

Optimised sizing and operational dispatch of grid-connected PEM electrolysers for hydrogen-fired gas turbines using a multi-objective framework: A HyCoFlex case study

Nikolaos Skordoulias^a, Sotirios Karellas^b

^a *Laboratory of Thermal Processes, Thermal Engineering Section, School of Mechanical Engineering, National Technical University of Athens (NTUA), Athens, Greece, nskordoulias@mail.ntua.gr, CA*

^b *Laboratory of Thermal Processes, Thermal Engineering Section, School of Mechanical Engineering, National Technical University of Athens (NTUA), Athens, Greece, sotokar@mail.ntua.gr*

Abstract:

Thermal power plants, particularly gas turbines, play a crucial role in maintaining the resilience of electricity grids by balancing the variability of renewable energy generation. However, they predominantly rely on fossil fuels, such as natural gas, highlighting the urgent need to decarbonize thermal power generation. One promising pathway is the use of hydrogen produced via water electrolysis powered by renewable electricity, offering a sustainable alternative fuel for these plants. In this study, a novel two-level, multi-objective optimisation framework is developed that simultaneously optimises the design and operation of a PEM electrolyser system supplying hydrogen to an advanced hydrogen-fired gas turbine. The inner optimisation loop focuses on operational strategies, minimising operating costs subject to technical and sizing constraints. The outer loop performs system sizing and planning, identifying optimal capacities for the PEM electrolyser. By integrating these two levels, the framework yields Pareto-optimal system configurations that balance short-term operational expenditures with long-term economic performance indicators, including the Levelised Cost of Hydrogen (LCOH). The methodology is applied to the HyCoFlex pilot-scale facility, featuring an advanced 12 MW SGT-400 hydrogen-fired gas turbine, to determine cost-effective pathways for meeting a defined hydrogen demand. Two hydrogen-demand scenarios, 50% and 100% H₂ vol blends, were analysed, yielding optimal electrolyser capacities of 8 MW and 45 MW, with LCOH values of 5.29 €/kg and 5.26 €/kg, respectively, all compliant with RFNBO carbon-intensity criteria.

Keywords:

Cogeneration; Dynamic simulations; Hydrogen; Levelised Cost of Hydrogen; Optimisation; PEM electrolysis.

1. Introduction

Gas turbines play a crucial role in ensuring the stability and reliability of modern power systems by balancing the variability and intermittency of Renewable Energy Sources (RES)[1,2]. Their fast ramping capabilities make them well-suited to respond to fluctuations in electricity supply and demand. However, gas turbines predominantly rely on fossil fuels, such as natural gas, contributing to greenhouse gas emissions and hindering the transition to fully decarbonised energy systems.

Hydrogen has emerged as a promising alternative fuel, offering the potential for low-carbon or even carbon-free power generation when produced from renewable electricity[3–6]. Despite its advantages, the large-scale deployment of hydrogen faces significant challenges, particularly related to its high production cost and the availability of sufficient quantities to meet industrial demand[7].

In this context, the development of advanced methodologies and optimisation frameworks for the optimal sizing and dispatch of hydrogen production systems is essential. Such approaches can reduce overall system costs, improve operational efficiency, and ensure that hydrogen infrastructure is neither under- nor over-dimensioned, thereby supporting its effective integration into future energy systems.

The novelty of this study lies in extending the existing literature through the development of a detailed dynamic PEM electrolyser model that captures partial-load behaviour, multiple operating states, and state transition dynamics, enabling a more accurate assessment of hydrogen integration in cogeneration systems. Furthermore, a comprehensive two-level optimisation framework is proposed, allowing for the simultaneous optimisation of electrolyser sizing and dispatch to meet the hydrogen demand of advanced gas turbines, while effectively balancing long-term objectives, such as the Levelised Cost of Hydrogen (LCOH), with short-term operational costs. Finally, the framework is validated using real-world data and boundary conditions from the HyCoFlex pilot Power-to-H₂-to-Power facility in Saillat-sur-Vienne, France.

2. Methodology

2.1. PEM electrolyser modelling

The objective of this paper is the development of a mathematical optimisation framework for the joint optimal sizing and dispatch of a PEM electrolyser unit to cover the hydrogen demand in an advanced gas turbine that can operate with H₂ blends up to 100% vol. For the dynamic operation of the PEM electrolyser unit, a multi-state electrolyser model at module level was developed based on the technical specifications of the Siemens Energy Silyzer 200 unit installed on-site. Each electrolyser module is composed of several stacks supported by a dedicated power supply system, comprising rectifiers and transformers, converting AC to DC and operational electrolyser voltage and shares a common Balance of Plant (BoP), which includes water pumps, water purification, a control system, heat exchangers, water–gas separators, and gas dryers.

The model can also be expressed in a Mixed Integer Linear Programming (MILP) compatible formulation, enabling seamless integration into system sizing and operational dispatch optimisation algorithms. It captures multiple operating states (on, standby, and off) and corresponding time transitions (coldstart, hot start), while also incorporating variable specific energy consumption as a function of power load and minimum partial-load constraints to ensure safe operation. The electrolyser module is represented as operating in three distinct states:

- Off state, δ_{off}^i : The electrolyser is fully depressurised at ambient temperature and pressure, with no hydrogen production and zero power consumption.
- Standby state, δ_{stb}^i : The electrolyser module remains pressurised and at operating temperature but is not producing hydrogen. Power consumption in this state is set to 1% of the rated power, according to literature and project data.
- On state, δ_{on}^i : The electrolyser module is fully pressurised and operational, capable of producing hydrogen within a load range of 30% to 100% of its rated power. At system level the minimum power load is equal to 10%, enabling one of the modules to operate at minimum partial load, and thus increasing flexibility and modularity. Conversion efficiency at the module level varies with power load, as shown in **Figure 1**.

Given these operational states, a hot start is defined as the process of transitioning from a standby state to on state, while a cold start refers to the process of transitioning from off state to on state. The time required for the electrolyser stack to perform cold start and hot start are considered equal to 30 min and 3 min respectively, according to project and literature data[8,9].

