Market power in Power-to-Gas and related markets? Preliminary insights for the upcoming interrelated power, gas, and hydrogen industries.

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Abstract

In recent years, low-carbon hydrogen has evolved from a cutting-edge technology to an essential energy carrier for the energy transition. Produced from renewable electricity by power-to-gas (PTG), it could play a significant role in the energy sector's decarbonization by alleviating the curtailment of variable renewable electricity and replacing conventional fuels. In Europe, the first pilot projects are underway, and technology investments are expected in the coming years. However, issues on the industrial organization of PTG assets have so far little been discussed. As PTG investments are currently undertaken by companies with a strong presence in the power, gas, or hydrogen markets, one can wonder whether ownership matters for the efficient operation of these markets and whether that ownership substantially affects the market's outcomes.

We propose a generic computerized model of the power, gas, and hydrogen industries and their interactions to investigate the effects of market powers and strategic considerations on future market outcomes. We consider seven scenarios whereby PTG belongs to various strategic players who differ in their generation units.

Market simulations show that PTG operation varies according to PTG ownership: producers already established in the hydrogen market tend to make little use of PTG, whereas renewable electricity producers tend to use it more to optimize revenues from different markets. Although PTG increases overall welfare, heavy use may raise social and environmental concerns. Social, because the global welfare distribution among agents is unequal, and environmental, because PTG use could indirectly lead to an increase in carbon-based electricity generation.

1 Introduction

Alongside renewable electricity, hydrogen is presented in many scenarios as a crucial energy carrier for the energy transition [1]. Currently produced from natural gas through steam methane reforming (SMR), hydrogen can be obtained from renewable electricity by electrolysis of water. This technology, called Power-to-Gas (PTG), could play a significant role in the energy sector's decarbonization and the industry's adaptation to climate issues. Seasonally storable, electricity-based hydrogen production can alleviate the curtailment of variable renewable electricity (VRE) and bring spatial and temporal flexibility to the electricity system. It can also replace coal, oil, natural gas, and conventional hydrogen for uses where energy needs cannot easily be met by electricity and thus contribute to energy security by decreasing dependency on fossil fuels.

On a European scale, favorable conditions are met for deploying a hydrogen market. Indeed, Europe is a world leader in hydrogen technology, and its industrial base can play a crucial role in fostering scientific progress and rapid scale-up of hydrogen manufacturing [2]. Moreover, the European Commission has detailed a European Hydrogen Strategy [3] and has set in the Fit for 55 package a target of 44 GW installed electrolyzers capacity by 2030 [4], recently increased to 80 GW in the REPowerEU plan [5].

Europe could be one of the forerunners in developing the hydrogen market. In the short term, the focus is on developing pilot projects and hydrogen valleys [6]. Research and development are also being carried out to design large-capacity electrolyzers and reduce their costs to make PTG a competitive technology [7]. In the medium term, close attention must be paid to developing the hydrogen market design framework to move from pilot projects to a mature, transparent, and liquid hydrogen market. Indeed, the development of the hydrogen market is unique. It is a top-down market where regulations are decided before trade develops. During this ramp-up period, research is needed to develop appropriate regulation to stimulate supply and demand while ensuring free competition in the long-term.

PTG is a sector coupling technology at the border between the electricity, gas, and future hydrogen markets. Studying the impact of the introduction of PTG in the energy system requires considering these markets together. Against this background, PTG as a sector coupling technology is the subject of growing literature. The literature review made by Blanco has examined the benefits of PTG as a source of flexibility in more than 60 studies [8]. It shows that although PTG is at its early stages, it could serve as a substitute for seasonal electricity storage and is relevant in scenarios with high variable renewable energy (VRE) penetration. In [9], Vandewalle & al develop an operational model to study the impact of PTG on the electricity, gas, and CO_2 markets. The authors demonstrate that PTG lessens gas price pressure and energy curtailment and decreases the need for CO_2 storage. In [10], Roach & Meeus consider an equilibrium model of the electricity and gas markets, in which these markets are cleared separately but coupled by PTG. They investigate the effects of the PTG investment decisions on price and welfare and found that the electricity and gas sectors have aligned motivations to engage around PTG. Li & Mulder develop a short-term equilibrium model of an integrated electric and hydrogen market to study the impact of hydrogen demand on the flexibility services provided by PTG [11]. They show that PTG reduces electricity price volatility but that hydrogen demand lessens this effect. In this setting, renewable electricity producers, PTG producers, and hydrogen consumers benefit from adding PTG, whereas PTG reduces electricity consumers' welfare. Finally, to our knowledge, Koirala & al are the only ones to study a system of electricity, hydrogen, and gas markets together [12]. They demonstrate that the interconnection of electricity, methane, and hydrogen infrastructure through, among others, electrolyzers, gas, and hydrogen-fired power plants offers the future energy system the flexibility it requires.

However, PTG is still a niche technology with high investment costs [7]. Although research is underway to reduce these costs, it may need regulatory support to scale-up. Designing such regulations requires a clear understanding of the impact it will have on the different players in the energy markets. For instance, Lynch & al represent electricity producers with different generation portfolios to study market and portfolio effects on PTG investment and operations [13]. They highlight that even if PTG is non-profitable, producers with renewable production in their portfolio are incentivized to invest in it as PTG increases power demand during periods of low net demand and thus drives up electricity prices. In [14], Schlund & al study the impact of a renewable hydrogen quota on the European electricity and gas market. They show that a quota could help stimulate investment in renewable electricity and electrolyzers to produce electricity-based hydrogen and synthetic methane. However, such a regulation redistributes welfare from gas consumers to renewable electricity producers and may result in a decline in total welfare.

Nevertheless, one can wonder whether the findings obtained when positing the presence of pure and perfect competition also hold in case of imperfect competition. To the best of our knowledge, there are no papers that study the impact of potential market power on PTG. In contrast, in the case of storage, extensive literature investigates the influence of market imperfection on electricity storage operations. For instance, Schill & Kemfert study pumped hydro storage use when electricity market players have strategic behavior [15]. They show that strategic operators under-utilize storage, and that welfare losses may result from the strategic use of storage if an oligopolistic firm with conventional production capacity controls all storage capacity. Virasjoki & al demonstrate in [16] that the strategic use of energy storage units by electricity producers can make it less efficient to reduce both congestion and ramping costs. In [17], Sioshansi shows that in an imperfect market, the use of electricity storage varies depending on storage ownership. Indeed, as electricity storage can decrease the value of energy arbitrage and reduce consumer energy costs and generator profits, merchant storage operators will generally under-use storage, whereas electricity consumers will overuse it compared to the social optimum.

Our paper seeks to investigate whether such effects are to be expected in the context of the introduction of PTG into the energy system. Indeed, PTG investments are currently undertaken by large companies with a strong oligopolistic presence in the energy sector [18]. Furthermore, these large firms substantially differ in nature. Depending on the case, electrolyzers will be owned by either existing electricity producers, gas midstreamers, hydrogen producers, or independent private players. Against this background, market power considerations can naturally affects markets outcomes and thus the profits yielded by the market participants: on the one hand, players in the gas or hydrogen systems, for whom PTG constitutes a source of production in competition with their other activities, and on the other hand, players in the electricity system, for whom PTG represents an additional source of income. In case of a multi-market player, the actions taken in one market may affect the firm's profitability in the other market and one also has to consider the effects of the resulting strategic interactions on the firm's decisions.

In this paper we examine the effects of these market power and strategic considerations on the future market outcomes. To investigate it, we propose a generic computerized model of the power, gas and hydrogen industries and their interactions. We thus specify and solve a market equilibrium formulated as an instance of a Mixed Complementarity Problem (MCP). MCP have been developed for various issues encountered in the energy sector [19], and has the merit of being directly connected with non-cooperative game theory since the model allows for a direct representation of the interactions between interdependent players. Each player is posited to solve a player-specific optimization problem, and the MCP format allows to compute a Nash equilibrium.

Consistent with the usual static comparisons conducted in standard industrial organization textbooks, the model is solved using a predefined set of alternative market structures that are representative of the different ownership models that can be envisioned for the PTG assets. We then methodically compare the obtained market outcomes in the gas, power, and hydrogen markets and analyze the equilibrium prices, quantities and the resulting social implications.

Our paper is organized as follows. We present our modeling of the electricity, gas, and hydrogen markets and the the optimization problems of the different agents in section §2. Section §3 provides data and list the different scenarios considered. Results are detailed in section §4. Finally, we summarise our main conclusions and suggest some avenues of research for future studies in the conclusion section §5.

2 Methodology

2.1 Model overview

The present analysis is based on a stylized partial equilibrium model that applies principles from game theory and optimization to simulate the interactions between the markets for natural gas, power and hydrogen. The model is formulated as a deterministic, discrete-time, finite-horizon oligopoly model that explicitly takes into account the imperfectly competitive structures prevailing in these three sectors. By construction, the model captures the strategic interactions between the different types of oligopolistic players operating in these industries.

Our modeling framework considers an annual time horizon to account for seasonal variations in energy demand and supply. It overlooks investment considerations as it solely focuses on the operations of assets with exogenously predetermined capacities. Furthermore, the model overlooks spatial considerations and the role of energy transportation infrastructures.

All individual suppliers are depicted as profit-maximizers under specific constraints, with a distinctive revenue and cost structure for each supplier type. The agent's behavior and strategy sets are further detailed in the next subsection. For the moment, we simply stress that the model includes Cournot players capable to exert market power by withholding supplies to force up prices for larger profits. As we clarify in the next subsection, the multi-markets agents with vertically related operations can also exert market power on the buyer side by withholding purchases to obtain lower input prices.

