N°2024 – 04 • SEPTEMBER 2024

WORKING PAPER

Strategic Investments: Electrolysis vs. Storage for Europe's Energy Security in the Hydrogen Era

Ange BLANCHARD [1*, 2*, 3*]

European hydrogen demand is projected to surge in the upcoming decade, leading to a potential risk of excessive dependence on imports, which may exceed 50% by 2035. This paper compares two strategies to tackle this hydrogen import disruption vulnerability. The first option is to invest in Underground Hydrogen Storage (UHS) for strategic stockpiling. The second option is to increase electrolysis capacity to inflate local production potential. We identify the most effective investment strategies for Central Western Europe (CWE) in 2035 by implementing a Multistage Stochastic Dynamic Programming (MSDP) model. Results show electrolysis outperforms UHS in preventing import disruption risks, although the two technologies are complementary. Notably, electrolysis represents 95% of the strategic investment budget. The overall cost of the optimal strategic investment remains modest, amounting to 5-10% of the total investment in hydrogen infrastructure.

JEL CODES: Q41; Q42; C61; Q48

1* The Industrial Engineering (IE) Research Department (LGI), CentraleSupélec
2* Paris-Saclay University
3* Climate Economics Chair (CEC)

I am indebted to Olivier Massol, Sebastien Lepaul, Julien Ancel, Adrien Nicolle, and Camille Mégy for their insightful suggestions. The remaining errors are, of course, my responsibility. I also thank the participants at the conference on Sustainability, Environment, and Social Transition in Economics and Finance (SESTEF, Southampton 2023), Stéphane Goutte, Anna Creti, and Marc Baudry for their useful remarks. This work was jointly supported by the Chair "The Economics of Natural Gas" and the "Climate Economics Chair." The views expressed herein are strictly those of the author and should not be construed as reflecting the opinions of my affiliations.

KEYWORDS

Hydrogen storage | Electrolysis | Strategic investment | Energy security | Dynamic programming

Executive summary

Hydrogen is poised to become a critical component of Europe's energy transition, with demand expected to rise sharply in the coming decade. However, this surge in demand introduces a significant risk: Europe may become overly reliant on hydrogen imports, potentially leading to an import dependency exceeding 50% by 2035. This paper compares two options to mitigate this vulnerability and ensure a secure and stable hydrogen supply for Central Western Europe (CWE) by 2035: strategic investment in UHS and electrolysis.

Key Findings

1. Investment in Underground Hydrogen Storage (UHS):

UHS provides a means of strategic stockpiling, allowing hydrogen to be stored during periods of low demand and utilized during supply disruptions. However, it requires substantial upfront investment and filling costs.

2. Expansion of Electrolysis Capacity:

Electrolysis enables the domestic production of hydrogen using renewable energy sources, thereby reducing reliance on imports. Massive electrolysis in times of energy scarcity may inflate electricity prices to unsustainable levels, though.

3. Complementarity of Technologies:

Our analysis shows that electrolysis outperforms UHS in mitigating import disruption risks. Indeed, the optimal pathway to hedge against hydrogen disruption involves spending 95% of the dedicated budget on electrolysis rather than UHS. Although electrolysis emerges as the dominant strategy, UHS and electrolysis are not mutually exclusive. In fact, they are complementary, with UHS providing a buffer against short-term supply fluctuations and electrolysis ensuring long-term sustainability. The cost of energy security is found to be low, representing 5-10% of the total investment required for hydrogen infrastructure in the region.

Policy Recommendations

1. Prioritize Investment in Electrolysis:

Governments should focus on accelerating the deployment of electrolysis infrastructure across CWE. This approach will not only reduce import dependency but also enhance energy resilience by leveraging domestic renewable energy sources.

2. Strategic Integration of UHS:

While electrolysis should be the primary focus, UHS should not be neglected. Governments should support the development of UHS facilities as a complementary measure, ensuring that Europe has a robust safety net in case of supply disruptions.

Conclusion

The findings of this paper indicate that investing in electrolysis is the most effective strategy to mitigate the risks associated with hydrogen import dependency. However, a balanced approach that also includes UHS will provide additional security and flexibility. By implementing these recommendations, CWE can build a resilient hydrogen infrastructure that supports a sustainable and secure energy future.

1. Introduction

In the wake of Russia's attack on Ukraine in February 2022, Europe faces a dual mandate: the urgent need to decarbonize its economy and fortify its energy security. In this context, the EU intends to become "the first major economy to set out a strategy on economic security."[1] At the core of this transformative effort lies hydrogen, presented by the EU Commission as a linchpin for decarbonizing gas-intensive industries such as refineries, fertilizers, chemicals, steelmaking, and, to a lesser extent, transportation. Hydrogen can be locally produced through electrolysis using electricity and water. This process — referred to as Power-to-Gas (PtG) in the literature — can help to simultaneously decarbonize the economy and reduce dependence on imports if the electricity is routed from low-carbon sources. To this end, the European Commission revealed the *REPowerEU* initiative in March 2022, aiming at liberating Europe from its dependence on Russian fossil fuels by 2030. The initiative sets an ambitious objective of 10 million tons (Mt) of renewable hydrogen production by the same deadline. Achieving this goal requires at least 65 to 80 GW of electrolysis capacity in the European Union, which surpasses the 40 GW target set in the EU Hydrogen Strategy of July 2020 and the *Fit-for-55* package of July 2021 (IEA, 2022).

Industrial projects working within the EU schemes are already underway. By 2030, the expected capacity from announced projects of 39 GW will be approaching the 40 GW threshold outlined in the *Fit-for-55* package, though it falls short of the 80 GW in the *REPowerEU* Plan (IEA, 2022). Even under an optimistic scenario, with electrolysis capacity reaching the 80 GW target, the European hydrogen demand would eclipse domestic production capabilities. Hydrogen imports will thus be critical for Europe, with an expected level of 10 Mt by 2030,[2] half of its needs. More imports are potentially needed if domestic production faces hurdles in meeting official ambitions.

European countries are already planning to import foreign hydrogen. The Netherlands has positioned itself as a critical entry hub for European imports, exemplified by the plans to start importing green hydrogen to the port of Rotterdam as early as 2025, which will supply Europe with 4.6 Mt/year of H2 by 2030 (Chen et al., 2023). The German government has entered into nearly a dozen agreements with different nations, including Canada, Namibia, Brazil, Australia, Chile, and Saudi Arabia (Dejonghe et al., 2023). Additionally, Germany has launched a unique double auction system for hydrogen imports, allocating €4 billion over ten years through the "H2Global" initiative. Although Europe's future reliance on hydrogen imports remains uncertain, it raises potential energy security concerns, particularly in light of the issues experienced with natural gas in 2022. Navigating this technological transition is crucial for shaping the

[1] Ursula von Der Leyen, Presentation of the economic security strategy, 20/06/2023.
[2] *REPowerEU* plan.

global hydrogen economy. Indeed, potential infrastructural vulnerabilities (e.g., the 2022 Nord Stream gas pipeline incident) highlight the need for Europe to balance costs, energy security, and decarbonization ambitions to ensure a robust and reliable hydrogen economy (Guidehouse, 2022).

Few studies have delved into the question of hydrogen security of supply. Carlson et al. (2023) identify hydrogen's geopolitical, market, and trade risks. They quantify import costs from eight countries, discussing related risks. Dejonghe et al. (2023) suggest hydrogen trade may follow the natural gas market's development, involving bilateral contracts to secure early investments, potentially leading to import dependency. The author presents diversification and strategic investments in hydrogen storage as critical tools for mitigating reliance on a few partners. Nuñez-Jimenez and De Blasio (2022) explore three strategic scenarios for the EU hydrogen market and exhibit the trade-off between affordable and reliable hydrogen imports. They also propose hydrogen strategic storage as an option for managing geopolitical risks in the hydrogen market while preserving a cost advantage.

Despite recognizing storage's role in ensuring hydrogen security, these studies fail to address practical questions such as the level of investment needed for this aim. Additionally, they uniquely focus on storage as a strategic investment, drawing on historical practices from the oil and gas sectors. Proskuryakova (2018) argues that energy security theories are still entrenched in the centralized energy systems paradigm of fossil fuels, while new technologies like renewables and hydrogen challenge this state of the world. The author emphasizes the need for new energy security frameworks that align with the ongoing energy transition. Indeed, hydrogen shows distinct characteristics that call for reassessing traditional energy security strategies. Electrolysis allows for hydrogen production virtually anywhere an electric grid or source is available, contrasting with the oil and gas resources that are geographically limited. This important feature allows for new hedging strategies, including reliance on local production when the disruption occurs. Therefore, the fossil fuel energy security literature suffers from an important loophole when considering new energy sources and vectors like hydrogen. Import diversification (Cohen et al., 2011), taxation (Markandya and Pemberton, 2010), and strategic storage discussions are relevant for both fossil fuels and hydrogen, but the latter deserves a thorough and specific analysis.

This paper fills a gap in the literature by exploring two technical options for mitigating hydrogen import disruption risks: local production through electrolysis and strategic storage with Underground Hydrogen Storage (UHS). We aim to determine if one option is superior and how they interact within an integrated electric-hydrogen system.

