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Green or blue? Enabling industrial decarbonization and demand response with hydrogen for high temperature process heating

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***Abstract*—Vinyl chloride monomer production coupled with chlor-alkali electrolysis is an industrial process that requires high temperature process heat. One option for providing this process heat in a decarbonized energy system is with either green or blue hydrogen. The demand for hydrogen with low CO_2 intensity will increase with emission restrictions, and the potential for industrial demand response will rise with higher shares of variable renewables in the electricity grid. However, knowledge regarding how the different hydrogen types affect the costs of industrial processes and their flexibility potential is scarce. Hence, we apply a cost-optimization model to assess the decarbonization of the heating process, and the flexibility of the process depending on the hydrogen source. We find that the ability to switch between both green and blue hydrogen is beneficial for the industrial actor, and that the flexibility is highest with an equal share of green and blue hydrogen.**

***Index Terms*—Decarbonization, demand response, electrolysis, heating systems, optimization methods**

I. Introduction

As the power system is shifting towards more variable renewable electricity (VRE) generation, combined with increasing electric demand, the need for demand side flexibility is increasing [1]. The request for decarbonization and electrification of industry increases the strain on the power system, and identifying demand response potentials in industry is important for power system balancing and for better utilization of existing electricity grid infrastructure.

Heating accounts for nearly two thirds of the total energy demand of European industries, with high temperature heating above 500 °C making out more than half of the demand [2]. The chemical industry subsector is the second largest consumer of industrial process heat, mainly at temperatures above 500 °C [3].

Industrial demand response has been investigated in several research activities, but the large potential has yet to be fully utilized [4]. The chlor-alkali electrolysis (CAE) process combined with the production of vinyl chloride monomers (VCM) has been identified as a process with large potential for demand side flexibility [5]. Around 30 % of worldwide production of chlorine is processed to VCM and further to polyvinyl chloride (PVC) [6]. In Germany, chlorine production through CAE accounts for around 2 % of the electricity demand.

While CAE is based on electricity, the subsequent thermal cracker producing VCM requires high temperature heating at around 500 °C, typically produced by natural gas combustion. At those temperatures, hydrogen combustion is one of the most promising zero-emission alternatives with the ability to decarbonize the heat demand [7]. Replacing natural gas in burners with hydrogen may be enabled by retrofitting the existing components, rather than a full replacement [8]. However, this requires the production of hydrogen with a low CO_2 intensity. The existing alternatives are the production of green hydrogen through electrolysis using renewable electricity sources or blue hydrogen through natural gas reforming with carbon capture and storage (CCS). Green hydrogen is in most regions expected to be significantly more expensive than blue hydrogen in the near future [9]. The cost of green hydrogen is closely linked to electricity prices as well as the installation cost of Polymer electrolyte membrane (PEM) electrolyzers, which is predicted to decrease in the coming years. Reference [10] finds that green hydrogen production may become cheaper than blue hydrogen production in 2035-2040 in electricity systems with high renewable electricity production. However, this depends on the technological cost development of both hydrogen production technologies. Reference [11], investigates a case study of Texas in 2050, and which hydrogen production technology dominates the market in various low-carbon scenarios. They find that hydrogen is produced in approximately equal amounts of green and blue hydrogen, highlighting the importance of both technologies in a low-carbon energy system.

Hydrogen production from electrolysis has a large potential for balancing electricity systems with high shares of VRE, due to excellent potential for demand response. PEM electrolysis is able to go from zero load to full load in only a few seconds, with little degradation related to load variations. In [12] they present how providing grid reserves from PEM

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electrolysis may enable increased grid stability, and at the same time generate revenue for the owners. However, in an industrial context the production process is often constant, and intermediate storage of products or energy, or fuel switching alternatives, may be required to enable demand side flexibility. With increasing variations in electricity prices, combining green hydrogen production with either hydrogen storage or blue hydrogen import represents an opportunity to decrease energy costs.

To stabilize the power system, industrial demand response can provide flexibility in the long and short term, such as in day-ahead spot markets and intraday or reserve markets. Demand response may also include both load shedding or load shifting opportunities, both of which are valuable to the electricity market. We focus here on the day ahead spot market, and include both the opportunity to shift load through hydrogen storage from one hour to another, and electric load shedding by shifting to an alternative fuel not based on electricity. To measure the flexibility, the flexibility factor (FF) is well established in hydropower applications, and is also used in wind power to evaluate to what degree a producer is able to obtain higher prices than the average in the area. A producer with the ability to shift production to high-price hours will have a higher FF.