Figure 1 provides a compact overview of the three markets and the different agents under our baseline scenario that has no PTG.

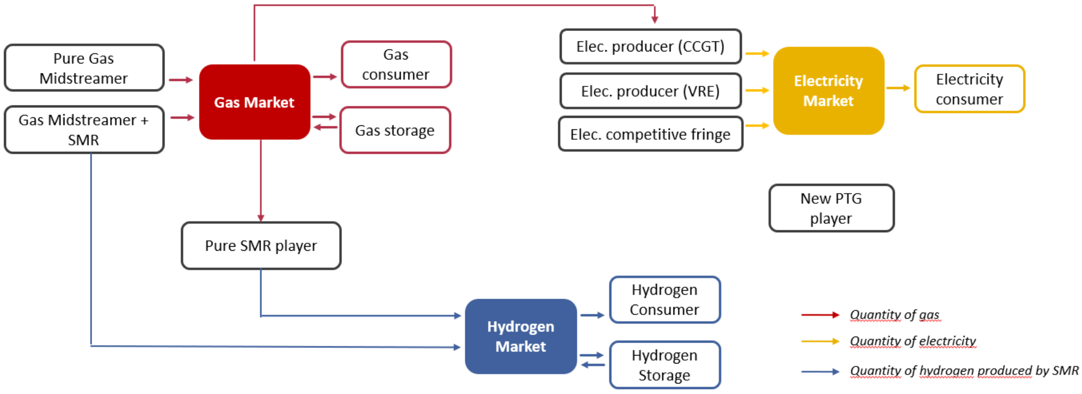

Figure 1: Overview of the three markets and the different agents under the baseline scenario

In each sector, the aggregate demand emanating from end-users is determined by a linear demand function. Regarding electricity supply, we assume that generation is operated by a group of Cournot firms and a competitive fringe. For simplicity, we only retain two generation technologies: either intermittent renewable sources (Variable Renewable Electricity, hereafter VRE) or dispatchable generation in the form of Combined Cycle Gas Turbine (CCGT).

Regarding natural gas supply, we consider a duopoly of midstream firms (a.k.a., shippers) which resell the gas purchased through long-term contracts (LTC). For simplicity, we assume that these LTCs are exogeneously determined and do not model the bargaining procedure between these firms and the producers of petroleum. We consider two different gas shippers: one that operates solely in the gas market, while the other also converts gas into hydrogen through SMR. Our setting also includes a price-taking gas storage operator capable to perform inter-temporal arbitrages whenever these are profitable.

Under our baseline scenario, hydrogen is solely produced from natural gas through SMR conversion. That supply is decided either by an independent SMR player or by the natural gas shipper equipped with SMR conversion capabilities. As hydrogen can be stored, we also consider a storage operator for that form of energy.

The setting retained in our baseline scenario has a generic nature. We use it as a reference case to examine how the insertion of PTG affects the market outcomes.[1] To conduct that analysis, we

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[1] There exist a variety of low-carbon hydrogen production technologies that vary in maturity and deployment. We focus on PTG and SMR as they are the most mature and widely deployed technologies in the current prospective scenarios [20].

define a series of alternative scenarios that represent various PTG-ownership structures. These scenarios are presented in Figures 2. Under these alternative scenarios, PTG is either operated by an independent pure player (H-NewProd) or by multi-market firms including electricity producers (E-CCGT, E-VRE), natural gas midstreamers (G-Gas), a gas midstreamer that also produce hydrogen through SMR (G-Gas+SMR), or a hydrogen producer that also operates a SMR (H-SMR).

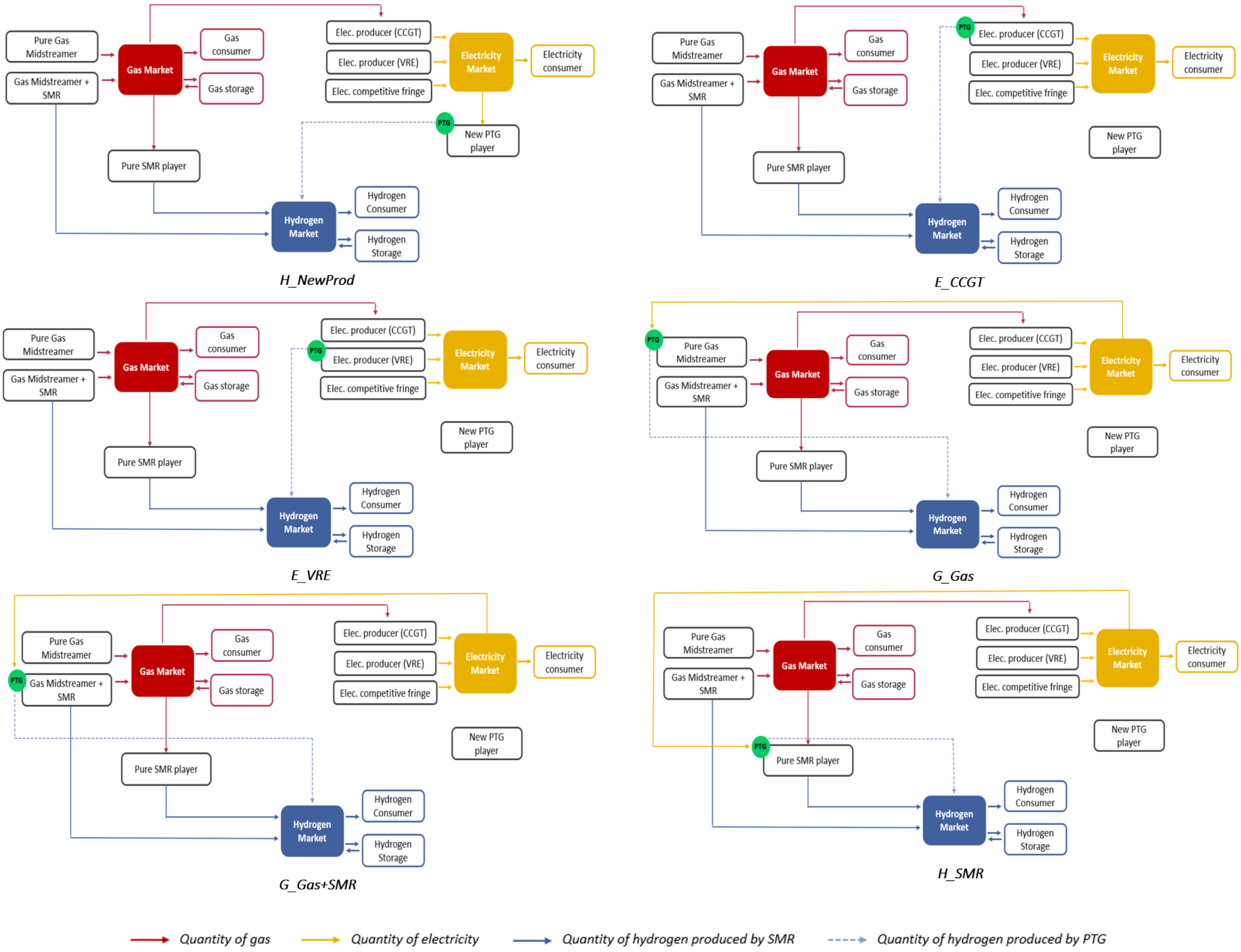

Figure 2: Schematic overview of the scenarios representing various PTG-ownership structure

2.2 Formulation of the model

The model formulation enables us to take both non-strategic and strategic players with market power into account. Indeed, the various players consider the following price function π when solving their optimization problem:

$$\pi = (1 - \delta).\pi^* + \delta.\Pi(.)$$

The parameter δ denotes the player's degree of market power. $\delta = 0$ if the actor has a perfectly competitive behaviour. In this case, it bases its operations on a perfectly competitive market-clearing price π^*. $\delta = 1$ if the actor has a Cournot oligopoly behaviour, and bases its operations on the price resulting from the inverse demand function $\Pi(.)$. In this case, producers know the inverse demand function and adapt their production accordingly, thus influencing the market price. In this model, we are interested in the market power of energy producers. Producers are the only ones with market power, and storage operators are non-strategic.

Our study covers a full year to consider the seasonal and weekly variation of energy demand. We assume that the electricity market clears hourly, while the hydrogen and gas markets clear daily, consistent with the organization observed in the gas and electricity spot markets. In the following, d stands for days, and h stands for hours.

In this section, we present the optimization problems of the different players and specify the market clearing condition for the three energies. The derived Karush-Kuhn-Tucker (KKT) conditions are detailed in the Appendix §6.1.

2.2.1 Electricity Market

Electricity producers: Each electricity producer p seeks to maximise its profit by optimising its electricity generation $q^E_{p,x,d,h}$ (for $x \in \mathcal{X}$ set of electricity sources) as well as its hydrogen generation $q^H_{p,PTG,d,h}$ when it owns PTG. Generation ramp-up $q^{E,up}_{p,CCGT,d,h}$ is also optimized for CCGT units subject to ramp-up constraints. The costs associated with the production of electricity are variable costs $C^E_{p,x,d}$ as well as ramp up costs $C^{E,up}_{CCGT,d}$. We note γ_{PTG} the conversion efficiency from hydrogen to electricity.