As the literature proposes, the first option for this aim is to use UHS sites as strategic assets. On a technical level, the possibility of underground hydrogen long-term storage is known, and the main challenges to its deployment have been identified. As early as 1986, Taylor et al. (1986) showed that UHS was a safe and economical way to store large volumes of electricity converted into hydrogen. More recently, Tarkowski (2019) reviewed the issues related to UHS implementation, showing that the deployment of large-scale UHS requires addressing geological, economic, legal, and social issues. Various studies have examined the feasibility of UHS in different countries or regions. Le Duigou et al. (2017) evaluated the techno-economic feasibility of hydrogen storage in salt caverns in France and showed that this storage method is technically possible in six regions. Lankof and Tarkowski (2020) delved into the Polish potential for UHS in salt caverns and found an important value of almost 5TWh in a single region near the city of Budin, in the Sout-West part of the country. Michalski et al. (2017) presented a preliminary assessment study on the UHS potential in Germany for storage in salt caverns. In an even more recent study, Kondziella et al. (2023) analyzed the potential and the need for long-term hydrogen storage in Germany and found that the geological resources exceed the need by orders of magnitude. Depending on the assumptions on hydrogen demand and investment in electrolyzers, they find a need for up to 67 TWh of UHS. Retrofitted existing natural gas storage caverns that can theoretically cover half of it.

The second and innovative approach relies on investing in an additional electrolysis capacity to compensate for any temporary import shortfall. This solution leverages Europe's ability to produce Hydrogen locally, unlike oil and gas, which could be crucial for mitigating the impact of potential disruptions.

Methodologically, we revisit the oil stockpiling literature following the 1973 and 1979 oil crises, utilizing Multistage Stochastic Dynamic Programming (MSDP) to address the uncertainty and sequential nature of the problem (Plummer, 1981; Teisberg, 1981; Chao and Manne, 1983). We build a numerical bottom-up model of the Central Western European (CWE) electricity and hydrogen markets in 2035. Electrolysis and UHS investments are endogenously determined, as well as dispatch decisions, to minimize the expected system cost over a one-year horizon. We account for both the uncertainty in renewable production and the risk of hydrogen import disruptions through a Markov chain: each month, VRE production is unveiled from a set of potentialities, and there is a probability of the system transitioning to a disrupted state, characterized by spiking hydrogen import prices. We employ the Stochastic Dual Dynamic Programming algorithm (SDDP) to solve an approximated version of this computationally challenging problem. First developed in Brazil by Pereira and Pinto (1991) and applied to the local hydro-dominated power system, SDDP is now increasingly popular for modeling and evaluating the value of any storage operations performed in an energy system (Philpott et al., 2016; Morillo et al., 2020; Dowson and Kapelevich, 2021).

The main contribution of this paper is to show how electrolyzers are a better-suited solution to hedge against hydrogen supply disruptions than UHS. We first carry out an analytical demonstration of that result in a simplistic yet insightful market situation. We show a more comprehensive numerical model yields similar conclusions, with electrolysis receiving 95% of the total strategic investments and displaying a twofold increase in relative capacity compared to UHS. However, this result is nuanced by the complementarity nature of the two technologies. Investing solely in electrolyzers to tackle the hydrogen import risk is suboptimal, and UHS proves useful at complementing electrolysis to this aim.

The paper is organized as follows. Section 2 contains the methodology, first developing analytical intuitions and then drawing on it to build a more complex numerical model. Section 3 presents the data for the application case in the CWE region, and the main results are presented and discussed in Section 4. Lastly, Section 5 offers some concluding remarks.

2. Methodology

Throughout this paper, we assume hydrogen and electricity demands to be inelastic. In this section, we first provide some analytical intuitions about the problem, whose limitations fuel the development of a more complex numerical model, presented in subsection 2.2.

2.1. Analytical intuitions

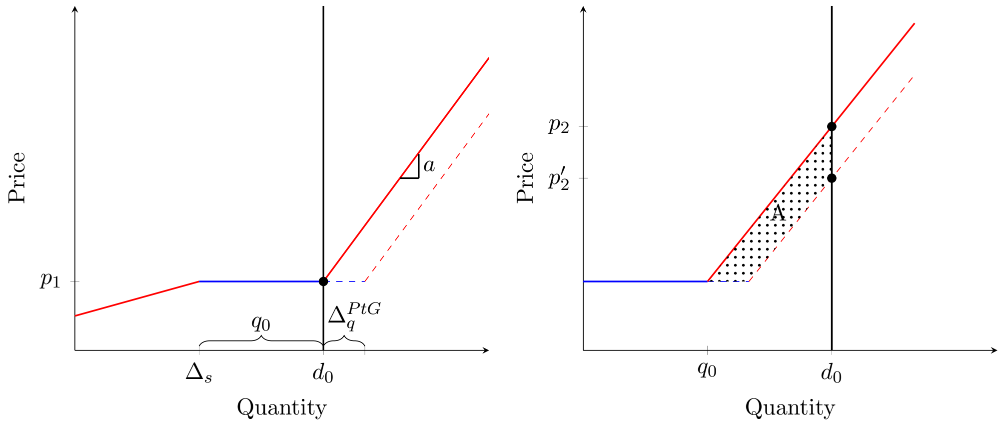
In this analytical exercise, consider a hydrogen supply function composed of three distinct parts. The first part is affordable hydrogen imported from regions with superior technical potential, enabling low-cost clean hydrogen production. The second part characterizes production through local electrolysis. For simplicity, we use a unique efficiency rate resulting in a plateau of hydrogen production at a specific cost determined by the price of the local electricity market. Thirdly, hydrogen can be expensive, sourced from regions with high production costs, characterized by a sharply rising marginal cost at a rate of a, see Figure (1a).

2.1.1. Insurance value of electrolysis

One possible way to handle the risk of supply disruption is to rely on other production sources to overcome this momentous struggle. In this study, we consider electrolysis to be the sole means of local hydrogen production. Investing in electrolysis capacity for strategic concerns incurs an upfront cost, creating a trade-off between the investment and its potential benefits during a disruption. The following analytical model elucidates the main drivers of this issue.

In a situation with no disruption risk, the optimal investment level in electrolysis (Power-to-Gas, PtG) is q_0. A premium is considered to face possible supply disruption on inexpensive import routes. The resulting electrolysis capacity is $q_0 + \Delta_q^{PtG}$. Figure (1a) displays the situation.

Suppose a shock on imports, translating into the vanishing of the inexpensive imported hydrogen. In this case, Figure (1b) displays the situation depending on the presence of an additional investment in electrolysis Δ_q^{PtG}. More electrolysis



(a) Initial situation

(b) A shock occurs

Figure 1: Illustration of the strategic value of a premium electrolysis capacity, Δ_q^{PtG}.

capacity results in a minor price increase, p_2', instead of $p_2 > p_2'$. This translates into a reduced overall system cost, whose magnitude is equal to the shaded area A. This cost-saving equals the difference between the total cost of the system with and without the presence of the extra capacity Δ_q^{PtG} (proof in Appendix A):

$$A = a\Delta_q^{PtG}(\Delta_s - \frac{1}{2}\Delta_q^{PtG}). \tag{1}$$

The additional capacity comes at the expense of a supplementary investment: $\gamma\Delta_q^{PtG}$, where γ is the marginal electrolysis' investment cost we consider constant. Given a disruption probability of π, optimal investment in additional electrolysis capacity maximizes the expected net savings, solving the First-Order Necessary Condition (FONC):

$$\frac{\partial(\pi A - \gamma\Delta_q^{PtG})}{\partial\Delta_q^{PtG}} = 0, \tag{2}$$

yielding

$$\Delta_q^{PtG,\star} = \Delta_s - \frac{\gamma}{a\pi}, \tag{3}$$

i.e., it is beneficial to invest in the technology until the marginal expected benefit $\pi a(\Delta_s - \Delta_q^{PtG})$ equals the marginal cost, γ. The benefit in investing increases with the probability of disruption π, the steepness of the supply curve a, and the magnitude of the supply shock, Δ_s. The Net Expected Savings (NES), which is equivalent to the welfare increase due to the investment in the strategic capacity $\Delta_q^{PtG,\star}$, is given by

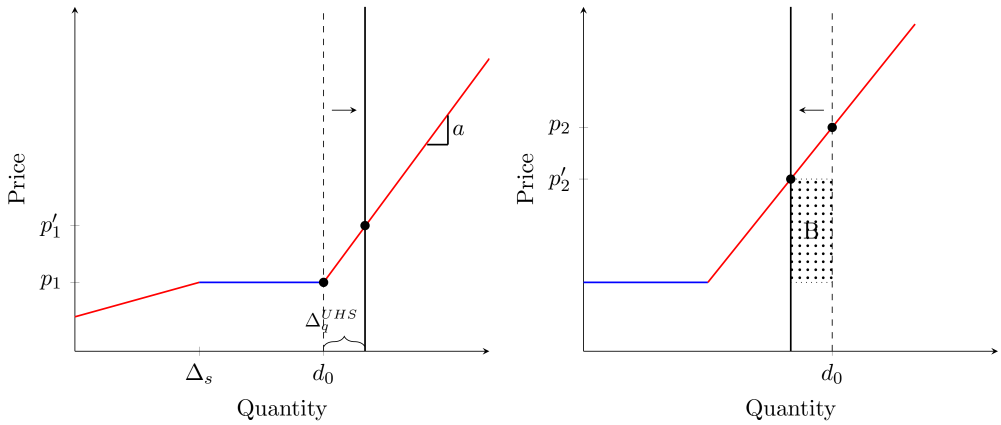
$$NES_{PtG} = \frac{a\pi}{2}\left(\Delta_s - \frac{\gamma}{a\pi}\right)^2 \tag{4}$$

(proof in Appendix C).

