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Economic and environmental valuation of green hydrogen decarbonisation process for price responsive multi-energy industry prosumer

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ABSTRACT

Carbon neutrality is one of the main goals in current power system planning and operation. Many different actions and solutions are presented and implemented so far, incorporating renewable energy sources at all levels of the system. With the raising prices of natural gas and its negative impact on the environment, particularly emphasised over the past two years, new technologies and energy vectors are emerging as potential for its replacement. High importance of the hydrogen energy vector, especially in the decarbonisation of the industry sector, is being put forward due to its advantages of zero greenhouse gas emissions, its capacity for storing energy and capability to balance the production of renewable energy sources. This paper brings a detailed mathematical model of a price driven, demand responsive, multi-energy industry facility, as a logic first implementer of hydrogen technologies due to its high and multi-energy consumption nature. The systematic analyses are conducted over a set of scenarios of local production, considering different hydrogen technologies as well as range of natural gas and electricity prices. The findings of the paper conclude that hydrogen technology implementation into a realistic industrial consumers processes results in zero local emissions production, high level of autonomy and resistance from the market disturbances. When compared with classic industrial layouts, the overall CO_2 footprint is reduced from around 30% to around 85%, depending on the scenario. The sensitivity analysis has proven that hydrogen layouts are comparable to natural gas layouts in terms of total costs, showing that hydrogen options result in lower cost in the range from 25% to 58%, depending on the observed scenario.

1. Introduction

Industry is one of the three dominant categories by final energy consumption in European union, making up around 25% [1]. Industrial facilities are complex systems composed of various processes for refinement from raw materials to final products, usually consuming various forms of energy such as natural gas, electricity and multiple pressure levels of steam or hot water for heat consuming processes. Traditionally, energy required to cover consumption is mostly procured from the external sources and is in smaller capacity produced locally. Being characterised by high energy usage, industrial facilities are responsible for large amount of emissions either indirectly from electricity purchase (emissions produced from electricity generation) or directly from locally consumed fossil fuel. Current climate law of European Union plans to achieve climate neutrality by 2050 for which emissions should have to be lowered by at least 55% by 2030 [2]. Direct emissions produced in industrial facilities can be reduced by replacing fossil fuels with some other energy vector with lower, or none whatsoever, emissions production. One such emerging energy vector is hydrogen [3]. It can be produced locally from electricity and can replace fossil fuels in local heat and electricity production [4]. These are not the only benefits as it can be used as effective energy storage; moreover some chemical and petrochemical industrial facilities already posses electrolysers since hydrogen is used as an input into their processes [5,6]. Although this approach negates local emissions, at the same time it creates higher electricity demand which in return increases indirect emissions. To circumnavigate this, in this paper, we introduced local renewable energy generation in terms of photovoltaic (PV) system [7]. Intermittent and unpredictable nature of PV system can be partially mitigated by cooperation with hydrogen technologies [8] and industrial system management. In this paper, hydrogen provides flexibility through energy storage while industrial system processes have the capability to react as price-responsive demand response [9] meaning the product refinement can be rescheduled to complement the rest of the system when required.

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Nomenclature

$\alpha_{\mathrm{p,\ t}}$	Number of time process p has started up to time t
$\beta_{\mathrm{p,\ t}}$	Electrical load of process p at the time t [MWh]
χ	Gas bought on the market [MWh]
$\chi_{\mathrm{b,\ t}}$	Gas input of boiler b at the time t [MW]
$\delta_{\mathrm{p,\ t}}$	Heating load of process p at the time t [MWh]
$\epsilon_{\mathrm{b,\ t}}$	Indicate whether the gas boiler b operate at time t
η_e^E	Efficiency of electrolyser e
$\eta_g^{G,el}$	Electric efficiency of fuel cell g
$\eta_g^{G,h}$	Heating efficiency of fuel cell g
η_h^H	Efficiency of hydrogen boiler h
$\gamma_{\mathrm{p,\ t}}$	Hydrogen load of process p at the time t [MWh]
$\iota_{\mathrm{p,\ t}}$	Indicate whether the process p is interrupted at the time t
$\kappa_{\mathrm{b,\ t}}$	Indicate whether the gas boiler b started from warm state at time t
$\mu_{\mathrm{p,\ t}}$	Amount of materials inside process p at the time t [t]
$\nu_{\mathrm{b,\ t}}$	Indicate whether the gas boiler b started from cold state at time t
$\omega_{\mathrm{p,\ t}}$	Number of time process p has ended up to time t
$\overline{\mu}_{\mathrm{p,\ t}}$	Material that entered process p at the time t [t]
$\overline{h}_t$	Input to hydrogen storage at the time t [MW]
ϕ_t	Volume of hydrogen stored at the time t [MWh]
π_t	Electricity bought/sold on the market at time t [MWh]
$\sigma_{\mathrm{i,\ t}}$	Storage of initial material i at the time t [t]
$\tau_{\mathrm{r,\ t}}$	Storage of intermediate material r at the time t [t]
$\theta_{\mathrm{b,\ t}}$	Indicate whether the gas boiler b is in cold state at time t
$\underline{\mu}_{\mathrm{p,\ t}}$	Material that left process p at the time t [t]
$\underline{h}_t$	Output to hydrogen storage at the time t [MW]
$\upsilon_{\mathrm{f,\ t}}$	Storage of final product f at the time t [t]
$\zeta_{\mathrm{b,\ t}}$	Indicate whether the gas boiler b is in warm state at time t
$a_{\mathrm{e,\ t}}$	Output power of electrolyser e at the time t [MW]
B, b	Set and index for each gas boiler
B_b^{cdt}	Time needed for gas boiler b to cool down [h]
B_b^{cs}	Additional gas needed to star boiler b from cold state [MWh]
B_b^k, B_b^l	Slope and y-intercept for gas-to-heat conversion of boiler b
B_b^{ws}	Additional gas needed to star boiler b from warm state [MWh]
C_t^{el}	Price of electricity in hour t [€/MWh]
C^{gas}	Price of gas [€/MWh]
$d_{\mathrm{g,\ t}}$	Input power of fuel cell g at the time t [MW]
E, e	Set and index for each electrolyser
F, f	Set and index for each final product
G, g	Set and index for each fuel cell
H, h	Set and index for each hydrogen boiler
I, i	Set and index for each intermediate material
$I_{\mathrm{f,\ p}}^{PI-F}$	Process input-final material coefficient matrix
$I_{\mathrm{r,\ p}}^{PI-I}$	Process input-intermediate material coefficient matrix
$I_{\mathrm{i,\ p}}^{PI-R}$	Process input-raw material coefficient matrix
$I_{\mathrm{f,\ p}}^{PO-F}$	Process output-final material coefficient matrix
$I_{\mathrm{r,\ p}}^{PO-I}$	Process output-intermediate material coefficient matrix
$I_{\mathrm{i,\ p}}^{PO-R}$	Process output-raw material coefficient matrix
$o_{\mathrm{b,\ t}}$	Output power of gas boiler b at the time t [MW]
P, p	Set and index for each process
$P_p^{\mathrm{I,\ max}}$	Maximum input of a process [t]
$P_p^{\mathrm{I,\ min}}$	Minimum input of a process [t]
P_{p}^{l}	Length of process i [h]
P_{p}^{Dl}	Length of interruption of process i [h]
$P_{\mathrm{p}}^{El,k}, P_{\mathrm{p}}^{El,l}$	Slope and y-intercept for electric load of process p
$P_p^{El,D}$	Electric load of process p when interrupted [MWh]
$P_{\mathrm{p}}^{Hl,k}, P_{\mathrm{p}}^{Hl,l}$	Slope and y-intercept for heat load of process p
$P_p^{Hl,D}$	Heat load of process p when interrupted [MWh]
$P_{\mathrm{p}}^{Ml,k}, P_{\mathrm{p}}^{Ml,l}$	Slope and y-intercept for hydrogen load of process p
PV_t	Production from photovoltaic in time t [MWh]
R, r	Set and index for each raw material
$S_f^{F,max}$	Maximum storage of final product f [t]
$S_f^{F,min}$	Minimum storage of final product f [t]
$S_f^{f,goal}$	Amount of final product f needed [t]
$S_i^{I,max}$	Maximum storage of intermediate material i [t]
$S_i^{I,min}$	Minimum storage of intermediate material i [t]
$S_i^{I,0}$	Initial storage state of intermediate material i v
$S_r^{R,max}$	Maximum storage of raw material r [t]
$S_r^{R,min}$	Minimum storage of raw material r [t]
T, t	Set and index for each time step
$\upsilon_{\mathrm{h,\ t}}$	Output power of hydrogen boiler h at the time t [MW]
$x_{\mathrm{p,\ t}}$	Indicate whether the process p operate at time t

In this paper, we analyse a realistic industrial facility designed as a price-responsive demand response system, with installed hydrogen technologies and a photovoltaic renewable energy system in order to lower its emissions and environmental impact.