The optimization problem of each electricity producer is detailed in (1):

$$\underset{\substack{q^E_{p,x,d,h},q^{E,up}_{p,CCGT,d,h},\\ q^H_{p,PTG,d,h}}}{\text{maximize}} \quad \sum_{d,h} w_d \cdot w_h \cdot \Bigg[\sum_{x\in\mathcal{X}} \Big(q^E_{p,x,d,h} \cdot \pi^E_{d,h} - q^E_{p,x,d,h} \cdot C^E_{p,x,d} \Big) - q^{E,up}_{p,CCGT,d,h} \cdot C^{E,up}_{CCGT,d} \tag{1a}$$

$$+ q^H_{p,PTG,d,h} \cdot \Big(\pi^H_d - \frac{1}{\gamma_{PTG}} . \pi^E_{d,h} \Big) \Bigg] \tag{1b}$$

subject to

$$q^E_{p,VRE,d,h} = K^E_{p,VRE} . AVA^E_{p,d,h} \qquad \forall d,h, \quad (\lambda^{E,1}_{p,d,h}), \tag{1c}$$

$$q^E_{p,CCGT,d,h} \leq K^E_{p,CCGT} \qquad \forall d,h, \quad (\lambda^{E,2}_{p,d,h}), \tag{1d}$$

$$q^H_{p,PTG,d,h} \leq K^H_{p,PTG} \qquad \forall d,h, \quad (\lambda^{E,3}_{p,d,h}), \tag{1e}$$

$$w_h \cdot q^E_{p,CCGT,d,h} \leq w_{h-1} \cdot q^E_{p,CCGT,d,h-1} + w_h \cdot q^{E,up}_{p,CCGT,d,h} \forall d,h, \quad (\lambda^{E,4}_{p,d,h}), \tag{1f}$$

$$0 \leq q^E_{p,x,d,h}, \quad 0 \leq q^{E,up}_{p,CCGT,d,h}, \quad 0 \leq q^H_{p,PTG,d,h} \qquad \forall d,h,x \tag{1g}$$

Revenues come from the sale of electricity on the electricity market (1a) and from the sale of hydrogen on the hydrogen market when producer p owns PTG (1b). We consider that the strategic electricity producers have market power not only in the electricity market but also in the hydrogen market. This reflects the fact that when these companies own PTG, their dominant position in the electric market could give them the ability to influence the price of hydrogen.

On the cost side, variable costs $C^E_{p,x,d}$ are composed of operation and maintenance costs, fuel costs and costs related to CO_2 emissions and are detailed in Appendix §6.2. Regarding hydrogen production, we suppose that the production of hydrogen by PTG does not cost anything more than the cost of the electricity needed to produce the hydrogen.

In addition, electricity producers are subject to several technical constraints. Renewable electricity generation is endogenously determined and equal to the resource availability, defined as the product of the renewable capacity $K^E_{p,VRE}$ and the availability factor for renewable energy generation $AVA^E_{p,d,h}$ (1c). For CCGT units maximum capacity restriction is imposed (1d). Ramp-up constraints (1f) are also considered, with w_h weighting coefficient of the representative hour, further described in subsection §2.3. Finally, hydrogen production from PTG is limited by PTG capacity (1e).

Electricity demand from end-users: We adopt a simplified representation of that demand and posit that the hourly aggregate quantity of electricity $D^E_{d,h}$ consumed by end-users (i.e., residential, tertiary and industrial users) is determined by the following demand linear function:

$$\forall d, h, \quad D^E_{d,h} = a^E_{d,h} - b^E_{d,h}.{\pi^E_{d,h}}^* \tag{2}$$

where the positive parameters $a^E_{d,h}$ and $b^E_{d,h}$ respectively represent the intercept and the slope of the demand function. These coefficients are time-varying and are exogenously determined for each time step (see Appendix §6.3).

Electricity market clearing constraint: The market-clearing conditions tie the separate power producers' optimization problems defined above to our simplified representation of the demand for electricity.

This condition ensures that, in each time period, the electricity demand is not greater than the aggregate output decided by the producers. The electricity demand includes the consumer demand $D^E_{d,h}$ as well as the electricity used to produce hydrogen $\frac{1}{\gamma_{PTG}}.q^H_{p,PTG,d,h}$. If electricity production exceeds demand, the surplus electricity is spilled.

$$\forall d,h,\quad 0 \leq \sum_{p,x} q^E_{p,x,d,h} - \Big(D^E_{d,h} + \sum_{p} \frac{1}{\gamma_{PTG}}.q^H_{p,PTG,d,h}\Big) \perp {\pi^E_{d,h}}^* \geq 0 \tag{3}$$

2.2.2 Gas Market

Gas midstreamers: Each gas midstreamer p seeks to maximise its profit by optimising the quantity of gas supplied to the market and obtained from long-term contracts $q^G_{p,d}$, as well as hydrogen generation from PTG ($q^H_{p,PTG,d,h}$) or SMR ($q^H_{p,SMR,d}$) when it has these technologies in its portfolio. γ_{SMR} is the conversion efficiency from hydrogen to gas, and γ_{PTG} the conversion efficiency from hydrogen to electricity.

The optimization problem of each gas midstreamer is detailed in (4):

$$\underset{\substack{q^G_{p,d}, q^H_{p,SMR,d},\\ q^H_{p,PTG,d,h}}}{\text{maximize}} \quad \sum_d w_d.\Big[q^G_{p,d}.\pi^G_d - q^G_{p,d}.\Big(C^G_{inter} + C^G_{slope}.q^G_{p,d}\Big)\Big] \tag{4a}$$

$$+ \sum_d w_d.\Big[q^H_{p,SMR,d}.\Big(\pi^H_d - \frac{1}{\gamma_{SMR}}.(\pi^G_d + C_{CCS})\Big)\Big] \tag{4b}$$

$$+ \sum_{d,h} w_d.w_h.\Big[q^H_{p,PTG,d,h}.\Big(\pi^H_d - \frac{1}{\gamma_{PTG}}.{\pi^E_{d,h}}^*\Big)\Big] \tag{4c}$$

subject to

$$q^H_{p,SMR,d} \leq K^H_{p,SMR} \qquad \forall d \quad (\lambda^{G,1}_{p,d}), \tag{4d}$$

$$q^H_{p,PTG,d,h} \leq K^H_{p,PTG} \qquad \forall d,h \quad (\lambda^{G,2}_{p,d,h}), \tag{4e}$$

$$0 \leq q^G_{p,d}, \quad 0 \leq q^H_{p,SMR,d}, \quad 0 \leq q^H_{p,PTG,d,h} \qquad \forall d,h \tag{4f}$$

Revenues come from the sale of gas on the gas market (4a) and from the sale of hydrogen produced by SMR (4b) or PTG (4c) on the hydrogen market when gas midstreamers own these technologies. In the same way as for electricity producers, we consider that strategic gas midstreamers have market power in both gas and hydrogen markets. However, they are price taker in the electricity market and adapt their electricity purchases to the market price ${\pi^E_{d,h}}^*$. The costs associated with the purchase of gas are represented by an linear function $C_{gas}(q^G_{p,d}) = C^G_{inter} + C^G_{slope}.q^G_{p,d}$, as modelled in [10].

As explained in subsection §2.2.1, the cost of producing hydrogen by PTG is the price the electricity needed to produce it. The cost of producing hydrogen by SMR corresponds to the price of the gas needed to produce it plus C_{CCS}, cost associated with the capture and sequestration of the CO_2 emitted by this technology. As modelled is [11], CCS cost is defined by:

$$C_{CCS} = \epsilon^{CO_2}.(\lambda.\pi^{CO_2} + (1-\lambda).c^{CCS})$$

Where ϵ^{CO_2} is the number of tons of carbon produced by methane reforming, π^{CO_2} is the carbon price and c^{CCS} is the CCS cost per ton of carbon, defined exogenously. Finally, λ is the fraction of carbon being emitted and $1-\lambda$ is the fraction being captured by CCS.

In addition, hydrogen production by SMR and PTG are respectively limited by SMR and PTG capacities (4d-4e).

Gas storage operator: Gas storage operator also aims at maximizing its profit. Price taker, it bases its injection, withdrawing and storage decisions ($r^G_{in,d}$, $r^G_{out,d}$ and $u^G_{stor,d}$ respectively) on the gas market price signal $\pi^{G\ *}_d$. An injection cost C^G_{in} is taken into account when the gas is injected into the storage.

$$\underset{\substack{u^G_{stor,d}, r^G_{in,d},\\ r^G_{out,d}}}{\text{maximize}} \quad \sum_{d\in\mathcal{D}} w_d.\left[r^G_{out,d}.\pi^{G\ *}_d - r^G_{in,d}.\left(\pi^{G\ *}_d + C^G_{in}\right)\right] \tag{5a}$$

subject to

$$r^G_{in,d} \leq T^G_{in}.K^G_{stor} \qquad \forall d \quad (\lambda^{G,1}_{stor,d}), \tag{5b}$$

$$r^G_{out,d} \leq T^G_{out}.K^G_{stor} \qquad \forall d \quad (\lambda^{G,2}_{stor,d}), \tag{5c}$$

$$u^G_{stor,d} \leq K^G_{stor} \qquad \forall d \quad (\lambda^{G,3}_{stor,d}), \tag{5d}$$

$$u^G_{stor,d} = u^G_{stor,d-1} + w_d.\left(r^G_{in,d} - r^G_{out,d}\right) \qquad \forall d \quad (\lambda^{G,4}_{stor,d}), \tag{5e}$$

$$0 \leq r^G_{in,d}, \quad 0 \leq r^G_{out,d}, \quad 0 \leq u^G_{stor,d} \quad \forall d \tag{5f}$$

Injection and withdrawal from storage are limited by storage capacity (K^G_{stor}) and injection and withdrawal daily rate (T^G_{in}, T^G_{out}) by constraints (5b-5c). Restriction (5d) ensures that the quantity of gas stored does not exceed the storage capacity. Finally, condition (5e) guarantees that the storage level at time d is equal to storage level at time d-1 plus the quantity of gas stored minus the quantity of gas extracted from storage during that period.