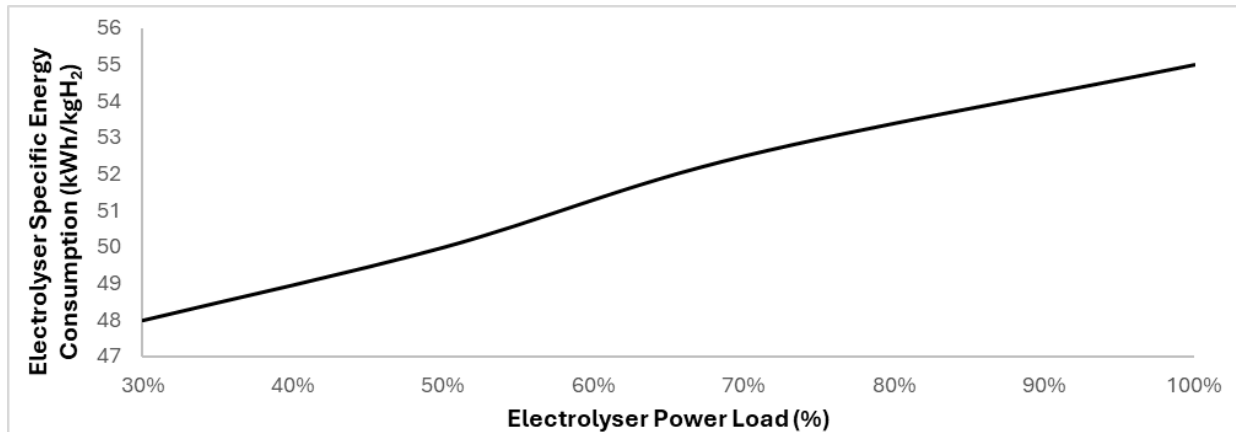


Figure 1. PEM electrolyser specific energy consumption with power load at module level

To formulate the mathematical description of the state transition, we first define three indicator binary variables δ_{on}^i , δ_{stb}^i , δ_{off}^i for on, standby and off states. It should be noted that the transition is a dynamic process, and

these variables are time-dependent. The electrolyser dynamic model is presented in the following equations, where i refers to the timestep of the simulation (1h).

$$\begin{aligned} P_{elec}^{min} \leq P_{elec}^i \leq P_{elec}^{rated} &\leftrightarrow \delta_{on}^i = 1 \\ P_{elec}^i = P_{elec}^{stb} &\leftrightarrow \delta_{stb}^i = 1 \\ P_{elec}^i = 0 &\leftrightarrow \delta_{off}^i = 1 \end{aligned} \quad (1)$$

$$\delta_{off}^i + \delta_{stb}^i + \delta_{on}^i = 1 \quad (2)$$

$$\delta_{coldstart}^i = \delta_{off}^{i-1} \cdot \delta_{on}^i \quad (3)$$

$$\delta_{hotstart}^i = \delta_{stb}^{i-1} \cdot \delta_{on}^i \quad (4)$$

Eq (1) links at each timestep i the electrolyser power consumption to each one of the three operation states: on state ($\delta_{on}^{i,k} = 1, \delta_{stb}^{i,k} = 0, \delta_{off}^{i,k} = 0$) where the power of the electrolyser is between minimum and rated power, standby state ($\delta_{on}^{i,k} = 0, \delta_{stb}^{i,k} = 1, \delta_{off}^{i,k} = 0$) where the power of the electrolyser is equal to standby power consumption and off state ($\delta_{on}^{i,k} = 0, \delta_{stb}^{i,k} = 0, \delta_{off}^{i,k} = 1$) where the power of the electrolyser is zero. Eq (2) ensures that the electrolyser is only in one of the three operation states at each timestep (1h). Eq (3) and (4) introduce binary variables that indicate cold start ($\delta_{coldstart}^i = 1$) and hot start ($\delta_{hotstart}^i = 1$) respectively. The automation and time transitions are illustrated in **Figure 2**.

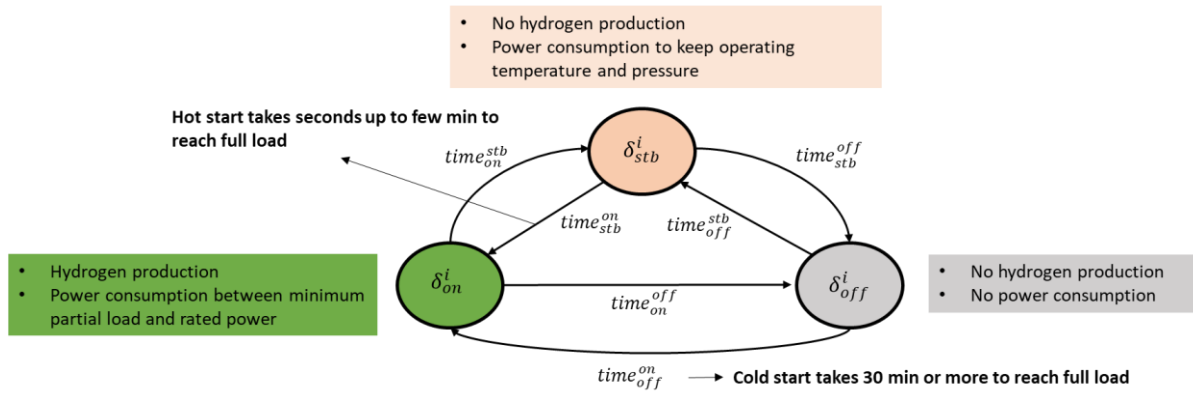


Figure 2. Electrolyser multi-state dynamic model and state transitions.

For the accurate calculation of hydrogen production from each electrolyser module at on state, a varying efficiency with electrolyser power load is considered. The errors arising from the use of static electrolyser efficiency can be substantial, particularly when the electrolyser operates under dynamic conditions, such as when operated dynamically according to day-ahead grid prices[8,10,11]. Models that incorporate load-dependent (power-varying) efficiency provide a significantly more accurate representation of system performance. The Beginning of Life (BOL) efficiency of each electrolyser module including Balance of Plant and Power Electronics (BOP & PE) consumption, expressed as specific energy consumption in kWh/kgH₂ at each timestep i calculated based on eq (5)

$$SEC_{system}^i = \left(-a \cdot \left(\frac{P_{elec}^i}{P_{elec}^{rated}} \right)^2 + b \cdot \left(\frac{P_{elec}^i}{P_{elec}^{rated}} \right) + c \right) \quad (5)$$

$$\dot{m}_{H_2}^i = \frac{P_{elec}^i}{SEC_{system}^i} \quad (6)$$

$$H_t = \sum_{i=1}^{i=8760} \dot{m}_{H_2}^i \quad (7)$$

The coefficients utilised in eq (5) to model the change of specific energy consumption with power load are based on a 2nd order polynomial equation fitted in MATLAB through the polyfit function with a coefficient of determination R²=0.99. The data points for fitting the 2nd order polynomial equation are derived from electrolyser s technical sheets (**Figure 1**). Eq (6) calculates the amount of hydrogen produced from the electrolyser at each timestep i based on the power consumption including partial load specific energy

consumption at system level. The annual hydrogen production from the electrolyser is calculated according to eq (7).

