Missing Risk Markets and Capacity Remuneration Mechanisms in Electricity-Hydrogen Systems

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***Abstract*—Hydrogen and derived fuels may act as long-term energy storage in climate-neutral energy systems. However, risk-averse investors will not invest in sufficient renewable electricity, back-up, electrolyzer and storage capacity if they are only remunerated for the hydrogen or electricity produced and markets for risk are missing. We develop a stochastic equilibrium model to study whether capacity markets can limit costs to consumers by restoring investments risk-neutral levels. Our results show that the efficacy of capacity markets depends on complementary instruments to ensure the availability of renewables. If risk-aversion and missing markets for risk reduce renewable build-out, capacity markets in the electricity and hydrogen sectors are needed to restore the overall capacity mix and limit consumer costs. If complementary instruments lift investments in renewables , a capacity market in the electricity sector suffices. In this situation, an additional capacity market in the hydrogen sector triggers a bias toward hydrogen-fired backup capacity. This illustrates that an integrated systems perspective is required to design future energy markets.**

***Index Terms*—Capacity remuneration schemes, capacity markets, hydrogen, missing risk market problem**

I. Introduction

REDUCING greenhouse gas emissions from the energy sector requires electrifying end-energy use and simultaneously deploying vast amounts of electricity generation from variable renewable energy sources (vRES). In climate-neutral systems, seasonal patterns in renewable output and extreme events such as prolonged periods of low renewable output in winter, known as ”kalte dunkelflautes”, necessitate the development of long-term storage solutions [1], [2].

Green hydrogen and its derivatives may provide this long-term storage solution in areas where alternatives, such as large hydro reservoirs, are unavailable [3]. Hydrogen, produced from renewable electricity via electrolyzers, may be stored in salt caverns [4]. These electrolyzers may provide short-term flexibility to the grid [5]–[7]. Hydrogen-fired turbines offer backup capacity to the electric power system during periods of low RES output [7]–[9]. The demand for electricity from the electrolyzers would increase the required installed electricity generation capacity and benefit renewable generators by reducing zero-price periods [6].

Ensuring system adequacy in such an integrated energy system would require investing in hydrogen storage capacity and backup turbines that may be infrequently used. Theoretically, an energy-only market (EOM; a market that only remunerates sold energy) should facilitate investor cost recovery and attract both an optimal level of investment and an optimal technology mix [10]. However, real-world distortions, such as price caps, imperfect information, and incomplete risk markets, have been shown to lead to suboptimal investment levels and technology choices in electricity markets [11]. Price caps lead to the ”missing money” problem. The inability of electricity market participants to allocate the risk to those who can most efficiently manage it has been called the ”missing market” problem [12], [13]. As illustrated for investments in the power sector [14]–[17], the investment risk may be substantial, as the returns on these backup assets would be highly uncertain. This risk may increase due to the volatility and downward pressure on electricity prices as the penetration of renewables increases, while the energy transition adds many uncertainties for investors [5], [13]. Our analysis shows that such risk-averse behavior and missing risk markets also lead to underinvestments in the hydrogen sector in an integrated electricity-hydrogen market.

Capacity remuneration mechanisms (CRMs) are a recognized solution for restoring the investment volume and, at least to an extent, correcting the technology mix in the electricity sector [18]. These CRMs offer additional compensation for generators based on derated capacity (to reflect their availability during scarcity). They are increasingly becoming a structural feature of the electricity market design in, e.g., Europe [19]. Many studies illustrated how capacity markets can compensate for under-investment by risk-averse investors in energy-only markets [14]–[17], [20]. These analyses typically build on stochastic equilibrium models, which can effectively represent market participants' behavior and incomplete or missing risk markets. While initially focused on conventional backup capacity, more recently, the integration of demand response and short-duration energy storage received considerable attention [21]–[23]. Schmitz et al. [22] focus on pumped hydro energy storage (PHES), whereas Askeland et al. [21] highlight how investments in PHES and battery energy storage are stimulated by a capacity market and reduce the need for thermal power plants. Fraunholz et al. [23] explain how the specification of who bears the risk of empty storage during scarcity situations and the derating of storage availability preclude a straightforward inclusion in CRMs.

However, it is unclear whether a CRM in the electricity sector alone would be sufficient to ensure system adequacy in integrated hydrogen-electricity systems. Such systems are more complex, as ensuring adequacy requires a combination of hydrogen-fired electricity generation capacity, hydrogen pro-

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duction capacity and hydrogen storage capacity. An integrated hydrogen-electricity system has more feedback loops than the current electric power sector and can be expected to exhibit different dynamic behavior. Today, in the absence of large-scale hydro, the natural gas system firms up the electricity system. Natural gas is stored during periods of low natural gas demand and can be made available in large volumes on short notice during periods of stress. In contrast, hydrogen must be produced from renewable electricity, which may require additional investments in vRES and electrolyzer capacity. Sufficient storage and discharge capacity must be available to feed hydrogen-fired back-up capacity during periods of low vRES output. Seasonal swings in demand, widespread use in other sectors and the low upfront investment cost of natural gas storage in depleted gas fields motivate large-scale gas storage. In contrast, long-duration hydrogen storage faces high upfront investment costs, which may not be recovered due to uncertainty on the size and patterns in hydrogen demand. In an EOM, it is left to the market to provide sufficient capacity for these different types of assets. However, the available volume of one type of asset may affect the business case of the other asset types. This poses challenges in valuing different technologies with and without capacity markets in the electricity and hydrogen systems.

Therefore, we investigate which market design can trigger sufficient investment in renewable electricity generation, electrolyzers and hydrogen storage capacity in a climate-neutral, integrated electricity and hydrogen system with risk-averse investors and missing markets for risk. We test the hypothesis that capacity markets in the hydrogen system allow restoring investment levels and lower expected risk-adjusted costs for consumers. By requiring that hydrogen turbine owners participate as capacity suppliers in the electricity capacity market and demand agents in the hydrogen capacity market to firm up their offer, they pass through the value of firm capacity from the electricity into the hydrogen domain. In turn, this allows valuing the contribution of storage discharge and electrolyzer capacity to firming up the electricity and hydrogen demand.

To this end, we develop a stochastic equilibrium model to compare the long-term equilibrium in a hydrogen-electricity system , building on the work of Höschle et al. [14]. We study the impact of risk-aversion and missing risk markets under three market designs: an energy-only market and capacity markets for electricity and hydrogen. Our results show that securing the availability of renewable electricity is a no-regret option. The necessity of capacity markets in both the electricity and hydrogen sectors to counteract the downward pressure on investment levels due to risk aversion depends on the availability of vRES capacity.

In summary, our contribution is twofold:

1) We formulate a mixed complementarity problem describing the non-cooperative Nash game between risk-averse investors on interdependent energy and capacity markets for hydrogen and electricity assuming missing risk markets. This model captures the interactions between investments and operational decisions regarding long-duration hydrogen storage, electrolyzers, hydrogen-fired turbines, and RES-based electricity generation. We extend the work of Höschle et al. [14] with the hydrogen system and include a state-of-the-art representation of long-duration energy storage [2].
2) In a case study, we demonstrate how risk aversion and missing risk markets impede optimal investments in such an integrated market, leading to increased consumer costs. We illustrate how a combination of capacity markets and/or policies to ensure vRES availability mitigates this adverse effect.

Our study provides policy-relevant insights into the benefits of a CRM in hydrogen-electricity systems. A CRM can achieve an adequate volume of electrolyzer, hydrogen-fired turbine and long-term storage capacity and thereby ensure system adequacy in a climate-neutral energy system.

The remainder of this paper is structured as follows. Section II outlines the methodology used to address the problem, the equilibrium model and the solution strategy. Section III discusses the case study. Lastly, Section IV concludes.

