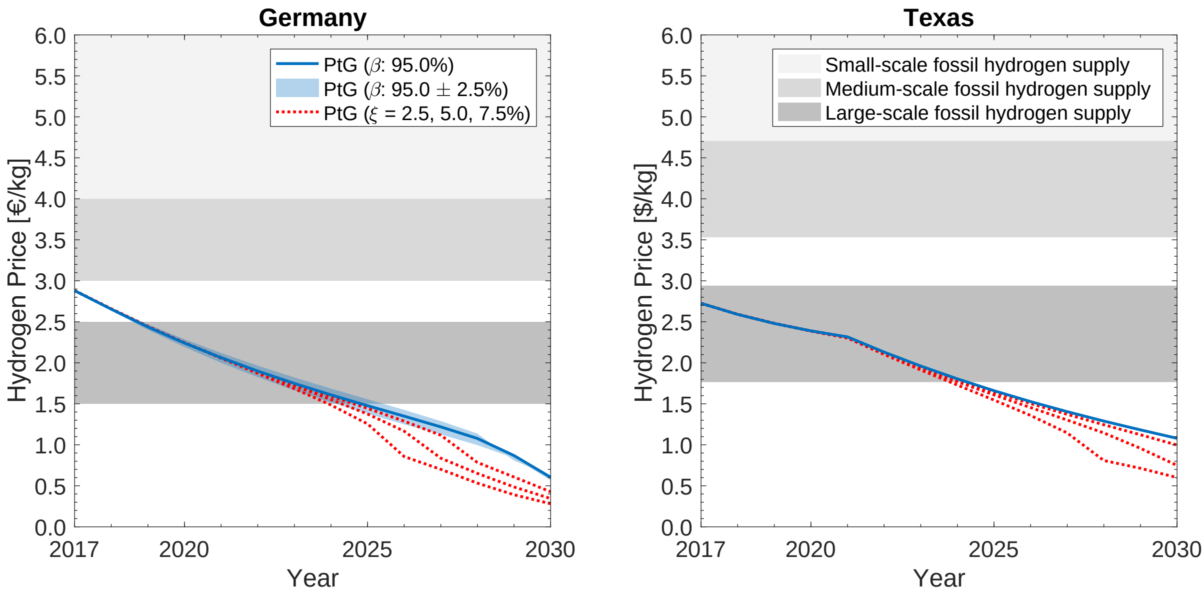

FIGURE 4.4: Prospects for the competitiveness of hydrogen.

Conversely, Figure 4.5 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 4.5 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%.[35] 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. 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, Glenk and Reichelstein, 2018, Jentsch, 2014, 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

[35] 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.

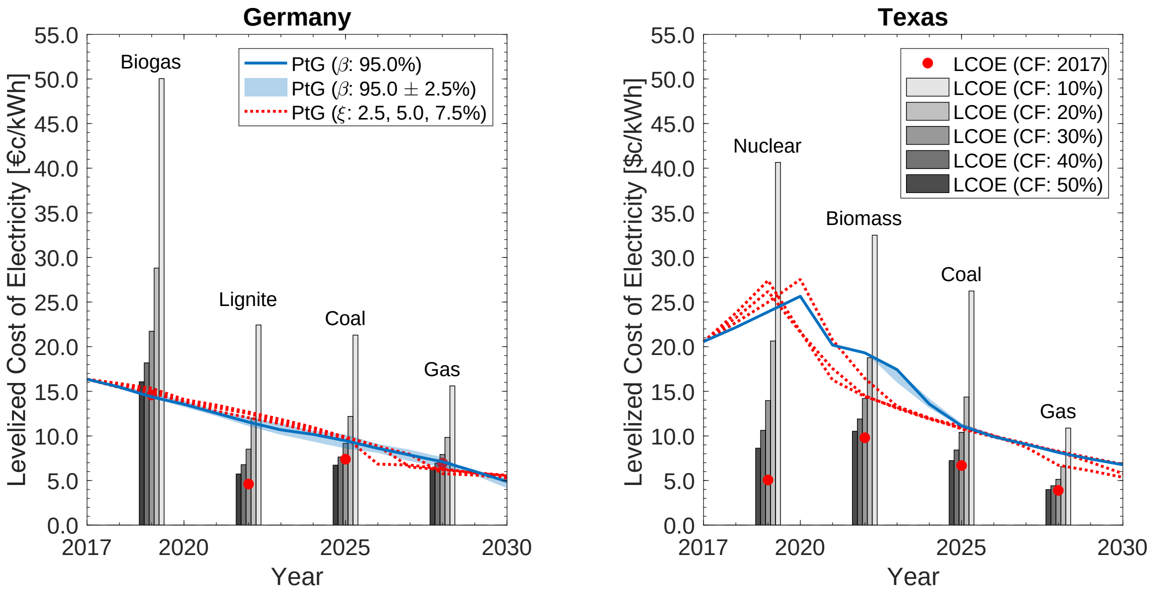

FIGURE 4.5: Prospects for the competitiveness of electricity.

in capital-intensive investments (Bertuccioli et al., 2014, Felgenhauer and Hamacher, 2015). Furthermore, the conversion of both grid and renewable energy allows the PtG facility to obtain a higher utilization than renewable energy alone would do (Glenk and Reichelstein, 2019). Finally, the calculations include the favorable trends in the costs and prices of wind energy and PtG.

4.6 Conclusion

No delivery of products and services goes without the associated stream of costs. This paper has proposed a framework for the characterization of unit cost relevant for product prices and capacity investments when productive capacity is shared among multiple outputs. Building upon the concept of levelized product cost, the relevant unit cost is 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 the relevant cost equals the constant price required for selling a product and is calculated by the levelized product cost. Contrary to the initial conceptualization, however, is a unique cross-sectional cost allocation that must be included in the calculation when capacity is shared.

The paper applies the framework to new Power-to-Gas (PtG) technology that can reversibly convert electricity to hydrogen. Reversible PtG can potentially solve the challenges of intermittent renewable energy and industrial decarbonization that both are becoming crucial in the transition towards a low-carbon economy. 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. A numerical 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, projects that both outputs will likely become competitive with the lower prices paid in large-scale applications over the coming decade. These promising results stem from the fact that the evaluations account for the ability to operate reversibly and trade the storage medium (hydrogen), which leads to an effective sharing of sizable joint costs.

The paper suggests several avenues for future research. In respect of the accounting theory, the analysis has confined attention to the characterization of levelized cost when capacity is shared. Subsequent work could further examine 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.

5 Conclusion

It is widely agreed that the world economies must transition towards decarbonized energy systems. The crucial question, however, remains whether this transition can be performed sufficiently fast so as to reduce carbon dioxide concentrations in the atmosphere and avert the most disastrous repercussions of a changing climate. This thesis examines the economics of renewable hydrogen produced from electricity via Power-to-Gas (PtG) technology. Renewable hydrogen has a major potential to reduce carbon emissions, but widespread adoption has so far been retained by the inability to generate clean hydrogen at low cost. With the recent technological progress for PtG systems and the rapidly changing economics of renewable energy sources, the question arises whether economic opportunities for renewable hydrogen can emerge.

In the context of this thesis, the subject of hydrogen production with PtG has been studied in three distinct essays. The first essay has examined the economic prospects for renewable hydrogen from the perspective of a possible corporate investor. The investor would seek to exploit real-time fluctuations in power prices and intermittent renewable electricity generation with a PtG facility that sources electricity purely from a renewable energy source. Crucial to the case is thereby that both energy systems are optimized in capacity sizes relative to each other. Calibrated to current market conditions in Germany and Texas, a numerical evaluation finds that renewable hydrogen is already cost competitive in niche applications with hydrogen supply generated from fossil fuels. Provided recent market trends continue, including sustained cost reductions and policy support, the evaluations project that renewable hydrogen will also become competitive with industrial-scale supply within the coming decade.