2.2. Mathematical formulation of two-level optimisation algorithm

A two-level optimisation algorithm, as shown in **Figure 3**, has been developed to jointly optimise sizing and dispatch of the electrolyser component and reveal the interaction between system planning and operation strategies.

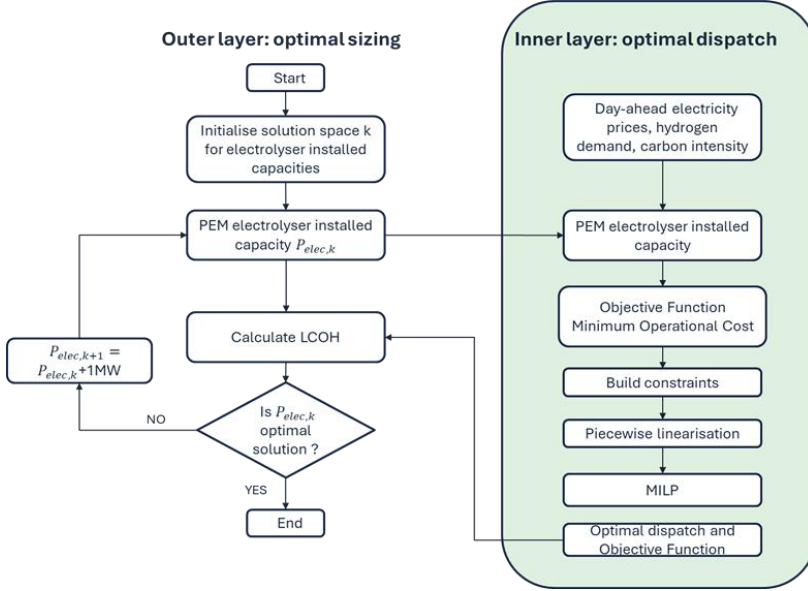


Figure 3. Two-level optimisation algorithm for optimal sizing and dispatch of PEM electrolyser

The outer optimisation layer addresses the trade-off between long-term economic performance and short-term operational objectives. Its primary goal is to determine the optimal PEM electrolyser capacity (installed power), within a pre-specified installed capacity solution space, that minimises both the lifetime Levelized Cost of Hydrogen (LCOH) and the overall objective function, eq(8), thereby ensuring an optimal balance between capital investment and operational efficiency throughout the system's lifetime while meeting hydrogen demand for the industrial cogeneration system with advanced gas turbine.

$$\min_{P_{rated}^{elec}} = \{LCOH, OBJ\} \quad (8)$$

$$10 \text{ MW} \leq P_{rated}^{elec} \leq 65 \text{ MW} \quad (9)$$

The inner-layer algorithm operates at an hourly resolution, optimising the dispatch strategy of the PEM electrolyser, specifically its power load and operational state, to minimise operational costs (OBJ, eq (10)) within a predefined time horizon, which can be set on a daily, monthly, or annual basis depending on the analysis scope.

$$\min_{OBJ} = \sum_{i=1}^{i=TW} C_{water}^i \cdot \delta_{on}^i + SRC \cdot \delta_{on}^i + C_{coldstart} \cdot l_i \cdot \delta_{coldstart}^i + C_{hotstart} \cdot l_i \cdot \delta_{hotstart}^i + l_i \cdot P_{elec}^{rated} \cdot (P_{grid}^i + FT_{grid}^i) \cdot (\delta_{on}^i + \delta_{stb}^i) \quad (10)$$

In eq (10), the first term includes the hourly water cost of the electrolyser (€/h) when the electrolyser is in on state ($\delta_{on}^i=1$). The hourly water cost is calculated in eq (11).

$$C_{water}^i = SC_{water} \cdot W_{cons} \cdot \dot{m}_{H_2}^i \quad \forall i \quad (11)$$

Here, SC_{water} is a fixed value representing the deionised water cost per cubic meter (€/m³) of deionised water consumed, W_{cons} is a fixed value representing the feed water consumption per kilogram of hydrogen produced (m³/kgH₂) and $\dot{m}_{H_2}^i$ is the hourly hydrogen production (kgH₂/h) according to eq (6).

To reveal the non-linear relationship between specific energy consumption at system level SEC_{system}^i and electrolyser power load l^i and keep the model in a MILP formulation a piece-wise linearisation is performed. Ten breakpoints are introduced to divide the curve into multiple linear segments, improving the accuracy of the estimated hydrogen production, especially at part load, while maintaining the linearity of the problem[10]. Then any point (SEC_{system}^i, l^i) within a certain piece can be estimated by a linear combination of the the two terminal points as shown in eq (12) and eq (13). The sum of the weights should be one and the weights should be non-negative as presented in eq (14).

$$SEC_{system}^i = \sum_b w_b^i \cdot SEC_{system}^b \quad \forall i \quad (12)$$

$$l^i = \sum_b w_b^i \cdot l_b \quad \forall i \quad (13)$$

$$w_b^i \geq 0, \sum_b w_b^i = 1 \quad \forall i \quad (14)$$

However, eq (12) and eq (13) are applicable only to the on state (δ_{on}^i) and therefore two ancillary variables δ_{SEC}^i and δ_l^i are introduced to release the constraints for standby state and off state. The M here is a sufficiently large constant, which could also be chosen as the electrolyser rated power.

$$SEC_{system}^i = \sum_b w_b^i \cdot SEC_{system}^b + \delta_{SEC}^i \quad \forall i \quad (15)$$

$$l^i = \sum_b w_b^i \cdot l_b + \delta_l^i \quad \forall i \quad (16)$$

$$-(\delta_{stb}^i + \delta_{off}^i) \cdot M \leq \delta_{SEC}^i, \delta_l^i \leq (\delta_{stb}^i + \delta_{off}^i) \cdot M \quad \forall i \quad (17)$$

The second term in eq (10) considers the hourly cost of degradation SRC (€/h), which occurs when the electrolyser is in on state. Due to the current lack of available information regarding the degradation effect due to frequent on/off cycles, SRC can be expressed as the cost of stack refurbishment SR (€) divided by the expected lifetime of this component SL (h), which will take place when the electrolyser is in on state (δ_{on}^i equal to 1).

$$SRC = \frac{SF}{SL} \quad \forall i \quad (18)$$

The third term in eq (10) accounts for the hourly cost (€/h) during the cold start up process, acting as a cost penalty for frequent cold start cycles. So, if the electrolyser is at off state during the previous timestep (i-1) and at on state during the current timestep (i) a cold startup has occurred that leads to additional operational costs.

$$C_{coldstart} = \frac{time_{off}^{on}}{1h} \cdot C_{off-on} \quad \forall i \quad (19)$$

In eq (19), the term $time_{off}^{on}$ refers to the time required for a cold start (off to on state) divided by the simulation timestep (1h) and the second term refers to a fixed cost for the cold startup process (€/h), calculated according to the amount of hydrogen lost during the cold start process[8,12,13].