II. Methodology

We study long-term equilibria in a climate-neutral, integrated hydrogen-electricity system. Risk-averse investors make investment and operational decisions based on hourly energy prices that are complemented by dedicated capacity markets in some scenarios. Risk markets are not considered. In addition to electricity generation assets, investors can invest in electrolyzers, hydrogen storage capacity, and hydrogen-fired turbines. The resulting non-cooperative Nash Game is formulated as a mixed complementarity problem (MCP).

We continue this section with a non-exhaustive list of essential assumptions in our modeling framework. Subsection II-B describes the MCP, whereas Subsection II-C discusses the solution strategy.

A. Assumptions

1) System: We exclude energy imports or exports and adopt a greenfield approach. The model simulates a long-run Nash equilibrium, considering the integrated energy markets over a one-year period. The system consists of the following technologies, each represented by a single actor: wind, solar, biomass, electrolyzers, hydrogen-fired turbines and long-duration hydrogen storage. We do not consider short-duration energy storage to avoid arbitrary assumptions on their availability during scarcity situations [24] and derating factors [25]. Similarly, the hydrogen storage is represented by a generic long-duration energy storage system. We do not consider the role of cushion gas or the state-of-charge dependency of the charge and discharge capacity. Two demand agents represent consumers in the hydrogen and electricity system.

2) Agents: Each price-taking agent optimizes investment and operational decisions to maximize a weighted average of the expected profit and the Conditional-Value-at-Risk (CVAR) of the profit, following, e.g., [17]. The uncertainty is characterized by 18 discrete scenarios that differ in electricity demand, availability factors dependent on weather conditions, and hydrogen demand. Each agent has the same attitude towards risk. Each actor can invest in only one type of technology, as diversifying the investment portfolio would allow internally hedging risk [17].

3) Electricity & hydrogen markets: The electricity and hydrogen markets are both cleared hourly. Within each market, actors offer the amount of energy that they are willing to generate or consume at the prevailing electricity and hydrogen prices. Wind, solar, biomass-fired power plants, and hydrogen-fired turbines produce electricity. The demand for electricity consists of a price-elastic demand function and the demand from electrolyzers. These electrolyzers and the long-term storage in salt caverns supply hydrogen to the hydrogen-fired turbines and a price-elastic demand agent. Note that sector-coupling agents (hydrogen turbines and electrolyzers) and long-term storage act as demand and supply agents. An electricity and hydrogen demand agent is price-elastic up to a predefined willingness to pay (WTP), and served demand is, therefore, endogenously determined.

4) Capacity markets: Depending on the scenario, we consider capacity markets in both the electricity and the hydrogen sectors. These introduce yearly remuneration for firm capacity offered by generators and producers. Participation in the electricity capacity market is allowed only for dispatchable generators (biomass and hydrogen-fired power plants). While today's capacity markets remunerate solar and wind as well, the associated derating factors in our climate-neutral energy system would be near-zero [26]. Including their participation in the capacity market is not expected to affect results, while this simplifying assumption avoids endogenizing the derating factor calculation. In the hydrogen capacity market, hydrogen storage assets and electrolyzers offer capacity. Discharge capacity is not derated. Remuneration for storage volume or hydrogen availability and penalties for unavailability during scarcity situations are not considered.

Demand for capacity is exogenous (e.g., it is set by the regulator) and inflexible. In the hydrogen capacity market, however, an endogenous term is added to represent the capacity demand from hydrogen-fired power plants, which are required to firm their capacity offer in the electricity capacity market. The demand agents and the hydrogen turbine owners bear the costs for capacity.

5) Temporal resolution: We model each year through a set of representative days $d \in \mathcal{D}$, each representing a fraction W_d of the year. To represent long-term storage and allow inter-period arbitrage, the Enhanced Representative Days formulation proposed by Gonzato et al. [2] is used.

B. Mixed complementarity problem

1) The electricity producer's problem: Each electricity producer $g \in \mathcal{G}$ tries to maximize the weighted (γ) sum of the expected profit $\sum_{s\in\mathcal{S}} P_s \cdot \Pi_{g,s}$ and the $CVAR_g$:

$$\max \quad \gamma \cdot \sum_{s\in\mathcal{S}} P_s \cdot \Pi_{g,s} + (1-\gamma) \cdot CVAR_g \tag{1a}$$

with

$$\Pi_{g,s} = R_{g,s} - C_{g,s} \tag{1b}$$

$$R_{g,s} = \lambda^{CM,e} \cdot cap_g^{CM,e} + \sum_{d\in\mathcal{D}} W_d \sum_{t\in\mathcal{T}} \lambda^e_{s,d,t} \cdot g^e_{g,s,d,t} \tag{1c}$$

$$C_{g,s} = \lambda^{CM,h} \cdot cap_g^{CM,h} + cap_g^e \cdot IC_g + \sum_{d\in\mathcal{D}} W_d \sum_{t\in\mathcal{T}} (VC_g \cdot g^e_{g,s,d,t} + \lambda^h_{s,d,t} \cdot g^h_{g,s,d,t}) \tag{1d}$$

$$CVAR_g = \alpha_g - \frac{1}{\beta} \sum_{s\in\mathcal{S}} P_s \cdot u_{g,s} \tag{1e}$$

subject to

$$0 \le g^e_{g,s,d,t} \le cap_g^e \cdot A_{g,s,d,t} \qquad \forall s,d,t \tag{1f}$$

$$g^e_{g,s,d,t} = \eta_g \cdot g^h_{g,s,d,t} \qquad \forall s,d,t \tag{1g}$$

$$0 \le cap_g^{CM,e} \le \Phi_g \cdot cap_g^e \tag{1h}$$

$$cap_g^{CM,e} = \eta_g \cdot cap_g^{CM,h} \tag{1i}$$

$$\alpha_g - \Pi_{g,s} \le u_{g,s} \qquad \forall s \tag{1j}$$

$$0 \le u_{g,s} \qquad \forall s \tag{1k}$$

For each scenario s, the profit $\Pi_{g,s}$ is calculated as the difference between revenues $R_{g,s}$ and costs $C_{g,s}$ (Eq. (1b)). Revenues stem from selling electricity $g^e_{g,s,d,t}$ at the electricity price $\lambda^e_{s,d,t}$ and capacity $cap_g^{CM,e}$ at the capacity market price $\lambda^{CM,e}$ (Eq. (1c)). Costs faced by investors (Eq. (1d)) include investment costs (capital costs IC_g times the installed capacity cap_g^e), variable costs (VC_g times $g^e_{g,s,d,t}$) and, for hydrogen turbines, hydrogen fuel costs (hydrogen price $\lambda^h_{s,d,t}$ times the amount of hydrogen used $g^h_{g,s,d,t}$) and costs to firm up their hydrogen demand (the capacity demanded $cap_g^{CM,h}$ times the hydrogen capacity price $\lambda^{CM,h}$). The latter costs only emerge if the hydrogen turbines offer capacity $cap_g^{CM,e}$ in the electricity capacity market. The formulation of CVAR (Eq. (1e)) introduces two auxiliary variables α_g and $u_{g,s}$ [27]. α_g represents with the endogenously determined Value-at-Risk. $u_{g,s}$ represents the difference in profit w.r.t. the VAR of the β worst scenarios [11].

Constraint (1f) limits the electricity offered $g^e_{g,s,d,t}$ to the installed capacity cap_g^e corrected by the availability factor of that time step $A_{g,s,d,t}$. Equation (1h) limits the capacity offered to the capacity market $cap_g^{CM,e}$ to the installed capacity cap_g^e corrected by the derating factor Φ. For hydrogen turbines, Eq. (1g) links the amount of electricity produced $g^e_{g,s,d,t}$ to the amount of hydrogen used as fuel $g^h_{g,s,d,t}$ via the turbine efficiency η_g. Similarly, Eq. (1i) expresses the demand in the hydrogen capacity market $cap_g^{CM,h}$ as the turbine capacity awarded in the electricity capacity market $cap_g^{CM,e}$ corrected for the efficiency η_g.

