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Unlocking nuclear flexibility through hydrogen production

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ABSTRACT

This paper proposes a novel strategy to enhance the profitability of long-term operated nuclear power plants during periods of low electricity market prices by co-producing hydrogen. The approach integrates a proton exchange membrane electrolyzer sized to utilize up to 50 % of the plant's nominal capacity (500 MW). This configuration effectively divides the nuclear facility into two conceptual units: a power-only plant and a combined hydrogen-and-power plant. The latter is capable of directing electricity to either the electrolyzer or the grid, depending on market conditions. The model employs real data from the Spanish day-ahead electricity market. Results show that, based on typical values for Spanish nuclear assets and market prices, a competitive levelized cost of hydrogen of 4.42 €/kg can be achieved. The analysis demonstrates that this combined hydrogen and power configuration significantly improves economic performance and provides a feasible pathway to enhance the competitiveness of nuclear assets in unfavorable electricity market conditions.

1. Introduction

In the current global context, the transition toward a sustainable energy system is essential to meet international climate commitments, such as those outlined in the Paris Agreement. Within this framework, nuclear energy can play a key role in the decarbonization process. However, the increasing integration of variable renewable energy (VRE) sources, such as wind and solar, poses significant challenges for nuclear power plants (NPPs), especially in markets where electricity prices frequently fall below the costs of generation. Projections indicate that VRE is anticipated to constitute 30 % of global electricity generation by 2030 [1], with estimates for Spain suggesting a level between 64 and 69 % [2]. The inherent variability associated with these renewable energy sources raises concerns regarding the stability of the power system and the continuous operation of nuclear facilities. This situation underscores the critical importance of nuclear flexibility in balancing the grid and preventing imbalances that could lead to blackouts in systems with high-renewable penetration [3]. A relevant case is the blackout that occurred in Spain in 2025, which affected millions [4] and exposed vulnerabilities within the existing power infrastructure, particularly in the context of the rising share of VRE. Far from being an isolated event, this incident serves as a clear indication of the necessity to enhance grid resilience and adopt strategies that provide flexibility and rapid response capabilities.

Recent evidence underscores a notable paradigm shift occurring within power systems globally: as the penetration of wind and solar energy increases, traditional baseload resources are yielding prominence to flexibility as the most highly valued attribute of the grid [5]. Countries such as Poland and Bulgaria have rapidly expanded wind and solar to above 20 % of generation, with days when PV exceeds 50 % of daytime demand. In Australia's National Electricity Market, the rapid development of VRE has coincided with increased curtailment, and frequent occurrences of zero or negative daytime prices. South Australia, in particular, has frequently experienced negative operational demand at midday due to distributed PV production [6] indicating that system operation must "flex" around renewables. In Germany, the Atomausstieg (nuclear power phase-out) concluded on April 15, 2023, with the decommissioning of the Isar 2, Emsland, and Neckarwestheim 2 reactors, after more than two decades of preparation. Since then, reliability of the power supply has increasingly depended on interconnections, demand-side measures, and flexible resources [7]. In the United Kingdom (UK), the 2024 coal phase-out has marked a decline in coal usage from approximately 40 % in 2012 to 0 % in 2024. Wind and solar energy, along with flexible gas resources, have effectively compensated for this decrease, resulting in record-low shares of fossil

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Nomenclature

Acronyms

AGR	Advanced gas reactor
BWR	Boiling water reactor
CHyP	Combined hydrogen and power
EHO	European Hydrogen Observatory
EPR	European Pressurized reactor
Gen III	Nuclear power plant of third generation
HTE	High temperature electrolysis
HTSE	High temperature steam electrolysis
HTR-PM	High temperature gas-cooled reactor-pebble-bed module
HTTR	High temperature engineering test reactor
IEA	International Energy Agency
LSCC	Liquid Salt Combined Cycle
LTE	Low temperature electrolysis
LTO	Long-term operation (referred to a nuclear power plant)
NPP	Nuclear power plant
NPV	Net present value
PEM	Proton exchange membrane electrolyzer
PHWR	Pressure heavy water reactor
POP	Power-only plant
PV	Photovoltaic
PWR	Pressurized-water reactor
SMR	Small modular reactor
SOFC	Solid oxide fuel cell
TES	Thermal energy storage
TRL	Technological readiness level
VRE	Variable renewable energy
VVER	Water water energetic reactor
WF	Wind farm