2.1.2. Insurance value of storage

Using a strategic reserve to navigate challenging circumstances is a well-established practice with applications in various sectors. Agriculture serves as a prime example. Farmers have stockpiled crops for millennia, creating a buffer against supply shocks. Similarly, critical resources such as energy have seen the implementation of strategic reserves, as exemplified by the International Energy Agency's (IEA) imposition of strategic oil stockpiles on member countries. One practice that is commonplace and aligns closely with our study of hydrogen storage is underground natural gas storage. Indeed, storing gas serves commercial purposes, smoothing seasonal demand fluctuations and stabilizing prices, but also embodies a strategic value. Indeed, after the Russian weaponization of natural gas in 2022, European gas storage proved crucial for energy security, buffering against disruptions and stabilizing prices amid geopolitical uncertainties (Sesini et al., 2022).

Similar to our development concerning electrolysis's strategic value, we provide a simple toy model that highlights the fundamentals of strategic storage in a two-period single commodity context. The situation is as shown in Figure 2.



(a) Initial situation

(b) A shock occurs

Figure 2: Illustration of the strategic value of storage.

In the initial phase, without any disruptions, the strategic reserve is replenished, leading to increased costs (see Figure (2a)). However, during disruptions, the previously stored hydrogen can be withdrawn from storage, mitigating some of the supply cut costs (see Figure (2b)). Overall, storage enables cost savings represented by the shaded area B (detailed proof in Appendix B):

$$B = a\Delta_q^{UHS}(\Delta_s - \Delta_q^{UHS}).$$

Considering a marginal investment cost of ρ and a probability of disruption π, the optimal level of investment satisfies the following FONC:

$$\frac{\partial(\pi B - \rho\Delta_q^{UHS})}{\partial\Delta_q^{UHS}} = 0, \tag{5}$$

which yields

$$\Delta_q^{UHS,\star} = \frac{1}{2}(\Delta_s - \frac{\rho}{a\pi}). \tag{6}$$

Similar to the previous section, this translates into a Net Expected Savings of

$$NES_{UHS} = \frac{a\pi}{4}\left(\Delta_s - \frac{\rho}{a\pi}\right)^2. \tag{7}$$

Comparing expressions (7) and (4), electrolysis proves more efficient than UHS for disruption hedging. Equal investment costs (in terms of €/GW) yield twofold expected cost savings with electrolysis over UHS. This is because investing in UHS for strategic concerns involves not only CAPEX but also the cost of filling and maintaining storage for potential disruptions. A significant expense that the electrolysis option avoids.

2.1.3. Interaction between both technologies

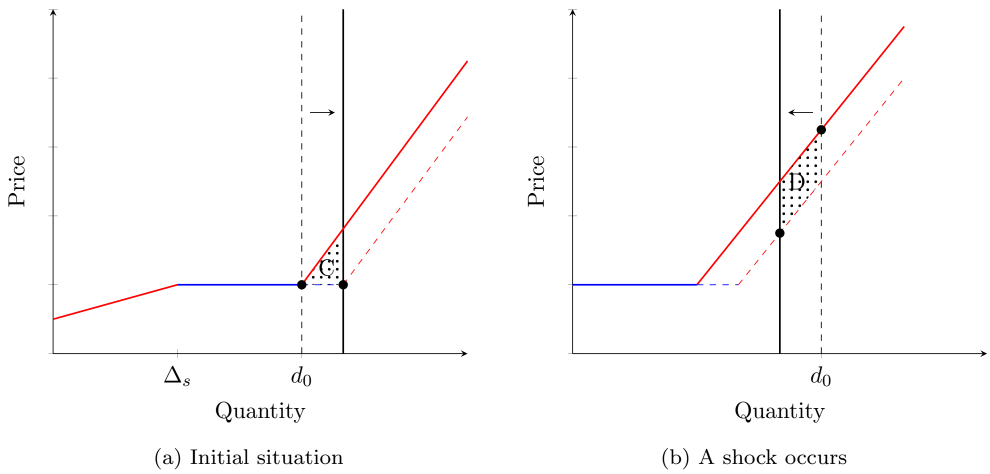


Figure 3: Interaction between electrolysis and UHS when considering a disruption.

The interaction between both technologies is depicted in Figure (3). Prior to any disruption, the technologies exhibit complementarity: increased electrolysis capacity reduces storage filling costs (area C in Figure (3a)). However, during system disruptions, the technologies partially substitute for each other, as indicated by area D. Investigating the dominant effect is crucial for discerning whether electrolysis and storage function as complements or substitutes. The total cost savings from investing in both UHS and electrolysis are:

$$T = A + B + C - D \tag{8}$$

$$T = A + B + \frac{1}{2}a(\Delta_q^{UHS})^2 - a\Delta_q^{UHS}\Delta_q^{PtG}. \tag{9}$$

The FONC yields

$$\begin{cases} \frac{\partial(\pi T - \gamma\Delta_q^{PtG} - \rho\Delta_q^{UHS})}{\partial\Delta_q^{PtG}} = 0 \\ \frac{\partial(\pi T - \gamma\Delta_q^{PtG} - \rho\Delta_q^{UHS})}{\partial\Delta_q^{UHS}} = 0 \end{cases} \Rightarrow \begin{cases} \gamma = \rho \\ \Delta_q^{PtG} = \Delta_q^{UHS} = \frac{1}{2}\left(\Delta_s + q_0 - \frac{\rho}{a\pi}\right). \end{cases}$$

In the general case where the condition $\gamma = \rho$ does not hold, no interior solution exists for this system of equations. The optimal solution then lies on the boundary of the solution space. As a result, the optimal investment strategy involves allocating resources to a single technology – either UHS or electrolysis – based on their relative investment costs:

$$\begin{cases} \Delta_q^{UHS} = \Delta_q^{UHS,\star} \\ \Delta_q^{PtG} = 0 \end{cases} \vee \begin{cases} \Delta_q^{UHS} = 0 \\ \Delta_q^{PtG} = \Delta_q^{PtG,\star}. \end{cases}$$

Identifying the threshold at which electrolysis surpasses storage in profitability unveils the relative break-even cost between these two technologies:

$$NES_{PtG} \geq NES_{UHS}, \tag{10}$$

yielding (proof in Appendix D):

$$\gamma \leq \rho + \frac{2-\sqrt{2}}{2}(a\pi\Delta_s - \rho) \geq \rho. \tag{11}$$

Therefore, electrolysis is more effective than UHS in mitigating supply disruptions across a wider spectrum of investment costs. Specifically, electrolysis surpasses UHS when investment cost discrepancies fall within a positive premium range of $\frac{2-\sqrt{2}}{2}(a\pi\Delta_s - \rho)$.

The principal insights from this analytical model are that:

1. Both electrolysis and storage can be used as appropriate solutions to tackle a risk of disruption on hydrogen imports.
2. When used together, UHS and electrolysis exhibit a subadditive effect that reduces relevance. It is optimal to invest in only one of the two technologies.
3. The optimal strategic investment depends on the respective investment costs of both technologies, but electrolysis is a more effective solution than UHS. Investing in electrolysis rather than storage is optimal if both technologies come at equal cost.

2.2. Numerical development

The above simple analytical model is instructive but fails to address questions that arise immediately. For instance, electrolysis raises electricity prices when producing, diminishing its effectiveness as a hedging asset. The extent of this impact remains unclear. Additionally, the two-stage model fails to effectively address the multistage nature of the problem, overlooking critical aspects such as the depletion of strategic hydrogen stocks – a significant limitation. Also, the former study does not include the uncertainty of VRE production, whereas this has an important impact on the problem at stake. Indeed, if the disruption occurs at a moment of high renewables output, it would be less expensive to produce hydrogen with electrolyzers than if the disruption occurs in a dark doldrum event of low VRE output. This variability from renewables also impacts the optimal investment level in electrolyzers and UHS, even when no disruption is considered. Indeed, a deterministic model suffers from the fact it overestimates the actual optimality of storage use. In the real world, storage operators rely on forecasts and heuristics grounded in historical experience to make decisions. Investment decisions also account for this variable nature of renewables, and this should be included in the analysis. The subsequent section introduces a sequential decision numerical model that incorporates these vital factors, enabling a comprehensive exploration of these questions.

2.2.1. Numerical model

To account for the impact of electrolysis on electricity prices and capture the multistage dynamics of UHS, we propose an MSDP model of the European electricity and hydrogen systems and their mutual interactions. The aim is to determine the optimal investment in UHS and electrolyzers and the dispatch strategy for the power and hydrogen markets, ensuring minimal expected system cost.

The electrical system comprises diverse generating plants with exogenously provided capacity and variable costs. Electrical demand is treated as inelastic. Domestic electricity production involves renewables or dispatchable plants, as shown in Figure (4). Hydrogen production options include electrolysis and imports. Investments in UHS facilities and electrolyzers are the sole investment decisions endogenously determined. We consider a full year segmented into 12 stages, each representing a month of 180 four-hour blocks. At the onset of each stage, the electricity production from Variable Renewable Energy sources (VREs, encompassing solar and wind) and the hydrogen import availability are known.

In dynamic programming, a crucial distinction lies between "state" and "decision" variables. "State" variables reflect the outcomes of past actions (investment, filling level of storage) and probabilistic events, whereas "decision" variables represent effective choices made at a given moment (electrolysis production, use of gas turbines, level of imports). Optimal values for "decision" variables yield the best-expected combination of outcomes in the current and future periods.