1.1. Relevant literature analysis

Although hydrogen as an energy vector is not a new concept, its usage has greatly increased as a substitute for fossil fuels over the past couple of years [10]. Hydrogen technologies have found wide variety of usage in energy markets. Great emphasis in the literature is placed on hydrogen as an energy storage [11], from its feasibility as a clean technology [12] to usage of various different hydrogen technologies [13]. Lagioia et al. [14] finds European hydrogen roadmap difficult to implement in a short-term as there are technical and infrastructure barriers in large-scale application, although they do believe that hydrogen technologies will find usage in heavy industry and heavy-duty transport. Similarly, the authors in [15] recognise importance of green hydrogen in decarbonisation of industrial sector and provides overview of country potential in production and industrial application of green hydrogen.

The research body presented here recognises the importance of hydrogen as an energy vector and its cooperation with renewable energy sources. Lebrouhi et al. [16] provides an overview on current development on hydrogen as an energy vector from technological and geopolitical viewpoint. According to their prediction around 60% of all GHG (greenhouse gas) emission reduction will come from renewables, green hydrogen and low carbon electrification. Amin et al. [17] analyse hydrogen production from renewable and non-renewable energy sources and their impact on environment. Paper [18] proposes a 100% renewable microgrid using hydrogen-based long-term storage. It provides the methodology for operation and finding the best sizing values for such a system. Integration of hydrogen technologies into the energy system is proposed in [19]. The paper discusses the integration of power to hydrogen and heat with seasonal hydrogen storage in a system with very high renewable energy penetration. The flexibility of hydrogen system is showcased by considering generation-load uncertainties and N-1 contingency of crucial devices. Miljan et al. [20] propose a profit maximisation model, cast as a bilevel algorithm, where the operation of a large scale battery storage system and electrolyser is optimised for day-ahead electricity market participation while simulating market clearing in the lower level. The paper analysed profits and utilisation for different sets of installed power capacities. Another important role of hydrogen is its use in heat production as it provides an alternative to fossil fuel usage. Samastil et al. [21] examine possibilities of green hydrogen in heat production in order to decarbonise heat demand sector in Great Britain. Their results have shown that there is potential for 20% of heat production from hydrogen. It should be noticed that majority of the analyses mentioned above focus on local production of hydrogen as transmission and procurement of hydrogen is a complex problem and some of the prominent solutions suggest using natural gas grid for hydrogen transportation [22]. With this in mind, there are opportunities opening for design of the hydrogen market where some aspects could follow the natural gas market design logic. In the line with this, Pavic et al. [23] consider a complex system with hydrogen technologies, RES and battery storage system in a multi market environment. They consider natural gas, electricity and hydrogen market while also providing ancillary services for the system operator in the form of automatic frequency restoration reserve. Hydrogen technologies will have a major impact on the energy market in the future, but based on the existing literature review, additional research is necessary.

The second identified gap focuses on maximising the benefits of hydrogen's role in industry facilities acting as active market participants, relying on hydrogen in both its inner processes and reducing energy costs by adjusting its interactions with energy systems driven by market prices. Industrial plants are energy-intensive and centralised consumers, meaning that they do not necessarily require any kind of aggregation, unlike smaller consumers [24]. They usually contain a certain degree of automatisation making them easier to operate. With this in mind, they are prime targets for implementation of demand-side flexibility [25], however, they are there is ample room for improvement in the literature [26]. The possibilities of demand-side management in metal casting industries are presented in [27], based on the day-ahead electricity market scheduling model and reserve provision. Similarly, [28] showcased the economic benefits of pulp and paper industries in the regulating power market as means to balance the ever-increasing share of renewable energy sources. The conclusions of the paper are that economic factors should be addressed when assessing the technical or theoretical possibilities to participate in DR program. Wang et al. [29] provide a framework for day-ahead scheduling and contract following with real-time demand response management. The industrial system observed in the paper is chlor-alkali production with a hydrogen production system and photovoltaic thermal system. Shoreh et al. [30] provide a detailed analysis of the possibilities of demand response programs in different industries. The methodology for industrial demand response based on batch process scheduling is presented in [31]. It is based on different smart pricing schemes such as time-of-use and peak pricing. A similar model is adapted to a real-world industrial plant by the same authors in [32]. Paper [33] provides detailed analysis and development status in hydrogen integration in the iron and steel industry. They report that up to 95% of CO_2 emissions reduction can be achieved by replacing classic coal blast furnaces with hydrogen. A detailed study was carried out for potential switches between these technologies with a conclusion that there are still challenges to overcome. On the other hand, they anticipate that by 2035 hydrogen technologies would be an important factor in industry decarbonisation. Techno-economic feasibility analysis for alternative hydrogen production from methane pyrolysis in steel-making industrial process is presented in [34] and compared to the classic electrolyser approach. The analysis yielded similar results for methane pyrolysis and electrolyser, concluding that both approaches are feasible, but noting that total emission for electrolyser is lower in systems with low emission energy mix.

Based on the above, the authors have recognised a research gap as hydrogen in industrial application is still sparsely researched topic. Some papers focus on different aspects of hydrogen but look at them individually, from its energy storage capabilities [35], electricity and heat production potential [36], industrial process utilisation [37] or emissions reduction potential [38]. Besides focusing on the above-mentioned topics, the paper will also explore environmental and economic benefits that can be achieved through market participation and renewable energy integration. Merging them into cohesive narratives to fill the gaps in the literature, which in our opinion, has not been well researched until this point. It needs to be noted that replacing natural gas and the entire gas infrastructure, from pipelines, boilers, etc., with hydrogen infrastructure includes multiple technical challenges and issues which have not yet been adequately researched to the author's best knowledge, as there is still not sufficient empirical evidence from the plants. Energy systems within industrial facilities are independent systems as they do not interfere significantly with industrial processes except on the points of transferring energy to the processes, so those challenges should not be insurmountable in practice. The authors acknowledge those challenges, from technical to security perspectives, and they need to be fully understood in the case of the proposed energy transition, however, this is out of the scope of the paper.

1.2. Contribution and organisation

In this paper, as two main scientific contributions, we:

- Propose a linear model of price-responsive demand response based industrial system scheduling with green hydrogen as an energy vector and photovoltaic renewable energy system,
- Define the economic breaking points for energy transition of fossil fuel driven industrial facility using green hydrogen and renewable sources.

The remaining of the paper is organised as follows. Section 2 provides concept and mathematical framework. Section 3 provides the case study. Section 4 discusses emissions reducing possibilities and Section 5 provides economic analysis. Finally, Section 6 concludes the paper.