None of the above reviewed studies have investigated how specific industrial demands may utilize blue or green hydrogen for decarbonization, or to what degree on-site production is competitive to import of hydrogen from an external market. We present a case-specific study of a decarbonized heating process, and how installation costs, electricity prices and blue hydrogen market prices affect the optimal fraction of green or blue hydrogen in the industrial process. We also present the FF as a metric for industrial demand response, and investigate to what degree the availability of an external hydrogen market affects the potential for flexibility of a decarbonized heating process with green hydrogen production.

The remainder of the paper in a methods-section in which we describe the process, the modelling framework and the key assumptions, a results-section where we describe the energy price sensitivities and the flexibility potential of the process, a discussion section and finally, a conclusion.

II. Method

This section describes the investigated industrial process, the cost-optimization model and the input parameters.

A. Process description

The production of VCM constitutes of four main sections, the CAE for chlorine production, the direct chlorination (DC) and oxychlorination (OXC) sections for ethylene dichloride (EDC) production and the thermal cracker section for the final production of VCM. An overview of the process is presented in Fig. 1, along with the possible routes for providing hydogen to the thermal cracker. The main energy consumers are the chlor-alkali electrolysis and the thermal cracker. While the electrolysis is based on electricity, and may be flexible when combined with intermediate product storage (EDC), the thermal cracker uses natural gas to produce the required heat, and requires constant operation. For further details on the production process, the interested reader is referred to [13].

In this study we focus on hydrogen as a replacement for natural gas, either locally produced with PEM electrolyzers or bought from a blue hydrogen market. We assume that the industrial facility is located near a blue hydrogen production site, enabling the availability of such a market, as well as the required infrastructure, such as pipelines. It is therefore assumed that the cost of this infrastructure is included in the market price of blue hydrogen.

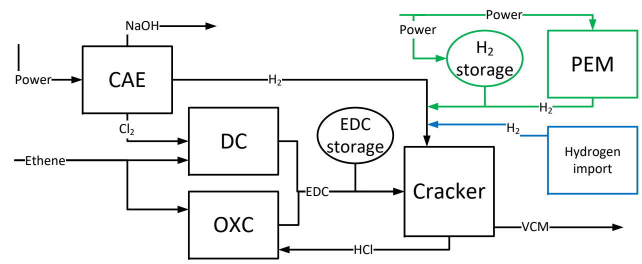

Fig. 1. CAE and VCM production process, with the infrastructure demand for the considered hydrogen options.

B. Modeling

The cost-optimization model is formulated as a linear optimization problem in Julia/JuMP, solved with Gurobi [14], [15]. The model is described in detail in [13], however a few changes are implemented in this study. For the evaluation of blue or green hydrogen, we are adding investment costs of the hydrogen storage and PEM electrolyzers to the objective function. In addition, the binary term determining on/off and minimum operational limits of the PEM electrolyzer has been omitted for computational reasons.

The modified objective function used in this study minimizes the total cost C^{total} and is described in (1)-(5).

$$\min\ C^{\text{total}} = C^{\text{el}} + C^{H_2,b} + C^{\text{LCC}} + C^{\text{inv}} \tag{1}$$

$$C^{\text{el}} = \sum_t (P_t^{\text{tot}} \cdot c_t^{\text{el}}) \tag{2}$$

$$C^{\text{H}_2,\text{b}} = \sum_t (\dot{E}_t^{\text{H}_2,\text{b}} \cdot c^{\text{H}_2,\text{b}}) \tag{3}$$

$$C^{\text{LCC}} = \sum_t ((LC^{\text{up}} + LC^{\text{down}}) \cdot c^{\text{LC}}) \tag{4}$$

$$\begin{aligned} C^{\text{inv}} = {} & P^{\text{PEM,max}} \cdot I^{\text{PEM}} \cdot \varepsilon^{\text{PEM}} \\ & + E^{\text{stor,H}_2\text{,max}} \cdot I^{\text{stor,H}_2} \cdot \varepsilon^{\text{stor,H}_2} \end{aligned} \tag{5}$$