For each four-hour block h of month m, the decision variables are:

- $P^k_{m,h}$, Generating power of dispatchable technology k, on hour h of month m;

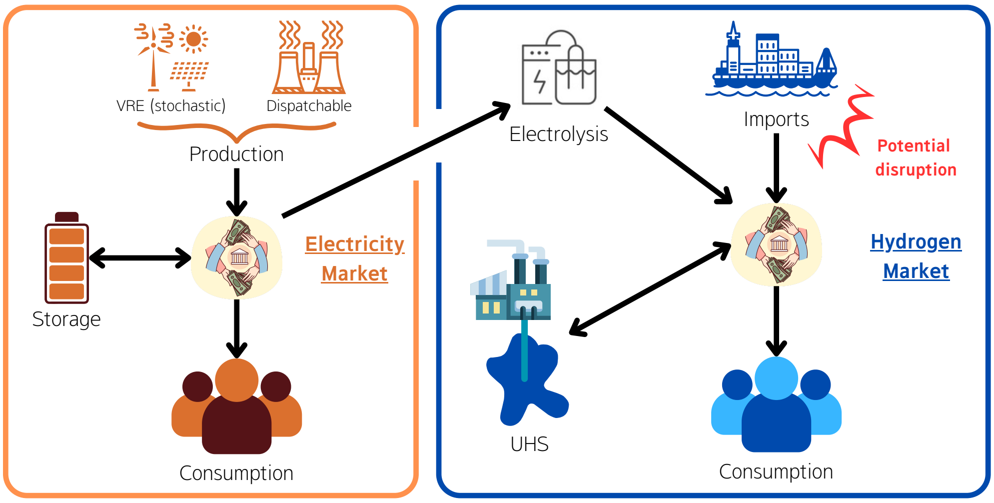


Figure 4: Numerical model overview.

- $P^{s,+/-}_{m,h}$, Withdrawing (+) or filling (-) storage s;
- $I^r_{m,h}$, Hydrogen imports from route r;

The optimization process aims to find the set of decision rules that minimize the expected costs across all stages, from 1 to 12. The objective function reads:

$$\min_{u_1} C_1(u_1) + \mathbb{E}_{\xi_2\in\Omega_2}\left[\min_{u_2\in U_2} C_2(u_2,\xi_2) + \mathbb{E}_{\xi_3\in\Omega_3}\left[... + \mathbb{E}_{\xi_{12}\in\Omega_{12}}\left[\min_{u_{12}\in U_{12}} C_{12}(u_{12},\xi_{12})\right]\right]\right], \tag{12}$$

with u_m the vector of decision variables and ξ_m the vector of random variables, for each stage m, respectively. $C_m(x,u,\omega)$ is the immediate cost of decision u_m. It accounts for both the electricity generation costs with dispatchable plants and hydrogen imports. The first stage of the year also comprises investment costs in UHS and electrolyzers (PtG), as detailed in equation (13). Each technology's Variable Cost (VC) is denoted as c^k, with generation level $P^k_{m,h}$.

$$C_1(x,u,\omega) = \sum_h\left[\sum_k c^k P^k_{1,h} + \sum_r c^r_{H2} I^r_{1,h}\right] + c^{UHS}_{inv}\cdot\overline{g^{UHS}} + c^{PtG}_{inv}\cdot\overline{g^{PtG}} \tag{13}$$

$$C_m(x,u,\omega) = \sum_h\left[\sum_k c^k P^k_{m,h} + \sum_r c^r_{H2} I^r_{m,h}\right], \quad \forall m > 1. \tag{14}$$

For a comprehensive exposition of the MSDP framework, we refer to Shapiro et al. (2009).

2.2.2. Technical constraints

We enforce the supply-demand equilibrium in the electricity market with equation (15). The total net level of electricity load is composed of the exogenous electricity demand plus electricity injected into grid storage, used for hydrogen production $P_{m,h}^{PtG}/\gamma^{PtG}$, and by UHS compressors when activated $(P_{m,h}^{UHS,-} + P_{m,h}^{UHS,+}) \cdot e^{comp}$. Here, γ^{PtG} represents the efficiency of electrolysis conversion.

$$d_{m,h}^{elec} + \frac{P_{m,h}^{PtG}}{\gamma^{PtG}} + (P_{m,h}^{UHS,-} + P_{m,h}^{UHS,+}) \cdot e^{comp} = \sum_{k} P_{m,h}^{k} + \xi_{m,h}^{pv} + \xi_{m,h}^{wind} \quad (\lambda_{elec}). \tag{15}$$

In the hydrogen market, equation (16) ensures that the total hydrogen supply for a specific four-hour block matches the exogenous demand $d_{m,h}^{H2}$ plus injected and withdrawn hydrogen, $P_{m,h}^{UHS,+/-}$:

$$d_{m,h}^{H2} + P_{m,h}^{UHS,-} = P_{m,h}^{PtG} + P_{m,h}^{UHS,+} + I_{m,h}^{H} \quad (\lambda_{H2}). \tag{16}$$

Due to linearity, strong duality holds, and the dual variables λ_{elec} and λ_{H2} of equations (15)–(16) model electricity and hydrogen prices, respectively.

In addition to the latter market clearing conditions, physical constraints apply to electricity and hydrogen systems. For instance, each dispatchable technology is bounded by its installed capacity $\overline{g^k}$ discounted by a certain derating factor $\delta_{m,h}^{k}$, which accounts for its availability rate over the year:

$$P_{m,h}^{k} \leq \overline{g^k} \cdot \delta_{m,h}^{k}, \quad \forall m, h, k. \tag{17}$$

Similarly, storage filling and withdrawing rates are constrained and proportionate to the total installed capacity. Limits guarantee that stored energy will remain below the installed capacity. Concerning VREs, our framework considers solar ($\xi_{m,h}^{pv}$) and wind ($\xi_{m,h}^{wind}$) electricity production as stochastic variables. Two sets encompass the possible VREs' production level: $\Omega_{pv}(m)$ and $\Omega_{wind}(m)$, revealing five potential realizations each. These sets are time-dependent, and for each stage, a monthly time series is extracted from the respective set (Figure 5).

2.2.3. Modeling hazard on hydrogen import routes

We aim to evaluate the strategic importance of hydrogen storage and electrolysis in potential supply disruption scenarios. Using a Markov chain, we consider three possible states of the system: "normal" with no disruptions, "small" akin to the loss of a single pipeline, and "large" similar to the impact of the restrictions on Russian gas imports after the Ukraine invasion (80% import capacity loss). We consider a hydrogen import supply function as presented in Figure (6), based on data from Carlson et al. (2023); Nuñez-Jimenez and De Blasio (2022); IEA (2022). Both disruption cases are assumed to last one month initially. Still, as instability feeds on itself, it is more likely to stay that way if a particular month is disrupted, as Table 1 shows.

The last row of Table 1 displays the system's long-run stationary proba-

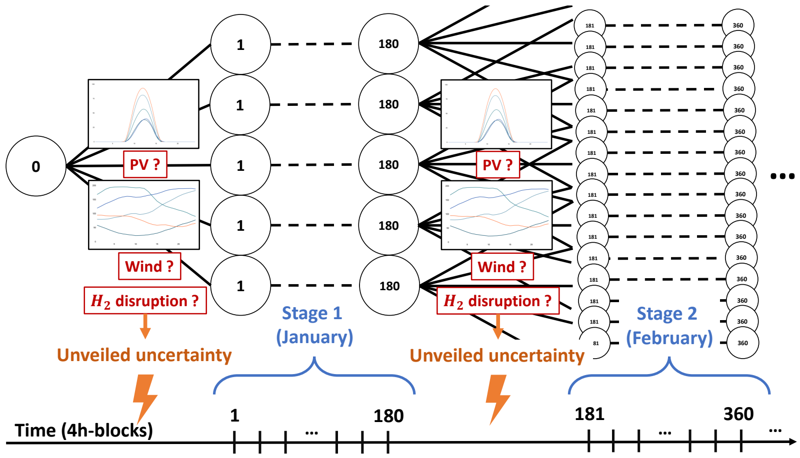


Figure 5: Schematic representation of how stochasticity is involved in the model.

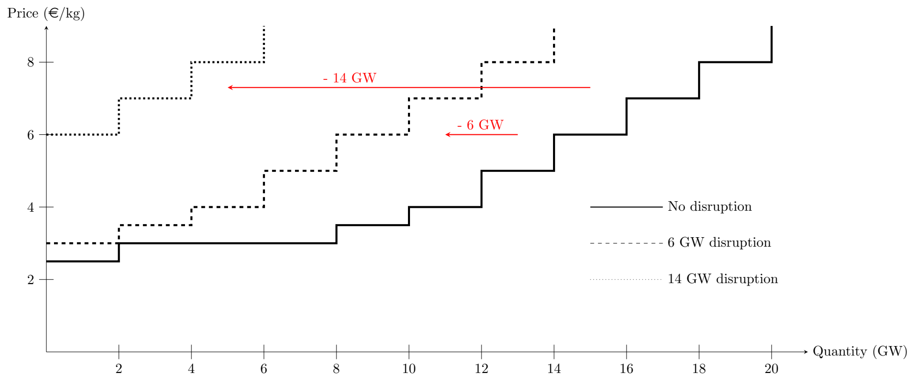


Figure 6: Hydrogen imports supply curves depending on the disruption status.

bilities. Over an extended period — say, 20 years — the hydrogen market is projected to be in a "normal" non-disruption state approximately 80% of the time, in a 6 GW disruption state about 13% of the time, and in a 14 GW disruption state roughly 7% of the time.

Table 1 outlines the disruption probabilities classified as the "base case" and Table 2 encompasses the probabilities under the alternative pessimistic scenario. Data for both tables are adapted from Chao and Manne (1983) and are for illustrative purposes as hydrogen international trade is still at a bourgeoning state. In a typical month m, the probability of a 6 GW disruption rises to 9% under the pessimistic assumption, triple that of the base case, while the likelihood of a 14 GW disruption increases to 6%, compared to 2% in the base case, making the alternative scenario approximately three times as pessimistic.