2) The electrolyzer problem: Electrolyzer owners $e \in \mathcal{E}$ maximize the weighted sum of the expected profit $\sum_{s\in\mathcal{S}} P_s \Pi_{e,s}$ and the $CVAR_e$ by selling hydrogen while paying investment and operational costs:

$$\max \quad \gamma \sum_{s\in\mathcal{S}} P_s \cdot \Pi_{e,s} + (1-\gamma) \cdot CVAR_e \tag{2a}$$

with

$$\Pi_{e,s} = R_{e,s} - C_{e,s} \tag{2b}$$

$$R_{e,s} = \lambda^{CM,h} \cdot cap_e^{CM,h} + \sum_{d\in\mathcal{D}} W_d \sum_{t\in\mathcal{T}} \lambda^h_{s,d,t} \cdot g^h_{e,s,d,t} \tag{2c}$$

$$C_{e,s} = \sum_{d\in\mathcal{D}} W_d \sum_{t\in\mathcal{T}} (VC_e \cdot g^h_{e,s,d,t} + \lambda^e_{s,d,t} \cdot g^e_{e,s,d,t}) + cap^e_e \cdot IC_e \quad (2d)$$

$$CVAR_e = \alpha_e - \frac{1}{\beta}\sum_{s\in\mathcal{S}} P_s \cdot u_{e,s} \quad (2e)$$

subject to

$$0 \le g^e_{e,s,d,t} \le cap^e_e \qquad \forall s,d,t \quad (2f)$$

$$g^h_{e,s,d,t} = \eta_e \cdot g^e_{e,s,d,t} \qquad \forall s,d,t \quad (2g)$$

$$0 \le cap^{CM,h}_e \le \eta_e \cdot cap^e_e \quad (2h)$$

$$\alpha_e - \Pi_{e,s} \le u_{e,s} \qquad \forall s \quad (2i)$$

$$0 \le u_{e,s} \qquad \forall s \quad (2j)$$

The profit $\Pi_{e,s}$ is the difference between revenues $R_{e,s}$ and costs $C_{e,s}$ (Eq. (2b)). Revenues are generated by selling hydrogen $g^h_{e,s,d,t}$ at the hydrogen price $\lambda^h_{s,d,t}$ and capacity $cap^{CM,h}_e$ at the hydrogen capacity price $\lambda^{CM,h}$ (Eq. (2c)). Costs (Eq. (2d)) include investment costs (capital costs IC_e times the installed capacity cap^e_e), variable operational costs (VC_e times $g^h_{e,s,d,t}$) and electricity costs ($\lambda^e_{s,d,t}$ times the electricity used $g^e_{e,s,d,t}$).

Equation (2f) limits the electricity input $g^e_{e,s,d,t}$ to the installed capacity cap^e_e. Constraint (2g) links the amount of hydrogen produced $g^h_{e,s,d,t}$ to the electricity consumption $g^e_{e,s,d,t}$ through the electrolyzer's efficiency η_e. Equation (2h) limits the capacity offered to the hydrogen capacity market $cap^{CM,h}_e$ to the installed capacity cap^e_e corrected by the efficiency η_e.

3) The hydrogen storage problem: Hydrogen storage companies $b \in \mathcal{B}$ try to maximize the weighted sum of the expected profit $\sum_{s\in\mathcal{S}} P_s \cdot \Pi_{b,s}$ and the $CVAR_b$:

$$\max \quad \gamma \sum_{s\in\mathcal{S}} P_s \cdot \Pi_{b,s} + (1-\gamma)\cdot CVAR_b \quad (3a)$$

with

$$\Pi_{b,s} = R_{b,s} - C_{b,s} \quad (3b)$$

$$R_{b,s} = \lambda^{CM,h} \cdot cap^{CM,h}_b + \sum_{d\in\mathcal{D}} W_d \sum_{t\in\mathcal{T}} \lambda^h_{s,d,t} \cdot d^h_{b,s,d,t} \quad (3c)$$

$$C_{b,s} = \sum_{d} W_d \sum_{t\in\mathcal{T}} \big(VC_b \cdot (d^h_{b,s,d,t} + c^h_{b,s,d,t}) + \lambda^h_{s,d,t} \cdot c^h_{b,s,d,t}\big) + cap^h_b \cdot IC^P_b + cap^{h,SOC}_b \cdot IC^E_b \quad (3d)$$

$$CVAR_b = \alpha_b - \frac{1}{\beta}\sum_{s\in\mathcal{S}} P_s \cdot u_{b,s} \quad (3e)$$

subject to

$$0 \le d^h_{b,s,d,t} \le cap^h_b \qquad \forall s,d,t \quad (3f)$$

$$0 \le c^h_{b,s,d,t} \le cap^h_b \qquad \forall s,d,t \quad (3g)$$

$$0 \le cap^h_b \quad (3h)$$

$$0 \le cap^{h,SOC}_b \quad (3i)$$

$$0 \le cap^{CM,h}_b \le cap^h_b \quad (3j)$$

$$0 \le e^h_{b,s,d,t} \le cap^{h,SOC}_b \qquad \forall s,d,t \quad (3k)$$

$$e^h_{b,s,d,t} = e^h_{b,s,d,t-1} + \eta^{ch}_b \cdot c^h_{b,s,d,t} - \frac{d^h_{b,s,d,t}}{\eta^{dh}_b} \qquad \forall s,d,t \quad (3l)$$

$$\alpha_b - \Pi_{b,s} \le u_{b,s} \qquad \forall s \quad (3m)$$

$$0 \le u_{b,s} \qquad \forall s \quad (3n)$$

$$\Delta e^h_{b,s,d} = \sum_{t\in\mathcal{T}} \big(\eta^{ch}_b \cdot c^h_{b,s,d,t} - \frac{d^h_{b,s,d,t}}{\eta^{dh}_b}\big) \qquad \forall s,d \quad (3o)$$

$$e^0_{b,s,d^*} = e^0_{b,s,d^*-1} + \sum_{d\in\mathcal{D}} V_{d^*,d} \cdot \Delta e^h_{b,s,d} \qquad \forall s,d^* \quad (3p)$$

$$0 \le \overline{\Delta e_{b,s,d}} \ge e^h_{b,s,d,t} - e^0_{b,s,d^*} \qquad \forall s,d \quad (3q)$$

$$0 \le \underline{\Delta e_{b,s,d}} \ge e^0_{b,s,d^*} - e^h_{b,s,d,t} \qquad \forall s,d \quad (3r)$$

$$e^0_{b,s,d^*} + \sum_{d\in\mathcal{D}} V_{d^*,d} \cdot \overline{\Delta e_{b,s,d}} \le cap^{h,SOC}_b \qquad \forall s,d^* \quad (3s)$$

$$e^0_{b,s,d^*} - \sum_{d\in\mathcal{D}} V_{d^*,d} \cdot \underline{\Delta e_{b,s,d}} \ge 0 \qquad \forall s,d^* \quad (3t)$$

$$e^0_{b,s,0} \le e^0_{b,s,365} + \sum_{d\in\mathcal{D}} V_{365,d} \cdot \Delta e^h_{b,s,d} \qquad \forall s \quad (3u)$$

In each scenario s, revenues are generated by selling hydrogen at the hydrogen price $\lambda^h_{s,d,t}$ by discharging the storage $d^h_{b,s,d,t}$ and by offering discharge capacity $cap^{CM,h}_b$ in the hydrogen capacity market, remunerated at $\lambda^{CM,h}$ (Eq. (3c)). Costs (Eq. (3d)) include investment costs (the sum of capital costs for the (dis)charge capacity IC^P_b times the (dis)charge capacity cap^h_b and the storage volume IC^E_b times the storage volume $cap^{h,SOC}_b$), the costs for filling the storage ($\lambda^h_{s,d,t}$ times the amount of hydrogen injected $c^h_{b,s,d,t}$) and variable costs (VC_b times the sum of $c^h_{b,s,d,t}$ and $d^h_{b,s,d,t}$).