The fourth term in eq (10) accounts for the hourly cost (€/h) during the hot start up process as electrolyser is, acting as a cost penalty for frequent hot start cycles. So, if the electrolyser is at standby state during the previous timestep (i-1) and at on-state during the current timestep (i) a hot startup has occurred that leads to additional operational costs.

$$C_{coldstart} = \frac{time_{stb}^{on}}{1h} \cdot C_{stb-on} \quad \forall i \quad (20)$$

In eq (20), the term $time_{stb}^{on}$ refers to the time required for a hot start (standby to on state) divided by the simulation timestep (1h) and the second term refers to a fixed cost for the hot startup process (€/h), calculated according to the amount of hydrogen lost during the cold start process[8,12,13].

The fifth term in eq (10) accounts for electrolyser electricity costs from the wholesale electricity market in each timestep (i) for both on and standby states, as the electrolyser consumes electricity in both cases. The hourly energy cost (€/h), which is the sum of the day-ahead electricity price P_{grid}^i (€/MWh) and variable grid charges FT_{grid}^i (€/MWh) multiplied by the electrolyser power consumed for both on and standby states.

In addition to the minimisation function, the following equations need to be considered as constraints to calculate the optimal dispatch of the plant:

$$\sum_{i=1}^{i=TW} \dot{m}_{H_2}^i \cdot \delta_{on}^i = HD \quad (21)$$

$$E_{import,grid}^i - P_{elec}^{rated} \cdot l^i \cdot \delta_{on}^i - P_{elec}^{stb} \cdot \delta_{stb}^i = 0 \quad \forall i \quad (22)$$

$$\delta_{on}^i + \delta_{stb}^i + \delta_{off}^i = 1 \quad \forall i \quad (23)$$

$$\sum_{i=1}^{i=TW} \delta_{coldstart}^i \leq N \quad (24)$$

$$\delta_{stb}^i \cdot \delta_{off}^{i-1} = 0 \quad \forall i \geq 1 \quad (25)$$

$$\delta_{off}^i \cdot \delta_{stb}^{i-1} = 0 \quad \forall i \geq 1 \quad (26)$$

$$l^i - \delta_{on}^i \leq 0 \quad \forall i \quad (27)$$

$$-l^i + MTR \cdot \delta_{on}^i \leq 0 \quad \forall i \quad (28)$$

$$0 \leq l^i \leq 1 \quad \forall i \quad (29)$$

$$E_{import,grid}^i \leq \delta_{import,grid}^i \cdot P_{elec}^{rated} \cdot l^i \quad \forall i \quad (30)$$

Eq (21) imposes that hydrogen production is equal to a pre-defined hydrogen demand for the established time window, HD.

Furthermore, eq (22) introduces the energy balance that needs to be maintained every hour. At each hourly timestep the total amount of power consumed from the electrolyser at on and standby states is equal to the amount imported from the grid. Eq (23) ensures that the electrolyser is in one of the three operation states at each timestep. Eq (24) limits the number of possible cold start-ups during TW, while Eq (25) and (26) restrict transitions from 'off state' to 'standby state' and vice versa. Eqs (27)-(29) impose that the electrolyser load at each hourly timestep is between minimum turndown ratio at system level (10% of rated power) and nominal power (100% of rated power) during production (on state), while it will assume a value of 0 if it is in 'off' or 'standby' states. Finally, eq (30) indicates that power imported from grid is always equal or below electrolyser demand.

Eqs (10)-(30) constitute a Mixed Integer Non-Linear Programming (MINLP) formulation, which after piecewise linearisation can be reformulated to a MILP problem which can be solved for each TW using the Gurobi solver in MATLAB environment. The main decision variables to be calculated are the states of operation of the electrolyser ($\delta_{on}^i, \delta_{stb}^i, \delta_{off}^i$) for each hour, the electrolyser load factor l^i and power consumption P_{elec}^i and the amount of hydrogen produced $\dot{m}_{H_2}^i$.

2.3. Annual performance indicators

LCOH is the key focus of modelling, as it is used as the basis for electrolyser sizing. This approach aligns with numerous studies that use LCOH as the primary metric for assessing the economic feasibility of green hydrogen production and utilization systems. LCOH is calculated based on eq (31) and represents the total discounted present cost of producing hydrogen, over the lifetime of the system, in units of €/kgH₂. The costs for each aspect of the overall system and its components are broken down into initial capital expenditure (CAPEX), annual operational expenditure (OPEX) including operation and maintenance as well as electricity and water costs. For the purpose of this work, a discount rate of 10% is assumed for the electrolyser as well as an economic lifetime of 20 years, similar to other studies[8,12,13]. The cost of stack replacement after 80.000 h of operation or maximum after 10 years is also considered in the calculation of LCOH.

$$LCOH = \frac{CAPEX_{elec,0} + \sum_0^t \frac{RC_t + OPEX_t + O\&M_{elec,t} + WC_t}{(1+r)^t}}{\sum_0^t \frac{H_t}{(1+r)^t}} \quad (31)$$

Where, t is the economic lifetime of the project (years), r is the interest rate (%), $CAPEX_{elec,0}$, is the capital expenditure for the PEM electrolyser at year 0, including stacks, balance of plant equipment (water-gas

separators, water purification, power electronics, heat exchangers, water pump and gas dryer) and EPC costs (€), RC_t , is the electrolyser stack replacement cost at year t (€), $OPEX_t$, is the electricity cost at year t (€), $O\&M_{elec,t}$, is the electrolyser fixed operation and maintenance cost at year t (€), WC_t , is the demineralized water cost at year t (€), H_t , is hydrogen production at year t (kgH₂). The main technoeconomic parameters of the system are presented in **Table 1**.

Table 1. Technoeconomic specifications for the case study.