Disruption, Month m	Disruption, Month m+1		
	Normal	6 GW	14 GW
Normal	0.95	0.03	0.02
6 GW	0.25	0.70	0.05
14 GW	0.10	0.20	0.70
Long-run stationary probabilities	0.80	0.13	0.07

Table 1: Base Case Disruption Probability Transition Matrix.
Reading: If month m was "normal," there is a 3% chance that month $m+1$ will endure a 6 GW disruption, a 2% chance it will be a 14 GW disruption, and a 95% chance it will stay normal.

Disruption, Month m	Disruption, Month m+1		
	Normal	6 GW	14 GW
Normal	0.85	0.09	0.06
6 GW	0.25	0.7	0.05
14 GW	0.1	0.2	0.7
Long-run stationary probabilities	0.57	0.28	0.16

Table 2: Pessimistic Alternative Disruption Probability Transition Matrix.

3. Application case

3.1. Geographical and temporal horizons

The developed stylized model is intentionally instructive rather than exhaustive. For tractability and to enable sensitivity analysis, our study specifically examines Central Western Europe (CWE), which comprises six countries: France, Belgium, the Netherlands, Luxembourg, Germany, and Denmark (Figure (7))[3]. This region currently dominates approximately 60% of European hydrogen consumption, hosting around 80% of the continent's electrolysis capacity, Fuel Cell Electric Vehicle fleet, and salt cavern storage capacity (IEA, 2021; Caglayan et al., 2021; Guidehouse, 2021). CWE is home to Europe's largest industrial ports, serving as pivotal hubs for hydrogen demand, with a well-established natural gas infrastructure that could be repurposed to streamline hydrogen transportation. Governments in CWE are committed to ambitious greenhouse gas reduction targets, signaling a strong interest in hydrogen for sustaining industrial activity. The region also holds untapped renewable energy potential in the

[3]Denmark, though not traditionally considered part of CWE, is included due to its significant role in renewable production and offshore wind development.

North Sea, which is crucial for decarbonization strategies.

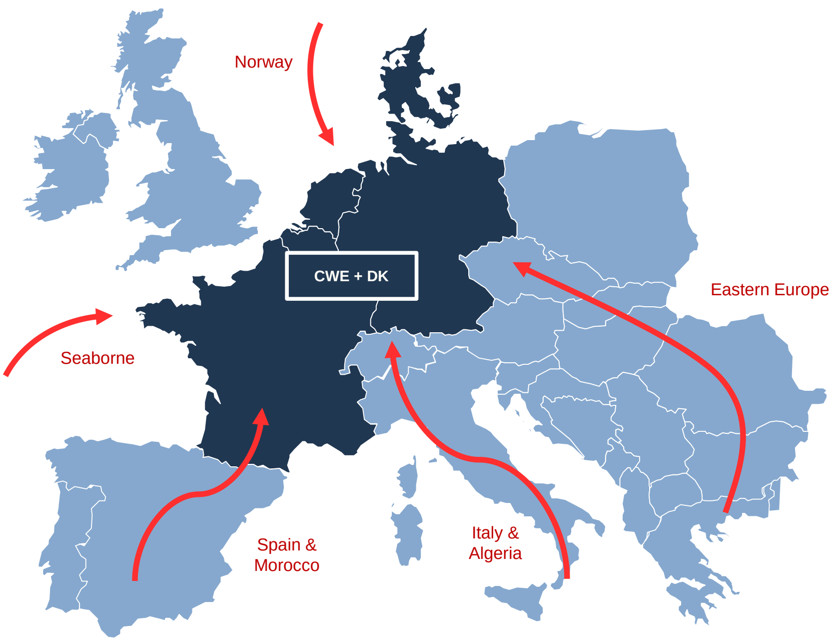


Figure 7: Geographical scope and hydrogen import routes.

We chose to explore our research question in 2035. This timeline allows for precise modeling of energy systems with available data and accurate projections while already assigning a significant role to Hydrogen (IEA, 2022; Van Wijk and Chatzimarkakis, 2020; EmberClimate, 2022).

3.2. Characterization of the electricity supply

Table (3) presents final assumptions regarding power generation capacities. Run-of-the-river (RoR) is an exogenous production pattern based on historical time series. Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT) are clustered into six levels of efficiency each. Nuclear is constrained by minimum and maximum power output thresholds, depending on the time of year, to account for maintenance operations on the French fleet. Open Cycle Oil Turbines (OCOT) serve as the system's peakers, generating electricity during periods of high demand and VREs low production, such as winter evening demand peaks. Pumped Hydro Storage (PHS) and chemical batteries (Battery Energy Storage System, BESS) are included since the latter's development is expected to grow quickly in the coming decade to complement renewables' production variability.

Variable Costs (VC) for each generation technology are computed, factoring in exogenous input prices (e.g., natural gas, uranium, oil), associated carbon emission factors, and the carbon price on the European Emission Trading System (EU-ETS), set at 130€/t.[4] Due to computational constraints, our study omits grid modeling. We adopt the copper plate assumption, asserting that any power plant can meet demand, overlooking potential congestion.

	Installed Capacity (GW)						
Technology	BeNeLux	DE	FR	DK	TOTAL	VC (€/MWh)	Derating
Waste	0.8	5.9	2.5	2	11.2	2	0.9
RoR	0.6	4.1	11.7	0	16.4	0	1
Hydro	0	0	9	0	9	0	1
Biomass	1.8	1.4	0.5	1.4	5.1	69	1
CCGT/CHP	21.1	36.4	9.2	1	67.7	89-115	0.88
OCGT	10.2	49.9	0.6	0	60.7	122-179	0.94
Nuclear	3.0	0	60.0	0	63.0	13	f(t)
OCOT	1.3	2.2	3.9	0	7.4	242	0.94
Lignite	0	6.4	0	0	6.4	135	0.87
Solar PV	38.3	220.0	48.3	4.0	310.6	0	-
Wind (Offshore)	18.9	40.0	7.4	13.0	79.3	0	-
Wind (Onshore)	13.8	115.0	47.8	5.5	182.1	0	-
PHS	2.1	9.8	5.5	0	17.4	0	0.54
BESS	10.7	33.8	18.7	3.5	66.7	0	0.86

Table 3: Electricity system assumptions.[5]

Reading: BeNeLux is modeled with a CCGT installed capacity of 21.1GW in 2035, with an average availability of 88% and VC ranging from 89-115€/MWh.

3.3. Hydrogen demand & supply specifications

The hydrogen demand assumption (net of demand fulfilled by hydrogen as a byproduct) aligns with national ambitions for 2035. We consider an annual hydrogen demand of 200 TWh (6 Mt) for the region, represented as a constant ribbon of 23GW.[6] Regarding cost assumptions, we assume that the electricity price solely determines the VC of electrolysis. Investment costs in electrolyzers and UHS are displayed in Table 4.

The exact amount and cost of hydrogen imports remain largely unknown. To model them, we assume that a diversification strategy allows hydrogen to be

[4] Pietzcker et al. (2021).

[5] EmberClimate (2022) compiles official states ambitions in the "stated policies" scenario. Derating factors are extracted from Villavicencio (2017)

[6] Assumptions about hydrogen demand are extracted from IEA (2021) and the authors' assumption.

[7] Costs assumptions from Michalski et al. (2017) and BloombergNEF (2019).

Technology	CAPEX	OPEX	Disc. factor	Total inv. cost (annualized)
Electrolysis	700 €/kW	3%	0.08	125 €/kW
UHS	380 €/MWh	4%	0.08	50 €/MWh

Table 4: Investment costs for UHS and electrolysis [7]

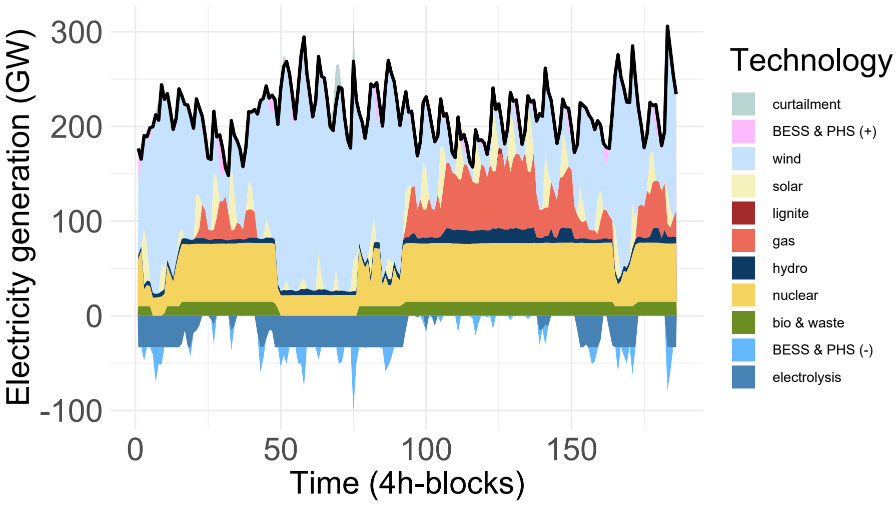


Figure 8: Power dispatch for January in one out of the 50 simulated years.

obtained from 10 sources of equivalent capacity. The hydrogen prices associated with these clusters range from 2.5 to 8 €/kg, as formerly presented in Figure (6).

4. Results and discussion

4.1. No disruption case: benchmark value for investment and general observations

First, we examine a scenario free from the risk of supply disruption. The model runs across multiple potential years of renewable production.