Constraint (3f)-(3g) limit the amount of hydrogen injected in and withdrawn from the storage. Equation (3k) limits the amount of hydrogen stored at every moment to the volume of the storage facility. The capacity offered in the hydrogen capacity market is limited to the discharge capacity (Eq. (3j)). Constraint (3l) tracks the state of charge (SOC) $e^h_{b,s,d,t}$ considering the charge and discharge efficiency η^{ch}_b and η^{dh}_b.

The Enhanced Representative Days (ERD) formulation (Eqs. (3o)-(3u)) proposed by Gonzato et al. [2] allows approximating the SOC evolution in non-representative days as a linear combination of the SOC evolution on representative days. Constraint (3o) introduces an auxiliary variable $\Delta e^h_{b,s,d}$ that represents the change in SOC on each representative day d for each scenario s. Constraint (3p) defines the base state of charge e^0_{b,s,d^*} for all the days of the year d^*, both representative and non-representative, with $V_{d^*,d}$ the ordering matrix containing the mapping of representative day d to non-representative days d^*. Equations (3q) and (3r) define the maximum positive and negative deviations from the base state of charge during a representative day, which allow defining limits on the state of charge limits for all days (Eqs. (3s)-(3t)). Last, a cyclic constraint ensures the final state of charge is at least equal to the state of charge at the start of the year (Eq. (3u)).

4) The consumer problem: We consider two aggregated consumers, one in the hydrogen sector and one in the electricity sector, based on [17]. As the two decision problems are identical, one general formulation is presented, in which super-

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scripts referring to hydrogen (h) or electricity (e) are omitted. Consumers maximize a weighted sum of their expected utility $\sum_{s \in \mathcal{S}} P_s \cdot \Pi_{c,s}$ and the $CVAR_c$:

$$\max \quad \gamma \sum_{s \in \mathcal{S}} P_s \Pi_{c,s} + (1-\gamma) CVAR_c \tag{4a}$$

with

$$d_{c,s,d,t} = d^{WTP}_{c,s,d,t} + d^{ELA}_{c,s,d,t} \tag{4b}$$

$$\Pi_{c,s} = \sum_{d \in \mathcal{D}} W_d \sum_{t \in \mathcal{T}} \Big[WTP \cdot d_{c,s,d,t} - (d^{ELA}_{c,s,d,t})^2 \cdot \frac{WTP}{2 \cdot \overline{d^{ELA}_{c,s,d,t}}} - \lambda^*_{s,d,t} \cdot d_{c,s,d,t} \Big] - \lambda^{CM,*} \cdot \overline{d^{CM,*}_c} \tag{4c}$$

$$CVAR_c = \alpha_c - \frac{1}{\beta} \sum_{s \in \mathcal{S}} P_s \cdot u_{c,s} \tag{4d}$$

subject to

$$0 \leq d^{WTP}_{c,s,d,t} \leq \overline{d^{WTP}_{c,s,d,t}} \qquad \forall s,d,t \tag{4e}$$

$$0 \leq d^{ELA}_{c,s,d,t} \leq \overline{d^{ELA}_{c,s,d,t}} \qquad \forall s,d,t \tag{4f}$$

$$\alpha_c - \Pi_{c,s} \leq u_{c,s} \qquad \forall s \tag{4g}$$

$$0 \leq u_{b,s} \qquad \forall s \tag{4h}$$

The inverse demand curve, characterizing the demand for hydrogen or electricity, consists of a horizontal segment at the maximum willingness to pay, and a linearly downward sloping segment. The demand $d_{c,s,d,t}$ can thus be split into demand that consumers only curtail if prices exceed their maximum willingness to pay ($d^{WTP}_{c,s,d,t}$) and elastic demand $d^{ELA}_{c,s,d,t}$, following [17]. Constraint (4e) limits the demand valued at the maximum willingness-to-pay $\overline{d^{WTP}_{c,s,d,t}}$. $\overline{d^{ELA}_{c,s,d,t}}$ limits demand that is price-elastic $d^{ELA}_{c,s,d,t}$ and is equal to $\frac{WTP}{m}$ where m is the slope of the elastic section of the inverse demand function (Eq. (4f)).

The utility of consuming electricity or hydrogen $\Pi_{c,s}$ is the difference between the integrated inverse demand function (first two terms in Eq. (4c)) and costs for procuring energy ($\lambda^*_{s,d,t} \cdot d_{c,s,d,t}$) and capacity ($\lambda^{CM,*} \cdot \overline{d^{CM,*}_c}$) (Eq. (4c)) [17]. The demand for capacity is set exogenously (see Section III). The $CVAR_c$ is computed via Eq. (4d) and Eqs. (4g)-(4h).

5) Market clearing: The electricity and hydrogen markets coordinate demand and supply:

$$\sum_{e \in \mathcal{E}} g^e_{e,s,d,t} + d^e_{c,s,d,t} - \sum_{g \in \mathcal{G}} g^e_{g,s,d,t} = 0 \qquad \forall s,d,t \tag{5a}$$

$$\sum_{e \in \mathcal{E}} g^h_{e,s,d,t} + \sum_{b \in \mathcal{B}} (d^h_{b,s,d,t} - c^h_{b,s,d,t}) - d^h_{c,s,d,t} - \sum_{g \in \mathcal{G}} g^h_{g,s,d,t} = 0 \qquad \forall s,d,t \tag{5b}$$

Capacity markets must balance the exogenous demand for electricity ($\overline{d^{CM,e}_c}$) and hydrogen generation capacity ($\overline{d^{CM,h}_c}$) with available supply:

$$\sum_{g \in \mathcal{G}} cap^{CM,e}_g = \overline{d^{CM,e}_c} \tag{5c}$$

$$\sum_{b \in \mathcal{B}} cap^{CM,h}_b + \sum_{e \in \mathcal{E}} cap^{CM,h}_e - \sum_{g \in \mathcal{G}} cap^{CM,h}_g = \overline{d^{CM,h}_c} \tag{5d}$$

Note that hydrogen-fired generation needs to firm up its capacity offers in the electricity generation capacity market ($cap^{CM,e}_g$) in the hydrogen capacity market ($cap^{CM,h}_g$, demand for capacity).

The dual variables associated with these market clearing constraints equal the price for electricity ($\lambda^e_{s,d,t}$), hydrogen ($\lambda^h_{s,d,t}$), electricity generation capacity ($\lambda^{CM,e}$), and hydrogen production or discharge capacity ($\lambda^{CM,h}$).

C. Solution strategy

To compute the Nash equilibrium of the game (Problems (1)-(4) and coupling constraints (5)), we use the Alternating Direction Method of Multipliers (ADMM), following [14], [15], [17]. The algorithm behaves as an iterative price search technique: in each iteration, the agents (Problems (1)–(4)) update their strategy given the current electricity, hydrogen and capacity prices, i.e., dual variables associated with the coupling constraints (Eqs. (5)). Subsequently, these prices are updated based on the imbalance in the coupling constraints.