The second essay has explored the synergistic value of combining a renewable energy source with a PtG facility to a vertically integrated system. Synergies arise as a result of market imperfections for the intermediary input factor electricity and of fluctuations in output and prices causing operational volatility. A certain synergistic benefit occurs for any vertically integrated system, but here a synergistic value is only attributed if the synergistic effect also suffices to overcompensate a negative net present value of one or both of the energy systems on their own. The analyses have derived necessary and sufficient conditions for the presence of synergistic value. Similar to environments without operational volatility, the conditions can be stated in terms of average costs and prices per unit. The only additions are covariance coefficients that adjust the average values for the extent to which price and output fluctuations align across the hours of the year.

Applying the model framework to wind energy and PtG in Germany and Texas, numerical calculations find that the presence of synergistic value in Germany is contingent on the market price of hydrogen being above some break-even level. This is because wind power in Germany is eligible to a governmental subsidy for renewable energy that ensures that it is cost competitive stand-alone. In the current market, the break-even value for stand-alone PtG is above the price for industrial-scale hydrogen supply but below the higher prices paid for medium-scale supply. Despite a supportive tax credit, wind energy in Texas, on the other hand, fails to be cost competitive with the low wholesale prices for electricity in the current market. Likewise PtG facilities are not viable stand-alone at the price level of transactions for industrial-scale supply. Nevertheless, the calculations find that the synergies that result from combining the two energy systems are sufficiently large for the vertically integrated energy system to have synergistic value.

The third essay has proposed a theoretical framework for the characterization of unit cost that can be useful for guiding capacity investment decisions when capacity is shared among multiple outputs. By converting and reconverting electricity to hydrogen on the same facility, new reversible PtG technology reflects a shared capacity and submits the promise to store energy at large scale. Building upon the concept of levelized product cost, my analysis shows that unit cost should reflect the constant revenue payment that an investor in the capacity would have to receive in order to break-even on the investment. The payment depends in type on the perspective of the investor and identifies the aggregation of upfront capacity expenditures with periodic operating expenses to the relevant cost and unit.

In application to reversible PtG in Germany and Texas, a numerical assessment finds that hydrogen production is already cost competitive with industrial hydrogen supply in the current economic environment if the reversible PtG facility is vertically integrated with a co-located wind energy source. Electricity obtained from reconverting hydrogen entails costs that are only competitive in niche applications at first. Recent market development, however, suggests a trend towards more favorable economics with which the electricity from reversible PtG is projected to also become competitive with the lower prices paid for conventional power generation.

Across the set of analyses, the main conclusion emerges that hydrogen produced with PtG will likely be sufficiently competitive so as to fulfill the promise of substantially reducing carbon emission. Sourcing electricity from both a renewable source and the electric grid, the numerical evaluations find that hydrogen from PtG is competitive with large-scale industrial hydrogen supply and can thus already reduce some carbon emissions profitably in the current market. For hydrogen produced purely from renewable energy to curtail all carbon emissions, the calculations indicate a profitable business case for corporate investors to arrive within the coming decade if recent market trends continue. This conclusion corroborates the potential of the technology to become a key element of decarbonized energy systems.

The findings of my analyses bear several implications for industry and policy, within and beyond the context of energy systems. Within energy, potential investors as well as policy makers receive a general framework to assess the economics of renewable hydrogen production in their specific case that is shaped by the resources and institutions available in their geographic region. Regulators can also use the framework as a tool to examine the power of policy measures that are intended to accelerate the transition to decarbonized energy technologies, like PtG. Recall, for instance, that waiving the feed-in requirement for wind energy in Germany to receive the subsidy or publicly funded rebates for the investment cost of PtG facility would be two such supportive mechanisms. In the general context, the frameworks of all three essays appear useful for analyzing issues in industrial settings with properties similar to energy systems. One example is the question of vertical integration under operational volatility that arises also in the area of agriculture. Volatile prices for crops could be hedged by farmers investing in machinery that transforms the crops to products with a fixed price. Another example is the issue of identifying relevant unit cost when capacity is shared among multiple outputs. Because of the many ways to apportion costs intertemporally among periods and cross-sectionally among outputs, this issue has been topic of a long-standing debate on productive capacity in both traditional manufacturing and service-oriented businesses.

After all, my analyses are not without limitations, which reveals several avenues for future research. With regard to the theoretical frameworks, all three analytical models are based on net present value analyses. Since a PtG facility generally reflects, from the perspective of a renewable power generator, a risk-reducing real option on the uncertain electricity price, it could be instructive to extend the frameworks by a real option approach for valuation. An alternative extension of the framework could be the addition of stochastic shocks to prices and output as frequently employed in the literature on capacity investments. Such shocks would also likely increase the option value of PtG investments and lower the break-even price for hydrogen obtained numerically. A third promising avenue is to further investigate the interpretation of the levelized cost concept as a measure of full cost. While my analysis has focused on the characterization of levelized cost when capacity is shared, much of the literature has discussed the efficiency of full cost for solving various managerial accounting problems.

In the area of clean energy systems, the analyses could be extended to model the dynamics of wind energy more profoundly so as to predict the competitive position of wind power specifically for different geographic regions and regulatory environments. Alternatively, the frameworks for evaluating hydrogen energy storage could be enhanced to a general concept of storing electricity over time. With the cost of battery storage systems falling rapidly, a race between various energy storage technologies is expected to emerge. Regarding the promise of synthetic fuels, it would be instructive to explore the synergies that arise from combining hydrogen production from surplus renewable electricity with carbon capture technology.

In meditation about life, the narrator in the novel *In Search of Lost Time* by the French author Marcel Proust remarks: “A change in the weather is sufficient to recreate the world and ourselves.” The research in this thesis is built on the premise that the prospects of the climate changing to outright dangerous conditions can trigger coordinated efforts for innovation of unprecedented global extent. The ultimate objective of these ambitions is to ensure that future generations will be able to flourish in an environment that is as nourishing as the one we enjoy today. Mankind has already gained important momentum on the road towards this goal by developing a range of technologies, including renewable hydrogen, that appear indispensable going forward. The majority of innovation, however, has yet to be discovered.

Appendix

Appendix to: The Prospects for Renewable Hydrogen Production

Proof of the NPV Expression

The NPV of a hybrid energy system of capacity sizes $(k_e = 1, k_h)$ is given by the present value of future operating cash flows less the initial capacity investment:

$$NPV(k_e, k_h) = \sum_{i=1}^{T} CFL_i(k_e = 1, k_h) \cdot \gamma^i - (k_e \cdot SP_e + k_h \cdot SP_h), \tag{5.1}$$

with $CFL_i(k_e, k_h)$ as the after-tax operating cash flow in year i. It is given by the difference between the pre-tax cash flow in year i, $CFL_i^o(k_e, k_h)$, and current corporate income taxes, given by the tax rate, α, applied to the taxable income, $I_i(k_e, k_h)$:

$$CFL_i(k_e, k_h) = CFL_i^o(k_e, k_h) - \alpha \cdot I_i(k_e, k_h). \tag{5.2}$$

The pre-tax operating cash flow in year i comprises the optimized contribution margin of a hybrid energy system less the fixed operating costs:

$$CFL_i^o(k_e, k_h) = x^{i-1} \int_0^m CM(t|k_e, k_h)dt - (k_e \cdot F_{ei} + k_h \cdot F_{hi}), \tag{5.3}$$

with $x < 1$ denoting the degradation factor, that is, the percentage by which capacity declines in each subsequent year. The firm's taxable income in year i is then given by the pre-tax cash flow less depreciation, with d_i denoting the allowable depreciation percentage in year i.

$$I_i(k_e, k_h) = CFL_i^o(k_e, k_h) - (k_e \cdot SP_e + k_h \cdot SP_h) \cdot d_i. \tag{5.4}$$

Combining the expressions in (5.2), (5.3), and (5.4), the net present value can be restated as:

$$\begin{aligned} NPV(k_e,k_h) =&(1-\alpha)\cdot\left[\sum_{i=1}^{T}\gamma^i\cdot\left(x^{i-1}\int_0^m CM(t|k_e,k_h)dt-(k_e\cdot F_{ei}+k_h\cdot F_{hi})\right)\right] \\ &-(1-\alpha\sum_{i=1}^{T}d_i\cdot\gamma^i)\cdot(k_e\cdot SP_e+k_h\cdot SP_h). \end{aligned} \tag{5.5}$$