The total cost of electricity C^{el} and blue hydrogen $C^{\text{H}_2,\text{b}}$ are the total energy costs of the system, calculated as the sum of consumed electric power P_t^{tot} and the spot price c_t^{el}, as well as the consumed hydrogen energy $\dot{E}_t^{\text{H}_2,\text{b}}$ and the hydrogen price $c^{\text{H}_2,\text{b}}$. The load change cost C^{LCC} penalizes the amount of load changes up and down $(LC^{\mathrm{up}} + LC^{\mathrm{down}})$ of the chlor-alkali electrolysis multiplied with the load change cost c^{LC}. The investment cost C^{inv} is the annualized value of the required capacity in PEM $P^{\mathrm{PEM,max}}$ and hydrogen storage $E^{\mathrm{stor,H_2,max}}$, multiplied with the respective investment costs per capacity I^i. The annuity ε is defined in (6), where r is the interest rate, and n is the lifetime of the component.

$$\varepsilon = \frac{\mathrm{r}}{1-(1+\mathrm{r})^{-\mathrm{n}}} \tag{6}$$

The FF is in hydropower a measure of the achieved price of the producer π^* in relation to the average price in the same period $\overline{\pi}$ [16], [17]. From the consumer side, it may be used to show the consumer's ability to shift load from high price to low price hours. If the electricity consumption is at a constant rate through the period, the FF will be 1.0, while shifting loads from high price to low price hours will increase the value. As increased flexibility means lower average paid prices for the consumer, we have defined the FF for the consumer side as presented in (7).

$$FF = \frac{\overline{\pi}}{\pi^*} = \frac{\overline{\pi}}{C^{el}_{tot}/P^{el}_{tot}} \tag{7}$$

The average paid price is the total cost of electricity in the period C^{el}_{tot} divided by the total consumption of electricity in the same period P^{el}_{tot}.

C. Input parameters

We simulate the production process for one year of operation, assuming a constant production rate of 60 ton/hour of VCM. The parameters used for efficiencies, energy demands and the production process in general are stated in [13]. In Table I, the specific input for this case study is presented.

TABLE I
INPUT PARAMETERS

	Value	Note
Blue H_2 market price	80 €/MWh$_{LHV}$	-
Electricity prices	2021 (NO2)	[18]
Interest rate	6 %	-
PEM installation cost	925 €/kW$_{el}$	[19]
PEM lifetime	20 years	[19]
H_2 storage installation cost	57 €/kWh$_{LHV}$	[20] (incl. compressors)
H_2 storage lifetime	25 years	[20]
CAE overcapacity	5 %	[21]
EDC storage	1140 tons	(24 hrs nom. operation)

III. RESULTS

The results are presented in two sections, focusing first on energy price variations and utilization of different hydrogen production alternatives, thereafter on flexibility of the process.

A. Installation cost and energy price sensitivities

When simulating one year of operation, we are able to gain insight into which origin the required hydrogen in the process has in cost-optimal operation. As the model is an investment and operational model, it chooses whether or not it is cost-optimal to invest in electrolyzers to produce hydrogen locally. The alternative is to buy all hydrogen from the market, which relies on a nearby natural gas reforming hydrogen production site with carbon capture and connection to a CO2 transport and storage system.

In Fig. 2, the fraction of green to blue hydrogen is presented as a function of blue hydrogen price, mean electricity price and installation cost of PEM electrolyzers. The electricity and hydrogen prices are scaled by a factor of 0.5 to 1.5 to the baseline, and the variation in installation cost of the PEM electrolyzers is from a future low level (possibly around 2040 [10], [19]) of 425 €/kW$_{el}$ to today's baseline level of 925 €/kW$_{el}$.

In all the investigated cases, the option of utilizing 100 % blue hydrogen dominates in scenarios with low blue hydrogen prices or high to mean electricity prices. However, when the blue hydrogen price increases, or the electricity price decreases, the cost-optimal solution is a mix between blue and green hydrogen production. This affects the entry level of installation of PEM electrolyzers, which changes significantly between the varying installation cost cases. When considering the current installation cost level of PEM electrolyzers, in Fig. 2 c), the model chooses to install PEM electrolyzers when the price of blue hydrogen is around 30 €/MWh higher than the mean electricity price. When comparing to the future low installation cost of PEM electrolyzers, in Fig. 2 a), the entry level of PEM electrolyzers is decreased to a level where blue hydrogen prices and mean electricity prices are closer to equal, with a gap of around 10 €/MWh.