Gas demand from consumers: Daily consumer demand for gas D^G_d is represented by the following linear function:

$$\forall d, \quad D^G_d = a^G_d - b^G_d.\pi^{G\ *}_d \qquad a^G_d > 0, b^G_d > 0 \tag{6}$$

a^G_d and b^G_d are respectively the intercept and the slope of the inverse demand function. These coefficients are exogenously determined for each time step (cf Appendix §6.3).

Gas market clearing constraint: The balance between gas demand and production is ensured by the gas market clearing condition. The gas demand includes the consumer demand D^G_d, gas used by CCGT to produced electricity ($\frac{1}{\gamma_{CCGT}}.q^E_{p,CCGT,d,h}$) as well as gas needed for hydrogen production by SMR ($\frac{1}{\gamma_{SMR}}.q^H_{p,SMR,d}$).

$$\forall d, \quad 0 \leq \sum_p q^G_{p,d} - \Big(D^G_d + \sum_p \frac{q^H_{p,SMR,d}}{\gamma_{SMR}} + \sum_p \sum_{h \in \mathcal{H}} \frac{q^E_{p,CCGT,d,h}}{\gamma_{CCGT}}\Big) + \Big(r^G_{out,d} - r^G_{in,d}\Big) \perp {\pi^G_d}^* \geq 0 \quad (7)$$

2.2.3 Hydrogen Market

Hydrogen producers: Each hydrogen producer p seeks to maximise its profit by optimising hydrogen generation. This hydrogen is produced by PTG ($q^H_{p,PTG,d,h}$), or by SMR ($q^H_{p,SMR,d}$) depending on the player's generation portfolio.

$$\underset{\substack{q^H_{p,SMR,d},\\ q^H_{p,PTG,d,h}}}{\text{maximize}} \quad \sum_{d \in \mathcal{D}} w_d \cdot \Big[q^H_{p,SMR,d} \cdot \Big(\pi^H_d - \frac{1}{\gamma_{SMR}}.({\pi^G_d}^* + C_{CCS})\Big)\Big] \tag{8a}$$

$$+ \sum_{d \in \mathcal{D}, h \in \mathcal{H}} w_d.w_h \cdot \Big[q^H_{p,PTG,d,h} \cdot \Big(\pi^H_d - \frac{1}{\gamma_{PTG}}.{\pi^E_{d,h}}^*\Big)\Big] \tag{8b}$$

subject to

$$q^H_{p,SMR,d} \leq K^H_{p,SMR} \qquad \forall d \quad (\lambda^{H,1}_{p,d}), \tag{8c}$$

$$q^H_{p,PTG,d,h} \leq K^H_{p,PTG} \qquad \forall d,h \quad (\lambda^{H,2}_{p,d,h}), \tag{8d}$$

$$0 \leq q^H_{p,SMR,d}, \quad 0 \leq q^H_{p,PTG,d,h} \qquad \forall d,h \tag{8e}$$

Revenues come from the sale of hydrogen produced by SMR (8a) and by PTG (8b). We consider that strategic hydrogen producers have market power in hydrogen market. However, they are price taker in both electricity and gas market and adapt their purchases to electricity and gas market prices, ${\pi^E_{d,h}}^*$ and ${\pi^G_d}^*$ respectively. With regard to costs, as explained in paragraphs §2.2.1 and §2.2.2, costs are related to the purchase of electricity for PTG, and to the purchase of gas and CCS cost for SMR. Finally, hydrogen production by SMR and PTG are respectively limited by SMR and PTG capacities (8c-8d).

Hydrogen storage operator: Similar to the gas storage operator, hydrogen storage operator is price taker and seeks to optimize its injection, withdrawing and storage decisions ($r^H_{in,d}$, $r^H_{out,d}$ and $u^H_{stor,d}$ respectively) to maximise its profit.

$$\underset{\substack{u^H_{stor,d}, r^H_{in,d},\\ r^H_{out,d}}}{\text{maximize}} \quad \sum_{d\in\mathcal{D}} w_d.\Big[r^H_{out,d}.\pi^{H\,*}_d - r^H_{in,d}\Big(\pi^{H\,*}_d + C^H_{in}\Big)\Big] \tag{9a}$$

subject to

$$r^H_{in,d} \leq T^H_{in}.K^H_{stor} \qquad \forall d \quad (\lambda^{H,1}_{stor,d}), \tag{9b}$$

$$r^H_{out,d} \leq T^H_{out}.K^H_{stor} \qquad \forall d \quad (\lambda^{H,2}_{stor,d}), \tag{9c}$$

$$u^H_{stor,d} \leq K^H_{stor} \qquad \forall d \quad (\lambda^{H,3}_{stor,d}), \tag{9d}$$

$$u^H_{stor,d} = u^H_{stor,d-1} + w_d.\Big(r^H_{in,d} - r^H_{out,d}\Big) \quad \forall d \quad (\lambda^{H,4}_{stor,d}), \tag{9e}$$

$$0 \leq r^H_{in,d}, \quad 0 \leq r^H_{out,d}, \quad 0 \leq u^H_{stor,d} \quad \forall d \tag{9f}$$

The hydrogen storage operator is subject to injection, extraction and storage capacity constraints (9b-9d). Condition (9e) guarantees that the storage level at time d is equal to storage level at time d-1 plus the quantity of hydrogen stored minus the quantity of hydrogen extracted from storage during that period.

Hydrogen demand from consumers: Daily consumer demand for hydrogen D^H_d is represented by the following linear function:

$$\forall d, \quad D^H_d = a^H_d - b^H_d.\pi^{H\,*}_d \qquad a^H_d > 0, b^H_d > 0 \tag{10}$$

a^H_d and b^H_d are respectively the intercept and the slope of the inverse demand function. These coefficients are exogenously determined for each time step (cf Appendix §6.3).

Hydrogen market clearing constraint: Finally, the balance between hydrogen demand, hydrogen produced by PTG and SMR and hydrogen injected and withdrawn from storage is ensured by the hydrogen market clearing condition.

$$\forall d, \quad 0 \leq \sum_p \Big(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PTG,d,h}\Big) - D^H_d + \Big(r^H_{out,d} - r^H_{in,d}\Big) \perp \pi^{H\,*}_d \geq 0 \tag{11}$$

2.3 Implementation

The market equilibrium complementarity model is comprised of the KKTs derived from the optimization problems and the market-clearing conditions. Since the profit functions are concave and the feasibility regions are convex, the points that satisfy the KKT conditions are therefore optimal solutions of the MCP.

This problem is programmed in GAMS. For convenience, the model was writen as an Extended mathematical programs (EMP). EMP model are processed by the JAMS solver which creates a scalar version of the given GAMS model. This scalar version of the model is then solved by the PATH solver.

Due to computational limitations, we use representative days and hours to represent intra-annual variability of supply and demand while limiting the computational time. To reflect the seasonal and weekly variations of energy demand, we consider eight sub-periods in one year, representing one weekday and one weekend day for each of the four seasons of the year. Then, we divide these representative days into five-time segments to preserve the daily fluctuation structure of the demand. Weighting coefficients w_d and w_h are assigned to them to reflect the share they represent over the year and are further described in the Appendix §6.2.

3 Application

3.1 Data

We calibrate the model using the Dutch energy system. Ideally situated to drive the adoption of hydrogen as a clean energy source, The Netherlands has a strong interest in developing this technology to achieve decarbonization targets and preserve the region's industrial activities [21]. Where future data forecasts are required, we use projections for the year 2030.

With regard to the electricity market, the overall installed capacities for electricity generation are derived from 2030 projections of the EU Reference scenario 2020 [22]. In our model, we consider that the installed capacity of renewables is 53 GW, and the installed capacity of CCGT is 12 GW. VRE capacity factor is variable. The values used are taken from the 2019 data from the data platform [23], and are provided hourly. The availability of CCGT is set at 85 %, in line with the assumptions taken by the International Energy Agency (IEA) in *IEA Projected Costs 2020* [24].

The existing electricity generation capacities are divided between three firms, as described in Table 1. Half of the VRE and CCGT capacities belong to two specialized producers: "E-VRE" for VRE, and "E-CCGT" for CCGT capacities. These two producers are price makers. The rest of the capacities belong to a competitive fringe to account for the existence of price taker producers in the electricity market since it was opened to competition in 2004.

	Fringe	E-VRE	E-CCGT
VRE	27	26	-
CCGT	6	-	6

Table 1: Electricity producers generation portfolio (GW)

In the stylized gas system, the supply of gas is divided between two strategic players: one pure gas midstreamer "G-Full Gas", and one gas midstreamer with SMR assets "G-Gas & SMR". Midstreamer's procurement cost function is represented by an linear function, with $C^G_{inter} = 15$ €/MWh and $C^G_{slope} = 0.000002$ €$/MWh^2$.

Regarding hydrogen production from gas, we assumed an installed SMR capacities of 10 GW. This value is a high estimate of the Dutch SMR capacity to prevent hydrogen production capacity from constraining hydrogen consumption in our model. These capacities are divided between "G-Gas & SMR" and "H-Full SMR", hydrogen producer with SMR only.