Symbols

$CAPEX_{ELY}$	Capital expenditure of the electrolyzer €/kg
$CAPOPEX_{feedstock}$	Capital and operational expenditures of the electricity supplied to the electrolyzer €/kg
CRF	Capital recovery factor 1/year
FC_E	Exported electricity capacity factor p.u.
FC_{H2}	Electrolyzer capacity factor p.u.
f_{om}	Expenditure factor of maintenance p.u.
f_{rs}	Expenditure factor of stack replacement p.u.
$\overline{g}$	Average consumption of the electrolyzer kWh/kg
H	Operation hours of the electrolyzer h/year
H_{stack}	Lifespan of the stack h
INV_{ELYe}	Specific investment of the electrolyzer €/kW
$LCOE$	Levelized cost of electricity of the nuclear power plant €/MWh
$LCOH$	Levelized cost of hydrogen €/kg
N	Lifespan of the Project years
$OPEX_{omELY}$	Operation and maintenance expenditure of the eletrolyzer €/kg
$OPEX_{repstack}$	Operation expenditure of replacement of the stack €/kg
$\overline{P}_{e,POP}$	Average equivalent price seen by POP due to the feed in tariff from the revenues of the hydrogen produced by the CHyP plant €/MWh
$P_{H2market}$	Market price of the hydrogen €/kg
$\overline{P}_{market}$	Average price of day-ahead market electricity price in the whole year €/MWh
$REVENUES_{surpluses}$	Revenues from electricity exported €/kg
$\overline{T}_{mp}$	Average market price of electricity produced when electrolyzer is off €/MWh
$wacc$	Weighted average capital cost p.u.
$\dot{W}_{ELY}$	Design power of the electrolyzer MW
$\dot{W}_{POP}$	Design power of the POP MW

fuels [8]. In Texas, the Electric Reliability Council of Texas, implemented the Contingency Reserve Service in June 2023 exemplifying the transition to a service-based remuneration model. This model prioritizes rapid, measurable flexibility for ramping and net-load management over the protection of inflexible capacity [9].

Within this framework, the appropriate policy and market-design response is to refrain from adding more baseload generation and, instead, to provide essential services such as dispatchable energy, frequency response, upward and downward reserves, and black-start capabilities [5]. This approach aligns with a systems perspective, whereby operating nuclear units with increased flexibility. Measures such as scheduling ramps, implementing load reductions during periods of high solar and wind generation, and offering regulation and reserves enhance the integration of VRE while safeguarding plant revenues. In [10], a representative high-flexibility case demonstrates that renewable curtailment can be reduced by 58 % and total operating costs can decline by 1.6 %. These findings underscore the importance of product and operational flexibility at scale.

Hydrogen production via electrolysis has emerged as a demand-side flexibility asset in energy systems, being capable of absorbing surplus renewable energy thereby mitigating the necessity for curtailment. Additionally, electrolysis can provide reserves by rapidly modulating consumption in response to system demands, whether by increasing or decreasing power usage as conditions require. Furthermore, it offers a viable means of chemical storage, enabling the decoupling of energy supply from demand over varied timescales (from hours to seasonal intervals) [11]. When applied to nuclear energy assets, [3] show that the integration of light water reactor (LWR) electricity and/or nuclear steam with electrolysis —potentially enhanced by thermal energy storage— can facilitate the operationalization of a synthetic baseload [5]. This integration has the potential to maintain reactor capacity factors at approximately 90 %, while achieving clean hydrogen production costs that are consistent with sub-2 $[1]/kg objectives. Moreover, such a synergistic approach stabilizes net load, promotes the large-scale integration of VRE, and enhances system resilience during periods characterized by low wind and low solar generation.

The synergy between nuclear energy and renewable sources is crucial for achieving cost-effective decarbonization. As shown in [12], integrating nuclear energy with VRE can lead to a reduction in system costs by as much as 30–50 $/MWh under deep decarbonization scenarios. Similarly, [13] highlights that high levels of VRE penetration, typically between 50–70 %, can increase costs due to the need for additional installed capacity and enhanced flexibility, reinforcing the role of nuclear as a stable and reliable energy source. In addition to these benefits, clean hydrogen emerges as a key energy vector for decarbonizing hard-to-abate sectors such as heavy industry, maritime transport, aviation, and refining. This is particularly relevant given that 97 million tonnes of hydrogen are currently produced each year, 99 % of which is derived from fossil fuel sources, resulting in significant greenhouse gas emissions [14].