When comparing Fig. 2 a), b) and c), it is seen that the fraction of green hydrogen is equal in all three cases in the region with PEM operation. The installation cost of PEM electrolyzers thus only affects the entry level of installation of electrolyzers, and not the operation. PEM electrolyzers are in all three cases installed at a capacity close to 38.8 MW$_{el}$, which is the minimum capacity required to cover the hydrogen demand of the cracker.

Hydrogen storage can increase the operational range of the electrolyzer, enabling higher production of hydrogen in periods of low electricity prices. However, in the cases investigated above, the hydrogen storage has too high installation costs to become a part of the cost-optimal solution. To evaluate the potential for hydrogen storage in a scenario of low electricity prices and high blue hydrogen prices, Fig. 3 presents the cost-optimal installed capacity of hydrogen storage under decreasing installation costs. As seen, the entry level cost of hydrogen storage, including compressors, is when the installation cost decreases below 40 €/kWh, down from the baseline level of 57 €/kWh. This is in the case of 50 % increase in hydrogen cost from baseline, and 50 % decrease in mean electricity price. The increase in installed capacity of PEM is presented in the same figure. It only has a marginal increase in the region of low installation costs.

B. Flexibility potential

The investigated CAE and VCM production process has some flexibility in its operation, due to the overcapacity of the

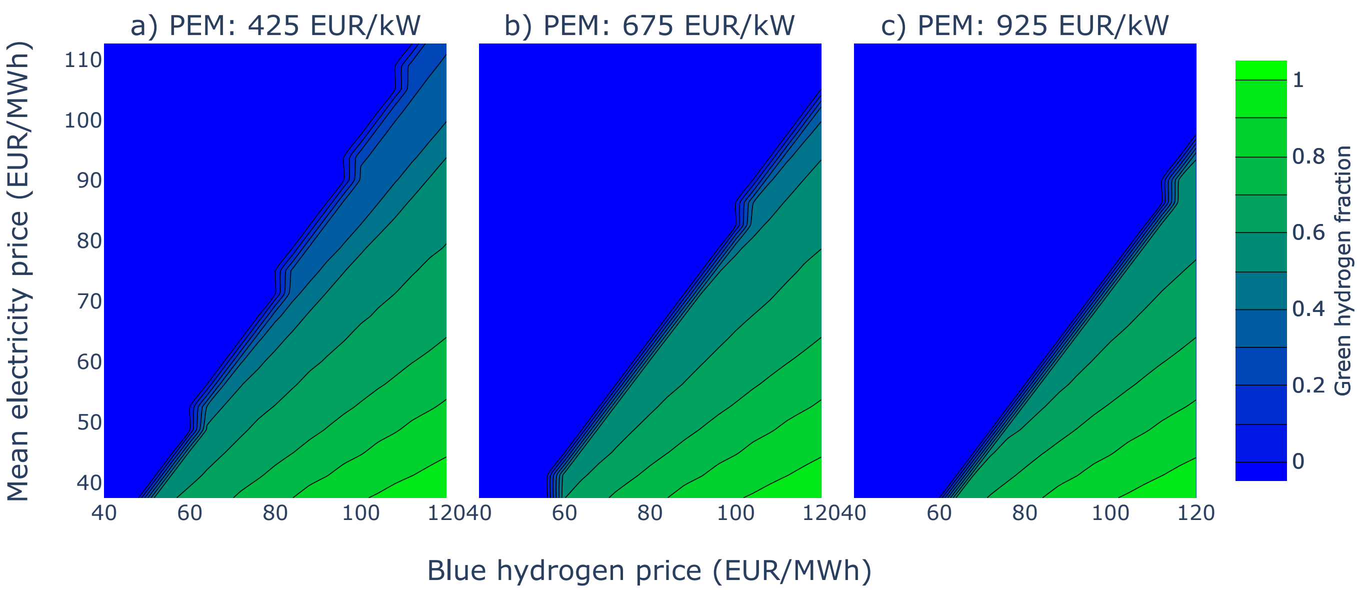

Fig. 2. Fraction of green hydrogen out of the total consumed hydrogen of the thermal cracker in cost optimal operation for variations in energy prices and PEM installation costs.