Parameter	Units	Value
Specific CAPEX	€/kW	1646
Specific OPEX	$\frac{\text{€}}{\text{kW}}/\text{year}$	27.33
Stack Refurbishment Cost	€/kW	544.80
Demin Water Cost	€/m ³	1.26
Variable Grid Charges ¹	€/MWh	6.61
Fixed Grid Charges	$\frac{\text{€}}{\text{kW}}/\text{year}$	37.464
Lifetime	h	80000
Minimum power load at module level	%	30
Minimum power load at plant level	%	10
Demin Water consumption	kg _{H2O} /kg _{H2}	11
Cold start time	min	30
Cold start cost	€/h	98
Maximum number of cold starts per year	–	3000
Hot start time	min	3
Hot start cost	€/h	10

Apart from the LCOH, in this chapter two additional annual performance indicators are defined in order to assess the different scenarios and dispatch strategies from a technical and environmental perspective.

$$CF_{elec,t} = \frac{\sum_{i=1}^{i=8760} \dot{m}_{H_2}^i}{\frac{P_{elec}^{rated}}{SEC_{system}^{rated}} \cdot 8760} \cdot 100\% \quad (32)$$

Eq (32) defines the annual electrolyser capacity factor (%), which is the percentage of the actual amount of hydrogen produced within a full-year of operation compared to the amount of hydrogen that it would be produced if the system was operated at its rated power.

$$CI_{H_2,t} = \frac{\sum_{i=1}^{i=8760} C_{grid}^i \cdot E_{import,grid}^i}{\sum_{i=1}^{i=8760} \dot{m}_{H_2}^i} \quad (33)$$

Finally, eq (33) defines the annual hydrogen carbon intensity (kgCO₂-eq/kgH₂), calculated as the sum of energy imported from the grid at each timestep ($E_{import,grid}^i$) multiplied by the time-varying French electricity grid carbon intensity C_{grid}^i based on [14], divided by the total annual hydrogen production.

¹ Variable grid charges consist of 4.14 €/MWh for public service obligations and 2.47 €/MWh for RES.

To demonstrate the applicability of the proposed two-level optimisation algorithm, it was implemented in a case study based on the operational boundary conditions of the HyCoFlex pilot-scale facility. In this case, the PEM electrolyser is assumed to participate in the French day-ahead electricity market, with the objective of identifying the optimal system size and dispatch strategy that minimise total costs while satisfying the hydrogen demand of the cogeneration unit. Two hydrogen demand scenarios are considered based on detailed heat and mass balances that quantified on hourly basis the hydrogen and natural gas demand for different hydrogen blends at cogeneration unit 100% power load.

- Scenario 1: 50% vol H₂ blend, corresponding to an annual hydrogen demand of 1,139 tpa.
- Scenario 2: 100% vol H₂ blend, corresponding to an annual hydrogen demand of 5,624 tpa.

Historical hourly day-ahead electricity prices (€/MWh) and carbon intensity values (kgCO₂eq/kWhe) for the French power grid were obtained from the ENTSO-E Transparency Platform for the year 2024[14] (**Figure 4** and **Figure 5**) and used as input time series for the analysis.

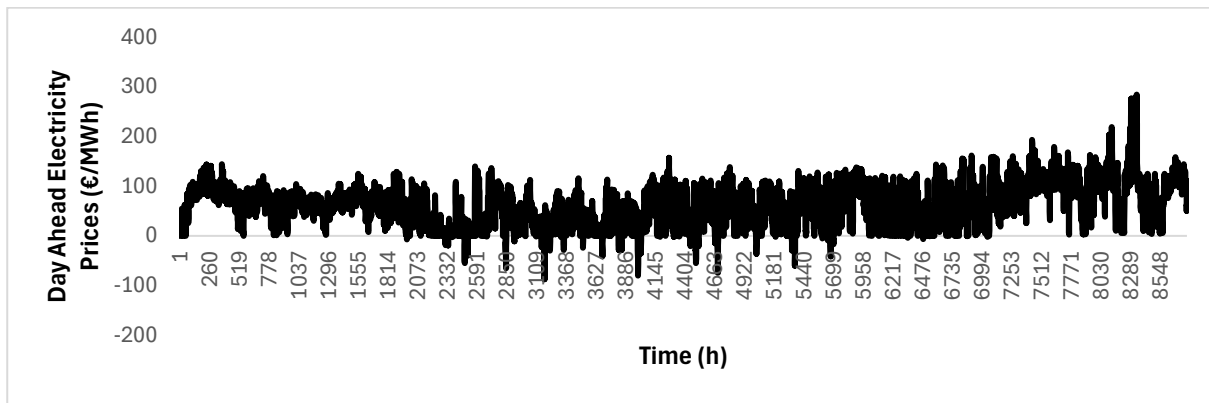


Figure 4. Historical hourly day-ahead prices, France 2024, ENTSO-E[14].

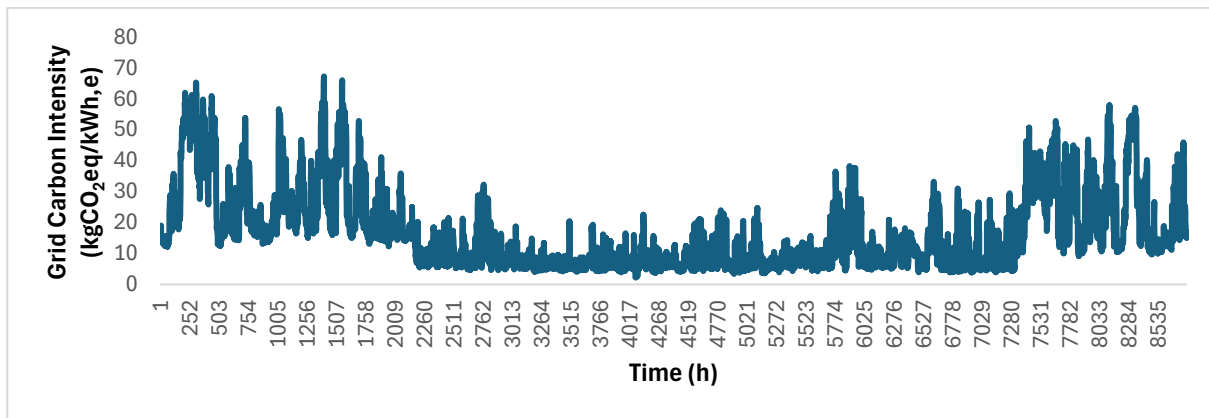


Figure 5. Historical hourly carbon intensity, France 2024, ENTSO-E[14]

3. Results

3.1. Impact of electrolyser size on LCOH, operational costs and carbon intensity

The impact of PEM electrolyser size in the LCOH, operational costs and hydrogen carbon intensity for the two hydrogen demand scenarios is presented in this section. It is worth noting that, due to the low carbon intensity of the French electricity grid, all simulated scenarios comply with the requirements of the latest delegated act[15,16] for classifying hydrogen as a Renewable Fuel of Non-Biological Origin (RFNBO). In every case, the resulting carbon intensity $CI_{H_2,t}$ of hydrogen production remains well below the threshold of 3.38 kgCO₂eq/kgH₂ and has values below 0.9 kgCO₂eq/kgH₂.