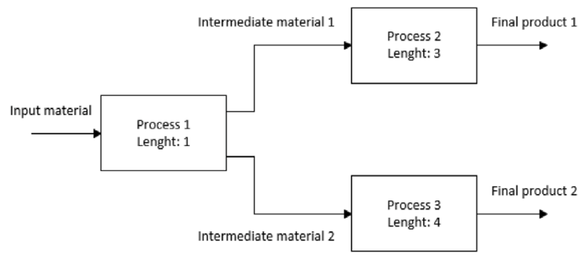

Fig. 1. Generic industrial process scheme.

2. Mathematical framework and concept

2.1. Concept

The presentation of the developed model is conceptually separated into two parts. The first part describes the processes which simulate industrial plant operation. The idea is that the entire product refinement from raw materials to end-product is simulated with various intermediate steps. From the perspective of this paper, these processes represent plant's consumption of energy. They can be optimally scheduled throughout optimisation horizon based on chosen objective function. This means that the consumption can be shifted and we can classify this part of the model as a price responsive demand response. Fig. 1 shows an example of the process scheme for an industrial plant. It contains three processes: one raw (input) material, two intermediate materials and two final products. Raw material is refined in process 1 into intermediate materials which are later on refined by process 2 and 3 into final products. Processes can have different lengths as shown in Fig. 1. Process with length of one is considered continuous which means that it produces outputs in every time step. Other processes are batch, meaning that they require more time steps to produce an output (i.e. inputs are taken in time step "N" and outputs are generated "l" time step later, where "l" is the length of batch process). Second part of the model deals with scheduling of the devices used to satisfy consumption of the processes. The devices can be powered by different energy vectors, meaning the model can optimise shifting between electricity and natural gas as fuels in order to minimise the total cost and showcase the differences. However, the goal of the developed model is to clearly identify the conditions in which full electrification of the industrial plant is possible and financially feasible, using hydrogen technologies and renewable energy sources. Detailed mathematical model is explained in the following section.

2.2. Mathematical model

In the proposed model one optimisation step is equal to one hour and the optimisation horizon varies depending on the scenario. A detailed demand model of an industrial plant with process scheduling is described further in this section. All continuous variables are positive unless stated otherwise.

Eqs. (1) and (2) calculate the number of times that batch/continuous cycles have started/finished at a specific time for the entire optimisation horizon using variables α and ω. In other words, if the length of the process is 2 h and at time t it has been running for 3 h in total, the start variable α will contain the value of 2 and the finish variable ω will be 1. Materials are inputted into the process to be refined into usable outputs. Process input can only be taken at the beginning of the batch cycle and outputted only at the end. The minimum and maximum amount of inputs is limited with constraints (3) and (4), where the difference "$\alpha_{p,\ t} - \alpha_{p,\ t\text{-}1}$" denotes whether the process has started or not. Variable $\mu_{p,\ t}$ is used to track the volume of materials currently being refined by the process which is enforced with constraint (5). This is important due to dependency of other variables in the model on its value (e.g. process consumption). Eqs. (6) and (7) set the total process output at its end. Total output is always equal to total input, but the input can be separated on multiple processes or even be noted as loss based on the given parameters. Similar to the start, end of the process is denoted with the expression "$\omega_{p,\ t} - \omega_{p,\ t\text{-}1} = 1$". These two constraints are if-then constraints, called indicator constraints, implemented in the used Gurobi solver [39]. In short, if the term on the left side is true then the constraint on the right side must be enforced, and if it is false the constraint is not enforced. Process outputs are finalised at the end of time t which is modelled as the beginning of the next time step $t+1$.

$$(\alpha_{p,\ t} - 1)\cdot P_p^l + 1 \le \sum_{k=1}^{t} x_{p,\ k} \le \alpha_{p,\ t}\cdot P_p^l \tag{1}$$

$$\omega_{p,\ t}\cdot P_p^l \le \sum_{k=1}^{t} x_{p,\ k} \le (\omega_{p,\ t}+1)\cdot P_p^l - 1 \tag{2}$$

$$\overline{\mu}_{p,\ t} \le P_p^{I,\ \max}\cdot(\alpha_{p,\ t} - \alpha_{p,\ t\text{-}1}) \tag{3}$$

$$\overline{\mu}_{p,\ t} \ge P_p^{I,\min}\cdot(\alpha_{p,\ t} - \alpha_{p,\ t\text{-}1}) \tag{4}$$

$$\mu_{p,\ t} = \mu_{p,\ t\text{ - }1} + \overline{\mu}_{p,\ t} - \underline{\mu}_{p,\ t} \tag{5}$$

$$\omega_{p,\ t} - \omega_{p,\ t\text{-}1} = 1 \rightarrow \underline{\mu}_{p,\ t\ +\ 1} = \mu_{p,\ t} \tag{6}$$

$$\omega_{p,\ t} - \omega_{p,\ t\text{-}1} = 0 \rightarrow \underline{\mu}_{p,\ t\ +\ 1} = 0 \tag{7}$$

During the production some processes can be interrupted for a certain amount of time, i.e. their production can be shifted without endangering progress or impacting the quality of the end product. Considering this, the process must always be in one of the three possible states (off mode, operation mode or interrupted mode). After the process has started its operation it must be either in operation mode ($x_{p,t} = 1$) or in interrupted mode ($\iota_{p,t} = 1$) until it is finished, else it is in off mode where both variables are equal to "0". To convey this behaviour, Eqs. (8)–(10) are introduced. Eq. (8) ensures that the process can only be interrupted when it is running, (9) ensures that the process is either running or is interrupted and (10) ensures that if the process is running at least one of the binary variables, $\iota_{p,t}$ or $x_{p,t}$, must be equal to 1. Eq. (11) defines the maximum length for process interruption at the start of each batch cycle.

$$\iota_{p,\ t} \le \alpha_{p,\ t} - \omega_{p,\ t} \tag{8}$$

$$\iota_{p,\ t} + x_{p,\ t} \le 1 \tag{9}$$

$$\iota_{p,\ t} + x_{p,\ t} \ge \alpha_{p,\ t} - \omega_{p,\ t} \tag{10}$$

$$\alpha_{p,\ t} - \alpha_{p,\ t\text{-}1} = 1 \rightarrow \sum_{k=t}^{t+P^l+P_i^{Dl}} \iota_{p,\ k} \le P_p^{Dl} \tag{11}$$

The load of the process depends on the state of the process at each time step: off, operational or interrupted mode. While in the operation state, the process is producing\refining the product and its consumption is linearly dependent on the volume of material the process is working on. The interrupted state considers that the process has started but was halted in order to shift demand. In this state, the process can have a fixed predefined consumption which is needed so the progress of the process is not lost. For example in aluminium production, the temperature must not fall below a certain threshold, so heating energy is needed [40]. Each process can have 3 types of load needed for product refinement, weather it is electricity to power devices such as motors and assembly lines, heat for smelting or hydrogen for chemical processing. Eqs. (12), (14) and (15) calculate the electrical, hydrogen and heating load when the process is in operation, respectively. If the process is interrupted fixed load is calculated with (13) and (16). When the process contains hydrogen load we consider it as an exothermic process that can be captured with a heat exchanger. This means that its heat consumption becomes heat production. In this case corresponding variable is initialised as a non-positive and Eq. (15) is multiplied with "−1".