The hydrogen approach has been developed by researchers such as Forsberg, who in [15] proposes that hydrogen produced through nuclear power could significantly contribute to the establishment of a sustainable energy economy. Furthermore, in [16], the author suggests nuclear co-production of hydrogen and oxygen for peak-time electricity

[1] $–€ parity (1 USD ≈ 1 EUR) is assumed for comparability.

generation using solid oxide fuel cells (SOFC), achieving efficiencies close to 70 %. In [17], this concept is further refined by eliminating the traditional boiler and directly injecting steam at 1500 °C — produced through the combustion of hydrogen, oxygen, and water— into high-temperature turbines. This technique facilitates a near-instantaneous response, essential for frequency regulation. As shown in [18], an hourly stochastic co-optimization can dynamically alternate between grid export and electrolysis based on specific price thresholds and process constraints, resulting in a higher net present value (NPV) than electricity-only operation. This strategy also encompasses the endogenous sizing of electrolyzer capacity and the selection of power-only plant (POP) or combined hydrogen-and-power (CHyP) plant dispatch rules. In addition, it includes the determination of hydrogen and thermal energy storage (TES) to maximize energy-price arbitrage and enhance revenues from system services.

This co-production strategy is already being explored in hybrid nuclear-renewable systems and may be applicable in markets characterized by high levels of renewable energy penetration, including Spain and others. For instance, an analysis of South Korea's 2030 renewable initiative [19] identified specific hours of the day, particularly during spring and autumn, when solar and wind generation consistently exceeds demand. These surplus periods can be directly leveraged by linking NPPs to hydrogen production. An electrolyzer functions as a controllable sink for excess electricity, thereby reducing renewable energy curtailment and smoothing net-load ramps without undermining nuclear availability. In line with this strategy, [20] proposes a flexible nuclear scenario for the UK, incorporating nuclear cogeneration with hydrogen to facilitate a high-VRE grid and achieve net-zero emissions by 2050. Moreover, a practical example can be found in North Dakota (USA), described in [21]. This system integrates wind and nuclear energy to produce hydrogen, which is subsequently supplied to Chicago, achieving a levelized cost of hydrogen (LCOH) of 3.1 $/kg and a levelized cost of electricity (LCOE) of 80.9 $/MWh. Hybrid autonomous nuclear–hydrogen complexes, like the one in [22], use electrolysis, hydrogen storage and combustion with thermal storage and low-power steam turbines to shift nuclear output from low- to high-demand periods, potentially outperforming pumped-storage hydropower under certain conditions.

TES also serves as a strategic solution for aligning VRE sources with the dynamics of electricity markets, notably in instances of renewable overgeneration and pronounced net-load ramps. As highlighted in [23], a Liquid Salt Combined Cycle (LSCC) coupling a molten-salt storage to a gas–steam power block can be co-located with a nuclear power unit and an electrolyzer. During off-peak periods, surplus nuclear energy is utilized to produce hydrogen, while both stored thermal energy and hydrogen can be dispatched to meet peak demand and facilitate time-shifting of energy supply. The LSCC attains a thermal efficiency of 47.6 % and maintains 90 % capacity factors for both the reactor and the electrolyzer. Its rapid ramping capabilities and grid-support functionality, including fast-frequency response, make it particularly well-suited for systems with high-VRE penetration. From an architectural perspective, a system-driven TES layout effectively decouples the baseload reactor from a flexible power generation block. This design allows for peak exports that can exceed the base output without cycling the reactor core, thereby contributing to a reduction in VRE curtailment [24]. Furthermore, situating large-scale TES between the nuclear island and the balance-of-plant enables a peak-to-base output capability of 2 to 5 times and value stacking— optimizing the use of high-price electricity and low-price hydrogen or process heat. This configuration not only minimizes operational and maintenance costs but also extends the lifespan of the components involved, as discussed in [25].

