Operational Volatility and Synergistic Value in Vertically Integrated Energy Systems

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Abstract

We examine the magnitude of synergistic effects in vertically integrated energy systems that arise when the external market for an intermediate input (electricity) is imperfect and the two subsystems are subject to operational volatility in terms of price and output fluctuations. The front part of our analysis develops a model for identifying when a vertically integrated energy system exhibits synergistic value. Specifically, we provide necessary and sufficient conditions for the value (NPV) of the integrated system to exceed the sum of the maximized values of the two subsystems on their own. We then apply this framework to current settings in Germany and Texas for systems that combine wind energy with Power-to-Gas (PtG) facilities for hydrogen production. Depending on the attainable market prices for hydrogen in particular 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.

Keywords: operational volatility, vertical integration, renewable energy, power-to-gas
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 Boyabatlı 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. 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. 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.

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

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.

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

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3Our 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.
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 U.S., 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, 2018). 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 2 develops the economic model for the identification of synergistic value in vertically integrated energy systems under conditions of operational volatility. Section 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 4 concludes the paper. Supplemental materials, including proofs, data sources and detailed simulation results are provided in the Online Appendix.

2 Economic Model

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 to the downstream production subsystem. While our model has multiple generic features, 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 is illustrated in Figure 1 and consists of 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.
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 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.

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. 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:

$$p_s(t) \begin{cases} \leq p_b(t) & \text{if } p_b(t) \geq 0, \\ = 0 & \text{if } p_b(t) < 0. \end{cases} \quad (1)$$

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 $\eta$, reflecting the amount of hydrogen that can be procured from 1 kWh of electricity. Accordingly, the conversion value of hydrogen is given by:

$$CV_h = \eta \cdot (p_h - w_h). \quad (2)$$

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:

$$CM(t|k_h) = [CV_h - p_b(t)] \cdot k_h, \quad (3)$$

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

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4For 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.
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 2, both the buying and the selling electricity price exceed the contribution margin 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:

\[ CM_1(t|k_e) = p_s(t) \cdot CF(t) \cdot k_e. \]  

(4)

In Phase 2, the buying price exceeds the contribution margin of hydrogen, which, in turn, exceeds the selling price: 

\[ p_b(t) \geq CV_h > p_s(t) \geq 0. \]

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 $t$:

$$z(t|k_e, k_h) \equiv \min\{CF(t) \cdot k_e, k_h\}. \quad (5)$$

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:

$$CM_2(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e + [CV_h - p^s(t)] \cdot z(t|k_e, k_h). \quad (6)$$

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:

$$CM_3(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e$$

$$+ [CV_h - p^s(t)] \cdot z(t|k_e, k_h)$$

$$+ [CV_h - p^b(t)] \cdot [k_h - z(t|k_e, k_h)]. \quad (7)$$

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:

$$CM_4(t|k_h) = [CV_h - p^b(t)] \cdot k_h. \quad (8)$$

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.

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5Proofs are shown in the Online Appendix.
**Lemma 1.** The optimized contribution margin of a vertically integrated energy system at time \( t \) is:

\[
CM(t|k_e, k_h) = p^s(t) \cdot CF(t) \cdot k_e \\
+ [p^{b+}(t) - p^b(t)] \cdot k_h \\
+ [p^+(t) - p^s(t)] \cdot z(t|k_e, k_h),
\]

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 (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.

### 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 system; see, for instance, [Islegen and Reichelstein (2011)](https://doi.org/10.2139/ssrn.1879739)\(^6\).

\(^6\)As shown in [Reichelstein and Rohlfing-Bastian (2015)](https://doi.org/10.1109/TVS.2015.2398347), this cost measure is also the relevant unit cost for optimal capacity investment decisions in the presence of future random shocks to demand.
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:

\[
LCOE = w_e + f_e + \Delta \cdot c_e, \tag{10}
\]

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 \(\Delta\) 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 overall LCOE:

- \(SP\): system price, the acquisition price of the generation capacity (in $ per kW),
- \(F_i\): fixed operating cost in year \(i\) of the generation facility (in $ per kW),
- \(\gamma\): discount factor with the cost of capital \(r\): \(\gamma = \frac{1}{1+r}\) (scalar),
- \(T\): useful economic life of the production facility (in years),
- \(x^{i-1}\): system degradation factor in year \(i\) (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 \(\gamma\) 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 and Reichelstein, 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:

\[
c_e = \frac{SP_e}{CF \cdot L}. \tag{11}
\]
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.

\[
f_e = \frac{\sum_{i=1}^{T} F_{ei} \cdot \gamma^i}{CF \cdot L}.
\]

(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 \( \alpha \) 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:

\[
\Delta = \frac{1 - \alpha}{1 - \frac{1}{\alpha}} \sum_{i=1}^{T} d_i \cdot \gamma^i.
\]

(13)

It is readily verified that \( \Delta \) is increasing and convex in the tax rate \( \alpha \). \( \Delta \) 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 \( \Delta \). 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). This credit is calculated as:

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

(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, \( p^s \):

\[
\epsilon(t) = \frac{CF(t)}{CF} \quad \text{and} \quad \mu(t) = \frac{p^s(t)}{p^s}.
\]

By definition:

\[
\frac{1}{m} \int_0^m \epsilon(t) = \frac{1}{m} \int_0^m \mu(t) = 1.
\]

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

\[
\Gamma^s = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu(t)dt.
\]

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:

\[
NPV(k_e) = (1 - \alpha) \cdot L \cdot (\Gamma^s \cdot p^s - LCOE) \cdot CF \cdot k_e.
\]

We refer to \( \Gamma^s \cdot p^s - LCOE \) as the profit margin per kWh for the renewable energy source.\(^7\) According to [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

\(^7\)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.
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 \textit{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. With subscript \( h \) denoting hydrogen, we then proceed analogously to the levelized cost of electricity to define the LFCH as:

\[
LFCH = f_h + \Delta \cdot c_h, \tag{19}
\]

where

\[
c_h = \frac{SP_h}{L}, \quad f_h = \frac{\sum_{i=1}^{T} F_{hi} \cdot \gamma^i}{L}. \tag{20}
\]

To express the NPV of a power-to-gas facility, we introduce the \textit{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:

\[
NPV(k_h) = (1 - \alpha) \cdot L \cdot (p^{b+} - p^b - LFCH) \cdot k_h, \tag{21}
\]

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-variation 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 energy system, \( p^+ - p^s \) at time \( t \):

\[
\mu^+(t) = \frac{p^+(t) - p^s(t)}{p^+ - p^s}. \tag{22}
\]

\footnote{The levelized fixed cost of hydrogen is similar to that in \cite{FarhatReichelstein2016}.}

\footnote{This entails the implicit assumption that the PtG can be maintained when it is idle and hence the capacity factor equals one.}
As before, the multiplicative deviation factor reflects a normalization so that \( \frac{1}{m} \int_0^m \mu^+(t) = 1 \). Finally, we denote by \( z(k_e, k_h) \):

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

(23)

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

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

(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 (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 \((k_e, k_h)\):

\[
NPV(k_e, k_h) > \max\{NPV(k_e, 0), 0\} + \max\{NPV(0, k_h), 0\}.
\]

(25)

Clearly, if the inequality in (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 homogenous of degree 1, that is, for any \(\theta > 0\), \(NPV(\theta \cdot k_e, \theta \cdot k_h) = \theta \cdot NPV(k_e, k_h)\).

### 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 \( t \in [0, 8760] \):

\[
\min \{ p^b(t), CV_h \} > p^s(t). \tag{26}
\]

Clearly, the inequality in (26) can only hold during time intervals that correspond to Phases 2 and 3 in the diagram illustrated in Figure 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:

\[
p^+ - p^s > LFCH - (p^{b+} - p^b). \tag{27}
\]

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 (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:

\[
\frac{\partial}{\partial k_h} z(1, k_h^*(1)) \cdot (p^+ - p^s) = LFCH - (p^{b+} - p^b). \tag{28}
\]

\(^{10}\)Our argument here assumes implicitly that the functions \( p^b(\cdot) \) and \( p^s(\cdot) \) are continuous functions.
The partial derivative of $z(1,k_h)$ with respect to $k_h$ is given by:

$$\frac{\partial}{\partial k_h} z(1,k_h) = \frac{1}{m} \int_{\{t | k_h \leq \text{CF}(t)\}} \mu^+(t) dt. \quad (29)$$

Clearly, $\frac{\partial}{\partial k_h} z(1,k_h)$ is decreasing in $k_h$ with $\lim_{k_h \to 0} \frac{\partial}{\partial k_h} z(1,k_h) = 1$ and $\lim_{k_h \to 1} \frac{\partial}{\partial k_h} z(1,k_h) = 0$. Thus $NPV(1, \cdot)$ is a single-peaked function of $k_h$. Furthermore, the fact that $NPV(k_e, k_h)$ is homogenous 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 illustrates these relationships for Scenario 2.

![Figure 3: Linearity of the size of the optimal PtG facility.](image)

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 $k_h \leq \text{CF} \cdot k_e$ 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 $\Gamma_s$, we denote by $\Gamma^+$ the co-variation coefficient between the capacity
factors and the real-time price premia of the vertically integrated energy system:

\[ \Gamma^+ = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu^+(t) dt. \]  

(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:

\[ \Gamma^+ \cdot (p^+ - p^s) > LCOE - \Gamma_s \cdot p^s. \]  

(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 \(\Gamma^+\), 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:

\[ \frac{\partial}{\partial k_e} z(k^*_e(1), 1) \cdot (p^+ - p^s) \cdot \Gamma^+ = LCOE - \Gamma_s \cdot p^s. \]  

(32)

where:

\[ \frac{\partial}{\partial k_e} z(k_e, 1) = \frac{1}{m} \int \{ t \mid CF(t) \cdot k_e < 1 \} \mu^+(t) \cdot CF(t) dt. \]  

(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.