Finally, we consider an installed electrolyzer capacity of 4 GW, in line with the Dutch National Climate Agreement ambition for 2030 [25]. Depending on the scenario considered, PTG may belong to the different actors mentioned above, or to "H-New Prod", a new strategic player.

CO_2 emissions are taken into account by applying a CO_2 price. We assume a CO_2 price of 30 € per tonne of CO_2 as in *IEA Projected Costs 2020* [24]. Finally, our assumptions regarding the parameters and costs of the various production methods and storage are described in Appendix §6.2. The construction of the three demand functions is explained in Appendix §6.3.

3.2 Scenarios

The objective of this study is to compare the market outcomes obtained in different cases where PTG belongs to dominant companies in the energy sector. To this end, as described in subsection §2.1, we study seven different cases. We first consider a baseline scenario without PTG, called "No PTG". Then, we examine six scenarios where PTG is owned by different producers with market power. As shown in Table 2, PTG owners differ in the energy production units they own.

Scenario	Owner's non PTG technology portfolio
No PTG	-
H NewProd	-
H SMR	Hydrogen (SMR)
G Gas	Gas
G Gas+SMR	Gas + Hydrogen (SMR)
E CCGT	Electricity (CCGT)
E VRE	Electricity (VRE)

Table 2: Overview of Scenarios

4 Results and discussion

The results detailed in section §4 were obtained using the model described in section §2 and the numerical values presented in section §3 and in the appendices. First, we study in sub-section §4.1 the overall effects of the introduction of PTG on the electricity, gas, and hydrogen generation and demand. In a second sub-section §4.2, we look more closely at the differences between the different scenarios regarding the use of PTG. The impact of the introduction of PTG on prices, welfare, and CO2 emissions are presented in sections §4.3, §4.4, and §4.5.

4.1 Overall effect of PTG introduction on production and demand

Firstly, we study the overall effects of the introduction of PTG on the electricity, gas, and hydrogen generation and demand by comparing the results obtained in the cases "No PTG" and "H New Prod". Comparing these two cases allows to study the influence of the addition of this technology linking the hydrogen and electricity sectors when the player owning PTG has no other energy production capacity. Table 3a and 3b show the differences in production and demand between these two cases.

Table 3: Comparison of annual production and demand by sector: differences between the cases "No PTG" and "H NewProd" (TWh)

(a) Comparison of annual production by sector

		CO-NoPTG	CO-H NewProd
Electricity	VRE	87.71	87.71
	CCGT	14.00	14.09
Gas		297.79	293.20
Hydrogen	SMR	16.52	13.07
	PTG	0	5.23

(b) Comparison of annual demand by sector

		NoPTG	H NewProd
Electricity	Consumers	100.46	94.33
	Elec -> H2	0	7.47
	Curtailment	1.25	0
Gas	Consumers	246.91	247.93
	Gas -> Elec	23.34	23.49
	Gas -> H2	27.53	21.79
Hydrogen		16.52	18.30

In the hydrogen market, the introduction of PTG leads to an increase in hydrogen production. Specifically, hydrogen production from SMR decreases, replaced by hydrogen production from PTG, which more than compensates for the decrease in hydrogen production from SMR.

In the gas market, the reduced use of SMR lessens the demand for gas needed for this conversion. However, this decrease leads to less pressure on the gas market which benefits direct consumers whose demand slightly increases. Overall, gas demand and thus gas generation decrease when PTG is added to the system.

In the electricity market, we can note that the electricity spilled in the case without PTG is fully exploited in the case with PTG. The PTG thus fulfils its role as a provider of flexibility. In the demand side, as PTG requires electricity to produce hydrogen, the electricity demand of PTG supplements consumer demand. This additional demand leads to more pressure on the electricity market at the expanse of consumers, whose consumption decreases. Finally, electricity production is slightly higher in the case with PTG than without PTG. Thus, the introduction of PTG leads to an increase in electricity production but less electricity available for direct electricity consumers.

4.2 PTG utilization of various players

The effects on production and demand described in subsection §4.1 are observed in all seven scenarios. However, their intensity depends on PTG utilization, which varies according to the scenarios. Figure 3 shows the annual hydrogen production mix for the different cases.

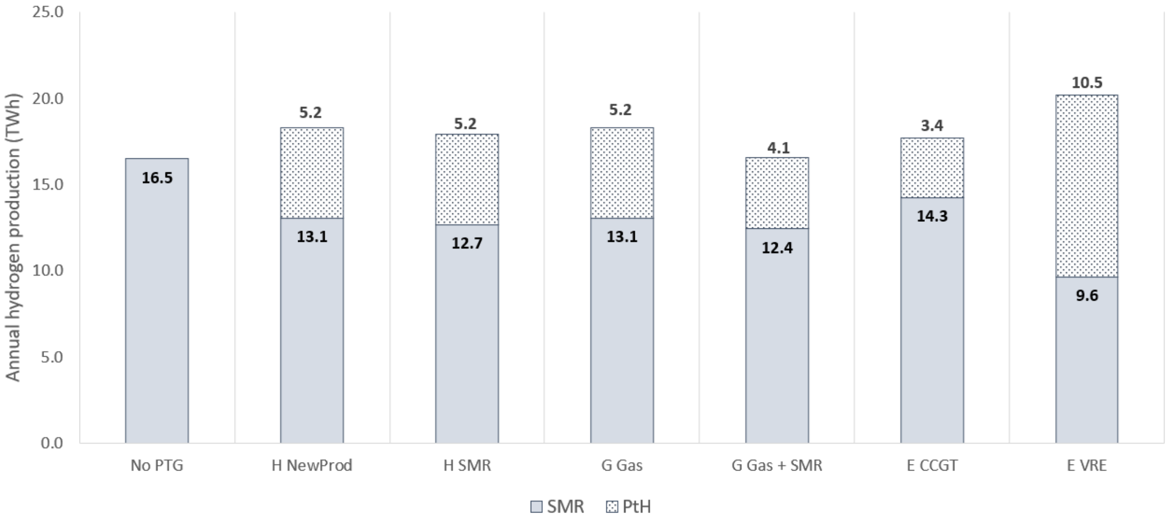

Figure 3: Annual hydrogen production per scenario (TWh)

In our model, the cost of producing electricity from CCGT is too high to make the hydrogen production by PTG attractive. The electricity used to produce hydrogen comes from renewable sources. Thus, the more renewable capacity producers have, the more attractive it is for them to use PTG.

This effect is particularly noticeable in the "E VRE" scenario, where PTG is used more than in other cases. Indeed, E-VRE has a large capacity of intermittent renewable energy at zero variable cost and has market power in both the electricity and hydrogen markets. Knowing that the hydrogen price is higher than the electricity price, it is always more profitable for E-VRE to use part of its electricity to produce hydrogen rather than sell it on the electricity market. In the other cases, the PTG owner does not have VRE capacities and only produces hydrogen during hours when the electricity mix is 100% renewable.

In the cases "H NewProd," "G Gas," and "H SMR," companies with PTG are price takers in the electricity market and price makers in the hydrogen market. Their use of PTG and the resulting hydrogen mix are thus very similar. However, in the "H-SMR" case, H-SMR owns SMR and PTG assets, two strategic substitutes [2]. Thus, hydrogen production by SMR is not as important as in the two previous cases where the PTG was owned by a new entrant in the hydrogen market.

As a gas midstreamer with market power in both gas and hydrogen markets, G-Gas+SMR has a dominant position against H-SMR in the hydrogen market. In the "G Gas+SMR" scenario, the increase in hydrogen production is not profitable for G-Gas + SMR: PTG is less used compared to the previous cases and is only used to replace part of G-Gas+SMR production.

Finally, "E CCGT" is the case where PTG is least used. Having market power in the electricity and hydrogen markets, E-CCGT is aware that PTG has increasing marginal costs and decreasing marginal revenues as it increases the demand for electricity and the supply of hydrogen. Thus, E-CCGT strategically chooses to use this technology less.

In summary, the more market power the PTG-owning company has, the more its hydrogen production by PTG will result from a strategic compromise between the revenues that can be obtained in each market. Thus, G-Gas & SMR and E-CCGT use PTG less than other companies while E-VRE use it more.

4.3 Price impact of PTG

As explained in subsections §4.1 and §4.2, the introduction of PTG changes electricity, hydrogen, and gas production and demand and thus impacts prices in the three markets.

Table 4 describes the price changes between the base case without PTG and the different scenarios with PTG. It shows that the average hydrogen price decreases in all scenarios with PTG compared to the base case scenario: the addition of a hydrogen production source increases hydrogen supply, which decreases the hydrogen price according to the hydrogen linear demand function (10).

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[2] This term was defined in Bulow, Geanakoplos, and Klemperer (1985) [26]. Production choices are strategic substitutes if raising the output of one technology lowers the marginal revenues of other technologies, generating a motivation to produce less of that technology.

In the gas market, the average gas price also decreases in all scenarios with PTG. Indeed, the increase in hydrogen production by PTG induces a decrease in hydrogen production by SMR. Less gas is needed for SMR, resulting in less demand on the gas market.

Finally, electricity price increases in all scenarios with PTG. The addition of PTG leads to a decrease in the amount of electricity available to direct consumers and sometimes to a rise in electricity production by more expensive production sources. Both aspects lead to an increase in the price of electricity.