Since the tax factor was defined as:

$$\Delta=\frac{1-\alpha\cdot\sum_{i=1}^{T}d_i\cdot\gamma^i}{1-\alpha}, \tag{5.6}$$

the expression for the NPV reduces to:

$$\begin{aligned} NPV(k_e,k_h) =&(1-\alpha)\cdot\left[\sum_{i=1}^{T}\gamma^i\cdot\left(x^{i-1}\int_0^m CM(t|k_e,k_h)dt-(k_e\cdot F_{ei}+k_h\cdot F_{hi})\right)\right. \\ &\left.-\Delta\cdot(k_e\cdot SP_e+k_h\cdot SP_h)\right]. \end{aligned} \tag{5.7}$$

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

$$\begin{aligned} NPV(k_e,k_h) =&(1-\alpha)\cdot L\cdot\left[\frac{1}{m}\int_0^m CM(t|k_e,k_h)dt-\frac{k_e\cdot F_{ei}+k_h\cdot F_{hi}}{m\cdot\sum_{i=1}^{T}x^{i-1}\cdot\gamma^i}\right. \\ &\left.-\Delta\cdot\frac{k_e\cdot SP_e+k_h\cdot SP_h}{m\cdot\sum_{i=1}^{T}x^{i-1}\cdot\gamma^i}\right]. \end{aligned} \tag{5.8}$$

The body of the paper and *Methods* introduced the levelized cost of electricity of the renewable energy source as $LCOE=f_e+\Delta\cdot c_e$ (assuming a zero variable cost for generating renewable electricity), and $LFCH=f_h+\Delta\cdot c_h$. Here, f_e and f_h refer to the time averaged operating fixed costs and c_e and c_h to the unit costs of capacity of the two subsystems. We thus obtain:

$$NPV(k_e,k_h)=(1-\alpha)\cdot L\cdot\left[\frac{1}{m}\int_0^m CM(t|k_e,k_h)dt-CF\cdot k_e\cdot LCOE-k_h\cdot LFCH\right]. \tag{5.9}$$

We now substitute with the optimized contribution margin:

$$\begin{aligned} NPV(k_e, k_h) =& (1-\alpha) \cdot L \cdot \left[\frac{1}{m} \left(k_e \int_0^m p_e(t) \cdot CF(t) dt + \int_0^m CP_h(t) \cdot z(t|k_e, k_h) dt \right) \right. \\ & \left. - CF \cdot k_e \cdot LCOE - k_h \cdot LFCH \right]. \end{aligned} \tag{5.10}$$

The final step accounts for the temporal co-variations in prices and capacity factors (Reichelstein and Sahoo, 2015). We denote $\epsilon(t)$ as the multiplicative deviation factor of $CF(t)$ from the yearly average CF and $\mu(t)$ as the multiplicative deviation factor of $p_e(t)$ from the yearly average p_e so that:

$$\epsilon(t) = \frac{CF(t)}{CF} \text{ and } \mu(t) = \frac{p_e(t)}{p_e}. \tag{5.11}$$

The average capacity factor is given by $CF = \frac{1}{m} \int_0^m CF(t) dt$ and the average electricity price is given by $p_e = \frac{1}{m} \int_0^m p_e(t) dt$. The covariation between the output and the price can then be captured by the co-variation coefficient:

$$\Gamma = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu(t) \; dt. \tag{5.12}$$

We further recall that, by definition, $\delta(t) \cdot CP_h = CP_h(t)$ and

$$z(k_e, k_h) \equiv \frac{1}{m} \int_0^m z(t|k_e, k_h) \cdot \delta(t) \; dt.$$

Taken together, the expression for the NPV simplifies to:

$$NPV(k_e, k_h) = (1-\alpha) \cdot L \cdot [(\Gamma \cdot p_e - LCOE) \cdot CF \cdot k_e + CP_h \cdot z(k_e, k_h) - LFCH \cdot k_h]. \tag{5.13}$$

■

Proof of Finding 1

For sufficiency, we show that given $k_e = 1$ the partial derivative:

$$\frac{\partial}{\partial k_h} NPV(k_e = 1, k_h) \bigg|_{k_h = 0} > 0, \tag{5.14}$$

if the inequality in Finding 2 holds.

$$\frac{\partial}{\partial k_h} NPV(1,k_h)\bigg|_{k_h=0} = CP_h \cdot \frac{\partial}{\partial k_h} z(1,0) - LFCH \tag{5.15}$$

$$= CP_h - LFCH > 0. \tag{5.16}$$

For necessity, suppose the condition in Finding 2 is not met, yet the hybrid energy system is economically viable and thus $NPV(1,k_h) \geq NPV(1,0)$ for some k_h. We then obtain:

$$NPV(1,k_h) - NPV(1,0) = \int_0^{k_h} \frac{\partial}{\partial k_h} NPV(1,u) du \tag{5.17}$$

$$= \int_0^{k_h} \left[CP_h \cdot \frac{\partial}{\partial k_h} z(1,u) - LFCH\right] du \tag{5.18}$$

$$\leq \int_0^{k_h} [CP_h - LFCH]\, du \tag{5.19}$$

$$= k_h \cdot [CP_h - LFCH] \tag{5.20}$$

$$< 0, \tag{5.21}$$

a contradiction. ■

Proof of Finding 2

Suppose the hybrid energy system is economically viable, that is, $NPV(1, k_h^*(1)) > 0$. Finding 1 established that $k_h^*(1) > 0$ if only if $CP_h - LFCH > 0$. Now suppose that, contrary to the claim, $CP_h - LFCH + (\Gamma \cdot p_e - LCOE) \cdot CF < 0$. It would then follow that:

$$NPV(1, k_h^*(1)) = (1-\alpha) \cdot L \cdot [CP_h \cdot z(1, k_h^*(1)) - LFCH \cdot k_h^*(1) + (\Gamma \cdot p_e - LCOE) \cdot CF] \tag{5.22}$$

$$\leq (1-\alpha) \cdot L \cdot [CP_h \cdot k_h^*(1) - LFCH \cdot k_h^*(1) + (\Gamma \cdot p_e - LCOE) \cdot CF] \tag{5.23}$$

$$\leq (1-\alpha) \cdot L \cdot [CP_h - LFCH + (\Gamma \cdot p_e - LCOE) \cdot CF] \tag{5.24}$$

$$< 0. \tag{5.25}$$

The first inequality follows from the observation that, by definition, $z(1, k_h^*(1)) \leq k_h^*(1)$, while the second inequality relies on $k_h^*(1) \leq 1$ due to the fact that $\lim_{k_h \to 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$. ■

Input Variables

	Germany	Texas	Source
General			
Economic lifetime	30 years	30 years	Michalski et al. (2017)
Corporate income tax rate	35.00 %	35.00 %	German and United States tax code
Degradation rate	0.80 %	0.80 %	Fraunhofer ISE (2013)
Depreciation rate	16y linear	5y MACRS	Bundesfinanzhof (2011), U.S. IRS (2015)
Cost of capital (WACC)	4.00 %	6.00 %	Fraunhofer ISI (2016), Moné et al. (2015)
Subsidy lifetime	20 years	10 years	EEG (2017), U.S. Department of Energy (2016)
Wind energy			
Capacity factor	30.27 %	34.61 %	Own data and ABB (2018)
Variable operating cost	0.00 €/kWh	0.00 $/kWh	ABB (2018)
Fixed operating cost	38.00 €/kW	17.00 $/kW	Wallasch et al. (2016), ABB (2018)
Acquisition cost	1,367 €/kW	1,596 $/kW	Deutsche WindGuard (2013), ABB (2018)
Power-to-Gas			
Conversion rate	0.019 kg/kWh	0.019 kg/kWh	Bertuccioli et al. (2014)
Variable operating cost	0.10 €/kg	0.08 $/kg	Estimation of water cost.*
Fixed operating cost	45.00 €/kW	39.50 $/kW	Own review, see *Methods* of paper
Acquisition cost	2,287 €/kW	2,009 $/kW	Own review, see *Methods* of paper

*Conversion to $ with average exchange rate of 2015 (1.1104 $/€, see European Central Bank) and United States state index (0.7910, Comello et al. (2018a)).