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

![Figure 4: Synergistic value for no cost competitive stand-alone energy system.](image)

**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:

$$(p^+ - p^s) \cdot z(1, k_h^*(1)) + (p^{b+} - p^b - LFCH) \cdot k_h^*(1) + (\Gamma_s \cdot p^s - LCOE) \cdot CF > 0. \tag{34}$$

ii) If the vertically integrated energy system has synergistic value, then $NPV(k_{e,1})$ is a single-peaked function of $k_h$, such that $NPV(k_{e,1})$ 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 (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:

$$p^+ - p^s + p^{b+} - p^b - LFCH + (\Gamma^s \cdot p^s - LCOE) \cdot CF > 0.$$  \hfill (35)

In contrast to the necessary and sufficient condition in (34), the preceding (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 (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 PtG 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 Application: Wind Energy and Power-to-Gas

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 Online Appendix for a comprehensive list).

Wind energy is eligible for a federal Production Tax Credit (PTC) in the U.S. 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)\textsuperscript{11}

Table 1 summarizes the calculation of the unit profit margin for wind energy in both jurisdictions\textsuperscript{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) as the difference between the winning bids and the observed selling prices adjusted with the co-variation coefficients. The estimates we obtain are cor-

\textsuperscript{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.

\textsuperscript{12}The profit margin in Germany is given by $\Gamma^* \cdot p^* + PP - LCOE$ and in Texas by $\Gamma^* \cdot p^* - LCOE$. Recall that the LCOE in Texas includes the PTC reduction.
robated 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 1: Profit margins for wind energy.

<table>
<thead>
<tr>
<th>Input variables</th>
<th>Germany</th>
<th>Texas</th>
</tr>
</thead>
<tbody>
<tr>
<td>System price, $SP_e$</td>
<td>1,180 €/kW</td>
<td>1,566 $/kW</td>
</tr>
<tr>
<td>Capacity factor, $CF$</td>
<td>30.33 %</td>
<td>44.39 %</td>
</tr>
<tr>
<td>Levelized $PP$ or $PTC$</td>
<td>1.81 €/kWh</td>
<td>1.31 $/kWh</td>
</tr>
<tr>
<td>Cost of capital (WACC), $r$</td>
<td>4.00 %</td>
<td>6.00 %</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Profit margins</th>
<th>Germany</th>
<th>Texas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Levelized cost of electricity, $LCOE$</td>
<td>4.83 €/kWh</td>
<td>2.42 $/kWh</td>
</tr>
<tr>
<td>Selling price of electricity, $p_s$</td>
<td>3.46 €/kWh</td>
<td>2.44 $/kWh</td>
</tr>
<tr>
<td>Co-variation coefficient, $\Gamma$</td>
<td>0.87</td>
<td>0.93</td>
</tr>
<tr>
<td>Profit margin</td>
<td>0.00 €/kWh</td>
<td>-0.15 $/kWh</td>
</tr>
</tbody>
</table>

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 3.93 €/kWh in Germany and 5.39 $/kWh in Texas (see the Online Appendix for details).

A PtG facility could be installed onsite or adjacent to a hydrogen customer. 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

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

Table 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 2: Profit margins for Power-to-Gas.

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

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 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 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, $p^+ - p^*$, 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, $p^+ - p^*$, at 2.24 $\$/kWh delivers a sufficiently strong synergistic effect which more than compensates for the two stand-alone losses (Proposition 4).

![Figure 5: Synergistic value of vertically integrated wind energy and PtG system.](image)

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 (25) holds.
as an equality. Figure 6 shows by how much the break-even price falls as a consequence of integrating the two energy systems. 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 yields a synergistic value even if both subsystems are unprofitable on their own. More broadly, the break-even values reported in Figure 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. Figure 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.

<table>
<thead>
<tr>
<th>Country</th>
<th>Stand-alone</th>
<th>Integrated</th>
<th>Renewable</th>
</tr>
</thead>
<tbody>
<tr>
<td>Germany (€/kg)</td>
<td>3.17</td>
<td>3.18</td>
<td>2.59</td>
</tr>
<tr>
<td>Texas ($/kg)</td>
<td>2.75</td>
<td>2.44</td>
<td>3.77</td>
</tr>
</tbody>
</table>

Figure 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 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

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14 We note in passing that the numbers reported in Figure 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.

15 This is the perspective taken in Glenk and Reichelstein (2018). 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.
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, the NPV is a single-peaked function of $k_h$ for any hydrogen price.

![Figure 7: Optimal Power-to-Gas Capacity Size.](image)

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 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 were to convert only renewable energy (Glenk and Reichelstein, 2018). 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.

### 3.4 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 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 (2018), 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, $\Gamma \cdot p^*(i)$, is assumed to decline to zero at a constant adjustment rate such that:

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

where $\beta < 1$ denotes the adjustment rate and $D(0) \equiv \max\{LCOE(0) - \Gamma \cdot p^*(0), 0\}$. 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 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 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 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 \( \xi \) values set equal to 2.5, 5.0 and 7.5\%, respectively.

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 US. 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 re-conversion to electricity may effectively compete with battery storage for electricity supply systems characterized by intermittent generation patterns.

**Supplemental Material**

Supplemental material to this paper is available at (Link when published).
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