Average Price	No PTG	H-NewProd	H-SMR	G-Gas	G-Gas+SMR	E-CCGT	E-VRE
Hydrogen	84.08	78.60	79.76	78.60	83.90	80.49	72.80
Gas	35.21	35.07	35.02	35.07	35.18	35.12	35.15
Electricity	55.77	62.00	61.97	62.00	60.38	59.47	67.37

Table 4: Comparison of the average electricity, gas and hydrogen prices (€/MWh)

Figure 4 details the distribution of electricity prices for the different scenarios. It highlights that PTG increases off-peak prices while prices obtained during periods of high demand are unchanged. This increase results from the fact that the PTG consumes electricity generated from renewable sources, which increases electricity prices when they are low. Furthermore, figure 4 also shows that PTG eliminates periods of surplus electricity. Indeed, with the exception of the "E CCGT" case, the cases with PTG no longer have zero price occurrences, which occur when part of the electricity produced is spilled. These results are consistent with those obtained by [13] and [11].

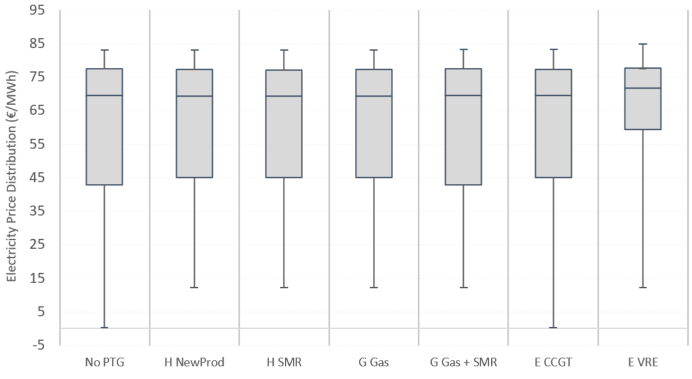


Figure 4: Electricity price distribution (€/MWh)

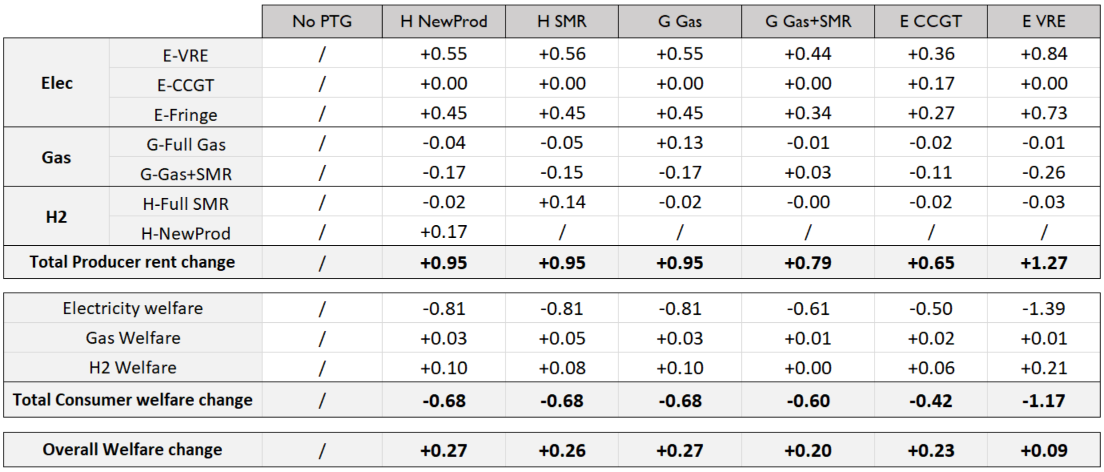
4.4 Impact on welfare and cost effectiveness of PtH

4.4.1 Welfare impacts

By modifying prices, the introduction of PTG impacts welfare. Figure 5 shows the PTG-related welfare effects in the different scenarios, i.e. the change in annual producer profit or consumer welfare over the year due to the addition of PTG to the system.

Firstly, the producers' profit associated with PTG is positive for electricity producers as the introduction of PTG leads to higher electricity prices. Then, for gas midstreamers and hydrogen producers, the variation in their profit is negative, except for the gas or hydrogen player who owns PTG. Indeed, although gas and hydrogen prices decrease, the strategic utilization of PTG allows these companies to increase their profit when they own PTG. With regard to consumer welfare, the introduction of PTG is beneficial for hydrogen and gas consumers and detrimental for electricity consumers. The more PTG is used, the greater these effects on the actor's welfare.

All in all, the change in overall welfare associated with the addition of PTG is positive. However, its distribution is unequal: direct consumers of electricity suffer from the introduction of PTG, while renewable electricity producers see their profits increase strongly.



		No PTG	H NewProd	H SMR	G Gas	G Gas+SMR	E CCGT	E VRE
Elec	E-VRE	/	+0.55	+0.56	+0.55	+0.44	+0.36	+0.84
	E-CCGT	/	+0.00	+0.00	+0.00	+0.00	+0.17	+0.00
	E-Fringe	/	+0.45	+0.45	+0.45	+0.34	+0.27	+0.73
Gas	G-Full Gas	/	-0.04	-0.05	+0.13	-0.01	-0.02	-0.01
	G-Gas+SMR	/	-0.17	-0.15	-0.17	+0.03	-0.11	-0.26
H2	H-Full SMR	/	-0.02	+0.14	-0.02	-0.00	-0.02	-0.03
	H-NewProd	/	+0.17	/	/	/	/	/
Total Producer rent change		/	**+0.95**	**+0.95**	**+0.95**	**+0.79**	**+0.65**	**+1.27**
Electricity welfare		/	-0.81	-0.81	-0.81	-0.61	-0.50	-1.39
Gas Welfare		/	+0.03	+0.05	+0.03	+0.01	+0.02	+0.01
H2 Welfare		/	+0.10	+0.08	+0.10	+0.00	+0.06	+0.21
Total Consumer welfare change		/	**-0.68**	**-0.68**	**-0.68**	**-0.60**	**-0.42**	**-1.17**
Overall Welfare change		/	**+0.27**	**+0.26**	**+0.27**	**+0.20**	**+0.23**	**+0.09**

Figure 5: Impact of PtH on welfare (Bn €)

4.4.2 PtH investment cost and profitability

Although the introduction of PTG improves the overall welfare of agents in the electricity, gas, and hydrogen markets over the year considered, its investment costs can be substantial. Thus, the cost of PTG is an essential factor to consider in determining whether it is a cost-effective option for market coupling.

To obtain the yearly capital cost of PTG, we first specify the total PTG investment cost. The numerical values used are taken from the article by Li & Mulder [11]. Then, we multiply this value to the capital recovery factor of PTG (CRF), defined as follow:

$$CRF = \frac{i.(1+i)^n}{(1+i)^n - 1} \tag{12}$$

With i the discount rate and n the estimated lifetime of PTG investment, in years. Considering a lifetime of 25 years, a discount rate of 5%, and an investment cost of 1 mln. Euro /MWh, we obtain a PTG cost equal to 0.71 billion euros.

Comparing this value to the overall welfare (Fig. 5), we can see that, for all scenarios, the investment costs are higher than the welfare gained from integrating PTG into the system. After considering the annualized costs of PTG, we find that although PTG is beneficial for some actors, it has adverse welfare effects.

When we look more specifically at the agent owning PTG, we can see that only E-VRE could have an incentive to invest in this structure, as the extra profit obtained by using PTG more than other agents are sufficient to cover the investment costs. However, this strategic use of PTG should not be valued as it increases the welfare gap between producers and consumers, especially in the electricity sector. For other producers, despite the strategic use of PTG, the increase in their profit associated with PTG is insufficient to compensate for the investment cost of PTG. Without an investment support mechanism, these companies have no incentive to invest in PTG.

4.5 Impact of PTG on CO2 emissions:

Figure 6 describes the change in CO_2 emissions by sector due to the introduction of PTG. For each scenario, the CO_2 emissions per sector are compared with those obtained in the "No PTG" case.

This graph shows that, in all scenarios, the introduction of PTG reduces the CO_2 emissions associated with gas and hydrogen production. Indeed, the production of hydrogen by PTG lessens the production of hydrogen by SMR, which emits more CO_2 than PTG. The reduction in gas demand associated with SMR utilization further decreases the CO_2 emissions related to this sector. The reduction of CO_2 emissions in the gas sector is particularly important in the "G-Gas+SMR" case, as G-Gas & SMR uses its market power to reduce hydrogen production by SMR without increasing gas production for direct consumers.

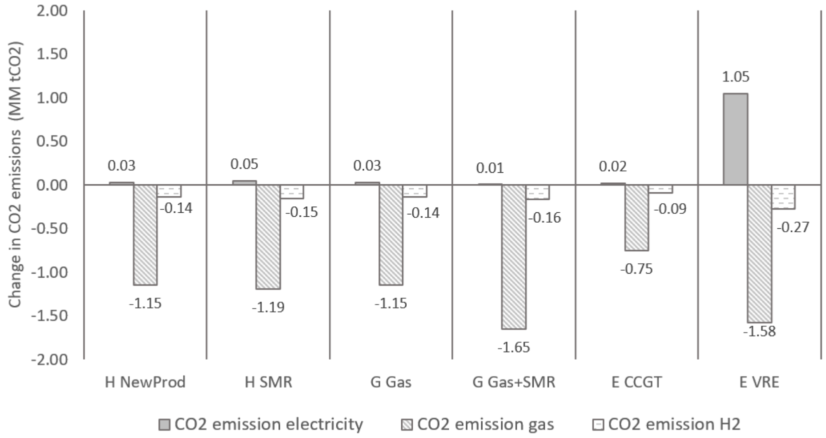


Figure 6: Impact of PTG on CO2 emissions - change in CO2 emissions by sector compared to the "No PTG" case

Along with the decreases in CO_2 emissions in these two sectors, the use of PTG increases CO_2 emissions from electricity generation. Indeed, the production of hydrogen by PTG consumes low-cost, decarbonized electricity production, which is sometimes replaced by carbon-based production (CCGT). This increase is particularly significant in the "E VRE" case, where the company uses a large part of its renewable production to produce hydrogen, forcing E-CCGT and E-Fringe to increase the use of CCGT to meet consumer demand.