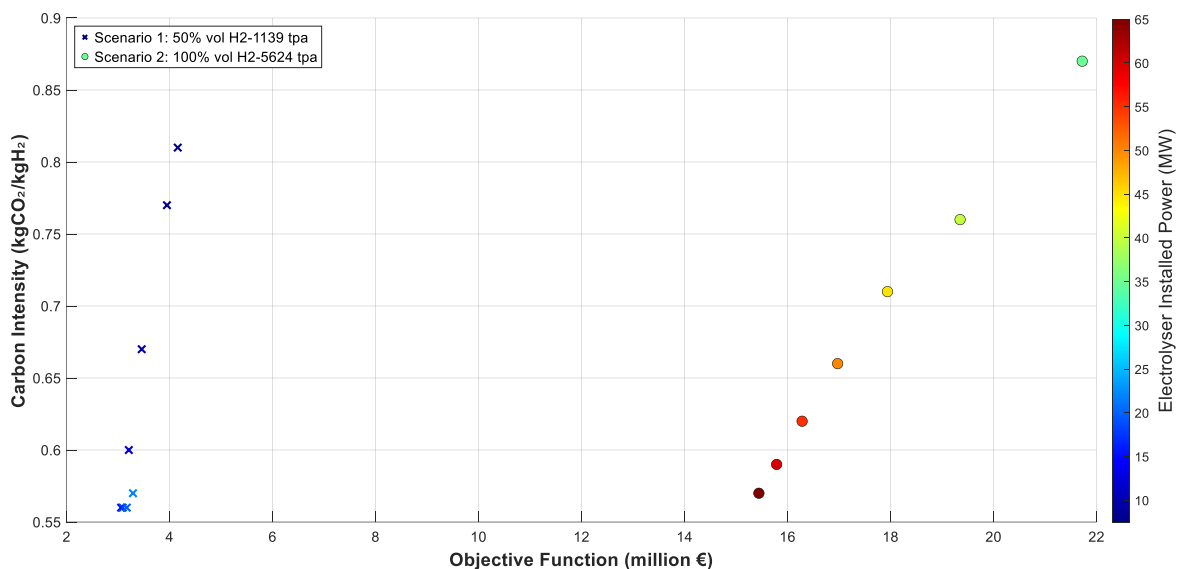


Figure 6. Impact of PEM electrolyser size on operational costs (objective function) and hydrogen carbon intensity for the two hydrogen demand scenarios (x marks represent Scenario 1, while dots represent Scenario 2)

A reduction in operational costs and hydrogen carbon intensity is observed as the PEM electrolyser capacity increases (**Figure 6**), since larger units operate at lower capacity factors and therefore require fewer operating hours to meet the same hydrogen demand for the cogeneration unit reducing electricity and water consumption costs. A comparison between Scenario 2 and Scenario 1 shows that higher hydrogen demand requires significantly larger installed PEM electrolyser capacities, in the range of 35–65 MW, which is nearly twice the capacity required under the low-demand scenario. In addition, operational costs increase by approximately 75%.

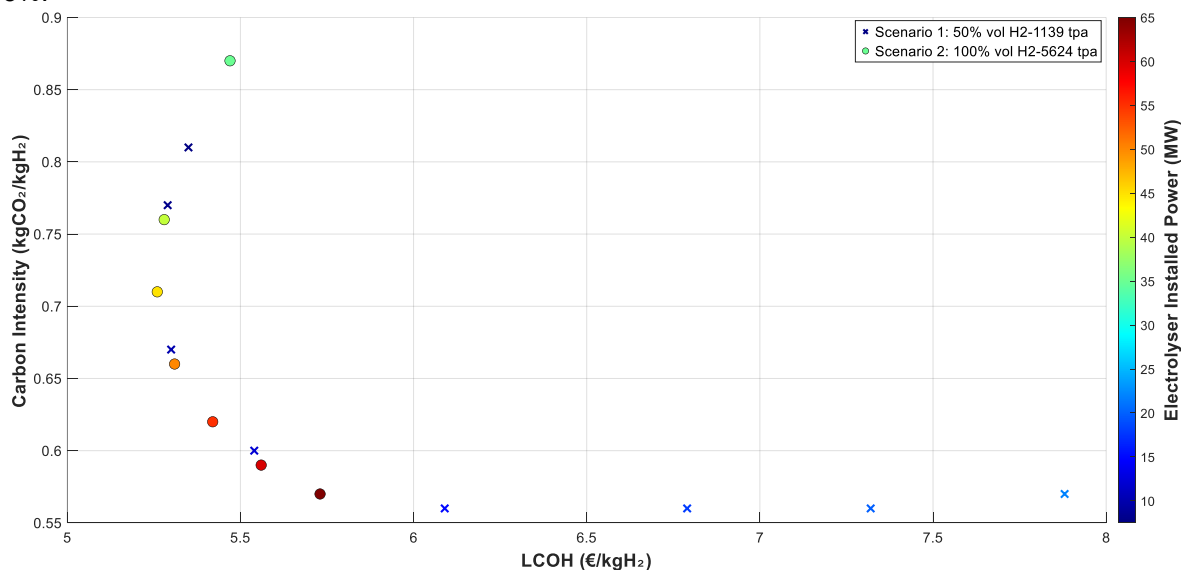


Figure 7. Impact of PEM electrolyser size on LCOH and hydrogen carbon intensity for the two hydrogen demand scenarios

As the PEM electrolyser size grows (moving from right to left in **Figure 7**), the LCOH exhibits an optimal point where the balance between CAPEX and OPEX minimises the overall production cost. Beyond this point, further increases in electrolyser capacity lead to higher LCOH values, as the CAPEX rise outweighs the operational cost savings achieved through improved flexibility and the capability of the electrolyser to exploit price arbitrage opportunities.

For the high hydrogen demand scenario (Scenario 2, 100% H₂ vol), the optimal PEM electrolyser capacity is 45 MW, resulting in an LCOH of 5.26 €/kgH₂, an annual operating cost of 17.9 Million €, a hydrogen carbon intensity of 0.71 kgCO₂eq/kgH₂ and a capacity factor of 77%. In contrast, for the lower hydrogen demand case

(Scenario 1, 50% H₂ by volume, 1139 tpa), the optimal capacity is 8 MW, corresponding to an LCOH of 5.29 €/kgH₂ and an annual operating cost of 3.9 Million €. In this case the carbon intensity is 0.77 kgCO₂eq/kgH₂ and the capacity factor is 88%.