Long-term operation (LTO) second-generation NPPs are well suited for producing low-cost hydrogen. However, they face technical challenges that limit their ability to rapidly adjust to fluctuations in electricity demand. One of these challenges is xenon poisoning, which affects reactor reactivity. Additionally, thermal stresses experienced in the secondary circuit contribute to increased fatigue during frequent power cycling. Other constraints include the plants' design for constant output, safety considerations, reduced efficiency during cycling, accelerated wear of components, and the high cost associated with flexible operational strategies. Consequently, maintaining continuous operation at a stable load is typically regarded as the optimal mode of operation. In the context of hybrid systems, these limitations can be mitigated by channeling excess nuclear-generated electricity to electrolysis, which also helps prevent the curtailment of renewable energy sources.

Electricité de France (EDF) has developed pressurized-water reactors (PWR) that are adeptly designed for load-following operations. These reactors can adjust their output rapidly, transitioning from 100 % to 20 % of nominal power twice per day in less than 30 min, achieving ramp rates of 30 to 40 MW/min [26]. Extensive operational experience over several decades indicates that such flexibility does not adversely affect nuclear safety or environmental integrity, nor does incur significant penalties in operations and maintenance.

Building on this, [27] propose coupling nuclear generation with electrolytic hydrogen production to shift output to off-peak periods while maintaining high-capacity factors and enabling product flexibility in addition to operational flexibility. For France in 2030, a 60 GW nuclear-fleet with 16.5–23 % wind and PV could supply 54–100 % of projected hydrogen demand through nuclear-powered electrolysis. The exact share depends on electrolyzer capacity and dispatch strategy. The feasibility of these strategies depends on hydrogen production technologies, which vary in maturity and efficiency [28]. Furthermore, the comparative review in [29] synthesizes critical factors such as operating windows, efficiencies, temperature requirements, technology readiness levels (TRLs), and dynamic operational challenges such as start-up and ramping processes. These factors are examined in the context of thermal integration of the systems within the nuclear island.

Low-temperature electrolysis (LTE) in PWRs is the most mature technology, achieving a TRL of 9 [30]. Hydrogen production can be integrated with the secondary system without directly affecting the primary reactor circuit. It facilitates the rerouting of surplus electricity during low-demand periods to hydrogen generation, thereby enhancing operational flexibility and generating additional revenue. Operational validation of thermal power dispatch coupled to a hydrogen production plant for nuclear–hydrogen cogeneration developed in [31] indicates a negligible impact on the performance of a standard PWR. During regular operation, reactor power deviations remain below 0.2 %. Furthermore, under conditions such as a severe steam-line break, the system displays limited consequences, resulting in a gross output drop of 36 MWe. These findings support the practical industrial integration of this technology.

Although boiling water reactors (BWRs) can also employ conventional electrolysis, their comparatively lower flexibility and safety considerations may render them less suitable for hydrogen coupling in LTE. Advanced reactor designs, including the AP1000 (Gen III +) have been evaluated for LTE integration, providing a reliable option for nuclear-based hydrogen production [32]. Proton exchange membrane (PEM) electrolysis is recognized as the most compact method for hydrogen production, and particularly well-suited for integration with nuclear power in hybrid energy systems due to its rapid response to power fluctuations. This technology is currently under investigation at various stages in several NPPs across the US, including Nine Mile Point, Davis-Besse and Palo Verde [33] as well as in additional nuclear–hydrogen demonstration projects worldwide [34].

Microreactors can provide process heat for low- and intermediate-temperature electrolysis. However, only a few designs can achieve the 700 °C range necessary for high-temperature hydrogen production routes. In particular, high-temperature electrolysis (HTE) using solid oxide electrolyzer cell (SOEC) operates between 700 °C and 1000 °C and can achieve efficiencies of up to 90 %. In contrast, the hybrid copper–-chlorine (Cu–Cl) thermochemical cycle has a peak operating temperature of around 530 °C with a maximum predicted thermodynamic efficiency of 49 %. It should therefore not be categorized with processes that operate at temperatures above 700 °C. Thermal coupling at these elevated temperatures is further limited by the selection of materials and heat-exchangers, and the cost of high-temperature heat exchangers increases significantly above 600 °C. Consequently, near- to mid-term nuclear hydrogen projects focus on low-temperature electrolysis [35].

Advanced reactors, particularly small modular reactors (SMRs) and certain Generation-IV concepts, are highly suitable for hydrogen cogeneration and hybrid operation in conjunction with VRE sources, in load-following mode. In a 600-MWth SMR configured for simultaneous electricity and hydrogen production within a decentralized mini-grid framework, it is possible to maintain flow conditions at the offtake while switching between various operating modes [36]. However, the performance of the system is constrained by the effectiveness of the recuperator and heat exchanger. Furthermore, compliance with the downstream thermochemical process requires a minimum gas outlet temperature at the end of the pipeline.