From an environmental perspective, these results show that without regulation, PTG may not reduce CO2 emissions: although this technology reduces CO_2 emissions from the gas and hydrogen sectors by producing renewable-based hydrogen, an extensive use of PTG could lead to an increase in CO_2 emissions from electricity generation and thus to the rise in overall CO_2 emissions.

5 Concluding remarks

In recent years, electricity-based hydrogen has evolved from a cutting-edge niche technology to an essential energy carrier for the energy transition. Produced from renewable electricity by power-to-gas (PTG), it could play a significant role in the energy sector's decarbonization by alleviating the curtailment of variable renewable electricity and replacing conventional fuels. In Europe, the first pilot projects are being developed, and technology investments are expected in the coming years. However, issues on the industrial organization of PTG assets have so far little been discussed. As PTG investments are currently undertaken by companies with a strong presence in the power, gas, or hydrogen markets, one can wonder whether ownership matters for the efficient operation of these markets and whether that ownership substantially affects the market's outcomes.

To examine this, this paper presents a market equilibrium formulated as an instance of a Mixed Complementarity Problem that presents the interactions between the power, gas, and hydrogen sectors. This model includes a stylized representation of the main types of producers in these markets and the strategic behavior of some market participants. We consider seven scenarios whereby PTG is controlled by various strategic players in the electricity, gas, and hydrogen sectors who differ in their own generation units. We calibrate the model using the Dutch energy system and use projections for 2030 where future data forecasts are required.

Market simulations show that, in an imperfect electricity, gas, and hydrogen market, PTG operation and, therefore, the effects linked to the introduction of PTG vary according to PTG ownership. Thus, agents with renewable electricity production capacities have an incentive to use PTG more compared to other agents. Conversely, strategic producers already established in the hydrogen market or with sector coupling technologies tend to use it less to optimize the revenues obtained in the different markets.

Comparing the short-term welfare associated with the introduction of PTG in the system with the costs of investing in PTG shows that even with strategic use of PTG, companies without renewable electricity production capacities have no incentives to invest in PTG. Only the company with renewables would have incentives to invest in this technology, as the extra profits obtained by using PTG more than other agents are sufficient to cover the investment costs.

However, this strategic use of PTG may be of concern. On the one hand, from an environmental perspective, the intensive utilization of PTG can lead to increased CO_2 emissions. Indeed, a substantial amount of variable renewable energy is used to produce hydrogen, sometimes replaced by carbon-based electricity to meet consumer demand. On the other hand, from a social point of view, heavy use of PTG reinforces the welfare gap between producers and consumers, especially in the electricity sector.

Our results suggest that regulating the renewable electricity that can be used to produce hydrogen could enable the production of low-carbon hydrogen while avoiding increased CO2 emissions and welfare losses for electricity consumers. At the same time, such regulation risks making the PTG unprofitable for renewable electricity producers. Thus, such regulation should potentially be coupled with an investment support mechanism to limit the strategic use of PTG while supporting its development. Research on the impact of such regulation on PTG operations could inform its formulation and will be the focus of future work.

Finally, future possible research directions could also include further analysis of the impact of market power on PTG investment decisions, as optimizing investments in addition to production could change the actors' PTG operations to compensate for the investment costs.

6 Appendix

6.1 KKT conditions

From (1a)–(1g), the electricity producers' KKT conditions are:

$$0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - \frac{\delta}{b^E_{d,h}}\left(\sum_x q^E_{p,x,d,h} - \frac{q^H_{p,PTG,d,h}}{\gamma_{PTG}}\right)\right] + \lambda^{E,1}_{p,d,h} \perp q^E_{p,VRE,d,h} \geq 0 \quad \forall p,d,h \tag{13}$$

$$\begin{aligned} 0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - \frac{\delta}{b^E_{d,h}}\left(\sum_x q^E_{p,x,d,h} - \frac{q^H_{p,PTG,d,h}}{\gamma_{PTG}}\right) - \frac{\partial C^E_{p,CCGT,d}}{\partial q^E_{p,CCGT,d,h}}\right] + \lambda^{E,2}_{p,d,h} \\ +w_d.\left(w_h.\lambda^{E,4}_{p,d,h} - w_{h-1}.\lambda^{E,4}_{p,d,h-1}\right) \perp q^E_{p,CCGT,d,h} \geq 0 \quad \forall p,d,h \end{aligned} \tag{14}$$

$$0 \leq -w_d.w_h.\left[{\pi^E_{d,h}}^* - C^{E,up}_{CCGT,d}\right] - w_h.\lambda^{E,4}_{p,d,h} \perp q^{E,up}_{p,CCGT,d,h} \geq 0 \quad \forall p,d,h \tag{15}$$

$$\begin{aligned} 0 \leq -w_d.w_h.\left[\pi^{H\,*}_d - \frac{{\pi^E_{d,h}}^*}{\gamma_{PTG}} - \frac{\delta}{b^H_d}.\left(\sum_{h\in\mathcal{H}} w_h.q^H_{p,PTG,d,h}\right) + \frac{\delta}{b^E_{d,h}.\gamma_{PTG}}.\left(\sum_x q^E_{p,x,d,h}\right.\right. \\ \left.\left. -\frac{q^H_{p,PTG,d,h}}{\gamma_{PTG}}\right)\right] + \lambda^{E,3}_{p,d,h} \perp q^H_{p,PTG,d,h} \geq 0 \quad \forall p,d,h, \end{aligned} \tag{16}$$

$$q^E_{p,VRE,d,h} = K^E_{p,VRE}.AVA^E_{p,d,h} \text{ with } \lambda^{E,1}_{p,d,h} \text{ u.r.s.}, \quad \forall p,d,h \tag{17}$$

$$0 \leq K^E_{p,CCGT} - q^E_{p,CCGT,d,h} \perp \lambda^{E,2}_{p,d,h} \geq 0\text{‘} \quad \forall p,d,h, \tag{18}$$

$$0 \leq K^H_{p,PTG} - q^H_{p,PTG,d,h} \perp \lambda^{E,3}_{p,d,h} \geq 0 \quad \forall p,d,h, \tag{19}$$

$$0 \leq w_{h-1}.q^E_{p,CCGT,d,h-1} + w_h.q^{E,up}_{p,CCGT,d,h} - q^E_{p,CCGT,d,h} \perp \lambda^{E,4}_{p,d,h} \geq 0 \quad \forall p,d,h, \tag{20}$$

From (4a)–(4f), the gas midstreamers' KKT conditions are:

$$0 \leq -w_d.\left[\pi^{G\,*}_d - \frac{\delta}{b^G_d}\left(q^G_{p,d} - \frac{q^H_{p,SMR,d}}{\gamma_{SMR}}\right) - \left(C^G_{inter} + C^G_{slope}.q^G_{p,d}\right)\right] \perp q^G_{p,d} \geq 0 \quad \forall p,d, \tag{21}$$

$$\begin{aligned} 0 \leq -w_d.\left[\pi^{H\,*}_d - \frac{\pi^{G\,*}_d + C_{CCS}}{\gamma_{SMR}} - \frac{\delta}{b^H_d}.\left(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PTG,d,h}\right)\right. \\ \left. + \frac{\delta}{b^G_d.\gamma_{SMR}}.\left(q^G_{p,d} - \frac{q^H_{p,SMR,d}}{\gamma_{SMR}}\right)\right] + \lambda^{G,1}_{p,d} \perp q^H_{p,SMR,d} \geq 0 \quad \forall p,d, \end{aligned} \tag{22}$$

$$0 \leq -w_d.w_h.\left[\pi^{H\,*}_d - \frac{\delta}{b^H_d}.\left(q^H_{p,SMR,d} + \sum_{h\in\mathcal{H}} w_h.q^H_{p,PTG,d,h}\right) - \frac{{\pi^E_{d,h}}^*}{\gamma_{PTG}}\right] + \lambda^{G,2}_{p,d,h} \perp q^H_{p,PTG,d,h} \geq 0 \quad \forall p,d,h, \tag{23}$$

$$0 \leq K^H_{p,SMR} - q^H_{p,SMR,d} \perp \lambda^{G,1}_{p,d} \geq 0\text{‘} \quad \forall p,d, \tag{24}$$

$$0 \leq K^H_{p,PTG} - q^H_{p,PTG,d,h} \perp \lambda^{G,2}_{p,d,h} \geq 0 \quad \forall p,d,h, \tag{25}$$