Results show a higher electrolysis production during summer, fueled by abundant solar energy, with lower electricity demand as depicted in Figure (9). Conversely, winter features higher wind turbine generation but elevated electricity prices due to increased heating consumption. Figure (8) displays the optimal power dispatch for the month of January in one of the 50 simulated years.

The optimal investment levels of UHS and electrolysis are approximately 3.9 TWh and 43 GW, respectively. These values fall between the official targets for the *REPowerEU* and *Fit-for-55* plans of 40 and 80 GW, respectively. Indeed, considering CWE constitutes approximately 60–80% of the European hydrogen landscape, our results translate into an overall electrolysis capacity of 54–71 GW

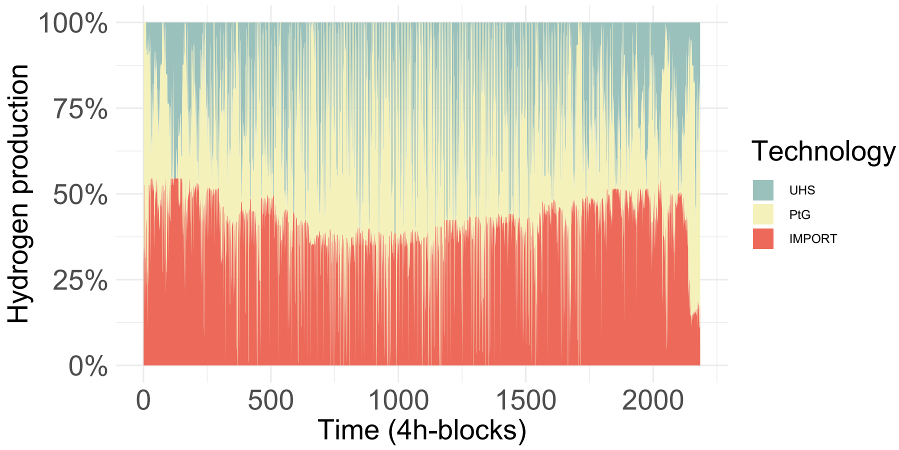


Figure 9: Hydrogen supply throughout the year.

in the EU.

In a typical summer week, storage insufficiency from batteries (BESS) and pumped hydro (PHS) leads to solar curtailment, and nighttime demand is met by gas-fired plants. Electrolyzers operate maximally during the day, and hydrogen imports peak at 13 GW, constituting 57% of the instantaneous supply. Contrastingly, winter weeks see increased wind energy generation, lower storage cycling rates, and smoother electrolyzer utilization. Higher winter electricity demand increases gas turbine usage compared to other seasons. Table 5 presents annual-scale results.

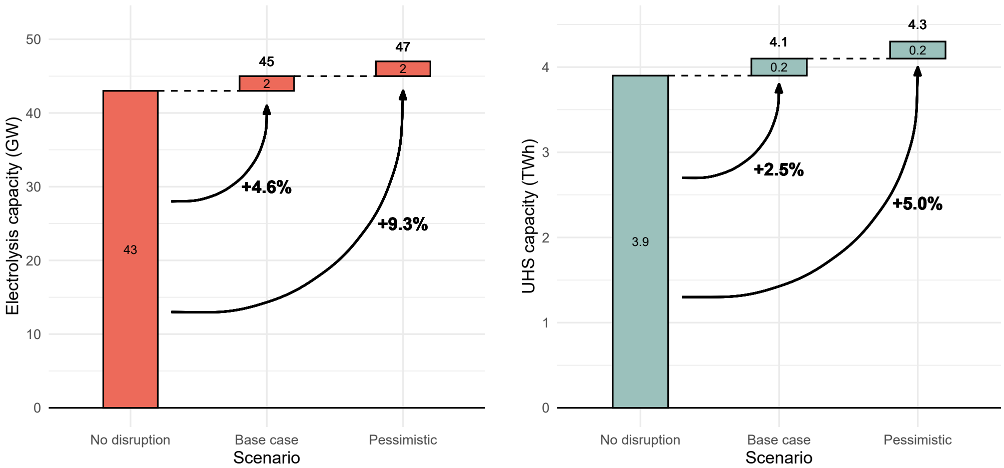
Regarding power prices, the average level is roughly 70 €/MWh and ranges from zero to almost 150 €/MWh. This volatility is unsurprising, given the substantial installation of VREs in our simulations. We observe starkly contrasting scenarios: periods of low VRE generation coincide with high prices attributed to peaking plants, while instances of power curtailment result in zero prices. Hydrogen prices are less volatile than electricity due to a large amount of storage and a large part of the hydrogen supply function being relatively flat, with an average of 3.5 €/kg. Market tensions prompt storage withdrawals, whereas substantial storage injections occur when hydrogen can be economically produced from excess, curtailed electricity.

4.2. Evolution of the investment level with the disruption risk

In this section, we seek to assess the premium value of UHS and electrolyzers when considering a supply disruption. By comparing these cases with the no-disruption scenario, we strive to determine the impact of investment in UHS and electrolysis in reducing import dependency and enhancing the security of supply. Figure (10) depicts the optimal investment decision regarding the disruption case in both technologies.

Variable	Value
Investment in electrolyzers	43 GW
Investment in UHS	3.9 TWh
Electrolyzers' load factor	0.34
H2 imports (Total)	63.7 TWh
Maximum H2 import	13 GW
Electricity curtailment (Total)	19.7 TWh
Electricity price (Average)	71€/MWh
Hydrogen price (Average)	3.5€/kg

Table 5: Key results on power and hydrogen production for a scenario with no disruption.



(a) Investment in Electrolysis

(b) Investment in UHS

Figure 10: Evolution in UHS and electrolysis investment level with the risk of supply disruption.

The optimal investment level increases with the probability of supply disruption. In a situation with no disruption risk, the optimal investment level relates to the purely retail value of assets. On the other hand, the optimal investment level is the highest in the high-risk scenario. It reaches 4.2 TWh for UHS and 47 GW of electrolysis, i.e., a premium of approximately one standard cavern of 210 GWh [8] and 4 GW of electrolyzers. About 5% of the installed UHS capacity and 9% of electrolysis capacity are motivated by the need to hedge against the risk of disruption. Interestingly, the two options are complementary for hedging against supply risk: the optimal approach is to invest in both UHS and electrolysis. However, electrolysis takes the higher ground as the relative increase in installed capacity is almost twice as high as for UHS. This shows electrolysis appears to be a more pertinent option for hedging compared to UHS.

[8] The average salt cavern capacity lies between 100 and 200 GWh.(Caglayan et al., 2021)

The strategic expansion of UHS and electrolyzers adds approximately €1.5 billion to €3 billion in incremental CAPEX costs to the hydrogen system in the base and pessimistic cases, respectively. This sum represents roughly 5–10% of our model's total investment cost allocated to UHS and electrolysis. For context, Erraia et al. (2023) estimated European public financial support for hydrogen initiatives up to 2030 at around €90 billion. Scaling our results for the EU as a whole, the strategic investment constitutes a modest share — specifically 2.8% to 5.6% — of the total subsidies earmarked for the sector.

Our results hence validate one insight from the analytical model of section 2.1, that is, an additional installed capacity of UHS and electrolyzers are indeed a useful option when it comes to hedging import disruption risks.

4.3. What is the best option for energy security?

We previously analytically showed that only one technology out of the two should prevail for hedging against a potential import disruption. Indeed, both UHS and electrolyzers supply hydrogen during disruptions, driving prices down and reducing revenues for both assets, and this effect outshines the complementarity both technologies display in moments of no disruption. However, the numerical model suggests UHS and electrolysis are complementary, meaning the complementarity of the two options is, in reality, more important than in the analytical model setup. This is due to three effects the analytical model does not take into account.

1. Electrolysis amplifies net electricity demand by utilizing electricity for hydrogen production, simultaneously elevating electricity prices and hydrogen production costs. This effect varies from minimal (e.g., if electricity is curtailed, yielding a zero price) to significant during electricity supply tension.
2. A disruption may occur with equal probability in any month, but the effectiveness of electrolysis in replacing lost hydrogen imports varies seasonally. In summer, electrolysis efficiently produces low-cost hydrogen with low electricity prices, providing effective hedging. Conversely, during a cold winter with low renewable production and high electricity prices, UHS may offer advantages over electrolysis.
3. Finally, during disruption episodes, hydrogen storage gains significance due to the strictly convex nature of the hydrogen import supply curve. The steeper curve during disruptions favors increased storage capacity to mitigate price fluctuations effectively. Therefore, beyond assisting the transition from normal conditions to disruption, UHS proves valuable within the disruption phase, facilitating arbitrage between high and very high price episodes.

The analytical models of Section (2.1) do not include these features, which is part of the reason why the analytical and numerical models yield different conclusions. The numerical model indicates that the optimal strategic investment pathway involves both UHS and electrolysis technologies. As a rule of thumb, an additional GW of electrolysis investment is optimal when combined with an extra investment of 50 GWh in UHS.

However, while both options are complementary, their value to the system is unequal. We observe a twofold increase in electrolysis capacity compared to UHS for the same level of risk (in relative terms, see Figure (10a)). Though electrolyzers have a higher investment cost than UHS, they offer a higher hedging value per unit of installed capacity. Indeed, the investment premium in electrolyzers constitutes 95% of the overall cost. In sharp terms, if given a €100 envelope for investing in both UHS and electrolyzers for hedging against disruption, €95 would be allocated to the latter technology. Therefore, while both models draw different conclusions regarding the complementarity or substitution between electrolysis and UHS, they concur that electrolysis is more efficient for energy security.