3.2. Optimal dispatch strategies

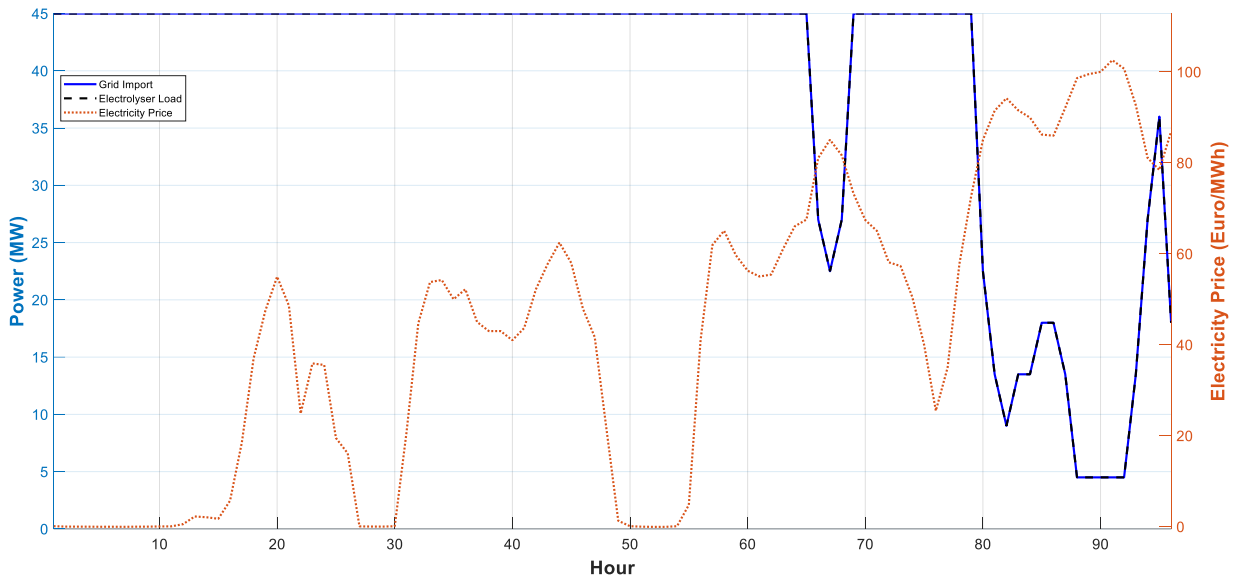


Figure 8. 45 MW PEM Electrolyser dispatch strategy for 96 hours, scenario 2 (5624 tpa, 100 %vol H₂)

Overall, PEM electrolyser operates in a dynamic way, taking advantage of price opportunities ramping up and down its power load in order to reduce operational costs. More specifically in **Figure 8**, the 45 PEM electrolyser operates at rated power when electricity prices are low (<65 €/MWh) producing cost-effective hydrogen to cover demand. At time periods with moderate electricity prices (65-98 €/MWh) operates at partial load to benefit from the higher efficiency and reduce operational costs. Finally, at time periods with high electricity prices (>98 €/MWh) electrolyser ramps down and operates at minimum partial load to reduce exposure to high prices.

To further demonstrate the importance of appropriate system sizing and the effectiveness of the developed two-level optimisation framework, **Figure 9** presents the results for the 45 MW PEM electrolyser and its corresponding dispatch strategy under the low hydrogen demand scenario (Scenario 1, 1,139 tpa, 50% vol H₂).

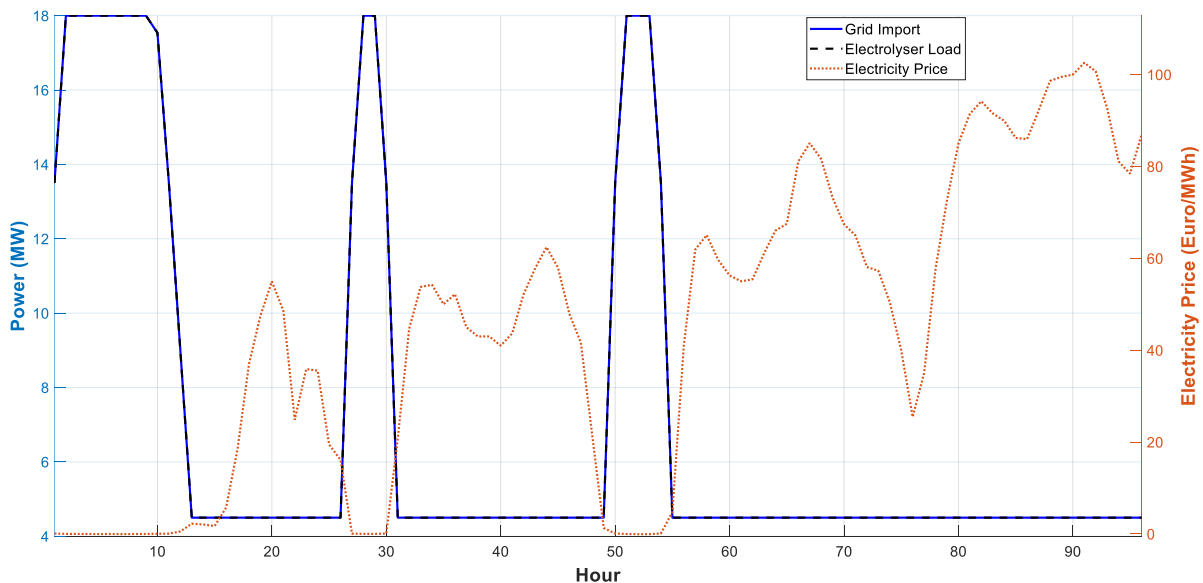


Figure 9. 45 MW PEM Electrolyser dispatch strategy for 96 hours, scenario 1 (1139 tpa, 50 %vol H₂).

The 45 MW PEM electrolyser is significantly oversized for the 50% H₂ blend, low hydrogen demand scenario, resulting in severe underutilization with a capacity factor of just 16%. Leading to an LCOH, 15.57 €/kgH₂ higher by 188% compared to the optimal case (8MW, LCOH=5.29 €/kgH₂). Optimal electrolyser sizing is highly sensitive to the maximum allowable hydrogen blending ratio of the cogeneration plant. An electrolyser dimensioned for 100% H₂ blending is not economically or operationally optimal when the system operates under 50% H₂ blending constraints.