An equilibrium is reached when the primal and dual residuals simultaneously meet a predefined convergence criterion. The primal residual is defined as the normalized L2-norm of the imbalances of each market clearing condition (Eqs. (5)). The dual residuals measure the differences in decision variables that appear in the market clearing conditions between two consecutive iterations. The primal convergence criterion is defined as 1% of the maximum demand in the hydrogen and electricity market multiplied by the number of time steps (24), the number of representative days (8) and the number of scenarios (18), following [14]. The convergence criterium for the capacity markets equals 0.1% of the capacity demand.

The models are implemented using the JuMP library in Julia and solved with Gurobi. All code, input data, and results are available via GitHub [28].

III. Case Study

We study the long-term equilibrium in a climate-neutral, integrated electricity-hydrogen system for different degrees of risk-aversion in three different market designs: (i) an energy-only market (EOM) for hydrogen and electricity; (ii) a hydrogen and electricity market complemented with a capacity market for dispatchable electricity generation (CM-E); and (iii) a hydrogen and electricity market complemented with a CM for dispatchable electricity generation capacity and for hydrogen production (CM-E+H_2).

The system is based on wind, solar PV, biomass, open-cycle hydrogen-fired turbines, electrolyzers (alkaline technology), and long-term hydrogen storage in salt caverns. Assumptions on capital costs, lifetimes, variable costs and efficiencies have been derived from the open model dataset of PyPSA-Eur [29], a recent study by TNO [30] and IEA [8] (Table I). Each asset's capital cost (IC) is computed from the corresponding overnight cost OC, annualized with a nominal discount rate r of 10% over the asset's lifetime.

The maximum willingness to pay is set to 1000 €/MWh for both the electricity and hydrogen sectors. The electricity demand valued at the maximum willingness to pay is set to

80% of the observed demand ($d^{hist}_{s,d,t}$) in the Netherlands in 2017-2022. The slope of the elastic demand section is obtained by interpolating between ($0.8 \cdot d^{hist}_{s,d,t}$, 1000) and ($d^{hist}_{s,d,t}$,$\lambda^{hist}_{s,d,t}$), in which $d^{hist}_{s,d,t}$ and $\lambda^{hist}_{s,d,t}$ are observed demand and wholesale price levels (see below) [31]. We assume an annual reference hydrogen demand of 2 $\mathrm{MtH_2}$. This represents an estimate of the hydrogen demand in the Netherlands post 2050 satisfied by domestic production [32]. This annual demand is distributed uniformly over the year, after which we scale it to reflect (i) the correlation between hydrogen and electricity demand and (ii) the temperature dependency. 80% of the hourly demand is valued at the maximum willingness to pay. The slope of the remainder of the inverse demand function is set to the average slope of the inverse electricity demand function.

The exogenous, inelastic demand in the electricity capacity market is set to the volume of dispatchable capacity calculated in a simulation considering an EOM and risk-neutral agents following [17]. Only biomass and hydrogen turbines are eligible in the electricity capacity market ($\Phi_g = 1$). Similarly, the inelastic demand in the hydrogen capacity market is set to the total electrolyzer and storage discharge capacity in the risk-neutral EOM simulation, corrected for the installed $\mathrm{H_2}$-turbine capacity.

Observations for the period 2017-2022 for the Netherlands describe the uncertainty in the availability of renewables and electricity demand [31]. Each of the six weather years is associated with three scenarios representing different levels of hydrogen demand: the reference demand, a 20% increase and a 20% decrease. This yields 18 scenarios, which we assume to occur with equal probability. Each year is represented via 8 representative days, using RepresentativePeriodsFinder.jl [2].

In what follows, we discuss investments, demand served, prices, the cost of hydrogen and electricity to consumers for the three different market designs with missing risk markets. We consider a scenario in which risk-averse investors – excluded from the capacity market or any other complementary policy – determine vRES capacity endogenously and another scenario that fixes it to the level of investments achieved by a risk-neutral social planner. These two extremes in terms of risk exposure of investors in solar and wind capacity allow testing the robustness of our results with respect to complementary policies that drive investments in solar and wind.

Throughout the discussion, the results of the risk-neutral case serve as a common reference. Introducing risk-aversion is expected to lead to reduced investment levels and elevated risk-adjusted costs to consumers when markets for risk are incomplete. We assess whether introducing capacity markets allows limiting the expected risk-adjusted cost to consumers by restoring investment levels.

A. Capacity mix

In an EOM, risk-neutral actors ($\beta = 1.0$) invest in 150.6 GW of electricity generation capacity, of which 93% is wind and solar. The remaining capacity comprises 7.5 GW of biomass and 2.5 GW of hydrogen-fired turbines. On the hydrogen side, investments include 33 GW_e of electrolyzers, 14.6 GW_{H2} of hydrogen storage discharge capacity and 11.4 TWh of storage. On average, the electrolyzers yield an additional electricity demand of 14.3 GWh/h, similar to the rest of the electricity demand. This capacity mix will serve as a reference to contrast investments of risk-averse agents under different market designs.

TABLE I: Assumptions for considered technologies. *O&M cost and the cost of biomass. **O&M cost only. The cost of hydrogen is computed endogenously (Eq. (1d)). The efficiency of the salt cavern represents the round trip efficiency (i.e., $\eta^{dh}_b \cdot \eta^{ch}_b$).

Technology	Overnight Costs ($M€/GW$)	Operational Costs ($€/MWh$)	Lifetime (yr)	Efficiency ($-$)	Ref.
Wind	1118	5	25	–	[29]
Solar	529	2	35	–	[29]
Biomass	4400	85*	25	–	[7], [29]
$\mathrm{H_2}$ turbine	450	2.7**	30	0.40	[33]
Electrolyzer	500	–	25	0.68	[29]
Salt Cavern	206 $M€/GW_{H_2}$ 150 $M€/TWh$	–	40	0.95	[8], [30]

1) Energy-only markets: Risk-averse agents invest in up to 9% less capacity (137 GW vs. 150.6 GW). Considering endogenous wind and solar investments, solar and wind capacity decreases exponentially as investors become more risk-averse. The impact on dispatchable capacity is more complex, as biomass generators partly replace low capital-cost hydrogen turbines, whose capacity is halved (-1.3 GW) (Figure 1a). The driver of this effect is that uncertainty affects the revenues of biomass and hydrogen-powered turbines differently, hence, lead to different risk exposure. Biomass availability and variable costs are assumed to be known, exposing biomass generators only to uncertain electricity prices. In contrast, hydrogen turbines face risks from uncertain hydrogen prices and hydrogen demand in addition to uncertain electricity prices. In addition, with less solar and wind due to increased risk aversion, hydrogen prices increase (Fig. 2, see below), reducing the profitability of hydrogen-fired turbines. If the wind and solar capacities are fixed (Figure 1b), the capacities of biomass and hydrogen turbines decrease. The reduction in hydrogen turbine capacity is half of the decrease in Fig. 1a.

The electrolyzer and storage discharge capacities decrease by up to 3.7 GW_{H2} (17%) and 3.5 GW_{H2} (24%) considering endogenous investments in wind and solar (Fig. 1d, solid lines). Less solar and wind reduce the number of low-price periods, reducing the profitability of electrolyzers and increasing hydrogen prices (Fig. 2, see below). Those reductions are halved with fixed wind and solar capacities (Fig. 1c, solid lines). Similarly, storage volumes reduce by up to 2 TWh assuming market-driven wind and solar investments, while this reduction is limited to 0.7 TWh with fixed solar and wind investments. These trends highlight how the availability of vRES is crucial in limiting the risk exposure of hydrogen investments.