Integrating an industrial hydrogen plant within or near a nuclear facility poses security challenges. For instance, [37] conducted a transient analysis of a high-temperature reactor coupled with a hydrogen plant, emphasizing the need for holistic safety assessments to ensure operational stability. Specific safety concerns have been evaluated for the high temperature engineering test reactor (HTTR), particularly regarding fire and explosion risks associated with flammable gases near the reactor building [38]. To mitigate hydrogen flammability risks, coupling hydrogen plants with nuclear reactors requires the use of intermediate heat exchangers made of nickel superalloys [29].

The economic viability of the hydrogen-nuclear integration largely depends on the low operational costs of the plants, making LTO of nuclear power units crucial for affordable nuclear hydrogen. By extending reactor lifetime beyond the original 40 years through modernization investments, both safe operation and competitive cost structures are ensured. The International Energy Agency (IEA) [39] provides an evaluation of the LCOE for various technologies, including LTO. Their assessment indicates that, with a discount rate of 7 % and an 85 % capacity factor, the LCOE for a 10-year LTO ranges from 31 to 36 $/MWh, primarily due to low capital costs and high operational reliability. For a 20-year LTO, the LCOE drops to 28–33 $/MWh, attributable to the extended amortization of fixed costs. This reduction in LCOE positions LTO as significantly more economical than newly constructed nuclear plants, which exhibit LCOEs ranging from 40 to 100 $/MWh, as well as fossil fuel plants equipped with carbon capture technologies. Moreover, LTO demonstrates competitive viability when compared to intermittent renewable energy sources, including onshore wind (with LCOEs from 30 to 80 $/MWh) and solar PV (30–100 $/MWh), depending on specific contextual factors. The favorable LCOE associated with LTO also facilitates competitive hydrogen production through PEM electrolysis, estimated at approximately 2.5 to 3 $/kg, leveraging surplus electricity in hybrid nuclear-renewable systems.

The investment scope associated with LTO typically encompasses the modernization of digital instrumentation and controls, the replacement of significant balance-of-plant components –including turbines, generators, and pumps– and targeted safety upgrades. According to [39], these initiatives result in capital additions estimated between 391 and 629 $/kW. This figure is substantially lower than the projected overnight cost of 4,500 $/kW for new nuclear facilities, particularly for first-of-a-kind (FOAK) projects that often incur even higher costs.

Against this backdrop, reported LCOH across nuclear hydrogen coupling pathways spans a broad range as a function of technology choice, siting, and integration strategy. A bottom-up analysis of U.S. LWR systems coupled to LTE estimates LCOH to range from 3.09 to 4.85 $/kg, with strong dependence on location and integration scheme [40]. By contrast, projections for high-temperature steam electrolysis (HTSE) span 1.2–3.5 $/kg, depending on technology and assumptions. Moreover, reactor-specific studies further illustrate this variability. High-temperature gas-cooled reactor-pebble-bed module (HTR-PM) concepts achieve 1.22–1.47 $/kg under favorable capital expenditure (CAPEX) and weighted average capital cost (WACC) conditions [41], another high-temperature gas-cooled reactor case reports 3.51 $/kg [42], a VVER-1000 configuration yields 2.88 $/kg [43], and high-temperature thermochemical cycles range from 2.80 to 2.99 $/kg for hybrid sulfur (HyS) and copper–chlorine (Cu–Cl), respectively [44].

The viability of nuclear-hydrogen hybridization is evidenced by a variety of ongoing projects. At the European level, initiatives such as Euratom's NPHyCo, GEMINI 4.0, and TANDEM are investigating the nuclear cogeneration of electricity, heat, and hydrogen. Specifically, NPHyCo focuses on integrating existing nuclear facilities with electrolysis systems while GEMINI 4.0 aims to enhance the efficiency of high-temperature reactors. Additionally, TANDEM seeks to integrate SMRs into hybrid energy systems. Findings from these projects indicate that while the technical viability of nuclear-hydrogen hybrids is established, their economic competitiveness is likely to depend on targeted governmental support [45]. At the international level, Table 1 provides details on capacity, technology, development stage, and hydrogen production costs for nuclear-hydrogen cogeneration projects. All of them recorded in the International Atomic Energy Agency database [46].