There are multiple reasons why electrolysis is more efficient than UHS in tackling a situation of import disruption. First, section 2.1 showed electrolysis outperforms UHS in a simple framework because it does not imply an operational trade-off between moments of normal supply and moments of disruption. Indeed, when investing in UHS for energy security, we pay a double cost: we need to invest in the technology, and we also need to fill the storage before using it. This is alike a working capital requirement that hinders the economic relevance of UHS. Electrolyzers do not suffer from the same pitfall, and overinvesting in the technology even brings benefits to the power system as it lowers the amount of curtailed electricity. Electrolysis also allows hedging for a potentially very long amount of time since it does not rely on a stock, while UHS can withdraw hydrogen for only a limited period before needing to refill.

4.4. Sensitivity analysis

Equation (D.1) highlights that the investment costs in UHS and electrolyzers play a crucial role in the decision-making process. Given the early stage of the hydrogen economy, uncertainties surround the actual costs and their future evolution. This section aims to shed light on the impact of investment costs on the preceding results through a sensitivity analysis. Table (6) shows the impact of a 15% CAPEX increase for either UHS, electrolysis, or both.

Changes in the cost of one technology affect the optimal investment levels of both. A 15% rise in electrolyzers' investment costs leads to an approximately 13% decrease in optimal investment (from 3.7 to 3.5 GW), with a similar decline observed for UHS despite unchanged costs (from 190.9 to 175.6 GWh).

The drop in UHS capacity reflects the complementarity between UHS and electrolyzers. Complementarity implies that a lower capacity in one technology leads to a lower optimal investment in the other, as discussed by Neetzow et al. (2018). Our analysis highlights the interdependence of electrolyzers and UHS, showing that a decrease in electrolyzers' capacity results in lower efficiency and reduced investment in UHS. In scenarios with high investment costs for both technologies, we observe a 21% decrease in UHS capacity and a 16% decrease

Cost Assumption		Investment					
		UHS (GWh)			Electrolysis (GW)		
Electrolysis	UHS	No dis.	High risk	Disc.	No dis.	High risk	Disc.
Base	Base	4026.2	4217.1	**190.9**	42.9	46.6	**3.7**
Base	High	3985.1	4160.7	**175.6**	42.9	46.4	**3.5**
High	Base	3730.6	3897.5	**166.9**	39.2	42.4	**3.2**
High	High	3701.3	3852.0	**150.7**	39.1	42.2	**3.1**

Table 6: Sensitivity analysis: the impact of a higher CAPEX for UHS and electrolyzers.

in electrolysis compared to the Base case. UHS's strategic capacity is more greatly affected by the rise in electrolysis investment cost than its own. With a unilateral increase in electrolysis cost, UHS capacity drops by 12.6% (from 190.9 to 166.9 GWh), while it decreases by only 8% (from 190.9 to 175.6 GWh) if the rise in costs impacts UHS alone. This counter-intuitive dynamic underscores the importance of electrolysis's investment cost compared to UHS's for driving strategic investment in the hydrogen market.

5. Conclusion and Policy implications

Hydrogen is pivotal for decarbonizing hard-to-abate sectors, with its significance set to rise sharply in the coming decade. Due to an expected rise in hydrogen demand, the EU aims to meet at least half its needs through imports by 2035. Given the risks of supply disruptions, effective hedging strategies are essential for a resilient hydrogen economy.

We explore two solutions for this strategic concern: investing in a capacity premium in electrolysis and Underground Hydrogen Storage (UHS). Using a Multistage Stochastic Dynamic Programming (MSDP) model for Central Western Europe in 2035, solved via the Stochastic Dual Dynamic Programming (SDDP) algorithm, we analyze their effectiveness against import disruptions.

Our findings show that while both technologies offer valuable hedging, electrolysis outperforms UHS, receiving 95% of strategic investment. This superior performance is due to the need for UHS to keep the storage filled to anticipate any disruption, which is costly. Unlike UHS, electrolysis can hedge against prolonged disruptions without being constrained by storage capacity.

Contrary to traditional views favoring hydrogen storage based on oil and gas practices, our study underscores the strategic advantage of local electrolysis. The 2022 European energy crisis highlighted the need for public sector support in addressing energy security risks, which private investors often neglect. Our analysis indicates that the costs associated with ensuring energy security are relatively modest, representing 5-10% of the total investment in hydrogen infrastructure.

Several underexplored aspects of this study merit further examination. While our stylized model captures critical electrolysis and UHS interaction aspects during supply disruptions, factors like the hydrogen network and nuanced demand patterns are not considered. Future research can refine these aspects with empirical data.

References

BloombergNEF (2019). Hydrogen: The economics of storage. Technical report, BloombergNEF.

Caglayan, D., Heinrichs, H., Robinius, M., and Stolten, D. (2021). Robust design of a future 100% renewable european energy supply system with hydrogen infrastructure. *International Journal of Hydrogen Energy*, 46:29376–29390.

Carlson, E. L., Pickford, K., and Nyga-Łukaszewska, H. (2023). Green hydrogen and an evolving concept of energy security: Challenges and comparisons. *Renewable Energy*, 219:119410.

Chao, H.-P. and Manne, A. S. (1983). Oil stockpiles and import reductions: A dynamic programming approach. *Operations Research*, 31(4):632–651.

Chen, P. S.-L., Fan, H., Enshaei, H., Zhang, W., Shi, W., Abdussamie, N., Miwa, T., Qu, Z., and Yang, Z. (2023). A review on ports' readiness to facilitate international hydrogen trade. *International Journal of Hydrogen Energy*, 48(46):17351–17369.

Cohen, G., Joutz, F., and Loungani, P. (2011). Measuring energy security: Trends in the diversification of oil and natural gas supplies. *Energy Policy*, 39(9):4860–4869.

Dejonghe, M., Van de Graaf, T., and Belmans, R. (2023). From natural gas to hydrogen: Navigating import risks and dependencies in northwest europe. *Energy Research & Social Science*, 106:103301.

Dowson, O. and Kapelevich, L. (2021). SDDP.jl : A julia package for stochastic dual dynamic programming. *INFORMS Journal on Computing*, 33(1):27–33.

EmberClimate (2022). New generation building a clean european electricity system by 2035. Technical report, EmberClimate.

Erraia, J., Foseid, H., Śpiewanowski, P., and Wahl, E. S. (2023). Hydrogen subsidies in the EU, norway, and the US. Technical report, Menon Economics.

Guidehouse (2022). Covering germany's green hydrogen demand: Transport options for enabling imports. Technical report, Guidehouse.

Guidehouse, G. (2021). Picturing the value of underground gas storage to the European hydrogen system. Technical report, Gas Infrastructure Europe.

IEA (2022). Global hydrogen review 2022. Technical report, IEA.

IEA, C. (2021). Hydrogen in north-western europe. Technical report, IEA, CIEP.

Kondziella, H., Specht, K., Lerch, P., Scheller, F., and Bruckner, T. (2023). The techno-economic potential of large-scale hydrogen storage in Germany for a climate-neutral energy system. *Renewable and Sustainable Energy Reviews*, 182:113430.

Lankof, L. and Tarkowski, R. (2020). Assessment of the potential for underground hydrogen storage in bedded salt formation. *International Journal of Hydrogen Energy*, 45(38):19479–19492.

Le Duigou, A., Bader, A., Lanoix, J., and Nadau, L. (2017). Relevance and costs of large scale underground hydrogen storage in france. *International Journal of Hydrogen Energy*, 42:22987–23003.

Markandya, A. and Pemberton, M. (2010). Energy security, energy modelling and uncertainty. *Energy Policy*, 38(4):1609–1613.

Michalski, J., Bünger, U., Crotogino, F., Donadei, S., Schneider, G., Pregger, T., Cao, K., and Heide, D. (2017). Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the german energy transition. *International Journal of Hydrogen Energy*, 42:13427–13443.

Morillo, J., Zéphyr, L., Pérez, J., Anderson, C., and Cadena, A. (2020). Risk-averse stochastic dual dynamic programming approach for the operation of a hydro-dominated power system in the presence of wind uncertainty. *International Journal of Electrical Power & Energy Systems*, 115:105469.

Neetzow, P., Pechan, A., and Eisenack, K. (2018). Electricity storage and transmission: Complements or substitutes? *Energy Economics*, 76:367–377.

Nuñez-Jimenez, A. and De Blasio, N. (2022). Competitive and secure renewable hydrogen markets: Three strategic scenarios for the european union. *International Journal of Hydrogen Energy*, 47(84):35553–35570.

Pereira, M. and Pinto, L. (1991). Multi-stage stochastic optimization applied to energy planning. *Mathematical Programming*, 52:359–375.

Philpott, A., Ferris, M., and Wets, R. (2016). Equilibrium, uncertainty and risk in hydrothermal electricity systems. *Mathematical Programming*, 157:483–513.

Pietzcker, R. C., Osorio, S., and Rodrigues, R. (2021). Tightening EU ETS targets in line with the European Green Deal: Impacts on the decarbonization of the EU power sector. *Applied Energy*, 293:116914.

Plummer, J. L. (1981). Policy implications of energy vulnerability. *The Energy Journal*, 2(2):25–36.

Proskuryakova, L. (2018). Updating energy security and environmental policy: Energy security theories revisited. *Journal of Environmental Management*, 223:203–214.

Sesini, M., Giarola, S., and Hawkes, A. D. (2022). Solidarity measures: Assessment of strategic gas storage on EU regional risk groups natural gas supply resilience. *Applied Energy*, 308:118356.

Shapiro, A., Dentcheva, D., and Ruszczyński, A. (2009). *Lectures on Stochastic Programming: Modeling and Theory*. Society for Industrial and Applied Mathematics.