2) Capacity market in the electricity sector: Adding a capacity market in the electricity sector restores the level of dispatchable power capacity to the level of the risk-neutral case. It partially mitigates the shift to biomass, assuming market-driven investments in solar and wind (Fig. 1a, dashed

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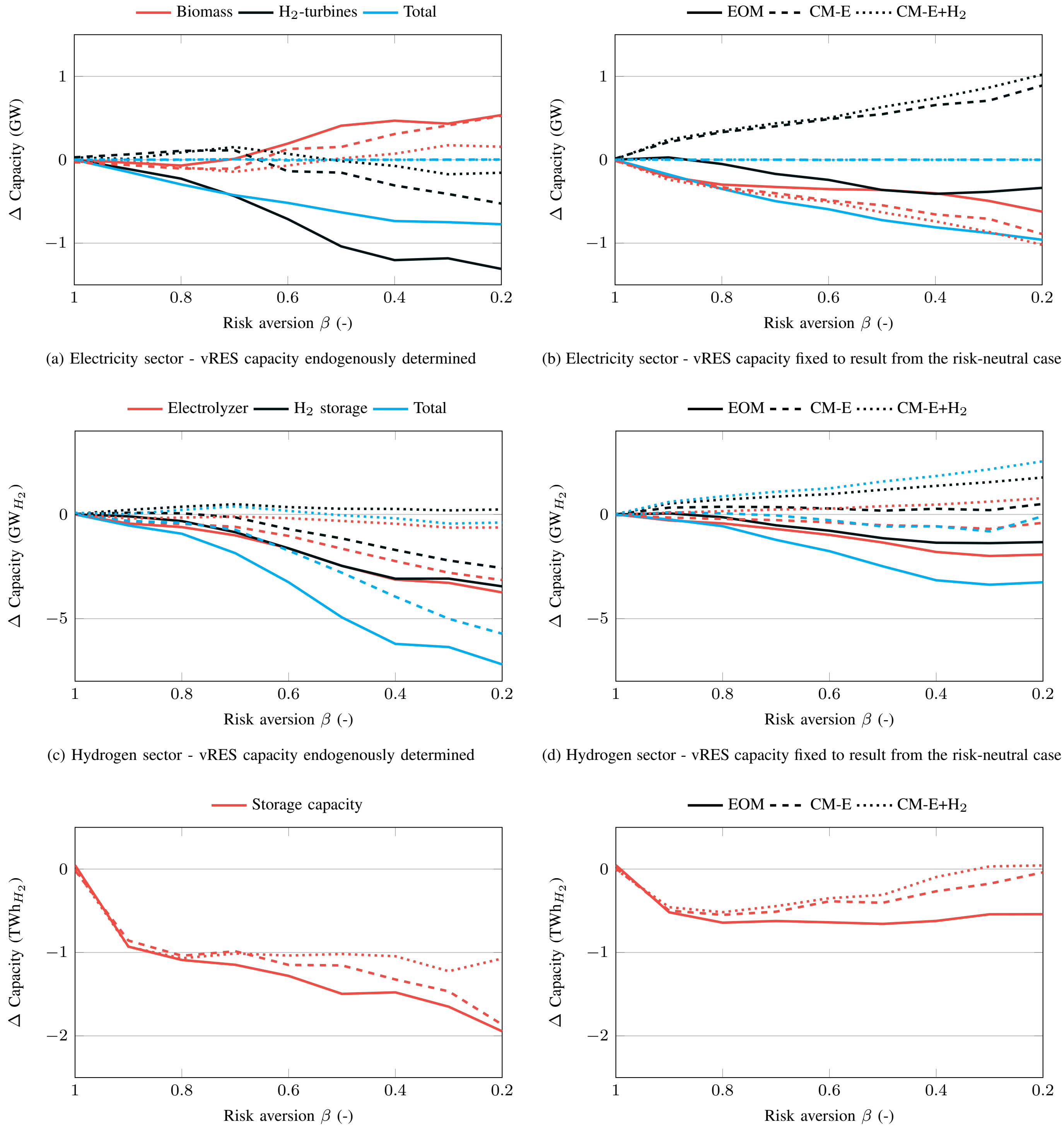


(a) Electricity sector - vRES capacity endogenously determined

(b) Electricity sector - vRES capacity fixed to result from the risk-neutral case

(c) Hydrogen sector - vRES capacity endogenously determined

(d) Hydrogen sector - vRES capacity fixed to result from the risk-neutral case

(e) Storage volumes - vRES capacity endogenously determined

(f) Storage volumes - vRES capacity fixed to result from the risk-neutral case

Fig. 1: Difference in installed capacity w.r.t. the risk-neutral reference case under the three considered market design as a function of the degree of risk aversion β. Wind and solar capacity are not shown because they are not renumerated in the electricity capacity market.

lines). However, since solar and wind capacities remain below their levels in the risk-neutral case, higher and more risky investments in hydrogen-fired turbines are still discouraged in favor of biomass despite its higher capital cost. This is contrary to the trends observed with fixed solar and wind capacity (Fig. 1b). In this case, introducing an electricity capacity market prompts a shift toward hydrogen turbines because of their lower capital costs while exacerbating the reduction of biomass capacity, which is more capital-intensive. This is in line with other findings on the effects of capacity markets in electricity-only studies [15], [17].

The capacity market in the electricity sector leads to an increase in investment in electrolyzers and hydrogen storage capacity. Assuming market-driven investments in solar and wind, the increase is insufficient to restore the electrolyzers, storage discharge capacity and storage volume to their risk-neutral levels (Figs. 1c and 1f). With fixed solar and wind capacity, the introduction of a capacity market in the electricity sector nearly restores the level of capacity in the hydrogen sector (Figs. 1d and 1f). The capacity market promotes hydrogen turbine capacity (Figs. 1b), which increases the demand for hydrogen, hence, investments in electrolyzer and storage capacity.

3) Capacity market in the hydrogen and electricity sector: Assuming market-driven wind and solar investments, this market design realigns the capacity mix with risk-neutral equilibrium (Fig. 1a, dashed-dotted lines). The difference in the capacity of each dispatchable technology with respect to the risk-neutral case does not exceed 0.2 GW. The hydrogen capacity market promotes investments in electrolyzer capacity and storage discharge capacity, with a bias towards discharge capacity (Fig. 1c). This promotes additional wind and solar investments (e.g., +9.5 GW compared to the EOM case at $\beta = 0.2$), as these electrolyzers form a flexible electricity demand, increasing capture prices for wind and solar. In addition, lower and less risky hydrogen prices (see below) minimize the bias toward biomass (Figure 1a). Note that the introduction of capacity markets in both sectors stabilizes the reduction in storage volume with increasing risk aversion, despite that it is not explicitly remunerated.

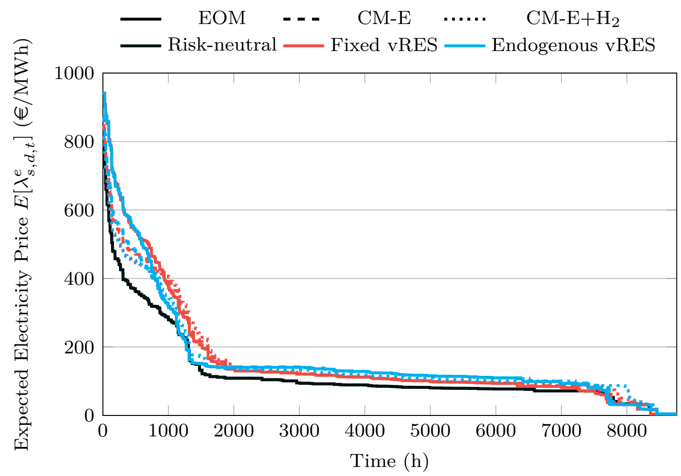
Fixed solar and wind capacities combined with capacity payments in the hydrogen sector lead to overinvestments in electrolyzer and storage capacity (Fig. 1d). This is driven by the combination of (i) the shift to hydrogen-fired turbines in the electricity system (see above) and (ii) the inelastic demand in the hydrogen capacity market, which is set to the total electrolyzer and storage discharge capacity in the risk-neutral EOM simulation, and the demand for hydrogen capacity from these H_2 turbines.