$$x_{p,\ t} = 1 \rightarrow \beta_{p,\ t} = \mu_{p,\ t}\cdot P_p^{El,k} + P_p^{El,l} \tag{12}$$

$$\iota_{p,\ t} = 1 \rightarrow \beta_{p,\ t} = P_p^{El,D} \tag{13}$$

$$x_{p,\ t} = 1 \rightarrow \gamma_{p,\ t} = \mu_{s,\ p,\ t} \cdot P_{p}^{Ml,k} + P_{p}^{Ml,l} \tag{14}$$

$$x_{p,\ t} = 1 \rightarrow \delta_{p,\ t} = \mu_{p,\ t} \cdot P_{p}^{Hl,k} + P_{p}^{Hl,l} \tag{15}$$

$$\iota_{p,\ t} = 1 \rightarrow \delta_{p,\ t} = P_p^{Hl,D} \tag{16}$$

The proposed model considers two types of materials: raw and intermediate materials. Both can be supplied to the process as input. The raw material is acquired beforehand, while intermediate material is produced in one of the processes within the observed plant and can be used in another process. Final products are process materials that do not need further refinement. Minimum and maximum available material storage is defined with (17), (19) and (21). If an intermediate material cannot be stored, minimum and maximum values are set to 0, which means that the material must be used immediately after it is produced. Eqs. (18), (20) and (22) connect storage (raw materials, intermediate materials and final products respectively) with inputs and outputs from the processes. Coefficients in "I" matrices used in mentioned equations correspond to the ratio of materials; for example, if process 1 takes raw materials 1 and 2 in ratio 60% and 40%, coefficients will be $I_{1,\ 1}^{PI-R} = 0.6$ and $I_{2,\ 1}^{PI-R} = 0.4$. The coefficients for other materials and products, not used by this process, will be zero. Each storage has a defined initial value (set in the hour 0). Both intermediate and final storage levels are defined for every $t \in (T+1)$ so that the process that has finished in the last hour T can output their products in hour T+1. No other action takes place at the time $T+1$. The initial value of the intermediate materials must be at least equal to the intermediate material in the hour $T+1$ as shown in (23). The final product has the required volume that needs to be produced at the end of the optimisation horizon $(T+1)$ defined by (24). Additionally, the optimisation can be split into multiple days where the above constraints can be defined for the end of each day instead for the entire optimisation horizon.

$$S_i^{R,min} \leq \sigma_{r,\ t} \leq S_i^{R,max} \tag{17}$$

$$\sigma_{r,\ t} = \sigma_{r,\ t\text{-}1} - \sum_{k=1}^{P} I_{r,\ k}^{PI-R} \cdot \overline{\mu}_{k,\ t} + \sum_{k=1}^{P} I_{r,\ k}^{PO-R} \cdot \underline{\mu}_{k,\ t} \tag{18}$$

$$S_r^{I,min} \leq \tau_{i,\ t} \leq S_r^{I,max} \tag{19}$$

$$\tau_{i,\ t} = \tau_{i,\ t\text{-}1} - \sum_{k=1}^{P} I_{i,\ k}^{PI-I} \cdot \overline{\mu}_{k,\ t} + \sum_{k=1}^{P} I_{i,\ k}^{PO-I} \cdot \underline{\mu}_{k,\ t} \tag{20}$$

$$S_f^{F,min} \leq \upsilon_{f,\ t} \leq S_f^{F,max} \tag{21}$$

$$\upsilon_{f,\ t} = \upsilon_{f,\ t\text{-}1} - \sum_{k=1}^{P} I_{f,\ k}^{PI-F} \cdot \overline{\mu}_{k,\ t} + \sum_{k=1}^{P} I_{f,\ k}^{PO-F} \cdot \underline{\mu}_{k,\ t} \tag{22}$$

$$\tau_{f,\ T+1} \geq S^{I,0} \tag{23}$$

$$\upsilon_{f,\ T+1} \geq S^{F,\ min} \tag{24}$$

The industrial facility can satisfy the process consumption by using various devices. Electricity consumption can be satisfied by purchasing it from the electricity market or by generating it locally. Hydrogen consumption is satisfied using local hydrogen production. Heat is also produced locally from various technologies that will be presented later in the paper. All of these devices in the model use at least four general constraints. Two of those constraints limit the minimum and maximum output power as shown in (25), except in case of the fuel cell where input power is constrained. The other two constraints are for minimum and maximum ramp rate of the device, shown in (26) and (27). Variables and parameters for the electrolyser are used as an example for these general constraints. Hydrogen storage is a bit more specific. It still retains Eq. (25) for its input and output power in this form. Maximum and minimum volume of hydrogen that can be stored (SOH, state of hydrogen) is modelled to be equal to (25), but without binary variables. Additionally, it requires a constraint (28) for tracking the stored hydrogen. Also, it requires that the initial value is set and that the SOH in the last hour is the same as initially set.

$$E_{e,t}^{min} \cdot y_{e,\ t} \leq a_{e,t} \leq E_{e,t}^{max} \cdot y_{e,\ t} \tag{25}$$

$$a_{e,t} - a_{e,t\text{-}1} \leq E_{e}^{rampdown} \tag{26}$$

$$a_{e,t\text{-}1} - a_{e,t} \leq E_{e}^{rampup} \tag{27}$$

$$\phi_t = \phi_{t-1} + \overline{h}_t - \underline{h}_t \tag{28}$$

Except for the above-mentioned general Eqs. (25)–(27), natural gas boilers have an additional set of constraints in the model. They have three different states, *on* state when it is in operation and two *off* states termed as *warm* and *cold* and defined by (29). When the boiler shuts down it transitions from *on* state to *warm* state from which it requires less energy for a start-up. This transition is modelled by constraint (30). When the cooldown time has passed and the boiler did not start again, it must transition to *cold* state (31), meaning it will require more primary energy to start up again. Eqs. (32) and (33) ensure that the impossible transitions between states cannot happen, e.g., from *cold* to *warm* state. When the boiler is starting, it requires additional energy input depending if it is in *warm* or *cold* state. Constraints (34) and (35) set binary variables $\nu_{b,t}$ and $\kappa_{b,t}$ to 1 if the boiler has started from *cold* or *warm* state, respectively. With (36)–(38), starting binary variables are hard constrained so they can only be 1 in case of (34) and (35). Total natural gas consumed by the boiler in each hour is calculated using (39), considering operation and start-up consumption.

$$\epsilon_{b,t} + \zeta_{b,t} + \theta_{b,t} = 1 \tag{29}$$

$$\zeta_{b,t} \geq \epsilon_{b,t-1} - \epsilon_{b,t} + \zeta_{b,t-1} - \theta_{b,t} \tag{30}$$

$$\theta_{b,t} \geq \sum_{k=t-B_b^{cdt}}^{t} (\zeta_{b,k} + \theta_{b,k}) - B_b^{cdt} - \epsilon_{b,t} + 1 \tag{31}$$

$$\zeta_{b,t} + \theta_{b,t-1} \leq 1 \tag{32}$$

$$\theta_{b,t} + \epsilon_{b,t-1} \leq 1 \tag{33}$$

$$\theta_{b,t-1} - \theta_{b,t} \leq \nu_{b,t} \tag{34}$$

$$\zeta_{b,t-1} - \zeta_{b,t} - \theta_{b,t} \leq \kappa_{b,t} \tag{35}$$

$$\epsilon_{b,t-1} + \kappa_{b,t} + \nu_{b,t} \leq 1 \tag{36}$$

$$\theta_{b,t} + \zeta_{b,t} + \kappa_{b,t} \leq 1 \tag{37}$$

$$\theta_{b,t} + \zeta_{b,t} + \nu_{b,t} \leq 1 \tag{38}$$

$$\chi_{b,\ t} = o_{b,t} \cdot B_b^k + \epsilon_{b,t} \cdot B_b^l + \nu_{b,t} \cdot B_b^{cs} + \kappa_{b,t} \cdot B_b^{ws} \tag{39}$$

The last group of equations connects all of the above mentioned processes and devices. They are basically enforcing the law of energy conservation. Consumed energy must be equal to produced and/or bought from the market. The first Eq. (40) is summing electricity consumption/production of all consumers (processes and electrolyser) and producers (PV and fuel cell) while selling surplus or buying deficit from the market. The next constraint (41) balances hydrogen, which can be produced with electrolyser, stored or consumed in processes, fuel cell or hydrogen boiler. The last balance Eq. (42) is for the heating energy which is produced by boilers or the fuel cell and consumed in processes. From these equations we can see how various energy vectors are intertwined and interact with each other; e.g., fuel cell which can be found in all three equations.