Cost Structure of a Power-to-Gas System

The cost for the balance of system is based on Verband kummunaler Unternehmen (2016).

	Value	Unit
Foundation and access	42.00	€/kW
Power connection	150.00	€/kW
Electrolyzer	1,863.00	€/kW
Piping	4.00	€/kW
Compression	56.00	€/kW
Buffer	52.00	€/kW
Feed-in system	56.00	€/kW
Other	64.00	€/kW
Total	**2,287.00**	**€/kW**

Feed-in Premium in Germany

Since we base the calculation on 2015, the Feed-in Premium falls under the Renewable Energy Act from 2014 (Art. 19, 49) for the first two years (EEG, 2014). The amount of the premium is the difference between a total value that is defined by law and a monthly average market value of wind energy. This total value amounts to 8.95 €¢/kWh for the first five years of operation and 4.95 €¢/kWh for the remaining 15 years. However, this period of the higher subsidy may be extended depending on the output of the wind park. The period is extended by one month per 0.36% difference by which the wind yield of the wind facility is below 130% of a reference output and by one month per 0.48% difference below 100% of the reference output. This benchmark is provided by an independent agency and amounts to 48,249,931 kWh for 5 years for the turbine in our study, an Enercon E-101 with 149m hub height (Fördergesellschaft Windenergie und andere Erneuerbare Energien, 2016). Thus, the calculation of the extension is given by:

	Specification	Value	Unit
Number of years with start premium		5.00	years
Reference output per turbine	100 %	9,649,986	kWh
Valuation basis	130 %	12,544,982	kWh
Average output per wind turbine (2015)		8,086,946	kWh
% of reference output		84.00	%
§49 (2) 1 - additional months	0.36 %	83.33	months
§49 (2) 2 - additional months	0.48 %	33.74	months
Total additional months of start premium		117.08	months
Additional years of start premium		9.76	years
Total number of years with start premium		**14.76**	**years**

The monthly average market value is the monthly average of the hourly spot prices weighted by the electricity produced in kWh and provided by Netztransparenz.de (2016).

Current Economic Viability of Renewable Hydrogen

As noted in the main text of the paper, the feed-in requirement of the subsidy in Germany reflects a prohibitively large opportunity cost to convert renewable energy to hydrogen. If the requirement was maintained in its current form, the break-even price of hydrogen would increase by 3.21 €/kg and therefore almost double.

	Germany	Texas
Wind energy		
Variable operating cost	0.00 €¢/kWh	0.00 $¢/kWh
Fixed operating cost	1.58 €¢/kWh	0.61 $¢/kWh
Capacity Cost	3.29 €¢/kWh	4.18 $¢/kWh
Tax factor	1.1463	1.0549
Levelized PP or PTC	4.73 €¢/kWh	1.99 $¢/kWh
Levelized cost of electricity	5.36 €¢/kWh	5.02 $¢/kWh
Electricity price	3.18 €¢/kWh	2.55 $¢/kWh
Co-variation coefficient	0.88	0.88
Profit margin of wind energy	0.65 €¢/kWh	-0.27 $¢/kWh
Power-to-Gas		
Fixed operating cost	0.63 €¢/kWh	0.55 $¢/kWh
Capacity Cost	1.67 €¢/kWh	1.82 $¢/kWh
Levelized fixed cost of hydrogen	2.54 €¢/kWh	2.47 $¢/kWh
Hybrid energy system		
Conversion premium of hydrogen	2.85 €¢/kWh	4.23 $¢/kWh
Break-even price of hydrogen	3.23 €/kg	3.53 $/kg
Optimal capacity of PtG	0.01 kW	0.29 kW

Appendix to: Operational Volatility and Synergistic Value in Vertically Integrated Energy Systems

Proof of Lemma 1

We show that the claim in the statement applies to the four phases identified in Figure 3.2 of the main text. In Phase 1, both electricity prices exceed the contribution margin of hydrogen: $p^b(t) \geq p^s(t) \geq CV_h \geq 0$. The operator will idle the PtG facility and only sell renewable energy. The optimized contribution margin of the vertically integrated energy system will be equal to the contribution margin of the renewable energy source. To see this, note that:

$$p^+(t) = \max\{\min\{p^b(t), CV_h\}, p^s(t)\} = \max\{CV_h, p^s(t)\} = p^s(t). \tag{5.26}$$

Furthermore:

$$p^{b+}(t) = \max\{p^b(t), CV_h\} = p^b(t). \tag{5.27}$$

The optimized contribution margin of the vertically integrated energy system in equation (3.9) of the main body thus reduces to:

$$CM(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e. \tag{5.28}$$

In Phase 2, the buying price exceeds the contribution margin of hydrogen, which, in turn exceeds the selling price: $p^b(t) \geq CV_h > p^s(t) \geq 0$. The facility will convert the generated renewable energy without purchases of additional energy from the market. We find that:

$$p^+(t) = \max\{\min\{p^b(t), CV_h\}, p^s(t)\} = \max\{CV_h, p^s(t)\} = CV_h, \tag{5.29}$$

and $p^+(t) - p^s(t) = CV_h - p^s(t)$. Since $p^b(t) \geq CV_h$, $p^{b+}(t) - p^b(t) = 0$. Consistent with (3.9), the optimized contribution margin of the vertically integrated energy system reduces to the contribution margin of the renewable energy source plus the conversion premium of renewable energy:

$$CM(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e + [CV_h - p^s(t)] \cdot z(t|k_e, k_h). \tag{5.30}$$

In Phase 3, both electricity prices are less than the contribution margin of hydrogen and non-negative: $CV_h > p^b(t) \geq p^s(t) \geq 0$. The plant will convert the generated renewable energy and buy energy from the market to produce as much hydrogen as possible. Thus:

$$\begin{aligned} CM(t|k_e, k_h) = {} & p^s(t) \cdot CF(t) \cdot k_e \\ & + [CV_h - p^s(t)] \cdot z(t|k_e, k_h) \\ & + [CV_h(t) - p^b(t)] \cdot [k_h - z(t|k_e, k_h)]. \end{aligned} \tag{5.31}$$

Equivalently:

$$\begin{aligned} CM(t|k_e, k_h) = {} & p^s(t) \cdot CF(t) \cdot k_e \\ & + [p^b(t) - p^s(t)] \cdot z(t|k_e, k_h) \\ & + [CV_h(t) - p^b(t)] \cdot k_h. \end{aligned} \tag{5.32}$$

In this scenario:

$$p^+(t) = \max\{\min\{p^b(t), CV_h\}, p^s(t)\} = \max\{p^b(t), p^s(t)\} = p^b(t), \tag{5.33}$$

and therefore $p^+(t) - p^s(t) = p^b(t) - p^s(t)$. Furthermore:

$$p^{b+}(t) = \max\{p^b(t), CV_h\} = CV_h, \tag{5.34}$$

so that $p^{b+}(t) - p^b(t) = CV_h - p^b(t)$ and (5.32) coincides with (3.9).