B. Electricity and hydrogen prices

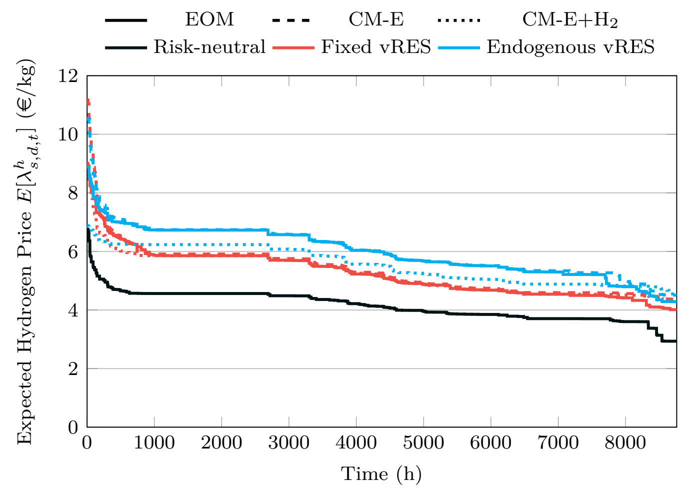
Table II and Fig. 2 summarize electricity and hydrogen prices under the three market designs considering risk-neutral agents, risk-averse agents with endogenous investments in vRES and risk-averse agents with vRES capacity fixed to the outcome in the risk-neutral case. Four trends can be observed.

First, electricity prices are well above zero for over 90% of the time across all cases, despite the high shares of variable, near-zero marginal cost renewables in the system. The flat part of the electricity price duration curves, covering over 80% of the year, illustrates how the opportunity costs of flexible demand – including electrolyzers – set electricity prices. Hydrogen prices vary between 3 €/kg and 11.4 €/kg.

Second, as expected, introducing risk aversion and the accompanying risk premium raises electricity prices across all market designs. The average electricity price ranges from 122 €$/MWh$ (all cases, risk-neutral) to 163 €$/MWh$ (EOM, risk-averse, endogenous vRES investments). Risk aversion results in more frequent and higher peak electricity price periods (Fig. 2): the average of the 5% highest prices increases



(a) Electricity price duration curves



(b) Hydrogen price duration curves

Fig. 2: Electricity and hydrogen price duration curves for the three market designs considering risk-neutral agents, risk-averse agents with endogenous investments in vRES ("free vRES") and risk-averse agents with vRES capacity fixed to the outcome in the risk-neutral case (fixed vRES"). The duration curves were computed per scenario, after which they were averaged across the 18 scenarios. Recall that the efficiency of the H_2 turbine and electrolyzer are assumed to be 0.4 and 0.68 (Table I). The lower heating value of hydrogen is 0.03333 MWh/kg.

TABLE II: Mean, median, average of peak (above 95% percentile) and average of low (below 5% percentile) hourly electricity ($€/MWh$) and hydrogen prices ($€/kg$) for the three market designs in three cases: risk-neutral agents, risk-averse agents with endogenous investments in vRES and risk-averse agents with vRES capacity fixed to the outcome in the risk-neutral case. Recall that the efficiency of the H_2 turbine and electrolyzer are assumed to be 0.4 and 0.68 (Table I). The lower heating value of hydrogen is 0.03333 MWh/kg.

(a) Electricity prices (€/MWh)

	Risk neutral ($\beta = 1.0$)				Risk averse ($\beta = 0.2$) Free vRES				Risk averse ($\beta = 0.2$) Fixed vRES			
	Mean	Median	High 5%	Low 5%	Mean	Median	High 5%	Low 5%	Mean	Median	High 5%	Low 5%
EOM	122.89	85.11	495.20	9.54	163.58	123.89	702.60	7.95	159.98	106.68	701.73	5.15
CM E					158.39	124.10	606.20	9.79	156.15	108.43	586.78	9.38
CM E+H2					154.88	114.52	552.83	11.19	156.49	107.75	554.75	10.08

(b) Hydrogen prices (€/kg)

	Risk neutral ($\beta = 1.0$)			Risk averse ($\beta = 0.2$) Free vRES			Risk averse ($\beta = 0.2$) Fixed vRES		
	Mean	High 5%	Low 5%	Mean	High 5%	Low 5%	Mean	High 5%	Low 5%
EOM	4.14	5.23	3.12	5.97	7.59	4.37	5.24	7.32	4.08
CM E				6.04	8.06	4.58	5.35	7.93	4.41
CM E+H2				5.54	6.44	4.71	5.24	6.92	4.42

from 488 – 495 €/MWh up to 702 €/MWh (EOM, risk-averse, endogenous vRES investments). As risk aversion decreases the volumes of renewables, electrolyzer, and hydrogen storage capacity in the system, less backup capacity (H_2-fired turbines) is available, and hydrogen is more expensive during peak demand periods. With less vRES capacity, electrolyzers and storage, stronger competition for renewable electricity drives up hydrogen and electricity prices. In contrast to electricity prices, risk aversion causes hydrogen prices to be higher throughout the year: average hydrogen prices increase by 1.4 – 1.9 €/kg (RES capacity fixed as in the risk-neutral case, "Fixed vRES") or 1.1 – 1.2 €/kg (endogenously determined RES capacity, "Free vRES"). Peak hydrogen prices, however, are most affected, with increases up to 2.8 €/kg.

Third, increasing the vRES capacity in the system by fixing it at the level of the risk-neutral EOM case decreases electricity and hydrogen prices during most of the year but not during high-price periods. This can be observed by comparing the results for risk-averse investors in the "free vRES" and "fixed vRES" cases in Fig. 2 and Table II. Across the different market designs, median electricity prices decrease by 14 €/MWh to 17 €/MWh, which dominates the impact of introducing a capacity market. The strongest impact is observed in the EOM-case, as the installed renewable capacity decreases the most under this market design when investors are risk-averse. The effect on hydrogen prices is limited to 0.7 €/kg, as lower electricity prices and hydrogen capacity payments increase the demand for hydrogen.

These impacts on electricity and hydrogen prices are reflected in the volumes of electricity and hydrogen demand that are served (Table III). Risk aversion increases electricity and hydrogen prices, reducing the volume of served demand, compared to the risk-neutral case. In the electricity sector, the reduction is more than 1 TWh in the EOM case, in the hydrogen sector, it is between 0.2 and 0.3 Mton. As demand is price elastic, this does not necessarily entail involuntary curtailment. Introducing capacity markets and/or increasing the amount of renewables in the system dampens this demand reduction. However, risk aversion and different market designs also yield different capacity mixes, with a different degree of dependency on hydrogen for back-up electricity generation.

TABLE III: Annual electricity served (TWh) and annual hydrogen demand served (MtH_2) for the three market designs in three cases: risk-neutral agents, risk-averse agents with endogenous investments in vRES ("Free vRES") and risk-averse agents with vRES capacity fixed to the outcome in the risk-neutral case ("Fixed vRES").