$$\pi_t = \sum_{k=1}^{E} \frac{a_{k,t}}{\eta_k^E} + \sum_{k=1}^{P} \beta_{k,t} - \sum_{k=1}^{G} d_{k,\ t} \cdot \eta_g^{G,el} - PV_t \tag{40}$$

$$\sum_{k=1}^{P} \gamma_{p,t} = \sum_{k=1}^{E} a_{k,t} - \sum_{k=1}^{G} d_{k,t} - \overline{h}_t + \underline{h}_t - \sum_{k=1}^{H} \frac{\upsilon_{k,t}}{\eta_k^H} \tag{41}$$

$$\sum_{k=1}^{P} \delta_{k,t} = \sum_{k=1}^{B} o_{k,t} + \sum_{k=1}^{G} d_{k,\ t} \cdot \eta_g^{G,h} + \sum_{k=1}^{H} a_{k,t} \tag{42}$$

The objective function is the cost minimisation of the operation; in this case, it is equal to electricity and natural gas bought from the

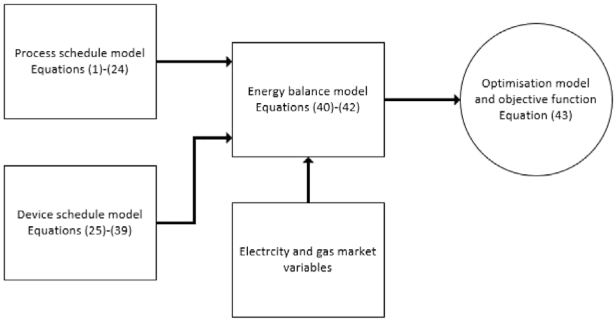

Fig. 2. Flowchart of the presented model.

market, as shown in (43). Fig. 2 summarises the logic and the assigned modelling equations of the presented model and its various segments.

$$\sum_{k=1}^{T} \pi_k \cdot C_k^{el} + \chi_{b,\ t} \cdot C^{gas} \tag{43}$$

3. Case study

3.1. Scenarios

Five different scenarios will be considered throughout the analysis. All scenarios will have the same amount of PV for a fair comparison. The same is valid for the capacity of the electrolyser, which is dimensioned to satisfy at minimum hydrogen consumption in the facility processes. They are as follows:

- Initial scenario (S0) - Classic layout utilising natural gas boiler.
- First scenario (S1) - Hydrogen layout with electrolyser, hydrogen storage and fuel cell.
- Second scenario (S2) - Hydrogen layout with electrolyser, hydrogen storage, hydrogen boiler and fuel cell with higher electrical and lower heating efficiency.
- Third scenario (S3) - Hydrogen layout similar to S1 with higher efficiency electrolyser, hydrogen storage and fuel cell
- Fourth scenario (S4) - Hydrogen layout similar to S2 with higher efficiency electrolyser, hydrogen storage, hydrogen boiler and fuel cell with higher electrical and lower heating efficiency

The initial scenario can be considered a classic layout found in industrial plants. Scenarios S1 to S4 incorporate hydrogen technologies in order to lower the emissions of the plants. S1 and S3 have similar layouts where the fuel cell is used for electricity and heat production, while S2 and S4 have a combination of the fuel cell and a hydrogen boiler. The efficiencies of the fuel cell varies such that in S1 and S3, its dimension is defined by the heat production, while in S2 and S4, its dimension is defined by the electricity production.

Across these four scenarios, we will also consider two different electrolyser types. The first one (in S1 and S2) represents an older type that was already part of the industrial plant, while the second one (S3 and S4) represents a new technology. Layout and interaction between energy vectors and consumption sectors is shown in Figs. 3 and 4, where electricity vector is marked in blue, gas vector in yellow, heat vector in orange and hydrogen vector in grey. It is noted next to the names of various elements in which scenarios are used. When no scenario is mentioned, means that they appear in all observed scenarios. Consumption sectors represent demand from processes that will be explained in the next subsection.

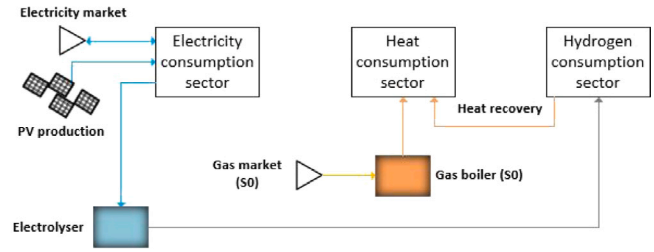

Fig. 3. Device layout of the industrial plant for S0.

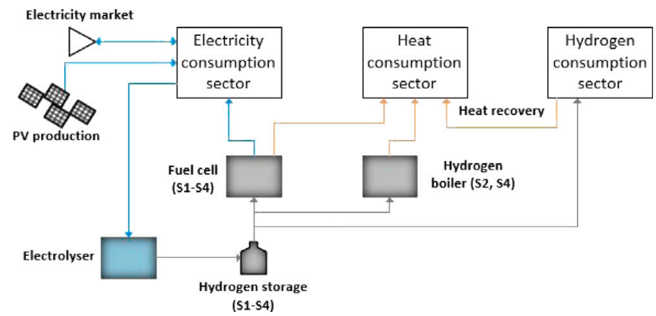

Fig. 4. Device layout of the industrial plant for S1–S4.

Table 1
Process electricity and heat consumption.

Process number	1	2	3	4	5
Electric consumption (MWh/t)	0.4	0.55	0.9	0.8	0.6
Heat consumption (MWh/t)	0.7	0.5	0.3	0	0.5

3.2. Input parameters

The layout of the processes in the industrial facility is shown in Fig. 5. It is composed of five processes, set in sequential order. One raw material, four intermediate materials and one final material can be identified in the figure. Raw material has to pass through all five processes to become the final product, denoted with arrows. The length of each process is shown in the brackets next to the process sequence number. Processes 2 and 5 are classified as continuous while the rest are defined as batch. Process 4 is the only one with hydrogen consumption and heat recovery system consuming 1 MWh of hydrogen per ton of material processed with heat recovery of 0.2 MWh/t. All other processes have electrical and heat consumption dependent on the materials processed, as shown in Table 1. The amount of input and output materials for each process are limited to 5 tonnes. There is a sufficient amount of raw materials to produce the required volume of the final product. All intermediate materials start at 0 capacity at the beginning. The optimisation is run for three days (72 h) with a step of one hour. This setup is chosen to suit the resolution used in European day-ahead spot markets, capturing all the relevant processes for the industrial facility but still being computationally feasible. Total amount of the required final product is 60 tonnes, while there is an additional requirement that 20 tonnes are produced each day (at the end of each 24-hour period). To produce one ton of the final material, 3.25 MWh of electricity, 1.55 MWh of heat and 1 MWh of hydrogen are needed while recovering 0.2 MWh of heat.