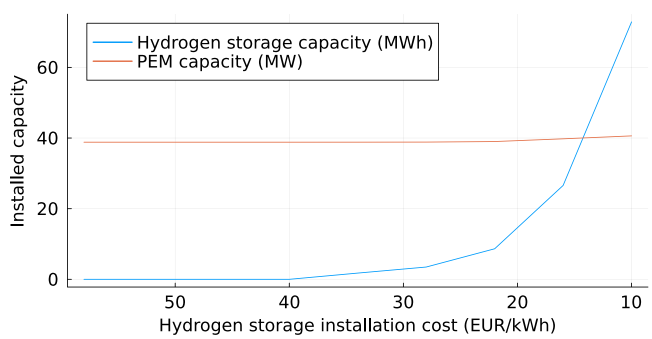

Fig. 3. Installed hydrogen storage capacity as a function of installation costs, in the 50 % electricity price, 150 % hydrogen price scenario.

CAE of 5 % and the EDC storage of 24 hours of operation. However, when PEM electrolyzers are installed, they may increase flexible operation on the basis of variations in electricity prices. The PEM electrolyzers may be used in combination with a hydrogen storage to enable price arbitrage, or they may be shut off in periods of high eletricity prices, replacing the required hydrogen in the process by blue hydrogen. In the investigated cases, the hydrogen storage is too expensive, thus the fuel switching alternative to blue hydrogen is the only flexibility potential utilized.

In Fig. 4, the FF of the process is presented for the same cases as in Fig. 2. In the region of only blue hydrogen, in the upper and left sections of all the cases, the FF is around 1.02. All flexibility is provided by the general flexibility potential through CAE flexibility with EDC storage. When a PEM electrolyzer is installed, it increases electric demand in the periods where the cost of PEM hydrogen is lower than blue hydrogen, thus increasing the flexibility of the process. When comparing Fig. 4 a) to c), the increased region of PEM operation also increases the region of elevated FF. At higher blue hydrogen prices, the fraction of green hydrogen increases, reducing the FF of the process. Thus, it has to be noted that the highest flexibility can be achieved at a green hydrogen fraction of around $40\,\%$ to $60\,\%$ reducing the operational costs through inclusion of blue hydrogen import.

IV. Discussion

For a case study on a combined CAE and VCM production process, we find that decarbonization of an industrial heating process can benefit from the ability to switch between self-production of hydrogen and an external hydrogen market under certain conditions. While an industry actor without access to a hydrogen market will need to produce its own hydrogen, the availability of a nearby external production site may enable both reduced cost and increased demand side flexibility. However, with the current installation cost of PEM electrolyzers, and in the baseline energy price scenario, the cost-optimal solution is based on 100 % blue hydrogen. Thus, in order to facilitate for a higher uptake of flexible PEM electrolyzers in industrial heating applications, either the electricity prices or the PEM installation costs must decrease, or the natural gas prices must increase, leading to increased blue hydrogen prices.

The installation cost of PEM electrolyzers has a large effect on the window of operation of electrolyzers in this study. Even in the case of low PEM installation costs, the results show that the electricity prices must change in favour of green hydrogen to achieve competitiveness between green and blue hydrogen production. However, as electricity prices are expected to decrease with increasing share of renewables, the window of opportunity of green hydrogen will open, and the