Finally, the buying price is negative in Phase 4. By assumption, $p^b(t) \leq 0 = p^s(t)$. The plant operator will only buy energy from the market to convert it to hydrogen and refrain from selling renewable energy. We find that:

$$p^+(t) = \max\{\min\{p^b(t), CV_h\}, p^s(t)\} = \max\{p^b(t), p^s(t)\} = p^s(t), \tag{5.35}$$

and $p^+(t) - p^s(t) = 0$. Furthermore:

$$p^{b+}(t) = \max\{p^b(t), CV_h\} = CV_h, \tag{5.36}$$

and $p^{b+}(t) - p^b(t) = CV_h - p^b(t)$. The expression in (3.9) therefore reduces to the contribution margin of a stand-alone PtG plant running on grid electricity only:

$$CM(t|k_e, k_h) = [CV_h(t) - p^b(t)] \cdot k_h. \tag{5.37}$$

■

Proof of Lemma 2

The NPV of a vertically integrated energy system is given by the present value of future operating cash flows less the initial capacity investment:

$$NPV(k_e, k_h) = \sum_{i=1}^{T} CFL_i(k_e, k_h) \cdot \gamma^i - (k_e \cdot SP_e + k_h \cdot SP_h), \tag{5.38}$$

with $CFL_i(k_e, k_h)$ as the after-tax operating cash flow in year i. It is given by the difference between the pre-tax cash flow in year i, $CFL_i^o(k_e, k_h)$, and current corporate income taxes, given by the tax rate, α, applied to the taxable income, $I_i(k_e, k_h)$:

$$CFL_i(k_e, k_h) = CFL_i^o(k_e, k_h) - \alpha \cdot I_i(k_e, k_h). \tag{5.39}$$

The pre-tax operating cash flow in year i comprises the optimized contribution margin of a vertically integrated energy system less the fixed operating costs:

$$CFL_i^o(k_e, k_h) = x^{i-1} \int_0^m CM(t|k_e, k_h)dt - (k_e \cdot F_{ei} + k_h \cdot F_{hi}), \tag{5.40}$$

with $x < 1$ denoting the degradation factor, that is, the percentage by which capacity declines in each subsequent year. The firm's taxable income in year i is then given by the pre-tax cash flow less depreciation, with d_i denoting the allowable depreciation percentage in year i. For simplicity, we assume that the same depreciation schedule applies to all components of the vertically integrated energy system:

$$I_i(k_e, k_h) = CFL_i^o(k_e, k_h) - (k_e \cdot SP_e + k_h \cdot SP_h) \cdot d_i. \tag{5.41}$$

Combining the expressions in (5.39), (5.40), and (5.41), the net present value becomes:

$$\begin{aligned} NPV(k_e,k_h) =& (1-\alpha)\cdot\left[\sum_{i=1}^{T}\gamma^i\cdot\left(x^{i-1}\int_0^m CM(t|k_e,k_h)dt-(k_e\cdot F_{ei}+k_h\cdot F_{hi})\right)\right] \\ & -(1-\alpha\sum_{i=1}^{T}d_i\cdot\gamma^i)\cdot(k_e\cdot SP_e+k_h\cdot SP_h). \end{aligned} \tag{5.42}$$

Since the tax factor was defined as:

$$\Delta=\frac{1-\alpha\cdot\sum_{i=1}^{T}d_i\cdot\gamma^i}{1-\alpha}, \tag{5.43}$$

the expression for the NPV reduces to:

$$\begin{aligned} NPV(k_e,k_h) =& (1-\alpha)\cdot\left[\sum_{i=1}^{T}\gamma^i\cdot\left(x^{i-1}\int_0^m CM(t|k_e,k_h)dt-(k_e\cdot F_{ei}+k_h\cdot F_{hi})\right)\right. \\ & \left.-\Delta\cdot(k_e\cdot SP_e+k_h\cdot SP_h)\right]. \end{aligned} \tag{5.44}$$

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

$$\begin{aligned} NPV(k_e,k_h) =& (1-\alpha)\cdot L\cdot\left[\frac{1}{m}\int_0^m CM(t|k_e,k_h)dt\right. \\ & \left.-\frac{\sum_{i=1}^{T}\gamma^i\cdot(k_e\cdot F_{ei}+k_h\cdot F_{hi})}{m\cdot\sum_{i=1}^{T}x^{i-1}\cdot\gamma^i}-\Delta\cdot\frac{k_e\cdot SP_e+k_h\cdot SP_h}{m\cdot\sum_{i=1}^{T}x^{i-1}\cdot\gamma^i}\right]. \end{aligned} \tag{5.45}$$

The body of the paper introduced the levelized cost of electricity of the renewable energy source as $LCOE=f_e+\Delta\cdot c_e$ (assuming a zero variable cost for generating renewable electricity), and $LFCH=f_h+\Delta\cdot c_h$. Here, f_e and f_h refer to the time averaged operating fixed costs and c_e and c_h to the unit costs of capacity of the two subsystems. We thus obtain:

$$NPV(k_e,k_h)=(1-\alpha)\cdot L\cdot\left[\frac{1}{m}\int_0^m CM(t|k_e,k_h)dt-CF\cdot k_e\cdot LCOE-k_h\cdot LFCH\right]. \tag{5.46}$$

Lemma 1 allows us to substitute the following expression for the optimized contribution margin:

$$
\begin{aligned}
NPV(k_e, k_h) =&(1-\alpha) \cdot L \cdot \left[\frac{1}{m} \left(k_e \int_0^m p^s(t) \cdot CF(t) dt \right.\right. \\
&+ \int_0^m [p^+(t) - p^s(t)] \cdot z(t|k_e, k_h) dt + k_h \int_0^m \left(p^{b+}(t) - p^b(t)\right) dt \Bigg) \\
&\left. - CF \cdot k_e \cdot LCOE - k_h \cdot LFCH \right].
\end{aligned} \tag{5.47}
$$

The final step accounts for the temporal co-variations in prices and capacity factors. We recall from the main text that $\epsilon(t)$ denotes the multiplicative deviation factor of $CF(t)$ from the yearly average CF and $\mu(t)$ as the multiplicative deviation factor of $p^s(t)$ from the yearly average p^s so that:

$$
\epsilon(t) = \frac{CF(t)}{CF} \text{ and } \mu(t) = \frac{p^s(t)}{p^s}. \tag{5.48}
$$

The average capacity factor is given by $CF = \frac{1}{m} \int_0^m CF(t) dt$ and the average selling price is given by $p^s = \frac{1}{m} \int_0^m p^s(t) dt$. The covariation between output and the price can then be captured by the co-variation coefficient:

$$
\Gamma^s = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu(t) \, dt. \tag{5.49}
$$

We further recall that, by definition, $\mu^+(t) \cdot (p^+ - p^s) = p^+(t) - p^s(t)$ and

$$
z(k_e, k_h) \equiv \frac{1}{m} \int_0^m z(t|k_e, k_h) \cdot \mu^+(t) \, dt. \tag{5.50}
$$

Taken together, the expression for the NPV simplifies to:

$$
\begin{aligned}
NPV(k_e, k_h) =&(1-\alpha) \cdot L \cdot [(\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e \\
&+ (p^{b+} - p^b - LFCH) \cdot k_h \\
&+ (p^+ - p^s) \cdot z(k_e, k_h)].
\end{aligned} \tag{5.51}
$$

■

Proof of Proposition 1

If both stand-alone systems are cost competitive, the vertically integrated energy system has synergistic value whenever:

$$p^+ - p^s > 0. \tag{5.52}$$

It follows directly from the definition of $p^+(t)$ that:

$$p^+(t) = \max\{\min\{CV_h, p^b(t)\}, p^s(t)\} \geq p^s(t), \tag{5.53}$$

and that (5.52) is fulfilled if and only if it holds that:

$$\min\{CV_h, p^b(t)\} > p^s(t) \text{ for some } t. \tag{5.54}$$

■

Proof of Proposition 2

(i) For sufficiency, we show that given $k_e = 1$ the partial derivative:

$$\frac{\partial}{\partial k_h} NPV(k_e = 1, k_h)\bigg|_{k_h=0} > 0, \tag{5.55}$$

if the inequality in equation (3.27) of the main body holds.

$$\frac{\partial}{\partial k_h} NPV(1, k_h)\bigg|_{k_h=0} = (p^+ - p^s) \cdot \frac{\partial}{\partial k_h} z(1, 0) + (p^{b+} - p^b) - LFCH \tag{5.56}$$

$$= (p^+ - p^s) + (p^{b+} - p^b) - LFCH > 0. \tag{5.57}$$

For necessity, suppose the condition in (3.27) is not met, yet the vertically integrated energy system exhibits synergistic value and thus $NPV(1, k_h) \geq NPV(1, 0)$ for some k_h. We obtain:

$$\begin{aligned}
NPV(1, k_h) - NPV(1, 0) &= \int_0^{k_h} \frac{\partial}{\partial k_h} NPV(1, u) du && (5.58)\\
&= \int_0^{k_h} \left[(p^+ - p^s) \cdot \frac{\partial}{\partial k_h} z(1, u) + (p^{b+} - p^b) - LFCH\right] du && (5.59)\\
&\leq \int_0^{k_h} \left[(p^+ - p^s) + (p^{b+} - p^b) - LFCH\right] du && (5.60)\\
&= k_h \cdot \left[(p^+ - p^s) + (p^{b+} - p^b) - LFCH\right] && (5.61)\\
&< 0, && (5.62)
\end{aligned}$$

a contradiction.