All scenarios contain a PV system whose curve is generated using [41,42] and is shown in Fig. 6. The initial scenario (S0) contains a boiler sized so it can produce enough heat needed at any time, with rated power of 50 MW. The parameters of its efficiency curve are 1.12 for the slope and 1 for the y-intercept. All the other heat-producing

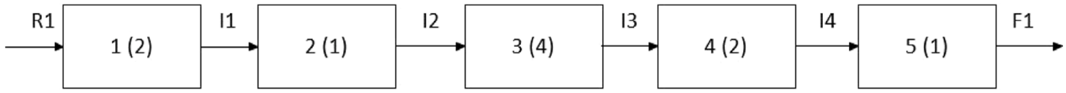

Fig. 5. Process layout of the industrial plant.

equipment (mainly fuel cells and hydrogen boilers) are also sized so they have roughly the same heat production as a natural gas boiler. The output power of the electrolyser is 25 MWh with the efficiency of 66% [43], used in S1 and S2. Since there have been reports of a higher efficiency electrolyser technologies, we decided to incorporate the one with the efficiency of 80% [44] into our analyses in S3 and S4. Hydrogen storage is the same for all scenarios and can store up to 300 MWh of hydrogen with the maximum input and output power of 300 MW if needed. Two different fuel cells are used, both with an input power of 100 MW. The first one has electric efficiency of 37% and heating efficiency of 52%, used in S1 and S3. This fuel cell is chosen due to a better fit with the heat consumption of the industrial facility. The second fuel cell has a higher electric efficiency of 47% and lower heat efficiency of 36% (used in S2 and S4) and is constructed to work in conjunction with the hydrogen boiler [45]. The last hydrogen device is a boiler with an output power of 50 MW and efficiency of 85%, used in S2 and S4. Although hydrogen boilers that use only hydrogen are not yet commercially available they are considered to get a comprehensive insight into all future options. Device sizes were chosen iteratively so they can cover required consumption by the industrial processes in all time steps, without making them oversized. We do not claim these sizes are optimal, but that they are sufficient for purposes of the industrial plant. Natural gas prices are taken from [46] and electricity prices from Croatian power market [47]. Both prices are taken from late 2021 (before the rapid increase in prices in 2021 in Europe). Natural gas price is equal to 90 €/MWh and electricity price can be seen in Fig. 7. The case studies for sensitivity analyses are created by taking two base prices and multiplying them with a selected factor. This means the natural gas price multiplier goes from 0.5 to 3 with a step of 0.5 (6 prices in total), while the electricity price multiplier goes from 0.5 to 2 with a step of 0.5 (4 prices in total). When combined, there are 24 cases in total. Historically, electricity and natural gas prices had a certain correlation between them, but are lately becoming more decoupled from one another especially in the European Union [48,49]. The above-described price scenarios are not designed to reflect fully realistic scenarios, but to capture past and future trends and ratios of natural gas and electricity prices. Lastly, the specific CO_2 emission intensity for electricity bought from the electricity market is 133 kg/MWh [50] and for natural gas is 386 kg/MWh [51]. Nitrogen oxide (NO_x) and carbon monoxide (CO) are produced locally by burning natural gas with specific emissions being 0.2 kg/MWh for NO_x and 0.04 kg/MWh for CO. Please note that model is created in a way that parameters and layout of processes are easily changed and adjusted for different industrial plants and are not limited to ones presented in our case study. Parameters for devices used to cover consumption can be easily changed and they can be removed or added when needed. The model also leaves room for the implementation of various features, devices, etc., considering that they can be modelled appropriately.

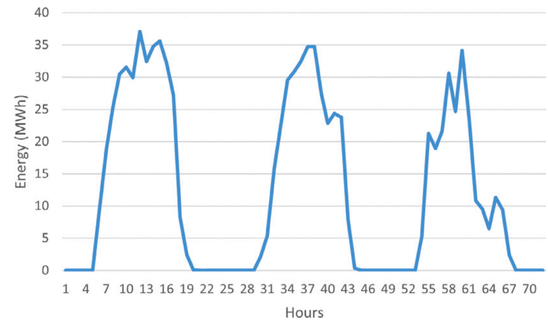

Fig. 6. Photovoltaic production.

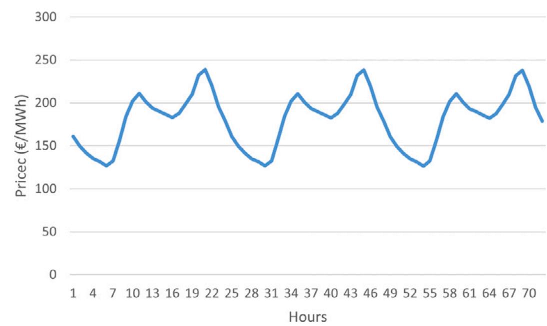

Fig. 7. Base electricity prices.

4. Discussion on the reduction of GHG emissions

In this Subsection we will analyse the impact of hydrogen decarbonisation of the industrial facility on energy exchange with a grid and on greenhouse gas emissions (CO_2, NO_x and CO). Due to brevity we will focus only on scenarios S0 and S1 (as representatives of traditional natural gas and modern decarbonised layouts), with two different capacities of installed PV and with two different electricity trading policies. We choose to showcase GHG emission analysis only for S1, as we believe it to be sufficient to show all effects of it and keep analysis efficient and well organised. Also, we chose exactly S1 as it was the worst option out of four observed scenarios, as will be shown in economic analysis. Two different PV capacities are: (i) higher PV capacity with the production curve shown on Fig. 6 and (ii) lower PV capacity which is 50% of PV capacity in (i). Two different trading policies refer to: (i) trading on the electricity market as explained in Section 3 and (ii) the same strategy as in (i) with the penalisation of the sold electricity aiming at maximisation of local consumption. Penalisation of energy injected back to the grid effectively raises self sufficiency of the system and lowers emissions accordingly. Above mentioned scenarios are not necessarily economically optimal but are created to showcase possibilities of hydrogen as an energy vector and to be in line with the recent trends in different countries where many end-users, including industry facilities, are looking into becoming more grid independent and sustainable regardless the cost optimality criteria. The total calculated CO_2 emissions are the result of two specific processes. The first one is caused by burning natural gas in the boiler and emitted from the industrial plant. The second one is the indirect one and is a result of purchasing electricity from the market (which is dependant on the energy mix). The NO_x and CO emissions are only produced by burning natural gas.

Tables 2 and 3 show the results for total import/export of electricity and natural gas and total CO_2 emissions for all cases. A general observation from both tables, as expected, is that S0 scenario creates higher emissions than S1. S1 scenario has significantly lower CO_2 emissions primarily as it does not relay on the natural gas for heat production as it can use hydrogen as an alternative and produce zero NO_x and CO emissions. As a result there is an increase in S1 electricity import, used for the consumption of the electrolyser to produce hydrogen. Since the specific CO_2 emissions of electricity are lower than that of natural gas, even when taking into account the efficiencies of boiler and

Table 2
Results comparison without penalised export.

Scenario	PV	Electricity import (MWh)	Electricity export (MWh)	Natural gas import (MWh)	Total CO_2 emissions (kg)
S0	Lower	299.16	138.55	283.08	149057.2
S1	Lower	764.28	180.84	0	101649.2
S0	Higher	209.12	498.72	280.84	136217.4
S1	Higher	636.8	503.57	0	84693.8

Table 3
Results comparison with penalised export.

Scenario	PV	Electricity import (MWh)	Electricity export (MWh)	Natural gas import (MWh)	Total CO_2 emissions (kg)
S0	Lower	197.91	37.3	485.91	137489.6
S1	Lower	583.44	0	0	77596.9
S0	Higher	89.75	379.35	374.39	121808.4
S1	Higher	133.23	0	0	17719.23

Table 4
NO_x and CO emissions.

S0	No penalised export		Penalised export	
PV	Lower	Higher	Lower	Higher
NO_x (kg)	56.62	56.17	97.18	74.99
CO (kg)	11.32	11.23	19.44	14.99

electrolyser, total emissions are lowered in S1 as oppose to S0 across all cases; as shown in Tables 2 and 3.

In the case of higher capacity of local PV, both S0 and S1 have lower overall emissions compared to lower PV capacity as they sell the surplus of locally produced electricity and therefore offset the emission from imported electricity. In the first analysis, ((Table 2) CO_2 emissions reduction is 31% and 37% for lower and higher PV, respectively, while for the second analysis (Table 3) is 43% and 85%.