From (5a)-(5f) the gas storage operator's KKT conditions are:

$$0 \leq -w_d.\pi_d^{G\,*} + \lambda_{stor,d}^{G,2} + w_d.\lambda_{stor,d}^{G,4} \perp r_{out,d}^{G} \geq 0 \quad \forall d, \tag{26}$$

$$0 \leq w_d.(\pi_d^{G\,*} + C_{in}^{G}) + \lambda_{stor,d}^{G,1} - w_d.\lambda_{stor,d}^{G,4} \perp r_{in,d}^{G} \geq 0 \quad \forall d, \tag{27}$$

$$0 \leq \lambda_{stor,d}^{G,4} - \lambda_{stor,d-1}^{G,4} \perp u_{stor,d}^{G} \geq 0 \quad \forall d, \tag{28}$$

$$0 \leq T_{in}^{G}.K_{stor}^{G} - r_{in,d}^{G} \perp \lambda_{stor,d}^{G,1} \geq 0` \quad \forall d, \tag{29}$$

$$0 \leq T_{out}^{G}.K_{stor}^{G} - r_{out,d}^{G} \perp \lambda_{stor,d}^{G,2} \geq 0` \quad \forall d, \tag{30}$$

$$0 \leq K_{stor}^{G} - u_{stor,d}^{G} \perp \lambda_{stor,d}^{G,3} \geq 0 \quad \forall d, \tag{31}$$

$$u_{stor,d}^{G} = u_{stor,d-1}^{G} + w_d.\Big(r_{in,d}^{G} - r_{out,d}^{G}\Big) \text{ with } \lambda_{stor,d}^{G,4} \text{ u.r.s.}, \quad \forall d, \tag{32}$$

From (8a)–(8e), the hydrogen producers' KKT conditions are:

$$0 \leq -w_d.\left[\pi_d^{H\,*} - \frac{\delta}{b_d^H}.\Big(q_{p,SMR,d}^{H} + \sum_{h\in\mathcal{H}} w_h.q_{p,PTG,d,h}^{H}\Big) - \frac{\pi_d^{G\,*} + C_{CCS}}{\gamma_{SMR}}\right] + \lambda_{p,d}^{H,1} \perp q_{p,SMR,d}^{H} \geq 0 \quad \forall p,d, \tag{33}$$

$$0 \leq -w_d.w_h.\left[\pi_d^{H\,*} - \frac{\delta}{b_d^H}.\Big(q_{p,SMR,d}^{H} + \sum_{h\in\mathcal{H}} w_h.q_{p,PTG,d,h}^{H}\Big) - \frac{\pi_{d,h}^{E\ *}}{\gamma_{PTG}}\right] + \lambda_{p,d,h}^{H,2} \perp q_{p,PTG,d,h}^{H} \geq 0 \quad \forall p,d,h, \tag{34}$$

$$0 \leq K_{p,SMR}^{H} - q_{p,SMR,d}^{H} \perp \lambda_{p,d}^{H,1} \geq 0` \quad \forall p,d, \tag{35}$$

$$0 \leq K_{p,PTG}^{H} - q_{p,PTG,d,h}^{H} \perp \lambda_{p,d,h}^{H,2} \geq 0 \quad \forall p,d,h, \tag{36}$$

From (9a)-(9f) the hydrogen storage operator's KKT conditions are:

$$0 \leq -w_d.\pi_d^{H\,*} + \lambda_{stor,d}^{H,2} + w_d.\lambda_{stor,d}^{H,4} \perp r_{out,d}^{H} \geq 0 \quad \forall d, \tag{37}$$

$$0 \leq w_d.(\pi_d^{H\,*} + C_{in}^{H}) + \lambda_{stor,d}^{H,1} - w_d.\lambda_{stor,d}^{H,4} \perp r_{in,d}^{H} \geq 0 \quad \forall d, \tag{38}$$

$$0 \leq \lambda_{stor,d}^{H,4} - \lambda_{stor,d-1}^{H,4} \perp u_{stor,d}^{H} \geq 0 \quad \forall d, \tag{39}$$

$$0 \leq T_{in}^{H}.K_{stor}^{H} - r_{in,d}^{H} \perp \lambda_{stor,d}^{H,1} \geq 0` \quad \forall d, \tag{40}$$

$$0 \leq T_{out}^{H}.K_{stor}^{H} - r_{out,d}^{H} \perp \lambda_{stor,d}^{H,2} \geq 0` \quad \forall d, \tag{41}$$

$$0 \leq K_{stor}^{H} - u_{stor,d}^{H} \perp \lambda_{stor,d}^{H,3} \geq 0 \quad \forall d, \tag{42}$$

$$u_{stor,d}^{G} = u_{stor,d-1}^{H} + w_d.\Big(r_{in,d}^{H} - r_{out,d}^{H}\Big) \text{ with } \lambda_{stor,d}^{H,4} \text{ u.r.s.}, \quad \forall d, \tag{43}$$

6.2 Assumptions on parameter and variable values

Weight of representative days and hours Table 5 and 6 describe the representative days and hours used in the model and their respective weights.

Days	Description	w_d
1	Summer - Week	88
2	Summer - Weekend	35
3	Autumn - Week	44
4	Autumn - Weekend	17
5	Winter - Week	86
6	Winter - Weekend	34
7	Spring - Week	43
8	Spring - Weekend	18

Table 5: Representative Days description

Hours	Description	w_h
1	10PM - 2AM	4
2	2AM - 7AM	5
3	7AM - 12AM	5
4	12AM - 5PM	5
5	5PM - 10PM	5

Table 6: Representative Hours description

Electricity production - CCGT cost and technical parameters Electricity generation cost $C^E_{p,x,d}$ is detailed in equation (44).

$$C^E_{p,x,d} = C_t^{O\&M} + \frac{\pi_t^{fuel}}{\gamma_{fuel->elec}} + \pi^{CO_2} * \tau^{fuel} \tag{44}$$

$C^E_{p,x,d}$ is composed of operation and maintenance costs $C_t^{O\&M}$, fuel costs, and costs related to CO_2 emissions. The fuel costs are the price of fuel π_t^{fuel} divided by the efficiency of the fuel/electricity conversion $\gamma_{fuel->elec}$. The CO_2 emission cost is the CO_2 price π^{CO_2} multiplied by the CO_2 emission rate of the fuel τ^{fuel}.

The values of these different parameters as well as the values of the ramp up costs $C^{E,up}_{CCGT,d}$ for CCGT generation are detailed in Table 7. For this technology the price of fuel is the price of gas, obtained endogenously.

Operational cost $C^{O\&M}_{CCGT}$	[22]	2.3	$(€/MWh)$
Conversion efficiency $\gamma_{fuel->elec}$	[22]	0.58	
Ramp up cost $C^{E,up}_{CCGT,d}$	[16]	5.8	$(€/MWh)$
CO_2 emission rate τ^{fuel}	[16]	0.37	(t_{CO_2}/MWh)

Table 7: Technical parameters for CCGT generation units

Hydrogen production - cost and technical parameters With regard to hydrogen production, table 8 details the numerical values of the technical parameters used in our model. These data are taken from [11].

PtH conversion efficiency γ_{PTG}	0.7	
SMR conversion efficiency γ_{SMR}	0.6	
Tons of carbon produced by methane reforming ϵ^{CO_2}	0.2	(ton/MWh)
CCS cost per ton of carbon captured c^{CCS}	50	$(€/ton\ CO_2)$
fraction of carbon being emitted by methane reforming λ	0.2	

Table 8: Hydrogen technical parameters

Gas and hydrogen Storage parameters Working capacities as well as storage injection and withdrawal rates are derived from [27]. With regard to hydrogen storage, as the development of hydrogen storage is still in its early stages, we do not have projections for the working hydrogen capacity in 2030. This parameter is thus estimated from the hydrogen storage demand indicated in this study. This demand being 6.3 TWh for the North European countries considered, a storage potential of 6 TWh is assumed. Hydrogen storage injection and withdrawal rate is assumed to be equal to that of gas storage. Storage injection costs stem from [22].

Underground gas storage		
Working gas capacity K^G_{stor}	144	(TWh)
Storage injection and withdrawal rate T^G_{out} & T^G_{in}	0.02	
Storage injection cost C^G_{in}	0.7	$(€/MWh)$

Underground hydrogen storage		
Working hydrogen capacity K^H_{stor}	6	(TWh)
Storage injection and withdrawal rate T^H_{out} & T^H_{in}	0.02	
Storage injection cost C^H_{in}	0.7	$(€/MWh)$

Table 9: Hydrogen and gas storage parameters

6.3 Construction of the demand functions

Demand in these three markets is elastic. By construction of the model, this assumption is mandatory to represent Cournot Oligopoly behaviour, for which producers know the inverse demand function and can adapt their production to influence the price.
We consider that demand D_t is a linear and decreasing function of price π_t: $\forall t, D_t = a_t - b_t.\pi_t$
The coefficients a_t and b_t are obtained for each time step t thanks to the relations :

$$\forall t, a_t = (1-\epsilon).D^0_t$$

and

$$\forall t, b_t = -\epsilon.\frac{D^0_t}{\pi^0_t}$$

Where ϵ is the price elasticity, and D^0_t and π^0_t are demand and price parameters used to calibrate the demand function. We use a pre covid year data (2019) for baseline data on demand and prices. Price elasticities are assumed constant over the year, and are derived from [11].

Electricity demand function: Data on the demand for electricity comes from the ENTSOE transparency platform, and electricity prices are obtained in Eco2Mix RTE website.

Gas demand function: Data on the demand for gas comes from the ENTSOG transparency platform. Gas prices are derived from the World Bank Commodities Price Data (The Pink Sheet).

Hydrogen demand function: To calibrate the hydrogen demand function, the forecasts from [27] are used and reported on a daily scale. Hydrogen price and elasticity stem from [11].

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