(ii) If there is synergistic value, the first-order condition for the optimal $k_h^*(1)$ is:

$$\frac{\partial}{\partial k_h} NPV(1, k_h^*(1)) = \frac{\partial}{\partial k_h} z(1, k_h^*(1)) \cdot (p^+ - p^s) + (p^{b+} - p^b) - LFCH = 0. \tag{5.63}$$

The value of $k_h^*(1)$ is unique because $\frac{\partial}{\partial k_h} z(1, \cdot)$ is monotone decreasing in k_h. Furthermore, $NPV(1, \cdot)$ is increasing in k_h up to $k_h^*(1)$ and decreasing thereafter. ■

The proof for Proposition 3 is entirely symmetric.

Proof of Proposition 4

(i) If neither stand-alone system is cost competitive, the vertically integrated energy system has synergistic value whenever:

$$NPV(1, k_h^*(1)) \geq 0. \tag{5.64}$$

It follows directly from the characterization of the $NPV(k_e, k_h)$ in Proposition 2 that $NPV(1, k_h^*(1))$ is proportional to:

$$(p^+ - p^s) \cdot z(1, k_h^*(1)) + (p^{b+} - p^b - LFCH) \cdot k_h^*(1) + (\Gamma^s \cdot p^s - LCOE) \cdot CF, \tag{5.65}$$

thus establishing the claim.

(ii) The argument here is the same as those in the proofs of Propositions 2 and 3, where k_e and k_h, respectively, have been held fixed at the value of 1 kW. ■

Proof of Corollary to Proposition 4

Suppose the vertically integrated system has synergistic value, that is, $NPV(1, k_h^*(1)) > 0$. Proposition 2 established that $k_h^*(1) > 0$ if only if $p^+ - p^s + p^{b+} - p^b - LFCH > 0$. Now suppose that, contrary to the claim, $p^+ - p^s + p^{b+} - p^b - LFCH + (\Gamma^s \cdot p^s - LCOE) \cdot CF < 0$. It would then follow that:

$$
\begin{aligned}
NPV(1, k_h^*(1)) &= (1-\alpha) \cdot L\big[(p^+ - p^s) \cdot z(1, k_h^*(1)) + (p^{b+} - p^b - LFCH) \cdot k_h^*(1) && (5.66)\\
&\quad + (\Gamma^s \cdot p^s - LCOE) \cdot CF\big] \\
&\leq (1-\alpha) \cdot L\big[(p^+ - p^s) \cdot k_h^*(1) + (p^{b+} - p^b - LFCH) \cdot k_h^*(1) && (5.67)\\
&\quad + (\Gamma^s \cdot p^s - LCOE) \cdot CF\big] \\
&\leq (1-\alpha) \cdot L\big[(p^+ - p^s) + p^{b+} - p^b - LFCH && (5.68)\\
&\quad + (\Gamma^s \cdot p^s - LCOE) \cdot CF\big] \\
&< 0. && (5.69)
\end{aligned}
$$

The first inequality follows from the observation that, by definition, $z(1, k_h^*(1)) \leq k_h^*(1)$, while the second inequality relies on $k_h^*(1) \leq 1$ due to the fact that $\lim\limits_{k_h \to 1} \frac{\partial}{\partial k_h} z(1, k_h) = 0$. ■

Input Variables

	Germany	Texas	Source
General			
Economic lifetime	30 years	30 years	Michalski et al. (2017)
Corporate income tax rate	35.00 %	21.00 %	German and United States tax code
Degradation rate	0.80 %	0.80 %	Fraunhofer ISE (2013);
Depreciation rate	16y linear	100 % Bonus	Bundesfinanzhof (2011), U.S. Congress (2017)
Cost of capital (WACC)	4.00 %	6.00 %	Fraunhofer ISI (2016), Moné et al. (2015)
Subsidy lifetime	20 years	10 years	EEG (2017), U.S. Department of Energy (2016)
Wind energy			
Capacity factor	30.33 %	44.39 %	Own data and ABB (2018)
Variable operating cost	0.00 €/kWh	0.00 $/kWh	ABB (2018)
Fixed operating cost	38.00 €/kW	21.70 $/kW	Wallasch et al. (2016), ABB (2018)
Acquisition cost	1,180 €/kW	1,566 $/kW	Fraunhofer IWES (2017), ABB (2018)
Power-to-Gas			
Conversion rate	0.019 kg/kWh	0.019 kg/kWh	Bertuccioli et al. (2014)
Variable operating cost	0.10 €/kg	0.08 $/kg	Estimation of water cost.*
Fixed operating cost	45.00 €/kW	39.50 $/kW	Glenk and Reichelstein (2019)
Acquisition cost	2,074 €/kW	1,822 $/kW	Glenk and Reichelstein (2019)

*Conversion to $ with average exchange rate of 2015 (1.1104 $/€, see European Central Bank) and United States state index (0.7910, Comello et al. (2018a)).

Structure 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.)
Total industry price markup	€¢/kWh	1.3710	

In Texas, we use 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 according to §2.151.317 (a) (6) of the Texas tax code.

A PtG facility offering frequency control can provide "regulation down", as it is called in Texas, and the equivalent "negative Sekundärregelleistung" in Germany. 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, we assume 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:

$$p^b(t) = \phi(t) \cdot p^c(t) + (1 - \phi(t)) \cdot p^m(t), \tag{5.70}$$

where $p^c(t)$ denotes the price for calling energy per kWh, $\phi(t)$ the share of called capacity in hour t, and $p^m(t)$ the price for market energy per kWh. The capacity price adds to the conversion premium of hydrogen. Since the price is paid per kW, we divide it by the hours of standby to receive a price per kWh. With p^{sb} denoting the average standby price, the NPV becomes:

$$NPV(k_h) = \ (1 - \alpha) \cdot L \cdot (p^{b+} - p^b - p^{sb} - LFCH) \cdot k_h. \tag{5.71}$$

Offering frequency control requires the PtG facility to absorb electricity when called, which effectively reduces the capacity to convert renewable energy. Thus, $z(t|k_e, k_h)$ becomes:

$$z(t|k_e, k_h) \equiv \min\{CF(t) \cdot k_e, (1 - \phi(t)) \cdot k_h\}. \tag{5.72}$$

Stand-alone Wind Energy

	Germany	**Texas**
Variable operating cost	0.00 €¢/kWh	0.00 $¢/kWh
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	2.42 $¢/kWh
Selling price	3.46 €¢/kWh	2.44 $¢/kWh
Co-variation coefficient	0.87	0.93
Profit margin	0.00 €¢/kWh	-0.15 $¢/kWh

Stand-alone Power-to-Gas

	Germany	**Texas**
Fixed operating cost	0.63 €¢/kWh	0.55 $¢/kWh
Capacity Cost	1.51 €¢/kWh	1.65 $¢/kWh
Levelized fixed cost of hydrogen	2.36 €¢/kWh	2.22 $¢/kWh
Buying price of electricity	3.93 €¢/kWh	5.39 $¢/kWh
Medium-scale price of hydrogen	3.50 €/kg	4.00 $/kg
Medium-scale buying premium	2.93 €¢/kWh	2.67 $¢/kWh
Large-scale price of hydrogen	2.00 €/kg	2.50 $/kg
Large-scale buying premium	1.12 €¢/kWh	0.54 $¢/kWh
Medium-scale profit margin	0.57 €¢/kWh	0.44 $¢/kWh
Large-scale profit margin	-1.24 €¢/kWh	-1.69 $¢/kWh