However, when comparing counterpart scenarios between these two analysis, lower emissions are found in Table 3. In the analysis where exporting electricity is penalised, the results suggest higher local utilisation of PV as selling excess electricity is a less profitable option. In S1 scenario all electricity produced from the PV can be utilised locally as there is sufficient flexibility in form of consumption, elecrolyser and fuel cell scheduling; this is shown with the export of electricity equal to "0". On the other hand, S0 is not able to fully utilise locally produced PV electricity as there is a lack of flexibility due to usage of natural gas boiler as producer of heat.

The importance of local emission reduction is that its impact is much higher on the industry facility workers and their health as well as local population living in the proximity of the industry facility [52]. Considering only expected CO_2 emissions reduction, hundred millions fewer premature deaths worldwide could be mitigated as reported in [53]. Table 4 shows NO_x and CO emissions for S0. These emissions are only effected with natural gas consumption, meaning they are higher in a case with penalised export when the natural gas import is higher. These emissions are shorter range emission particles, with a range of up to 200 km. NO_x and CO emissions are fully mitigated when we replaced the locally burned fossil fuels with hydrogen.

From the emission reduction point, hydrogen technologies displace emission production to electricity producers. This entails that the exact emissions the industrial plant is responsible for are not exactly known at any given time, therefore average emissions are usually used. These specific emissions are highly dependent on the energy mix and will deeply vary from country to country. However, with current trends of increase in renewable energy sources and shutdown of high-emission power plants, specific emissions will surely drop in the future. This entails that the proposed industrial plant will have lower total emissions.

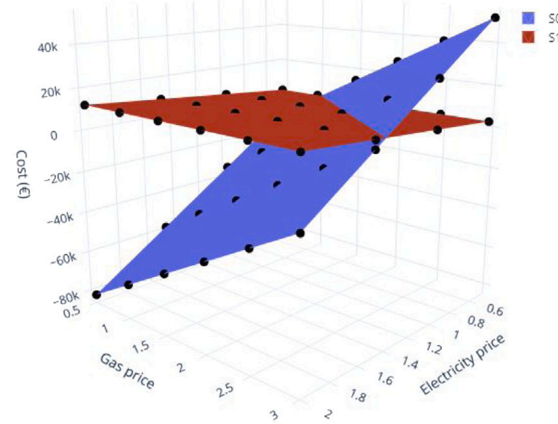

Fig. 8. Sensitivity analysis comparison of S0 and S1.

5. Economic aspects of decarbonised industry facility

As a baseline for all conducted sensitivity analyses, we consider the standard natural gas layout, or business-as-usual industry facility layout, defined as S0. The sensitivity analyses of different electricity and natural gas price ratios conducted in this subsection focusing on two main aspects for four hydrogen scenarios (S1–S4):

- are compared to the scenario S0 in order to validate economic feasibility of hydrogen technology in the observed industry facility.
- are compared to each other to understand how different technical characteristics of hydrogen equipment and their configuration impact the capability and flexibility of the industry facility to adopt to market price changes and disturbances.

5.1. Cost comparison: S0 vs S1–S4

In the transition to zero carbon energy system, green hydrogen is recognised as a pillar enabling this, especially with the energy intensive industry. However, the costs of the technology do not yet justify the investments. Here we focus on the operational aspects and discuss and analyse under which market conditions and prices does the replacement of the natural gas equipment with hydrogen becomes viable. To conclude, we conducted a sensitivity analysis comparing each defined hydrogen scenario (S1–S4) with the baseline natural gas scenario (S0). The optimisation for all scenarios (S0–S4) is conducted for 3 representative days and a range of natural gas and electricity prices. In total, 24 gas–electricity price cases are observed with different multipliers modifying the base price curve, as shown in Section 3.2. Used natural gas and electricity prices and their ratios are designed with the aim to define the points where the operational cost curves of S0 and S1–S4 intersect. These intersections define operating cost price parity between natural gas and hydrogen technology and can be seen as feasible points for hydrogen investments.

The results of 24 simulated cases, comparing S0 and S1, are shown in Fig. 8. Indicating that S1 has better results in 6 of natural gas–electricity price cases (25%), mostly when the natural gas price is very high (average price between 180–270 €/MWh) and electricity price is very low (average price of 90 and 180 €/MWh). Similar natural gas–electricity price logic and comparison of S0 with S2 is shown on Fig. 9 where S2 shows better results in 9 out of 24 cases (37.5%) and very similar results in two natural gas–electricity price cases. Fig. 10 is comparison with S3, where 12 out of 24 natural gas–electricity price cases are better (50%), with one case having similar cost. An interesting observation can be made here on the difference in the slope of the

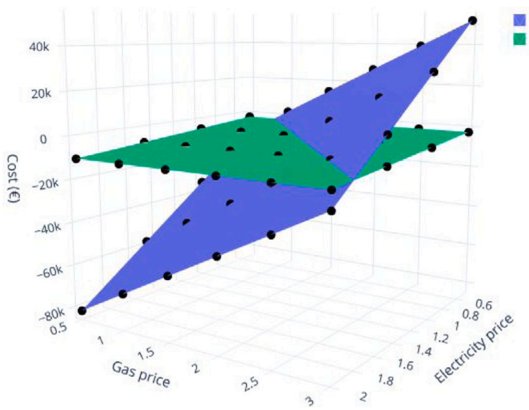

Fig. 9. Sensitivity analysis comparison of S0 and S2.

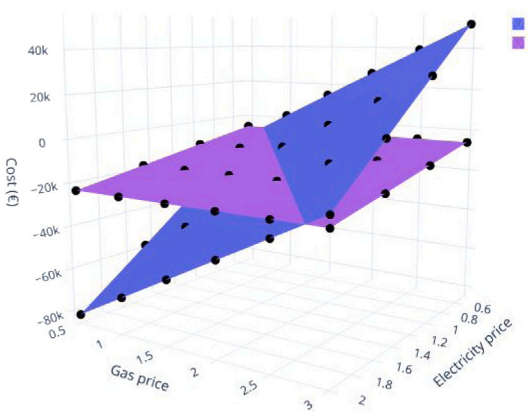

Fig. 10. Sensitivity analysis comparison of S0 and S3.

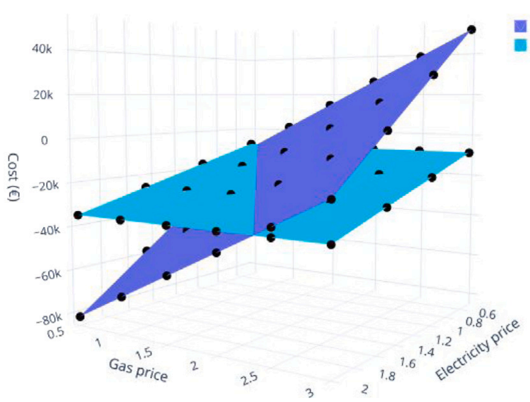

Fig. 11. Sensitivity analysis comparison of S0 and S4.

surface, where S0 has a much steeper slope, meaning that in S0 the industry facility is at much higher risk with regards to market prices than S3. Finally, in Fig. 11 a comparison is made between S4 and S0. S4 outperforms S0 in 14 out of 24 natural gas–electricity price cases (58%) and has very similar values in two other natural gas–electricity price cases. Same argumentation as with S3 can be used here, in terms of market price exposure.