Tarkowski, R. (2019). Underground hydrogen storage: Characteristics and prospects. *Renewable and Sustainable Energy Reviews*, 105:86–94.

Taylor, J., Alderson, J., Kalyanam, K., Lyle, A., and Phillips, L. (1986). Technical and economic assessment of methods for the storage of large quantities of hydrogen. *International Journal of Hydrogen Energy*, 11:5–22.

Teisberg, T. J. (1981). A dynamic programming model of the u. s. strategic petroleum reserve. *The Bell Journal of Economics*, 12(2):526.

Van Wijk, A. and Chatzimarkakis, J. (2020). Green Hydrogen for a European Green Deal A 2x40 GW Initiative. Technical report, Hydrogen Europe.

Villavicencio, M. (2017). *Analyzing the optimal development of electricity storage in electricity markets with high variable renewable energy shares*. PhD thesis, Université Paris Dauphine-PSL.

Appendix A. Cost savings due to electrolysis

Adding an extra capacity for electrolysis does not change the market situation during the first period when no disruption occurs (Figure (1a)). In period 2, the overall cost of the hydrogen supply depends on the presence of this strategic investment, Δ_q^{PtG} (Figure (1b)). In the case with no strategic investment, $\Delta_q^{PtG} = 0$ and the total cost is

$$\int_0^{q_0} p_1 \mathrm{d}x + \int_{q_0}^{d_0} a(x - q_0) + p_1 \mathrm{d}x = p_1 d_0 - a q_0 (d_0 - q_0) + \frac{a}{2}(d_0^2 - q_0^2), \quad \text{(A.1)}$$

whereas when the extra capacity Δ_q^{PtG} is present, the supply cost becomes

$$\int_0^{q_0+\Delta_q^{PtG}} p_1 \mathrm{d}x + \int_{q_0+\Delta_q^{PtG}}^{d_0} a(x - q_0 - \Delta_q^{PtG}) + p_1 \mathrm{d}x$$
$$= p_1 d_0 - a\left(q_0 + \Delta_q^{PtG}\right)\left(d_0 - q_0 - \Delta_q^{PtG}\right) + \frac{a}{2}\left(d_0^2 - \left(q_0 + \Delta_q^{PtG}\right)^2\right). \quad \text{(A.2)}$$

Subtracting both costs gives the value of the savings provided by the electrolysis' extra capacity:

$$(A.1) - (A.2) = A = a\Delta_q^{PtG}\left(\Delta_s - \frac{1}{2}\Delta_q^{PtG}\right), \tag{A.3}$$

with $\Delta_s = d_0 - q_0$.

Appendix B. Cost savings due to UHS

First, we calculate the additional cost in Period 1 with no disruption due to the filling of the strategic reserve:

$$\int_{d_0}^{d_0+\Delta_q^{UHS}} a(x-d_0) + p_1 \mathrm{d}x = \Delta_q^{UHS}(p_1 - ad_0) + \frac{a}{2}\left(2d_0\Delta_q^{UHS} + \left(\Delta_q^{UHS}\right)^2\right). \tag{B.1}$$

Second, we calculate the savings in Period 2 due to the presence of strategic storage:

$$\int_{d_0-\Delta_q^{UHS}}^{d_0} a(x-q_0) + p_1 \mathrm{d}x = \Delta_q^{UHS}(p_1 - aq_0) + \frac{a}{2}\left(2d_0\Delta_q^{UHS} - \left(\Delta_q^{UHS}\right)^2\right). \tag{B.2}$$

Finally, the net impact of the use of a strategic reserve is

$$(B.2) - (B.1) = B = a\Delta_q^{UHS}\left(\Delta_s - \Delta_q^{UHS}\right). \tag{B.3}$$

Appendix C. Net Expected Savings

Given an optimal investment level in electrolyzers of $\Delta_q^{PtG,\star} = \Delta_s - \frac{\gamma}{a\pi}$ and the net value of savings $\pi A - \rho\Delta_q^{PtG,\star}$, we find:

$$\begin{aligned} NES_{PtG} &= a\pi\left(\Delta_s - \frac{\gamma}{a\pi}\right)\left(\Delta_s - \frac{1}{2}\left(\Delta_s - \frac{\gamma}{a\pi}\right)\right) - \gamma\left(\Delta_s - \frac{\gamma}{a\pi}\right) \\ &= \frac{a\pi}{2}\left(\Delta_s - \frac{\gamma}{a\pi}\right)^2. \end{aligned}$$

The proof is similar for calculating NES_{UHS}.

Appendix D. Break-even cost

Inserting from Eq (3) and Eq (6), condition (10) yields

$$\frac{1}{2}\left(\Delta_s - \frac{\gamma}{ap}\right)^2 \geq \frac{1}{4}\left(\Delta_s - \frac{\rho}{ap}\right)^2. \tag{D.1}$$

This polynomial has two roots:

$$\begin{cases} \gamma_1 = \frac{2-\sqrt{2}}{2} a\pi\Delta_s + \frac{\sqrt{2}}{2}\rho \\ \gamma_2 = \frac{2+\sqrt{2}}{2} a\pi\Delta_s - \frac{\sqrt{2}}{2}\rho. \end{cases}$$

Under the hypothesis that investment in either technology is economically viable:

$$\rho \leq a\pi\Delta_s \wedge \gamma \leq a\pi\Delta_s, \tag{D.2}$$

we have

$$\begin{cases} \gamma_1 \leq \gamma_2 \\ \gamma_1 \geq 0. \end{cases} \tag{D.3}$$

The situation is displayed in Figure D.11.

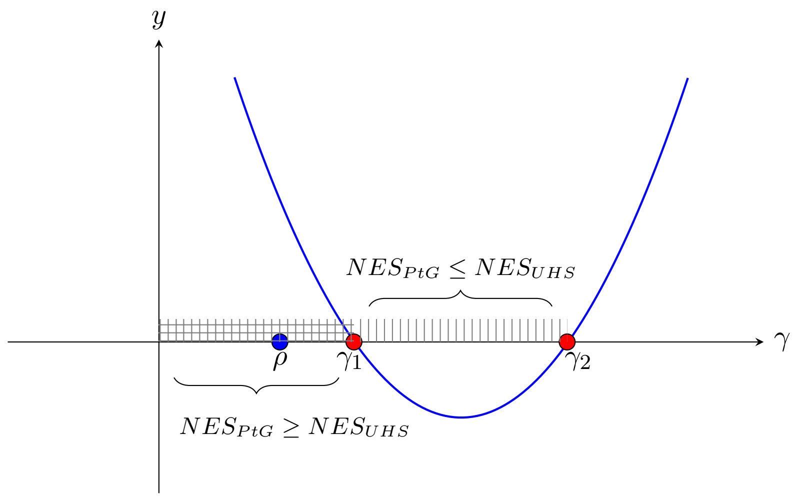


Figure D.11: Graphical representation of equation (D.1).

Equation (D.1) stipulates that it is economically more efficient to invest in electrolysis rather than storage if

$$\gamma \leq \gamma_1 \tag{D.4}$$

$$\text{or} \quad \gamma \geq \gamma_2. \tag{D.5}$$

Since $\rho \leq a\pi\Delta_s$, condition (D.5) implies that

$$\gamma \geq \frac{2-\sqrt{2}}{2} a\pi\Delta_s - \frac{\sqrt{2}}{2} a\pi\Delta_s \tag{D.6}$$

$$\Leftrightarrow \gamma \geq 2a\pi\Delta_s \tag{D.7}$$

$$\Rightarrow \gamma \geq a\pi\Delta_s, \tag{D.8}$$

which is inconsistent with assumption (D.2). Hence, only condition (D.4) is of interest.

It is more profitable to invest in electrolysis than UHS for all $\gamma \leq \gamma_1$. Since $\gamma_1 \geq \rho$, there is a preference for investing in electrolysis over UHS for strategic purposes. We quantify this competitive edge:

$$\gamma_1 - \rho = \frac{2-\sqrt{2}}{2}(a\pi\Delta_s - \rho). \tag{D.9}$$

Hence, we have shown that the break-even cost between electrolysis and UHS is set at such a value that electrolysis is preferable over UHS up to

$$\gamma = \gamma_1 = \rho + \frac{2-\sqrt{2}}{2}(a\pi\Delta_s - \rho). \tag{D.10}$$

WORKING PAPER

PREVIOUS ISSUES

Energy poverty has a justice dimension: comparing Bolivia, Côte d'Ivoire, and France — N°2024-03
Aliénor CAMERON, Maria GARRONNE

Carbon intensity and corporate performance: A micro-level study of EU ETS industrial firms — N°2024-02
Aliénor CAMERON, Maria GARRONNE

Are road pricing schemes efficient in polycentric cities with endogenous workplace locations? — N°2024-01
Romain GATÉ

Don't lead me this way: Central bank guidance in the age of climate change — N°2023-09
Pauline CIZMIC, Anna CRETI, Marc JOËTS

Subjective barriers and determinants to crop insurance adoption — N°2023-08
Richard KOENIG, Marielle BRUNETTE

Unlocking and supportive renewable gas in Europe: Policy insights from a comparative analysis — N°2023-07
Maria SESINI, Anna CRETI, Olivier MASSOL

If drywall could talk: A panel data double hurdle to assess new technology adoption in the French construction sector — N°2023-06
Esther RAINEAU-RISPAL

Why labels Fail: Fraud on a market for credence goods with unobservable skill heterogeneity among experts — N°2023-05
Esther RAINEAU-RISPAL

Working Paper Publication Directors :

Marc Baudry, Philippe Delacote, Olivier Massol