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

Proof of Proposition 1

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

$$NPV = \sum_{i=1}^{T} CFL_i \cdot \gamma^i - SP, \tag{5.73}$$

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 α multiplied with the taxable income, I_i:

$$CFL_i = CFL_i^o - \alpha \cdot I_i. \tag{5.74}$$

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

$$CFL_i^o = x^{i-1} \int_0^m CM(t)dt - F_i. \tag{5.75}$$

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

$$I_i = CFL_i^o - SP \cdot d_i. \tag{5.76}$$

Combining the expressions in (5.74), (5.75), and (5.76), the net present value becomes:

$$NPV = (1-\alpha) \cdot \left[\sum_{i=1}^{T} \gamma^i \cdot \left(x^{i-1} \int_0^m CM(t)dt - F_i \right) \right] - (1 - \alpha \sum_{i=1}^{T} d_i \cdot \gamma^i) \cdot SP. \tag{5.77}$$

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

$$NPV = (1-\alpha) \cdot \left[\sum_{i=1}^{T} \gamma^i \cdot \left(x^{i-1} \int_0^m CM(t)dt - F_i \right) - \Delta \cdot SP \right]. \tag{5.78}$$

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

$$NPV = (1-\alpha) \cdot L \cdot \left[\frac{1}{m} \int_0^m CM(t)dt - \frac{\sum_{i=1}^{T} \gamma^i \cdot F_i}{L} - \Delta \cdot \frac{SP}{L} \right]. \tag{5.79}$$

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

$$NPV = (1-\alpha) \cdot L \cdot \left[\frac{1}{m} \int_0^m CM(t)dt - LFC \cdot CF \right]. \tag{5.80}$$

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

$$CM = \frac{1}{m} \int_0^m CM(t)dt = \frac{1}{m} \int_0^m \big[\big(\eta^c \cdot p_h - w^c(t)\big) \cdot CF^c(t) + \big(p_e(t) - w^r\big) \cdot CF^r(t) \big] dt. \tag{5.81}$$

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

$$CM = \big[\eta^c \cdot p_h - w^c \cdot \frac{1}{m} \int_0^m \epsilon^c(t) \cdot \mu^c(t)dt \big] \cdot CF^c + \big[p_e \cdot \frac{1}{m} \int_0^m \epsilon^r(t) \cdot \mu^r(t)dt - w^r \big] \cdot CF^r. \tag{5.82}$$

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

$$CM = (\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r. \tag{5.83}$$

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

$$NPV = (1-\alpha) \cdot L \cdot \big[(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r - LFC \cdot CF \big]. \tag{5.84}$$

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

$$(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r \geq LFC \cdot CF. \tag{5.85}$$

■

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 given by:

$$CM^c(p_h) = \eta^c \cdot p_h \cdot CF^c(p_h) - w^c \cdot CF^c(p_h), \tag{5.86}$$

where

$$CF^c = \begin{cases} 1 & \text{if } \eta^c \cdot p_h > w^c, \\ 0 & \text{otherwise.} \end{cases} \tag{5.87}$$

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:

$$CM^r(p_h) = p_e \cdot CF^r(p_h) - \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot CF^r(p_h), \tag{5.88}$$

where

$$CF^r = \begin{cases} 1 & \text{if } p_e > \frac{1}{\eta^r} \cdot (p_h + \delta_h), \\ 0 & \text{otherwise.} \end{cases} \tag{5.89}$$

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:

$$CM^c(p_h) = \eta^c \cdot p_h \cdot CF^c(p_h) - \frac{1}{m}\int_0^m w^c(t) \cdot CF^c(t|p_h)dt. \tag{5.90}$$

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

$$\frac{\partial}{\partial p_h}CM^c(p_h) = \eta^c \cdot p_h \cdot \frac{\partial}{\partial p_h}CF^c(p_h) + \eta^c \cdot CF^c(p_h) - \frac{\partial}{\partial p_h}\left(\frac{1}{m}\int_0^m w^c(t) \cdot CF^c(t|p_h)dt\right) \geq 0. \tag{5.91}$$

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

$$\frac{\partial}{\partial p_h}CF^c(p_h) = \frac{1}{m}\int_{\{t|\eta^c \cdot p_h > w^c(t)\}} 1 \; dt, \text{ and} \tag{5.92}$$

$$\frac{\partial}{\partial p_h}\left(\frac{1}{m}\int_0^m w^c(t) \cdot CF^c(t|p_h)dt\right) = \frac{1}{m}\int_{\{t|\eta^c \cdot p_h > w^c(t)\}} w^c(t)dt. \tag{5.93}$$

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

$$CM^r(p_h) = \frac{1}{m}\int_0^m p_e(t) \cdot CF^r(t|p_h)dt - \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot CF^r(p_h). \tag{5.94}$$

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

$$\begin{aligned}\frac{\partial}{\partial p_h}CM^r(p_h) =& \frac{\partial}{\partial p_h}\left(\frac{1}{m}\int_0^m p_e(t) \cdot CF^r(t|p_h)dt\right) \\ &- \frac{1}{\eta^r} \cdot (p_h + \delta_h) \cdot \frac{\partial}{\partial p_h}CF^r(p_h) - \frac{1}{\eta^r} \cdot CF^r(p_h) \leq 0.\end{aligned} \tag{5.95}$$

$\frac{\partial}{\partial p_h} CM^r(p_h) \leq 0$, 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:

$$\frac{\partial}{\partial p_h} CF^r(p_h) = \frac{1}{m} \int\limits_{\{t|p_e(t)>w^r(t|p_h)\}} 1 \; dt, \text{ and} \tag{5.96}$$

$$\frac{\partial}{\partial p_h} \left(\frac{1}{m} \int\limits_0^m p_e(t) \cdot CF^r(t|p_h) dt \right) = \frac{1}{m} \int\limits_{\{t|p_e(t)>w^r(t|p_h)\}} p_e(t) dt. \tag{5.97}$$

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:

$$CM - LFC \cdot CF > 0, \tag{5.98}$$

$$(\lambda^c + \lambda^r) \cdot CM - (\lambda^c + \lambda^r) \cdot LFC \cdot CF > 0, \tag{5.99}$$

$$\lambda^c \cdot (CM - LFC \cdot CF) + \lambda^r \cdot (CM - LFC \cdot CF) > 0. \tag{5.100}$$

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:

$$\lambda^c \cdot (CM - LFC \cdot CF) > 0, \tag{5.101}$$

if follows that:

$$\lambda^r \cdot (CM - LFC \cdot CF) = (1 - \lambda^c) \cdot (CM - LFC \cdot CF) > 0, \text{ and} \tag{5.102}$$

$$CM - LFC \cdot CF > 0. \tag{5.103}$$

In contrast, 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:

$$NPV = (1-\alpha) \cdot L \cdot \left[CM - (\lambda^c + \lambda^r) \cdot \left(\frac{\sum_{i=1}^{T} \gamma^i \cdot F_i}{L} - \Delta \cdot \frac{SP}{L}\right)\right]. \tag{5.104}$$

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:

$$\begin{aligned} NPV = (1-\alpha) \cdot L \cdot \Big[&CF^c \cdot \Big(\eta^c \cdot p_h - w^c \cdot \Gamma^c - \lambda^c \cdot (f^c + \Delta \cdot c^c)\Big) \\ &+ CF^r \cdot \Big(p_e \cdot \Gamma^r - w^r - \lambda^r \cdot (f^r + \Delta \cdot c^r)\Big)\Big]. \end{aligned} \tag{5.105}$$

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

$$LCOH = \frac{1}{\eta^c} \cdot \big(w^c \cdot \Gamma^c + \lambda^c \cdot (f^c + \Delta \cdot c^c)\big). \tag{5.106}$$

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

$$LCOE = w^r + \lambda^r \cdot (f^r + \Delta \cdot c^r). \tag{5.107}$$

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

$$NPV = (1-\alpha) \cdot L \cdot \Big[CF^c \cdot \eta^c \cdot \Big(p_h - LCOH\Big) + CF^r \cdot \Big(p_e \cdot \Gamma^r - LCOE)\Big)\Big]. \tag{5.108}$$

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

$$p_h \geq LCOH, \text{ and } p_e \cdot \Gamma^r \geq LCOE. \tag{5.109}$$

■

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:

$$NPV = (1-\alpha) \cdot L \cdot (\Gamma \cdot p_e - LCOE) \cdot CF_e, \tag{5.110}$$

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:

$$ptc \equiv PTC \cdot \frac{\sum_{i=1}^{10} x^{i-1} \cdot \gamma^i}{(1-\alpha) \sum_{i=1}^{T} x^{i-1} \cdot \gamma^i}. \tag{5.111}$$

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 upon reasonable request.