5.2. Cost comparison: among S1–S4

In this analysis, we will compare all hydrogen scenarios (S1–S4) to each other to check how the hydrogen equipment configuration impacts

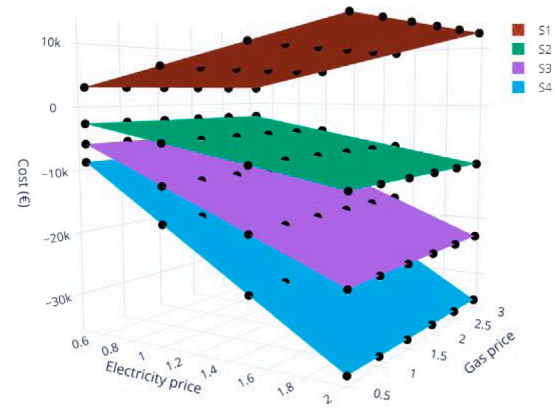

Fig. 12. Sensitivity analysis comparison of S1–4.

the overall industry facility exposure to changing energy prices. The results are visualised for all scenarios and prices as operational costs in Fig. 12. For easier understanding, one should keep in mind that the equipment layout in scenarios S1 and S3 and scenarios S2 and S4 is the same, as described in Section 3, with different efficiencies of the selected equipment. It also needs to be noted that the industry facility operation is heat driven, meaning that electricity from the fuel cell is treated as a byproduct and not correlated with local electricity demand.

Fig. 12 shows that higher efficiency electrolyser scenarios, S3 and S4, are characterised with the reduction of operational costs as prices of natural gas and electricity increase, exploiting the benefits of selling excess electricity at high electricity market prices (lower losses and higher flexibility). In opposite, since in S1 scenario there is no excess electricity produced, this scenario observes higher operational costs with the increase in natural gas and electricity prices. Interestingly, the S2 scenarios is least affected by the change in prices meaning the dimensioning of the units and heat and electricity ratio in that layout is most resilient to the price disturbances in the market.

The operational cost differences are very low between the four scenarios (S1–4) in case of overall low electricity and natural gas prices (average is 90 €/MWh for electricity and 45 €/MWh for natural gas). However, the differences increase to 45,000 euros between S1 and S4 for three-day optimisation in cases of higher electricity and natural gas prices (average is 360 €/MWh for electricity and 270 €/MWh for natural gas). Most of the differences between scenarios can be explained by efficiencies in heat production which directly affect the import of electricity. Heat is produced from hydrogen in either a fuel cell or a boiler. The fuel cell has lower heat production efficiency than the boiler, but additionally produces electricity. In S1 and S3 the fuel cell is the only way of producing heat, meaning electricity is produced as a side effect of heat production and is not always sold at the optimal market price. Fig. 13 shows the average power schedule of the fuel cells and the boilers in all scenarios for one set of prices (average electricity price of 180 €/MWh). In S2 and S4, there is a possibility of using multiple devices which leads to the decoupling of heat and electricity production making them independent from one another. It clearly shows that heat production from hydrogen boilers is price optimal option over fuel cells when combined in the selected scenarios (S2 and S4). This conclusion is stemming from the fact that the area beneath fuel cell curves is much lower than boiler curves. The needs for heat production from these devices are greater than electricity needs. According to results of optimisation the boiler is a better alternative, because of higher heating efficiency. Also, there might be an abundance of electricity sources to draw from to satisfy consumption while it is not beneficial to sell it. This also goes to show that electricity production

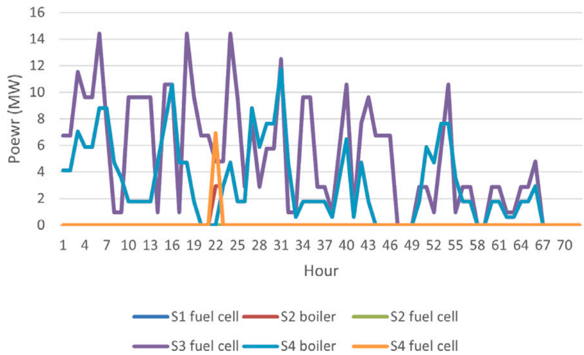

Fig. 13. Fuel cell and boiler average power schedule in S1, S2, S3 and S4.

from fuel cells is not that effective in terms of levelling the marginal cost of low-efficiency heat production.

5.3. Discussion on the economic analysis

It was shown in the results Section 5.1 how hydrogen industrial systems compare with classical natural gas based industrial systems from the economic perspective. Analysis concluded that hydrogen technologies can rival classically inexpensive natural gas technologies in industrial application under specific natural gas–electricity price couples. It was also shown that with newer technologies (e.g. more efficient or new technology of electrolyser and hydrogen boiler) overall cost shifts significantly in the favour of hydrogen. Comparison between different hydrogen scenarios (S1–S4) showcased possibilities of different technologies and layouts. In conclusion, S1 did not have the means to adapt to rising prices while S2, S3 and S4 managed to perform better with higher flexibility for electricity import and export. Higher efficiency of hydrogen technologies and their commercial availability would further decrease the operational costs. However, with already existing technologies and their efficiencies, adequate dimensioning and electricity-to-heat ratios can make an industry facility resilient to market price changes. Decoupling of electricity and heat production through usage of boiler was proven as a better option than concurrent production from fuel cell. Results presented in the paper should be taken somewhat conservatively. Some of the analysed scenarios are made assuming future hydrogen technologies' development as well as their future performance. Although these assumptions are backed up by the literature, it is uncertain how these technologies will develop in reality. Future price trends are impossible to predict; the price of gas and electricity might stagnate at current levels or return to former values. For these reasons the values in the analyses should not be considered as estimates or predictions, but rather as sensitivity analyses covering various future alternatives. There are also future possibilities for participation in different energy spot markets, for example on ancillary services, balancing or intraday markets, where internal flexibility can be further exploited for profit. This would, even more, built the case for the transition to hydrogen due to its flexibility potential, however, such analyses are out of the scope of this paper and part of future work. Another limitation of the paper is omitting the uncertain nature of PV production. Including PV uncertainty would make an impact on the results but could also push hydrogen layout scenarios to even higher profitability, once again, due to the additional flexibility they can provide. Hydrogen layouts would have an easier time compensating for the intermittent nature of PV production to reduce charges for the imbalance such production might create. Further flexibility provision is something that we plan to investigate in our future work.

6. Conclusion

The paper proposes an optimisation model and brings systematic analysis of decarbonisation strategy for multi-energy intensive industrial consumers replacing natural gas with emerging hydrogen technologies. Various different hydrogen layouts are presented and compared to traditional natural gas based layout. They consist of electrolysers with different efficiencies, hydrogen storage and a combination of fuel cell and hydrogen boiler for heat production. The models of different industry facility setups are cast as mixed integer linear optimisation model considering price responsive demand response process scheduling and energy device scheduling to satisfy consumption needs. Sensitivity analysis is conducted on the basis of different prices of electricity and natural gas comparing total costs of industrial plants with different layouts. The main findings are the following:

1. For lower electricity prices (average of 90 and 180 €/MWh) and higher natural gas prices (180 to 270 €/MWh), hydrogen layout brings lower costs in all cases compared to natural gas layout,
2. Newer hydrogen technology with higher efficiency and with fuel cells designed for higher electricity production reaches lower costs when compared with natural gas technology in 58% of the observed cases,
3. Combination of local renewables and flexibility from hydrogen technologies makes the industrial facility more resilient to energy price increases, seen as a less steep slope on sensitivity analysis figures,
4. Integration of hydrogen technologies significantly decreases total CO_2 emissions of the industrial facility are between 30% and 85% (depending on electricity trading policy and size of PV), as well as it completely removes all local greenhouse gas emissions (CO_2, NO_x and CO),
5. Hydrogen technology flexibility can increase the level of self-supply as it can bridge the difference between local consumption and production as well as help with the integration of renewable energy sources.

CRediT authorship contribution statement

Matija Kostelac: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Resources, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Ivan Pavić:** Writing – review & editing, Validation, Supervision, Resources, Methodology, Formal analysis, Conceptualization. **Tomislav Capuder:** Writing – review & editing, Validation, Supervision, Resources, Project administration, Methodology, Funding acquisition, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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