4. Conclusion

This study presented a comprehensive mathematical optimisation framework for the joint optimal sizing and dispatch of a PEM electrolyser integrated with an advanced gas turbine system capable of operating with hydrogen blends up to 100% vol. A detailed multi-state dynamic model of the electrolyser was developed, capturing realistic operational behaviour through discrete states (on, standby, off), start-up dynamics, and load-dependent efficiency. The formulation was successfully transformed into a MILP-compatible structure, enabling its integration into a two-level optimisation algorithm that simultaneously addresses long-term investment decisions and short-term operational strategies.

The results highlight the critical importance of accurately representing electrolyser dynamics and efficiency variations under flexible operation. The proposed framework effectively captures the trade-offs between CAPEX and OPEX, identifying optimal electrolyser capacities that minimise the LCOH while ensuring demand satisfaction. It was demonstrated that optimal sizing is highly sensitive to the hydrogen demand level and, consequently, to the blending ratio of hydrogen in the gas turbine. Oversizing leads to significant underutilisation and substantial cost increases, whereas appropriately sized systems achieve high capacity factors and competitive hydrogen production costs.

Furthermore, the optimal dispatch strategies reveal that dynamic operation in response to electricity price signals is essential for cost minimisation. The electrolyser adjusts its load to exploit low-price periods, operates efficiently at partial load during moderate prices, and minimises exposure during high-price intervals. This flexibility enhances economic performance while maintaining low carbon intensity, with all examined scenarios complying with RFNBO requirements due to the low-carbon electricity mix of France.

Overall, the proposed modelling and optimisation approach provides a robust and scalable tool for the design and operation of hydrogen production systems coupled with thermal power generation. It offers valuable insights for supporting the transition towards decarbonised energy systems, where green hydrogen plays a key role in enhancing flexibility, reducing emissions, and enabling higher penetration of renewable energy sources.

Acknowledgement

The authors would like to acknowledge funding received within the framework of the HyCoFlex research project, funded by the Clean Hydrogen Partnership and its members Hydrogen Europe and Hydrogen Europe Research under Grant Agreement No. 101138002.

References

- [1] HYDROGEN GAS TURBINES ETN Global Report Hydrogen Gas Turbines-ETN Global, (2024).
- [2] HYDROGEN DEPLOYMENT IN CENTRALISED POWER GENERATION A techno-economic case study HYDROGEN DEPLOYMENT IN CENTRALISED POWER GENERATION-A TECHNO-ECONOMIC CASE STUDY | 2, (n.d.).
- [3] Y. Li, X. Han, Y. Zhang, N. Skordoulis, X. Guo, J. Yan, S. Karellas, E. Kakaras, A large-scale power-to-H₂-to-power system adopting hydrogen mixed gas turbine for wind accommodation: Process modeling, optimal dispatch and economic feasibility analysis, *Int. J. Hydrogen Energy* 145 (2025) 345–357. <https://doi.org/10.1016/j.ijhydene.2025.06.034>.
- [4] X. Liu, M. Bertsch, A.A. Subash, S. Yu, R.Z. Szasz, Z. Li, P. Petersson, X.S. Bai, M. Aldén, D. Lörstad, Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems, *Int. J. Hydrogen Energy* 47 (2022) 624–644. <https://doi.org/10.1016/j.ijhydene.2021.01.087>.

- [5] E. Yilmaz, G. Carayon, S. Garmadi, P. Mccaig, N. Parsania, B. Witzel, S. Hermeth, B. Beesley, F. Ferroudj, N. Skordoulias, S. Karellas, S. Energy, E. Solutions, HYFLEXPOWER Project: Power-to-H2-to-Power Demonstration with 100% Green Hydrogen in an SGT-400 Gas Turbine, E3S Web of Conferences 663 (2025) 01013. <https://doi.org/10.1051/e3sconf/202566301013>.
- [6] N. Skordoulias, E.I. Koytsoumpa, S. Karellas, Techno-economic evaluation of medium scale power to hydrogen to combined heat and power generation systems, *Int. J. Hydrogen Energy* 47 (2022) 26871–26890. <https://doi.org/10.1016/J.IJHYDENE.2022.06.057>.
- [7] A. Mati, A. Ademollo, C. Carcasci, Assessment of paper industry decarbonization potential via hydrogen in a multi-energy system scenario: A case study, *Smart Energy* 11 (2023) 100114. <https://doi.org/10.1016/j.segy.2023.100114>.
- [8] Y. Zheng, S. You, H.W. Bindner, M. Münster, Optimal day-ahead dispatch of an alkaline electrolyser system concerning thermal–electric properties and state-transitional dynamics, *Appl. Energy* 307 (2022) 118091. <https://doi.org/10.1016/J.APENERGY.2021.118091>.
- [9] Clean Hydrogen JU - SRIA Key Performance Indicators (KPIs) - European Commission, (2021). https://www.clean-hydrogen.europa.eu/knowledge-management/strategy-map-and-key-performance-indicators/clean-hydrogen-ju-sria-key-performance-indicators-kpis_en (accessed April 9, 2024).
- [10] M. Tobias Baumhof, E. Raheli, A.G. Johnsen, J. Kazempour, Optimization of Hybrid Power Plants: When Is a Detailed Electrolyzer Model Necessary?, (n.d.).
- [11] N. Skordoulias, S. Karellas, D. V. Lyridis, S.G. Giannissi, G. Mitkidis, RES-electrolyser coupling within TRIERES hydrogen valley – A flexible techno-economic assessment tool, *Energy Convers. Manag.* 327 (2025) 119562. <https://doi.org/10.1016/J.ENCONMAN.2025.119562>.
- [12] G. Matute, J.M. Yusta, J. Beyza, L.C. Correas, Multi-state techno-economic model for optimal dispatch of grid connected hydrogen electrolysis systems operating under dynamic conditions, *Int. J. Hydrogen Energy* 46 (2021) 1449–1460. <https://doi.org/10.1016/J.IJHYDENE.2020.10.019>.
- [13] G. Matute, J.M. Yusta, N. Naval, Techno-economic model and feasibility assessment of green hydrogen projects based on electrolysis supplied by photovoltaic PPAs, *Int. J. Hydrogen Energy* 48 (2023) 5053–5068. <https://doi.org/10.1016/J.IJHYDENE.2022.11.035>.
- [14] ENTSO-E Transparency Platform, (n.d.). <https://transparency.entsoe.eu/> (accessed March 31, 2025).
- [15] Delegated regulation - 2023/1185 - EN - EUR-Lex, (n.d.). <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023R1185&qid=1704969410796> (accessed November 4, 2024).
- [16] Delegated regulation - 2023/1184 - EN - EUR-Lex, (n.d.). https://eur-lex.europa.eu/eli/reg_del/2023/1184/oj/eng (accessed October 17, 2025).