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:

$$p^b(t) = \phi(t) \cdot p^c(t) + (1 - \phi(t)) \cdot (p_e(t) + \delta_e), \tag{5.112}$$

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:

$$NPV = (1-\alpha) \cdot L \cdot \left[(\eta^c \cdot p_h - w^c \cdot \Gamma^c) \cdot CF^c + (p_e \cdot \Gamma^r - w^r) \cdot CF^r - LFC \cdot CF - p^{sb} \right]. \tag{5.113}$$

Input Variables

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

Cost of Conventional Power Generation

Germany	**Natural Gas**	**Lignite**	**Source**
Economic lifetime	30 years	30 years	Fraunhofer ISE (2018)
Acquisition cost	950 €/kW	3,000 €/kW	Fraunhofer ISE (2018)
Capacity factor	39.95%	60.50%	Agentur für Erneuerbare Energien (2013)
Degradation rate	0.40%	0.40%	Comello et al. (2018a)
Fixed operating cost	22.00 €/kW	120.00 €/kW	Fraunhofer ISE (2018)
Variable operating cost	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)	5.00%	5.00%	Fraunhofer ISI (2016), Moné et al. (2015)
Corporate income tax rate	35.00%	35.00%	German Tax Code
Depreciation rate	20y linear	20y linear	Bundesfinanzministerium (2018)

Germany	Lignite	Coal	Source
Economic lifetime	40 years	40 years	Fraunhofer ISE (2018)
Acquisition cost	1,900 €/kW	1,650 €/kW	Fraunhofer ISE (2018)
Capacity factor	68.49%	42.24%	Agentur für Erneuerbare Energien (2013)
Degradation rate	0.40%	0.40%	Comello et al. (2018a)
Fixed operating cost	36.00 €/kW	32.00 €/kW	Fraunhofer ISE (2018)
Variable operating cost	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)	5.00%	5.00%	Fraunhofer ISI (2016), Moné et al. (2015)
Corporate income tax rate	35.00%	35.00%	German Tax Code
Depreciation rate	25y linear	25y linear	Bundesfinanzministerium (2018)

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

Texas	Nuclear	Biomass	Source
Economic lifetime	50 years	30 years	ABB (2018), IEA (2015), NETL (2012)
Acquisition cost	4,122 $/kW	2,695 $/kW	ABB (2018), IEA (2015), NETL (2012)
Capacity factor	90.06%	57.70%	ABB (2018), IEA (2015), NETL (2012)
Degradation rate	0.40%	0.40%	ABB (2018), IEA (2015), NETL (2012)
Fixed operating cost	65.42 $/kW	31.23 $/kW	ABB (2018), IEA (2015), NETL (2012)
Variable operating cost	0.08 $¢/kWh	0.12 $¢/kWh	ABB (2018), IEA (2015), NETL (2012)
Fuel cost	0.54 $¢/kWh	4.92 $¢/kWh	ABB (2018), IEA (2015), NETL (2012)
Carbon dioxide emissions cost	0.00 $/t	0.00 $/t	ABB (2018), IEA (2015), NETL (2012)
Emissions performance	0.00 kg/kWh	0.00 kg/kWh	ABB (2018), IEA (2015), NETL (2012)
Cost of capital (WACC)	6.00%	6.00%	Fraunhofer ISI (2016), Moné et al. (2015)
Corporate income tax rate	21.00%	21.00%	U.S. IRS (2018)
Depreciation rate	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	4.08 €¢/kWh	7.57 €¢/kWh	1.56 €¢/kWh	3.08 €¢/kWh
Fixed operating cost	0.66 €¢/kWh	2.37 €¢/kWh	0.64 €¢/kWh	0.92 €¢/kWh
Capacity Cost	1.85 €¢/kWh	3.86 €¢/kWh	2.75 €¢/kWh	2.75 €¢/kWh
Tax factor	1.2029	1.2029	1.2349	1.2349
Levelized cost of electricity	6.96 €¢/kWh	14.59 €¢/kWh	4.61 €¢/kWh	7.40 €¢/kWh

Texas	Natural Gas	Coal	Nuclear	Biomass
Variable operating cost	2.26 $¢/kWh	2.49 $¢/kWh	0.62 $¢/kWh	5.04 $¢/kWh
Fixed operating cost	0.28 $¢/kWh	0.71 $¢/kWh	0.65 $¢/kWh	0.65 $¢/kWh
Capacity Cost	1.33 $¢/kWh	3.43 $¢/kWh	4.05 $¢/kWh	4.05 $¢/kWh
Tax factor	1.0150	1.0150	1.0150	1.0150
Levelized cost of electricity	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 5.1 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 outlying electricity prices cause a larger allocation of capacity-related costs. Levelized cost of hydrogen production remain unaffected.

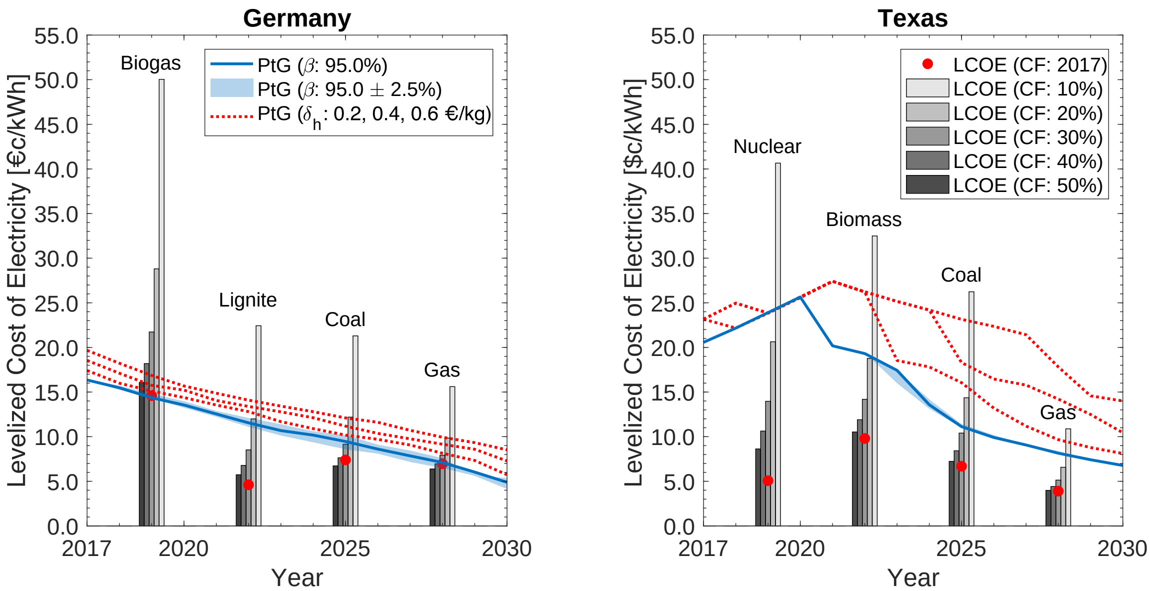

FIGURE 5.1: Prospects for the competitiveness of electricity with hydrogen markups.

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