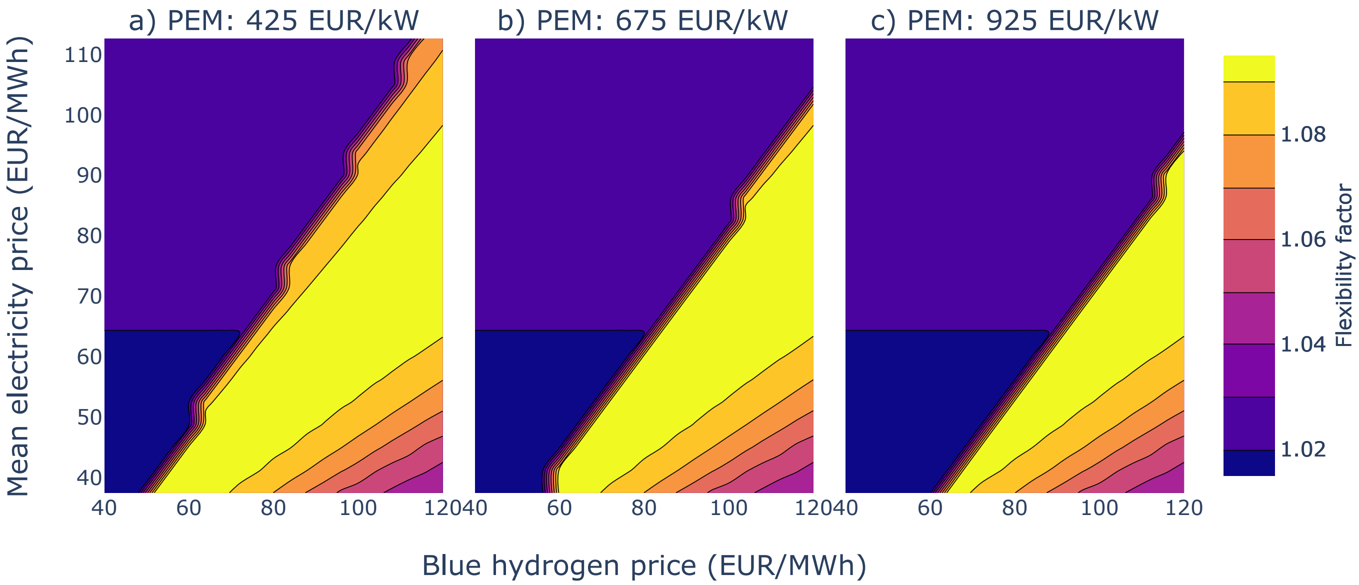

Fig. 4. Flexibility factor in cost optimal operation for variations in energy prices and PEM installation costs.

cost-optimal solution will likely be a mix of both green and blue. In the VCM production process, there is also a demand for oxygen in the oxychlorination process, which could be delivered by the PEM electrolysis. The cost effectiveness of electrolyzers could therefore be improved slightly, and this could be a field of further research.

Hydrogen storage is found to be too expensive for local on-site industrial demands in this study. Although hydrogen could enable increased demand response potential, the required hydrogen storage, hydrogen compressors and overcapacity of electrolyzers make the additional flexibility too costly. In the case of a nearby infrastructure with available blue hydrogen, it is in nearly all scenarios more cost-effective to use the blue hydrogen to achieve flexibility, than establishing an on-site storage. However, with decreasing cost of hydrogen storage and compressors, and with more variations in power prices, hydrogen storage could become cost-effective in the future.

The flexibility potential in the process when comparing it without local electrolyzers to the process with local electrolyzers increases, enabled by the possibility to switch between the cheapest source of hydrogen at any time. In an electricity system with increasing amounts of VRE, all potential demand response applications will become important. The highest flexibility of the process is found to be around 1.09, occuring at a green hydrogen fraction of around 50 %. When comparing this to a hydropower plant with seasonal storage, this is in the upper level of flexibility [22]. Thus, utilizing industrial demand response potential with fuel switching alternatives may prove valuable in balancing VRE, complementing hydropower and other regulated electricity generation technologies.

V. Conclusion

In this work we have investigated how installation costs of local PEM electrolysis and variations in energy costs affect the cost-optimal path of hydrogen-based decarbonization of an industrial heating process. We found that in a scenario with low PEM installation costs and baseline energy prices, blue hydrogen dominates the energy mix, with no installation of PEM electrolyzers in the industrial facility. However, with decreasing electricity costs, the possibility to switch between blue and green hydrogen at nearly equal amounts is the cost-optimal solution. At the current installation cost, and with the baseline hydrogen price, green hydrogen production is competitive at mean electricity prices below 52 €/MWh. However, at blue hydrogen prices below 50 €/MWh, green hydrogen is never competitive in our study.

The ability to switch between different origins of hydrogen also enables a higher process flexibility, enabling demand response, and a flexibility factor of up to 1.09. Hydrogen storage is in the short run too expensive for industrial applications when there is a possibility to use nearby production of blue hydrogen at demand. The flexibility is therefore enabled by fuel switching between green and blue hydrogen, with the highest flexibility enabled when the hydrogen originates from nearly equal amounts of blue and green production. The results show that industrial flexibility can be significant, and may both be profitable for the industrial actor, and provide important demand respons capabilities to increasingly VRE dominated electricity systems.

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