(a) Annual electricity demand served (TWh)

	$\beta = 1$	$\beta = 0.2$ Free vRES	$\beta = 0.2$ Fixed vRES
EOM	109.676	108.528	108.612
CM-E	109.687	108.677	108.764
CM-E+H_2	109.682	108.890	108.686

(b) Annual hydrogen demand served (MtH_2)

	$\beta = 1$	$\beta = 0.2$ Free vRES	$\beta = 0.2$ Fixed vRES
EOM	2.214	2.177	2.190
CM-E	2.214	2.174	2.187
CM-E+H_2	2.214	2.183	2.189

C. *Cost to consumers*

Risk aversion increases total risk-adjusted costs from 22.1 B€/year to 29.9 B€/year ($\beta = 0.2$) (Figure (a)). The risk-adjusted costs to consumers aggregate (i) all energy and capacity costs payable by consumers and (ii) the cost of involuntary load shedding. Average electricity costs increase from 116.7 €/MWh to 153.7 €/MWh and hydrogen costs from 4.22 €/kg to 6.02 €/kg in the EOM case (Fig. 3). Fixing the vRES capacity to the outcome of the risk-neutral case reduces the energy costs to consumers: total risk-adjusted costs are below 27.8 B€/year, hydrogen costs are limited to 5.32 €/kg and electricity costs maximally reach 147.7 $€/MWh$ in the EOM case.

The introduction of capacity markets in both markets reduces energy costs, as they lower the risk premiums required by generators, electrolyzers and storage owners. The decrease in expected risk-adjusted total costs to consumers is more pronounced if risk-averse vRES investors are fully exposed to market prices, with decreases in costs up to 1.8 B€/year (Figure (a)). However, an electricity capacity market alone decreases the costs to consumers by at most 0.5 B€/year or 4€/MWh for electricity. When combined with a fixed vRES capacity, it even increases the costs for hydrogen consumers because of a bias towards H_2-turbines, while the capacities of electrolyzer and hydrogen storage discharge are not increased proportionally , increasing the competition for H_2. The introduction of a hydrogen capacity market avoids cost increments in both the electricity and hydrogen sectors. This positive effect exists regardless of the vRES capacity but is more pronounced when vRES investments are market-driven.

IV. Conclusion

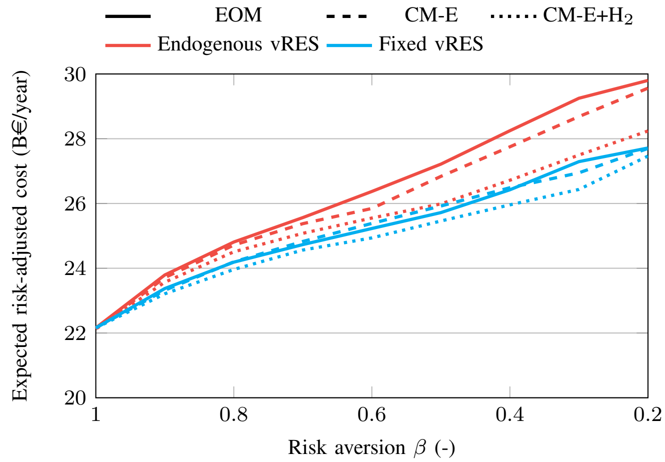
In a climate-neutral energy system, risk-averse investors will not invest in sufficient renewable electricity generation, hydrogen turbines, hydrogen production and storage capacity if they are remunerated via energy-only hydrogen and electricity markets and risk markets remain incomplete. Complementary policy measures, such as capacity markets and support instruments for renewables are required to restore investment levels and the capacity mix, limiting costs to consumers.

While capacity markets have been successfully introduced in the electricity sector, their efficacy in an integrated hydrogen-electricity system remained untested. We test three different market designs using an equilibrium model representing the interplay between risk-averse actors in integrated hydrogen-electricity markets, namely (i) EOM for hydrogen and electricity, (ii) a capacity market for dispatchable electricity generation, and (iii) capacity markets in the electricity and hydrogen sector. We consider a scenario with endogenous, market-driven vRES investments and one with exogenous, policy-driven wind and solar investments.

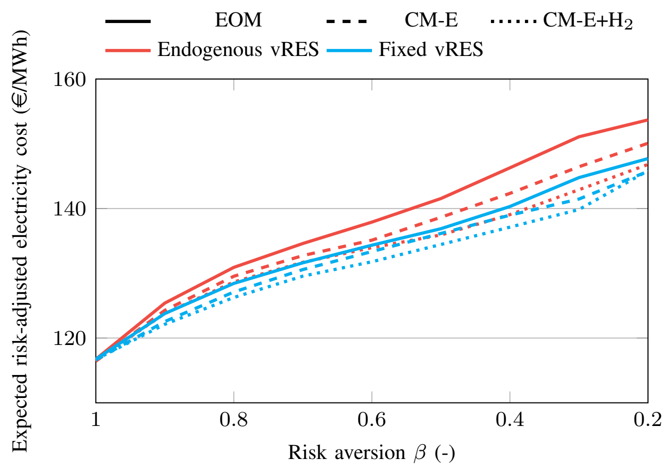
In line with the literature, our case study shows how risk-averse actors competing in energy-only markets reduce their investments, resulting in higher consumer costs, in abscence of markets for risk. Capacity markets dampen this effect, restoring the investment levels and limiting the energy cost for consumers, especially by limiting prices during peak demand periods. However, the efficiency of these capacity markets depends on complementary measures to support the build-out of renewables.

Exogenously ensuring solar and wind investments (e.g., via a complementary policy instrument) leads to lower electricity prices and therefore also lower hydrogen prices. The availability of renewables reduces the risk exposure of investments in hydrogen production and storage. Combining exogenous, policy-driven vRES investments with capacity markets may result in a bias towards low-capex, high-opex hydrogen-fired back-up capacity, in line with Kaminski et al. [17] and Mays et al. [15].

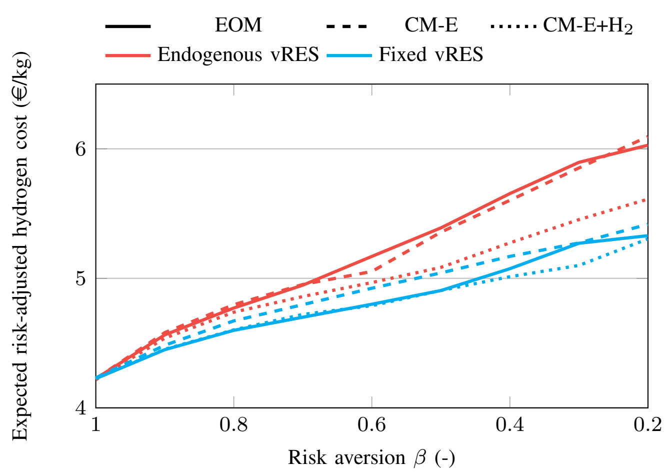
When investment in wind and solar is market-driven, it is also reduced if investors are risk-averse and markets for risk are incomplete, leading to higher electricity and hydrogen



(a) Risk-adjusted total cost to consumers (M€)



(b) Risk-adjusted average cost of electricity (€/MWh)



(c) Risk-adjusted average cost of hydrogen (€/kg)

Fig. 3: Total risk-adjusted cost to consumers (a), risk-adjusted average cost of electricity (b) and hydrogen (c) to consumers for the three market designs considering risk-neutral agents ($\beta = 1$), risk-averse agents with endogenous investments in vRES ("Free vRES") and risk-averse agents with vRES capacity fixed to the outcome in the risk-neutral case ("Fixed vRES"). The electricity and hydrogen cost encompasses energy and capacity payments (if applicable). The cost of complementarity vRES policies is not included.

prices. This results in a shift towards high-capex, low-opex biomass. In this case, a combination of capacity markets in the electricity and hydrogen sectors is needed to lift investments and limit costs to consumers.

Future work could entail a more detailed consideration of the cost structure and technical characteristics (e.g., state-of-charge dependent charge and discharge limits) of the long-duration energy storage. In addition, evaluating the performance of these markets in transition scenarios, e.g., when demand for hydrogen turns out to be lower than expected, would allow evaluating the regret associated with over- or underinvestments.

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