Despite extensive research on nuclear-hydrogen integration, including cogeneration frameworks, hybrid system designs, and demonstration projects, significant gaps remain in understanding the economic performance of such systems in actual volatile electricity markets with high VRE penetration. Most existing techno-economic analyses rely on idealized price assumptions, historical averages, or simplified dispatch strategies, rather than leveraging real-time market data to optimize operational decisions and quantify revenue potential. Furthermore, while the literature extensively discusses operational flexibility through reactor load-following, the potential of product flexibility strategies —which maintain constant reactor operation while dynamically allocating output between grid export and hydrogen production— remains underexplored. This gap is particularly significant for LTO NPPs in high-renewable markets such as Spain. Electricity prices often fall below generation costs for a significant part of the year, creating strong economic pressure on nuclear assets despite their inherently low LCOE compared to new plants. Countries and regions with high penetration of VRE — often accompanied by curtailment and low or negative prices— while also maintaining a substantial nuclear contribution include France, California, Texas, and Japan. Accordingly, the findings of this study are likely applicable to these areas to some extent.

Building on this context, this paper proposes hydrogen co-production as a strategic response to periods of low electricity market prices. The analysis demonstrates that this pathway can ensure the viability of nuclear generation even in comparatively high-LCOE markets—around 65 €/MWh in Spain—relative to typical LTO values of about 43 €/MWh (2024-adjusted) in countries such as Sweden, Switzerland, France, and the United States. This approach involves integrating an electrolyzer that can consume a substantial portion of the nuclear plant's electricity output. The feasibility of this configuration is assessed using a cogeneration methodology, whereby the electricity exported to the grid (when not consumed by the electrolyzer) is treated as a revenue stream and incorporated into the calculation of the LCOH. Several scenarios are evaluated using different LCOE values as proxies for both LTO and Gen III nuclear plants. Additionally, real data from the Spanish day-ahead electricity market is used to simulate system behavior and assess economic viability under actual market conditions.

2. Methods

Fig. 1 illustrates the price duration curve of the day-ahead electricity market in Spain for the period from March 11, 2024, to March 10, 2025. The LCOE of LTO NPPs in countries such as Sweden, Switzerland, France or the United States was approximately 32 €/MWh in 2020 [39]. After adjusting for inflation using the Chemical Engineering Plant Cost index for 2024 [47], this value increases to 43 €/MWh, consistent with current

Table 1
Overview of nuclear-based hydrogen initiatives.

Country	Project	Nuclear Tech.	Electrolyzer	Production	Status	LCOH [$/kg]	LTO	References
USA	Nine Mile Point	BWR	PEM (1.25 MW)	531 kg/day	Operational (March 2023)	4.85	Yes	[33,34,40]
USA	Davis-Besse	PWR	PEM (2 MW)	1 t/day	Planned	3,09	Yes	[33,34,40]
USA	Palo Verde	PWR	PEM (17 MW)	Not specified	Planned	4,77	Yes	[33,34,40]
USA	Prairie Island	PWR	SOEC (0.24–1 MW)	130 kg/day	Planned	0.69	Yes	[33,34,40]
UK	Heysham	AGR	LTE alk. (1 MW) PEM (1 MW)	800 kg/day	In planning	9–11	Yes	[33]
UK	Sizewell B	PWR	LTE (2 MW)	800 kg/day	Operational	Not available	Yes	[33,34]
UK	Sizewell C	EPR	HTE	800 kg/day	In planning (2030)	Not available	No	[34]
Canada	Bruce	PHWR	PEM (5 MW)	Not specified	Pilot	Not available	Yes	[33,34]
Russia	Kola	VVER	LTE AEM (1 MW)	Not specified	In planning (2027), pilot for 2025	Not available	Yes	[34]
Sweden	Ringhals	PWR	LTE (0.8 MW)	230 kg/day	Operational and expanding	Not available	Yes	[33,34]
Sweden	Oskarshamn	BWR	LTE Alk. (0.7 MW)	288 kg/day	Operational and expanding	Not available	Yes	[33,34]
Japan	HTTR	HTTR	Not available	Not available	Not available	Not available	No	[28]
China	HTR-PM	HTR-PM	Not available	Not available	Not available	Not available	No	[28]

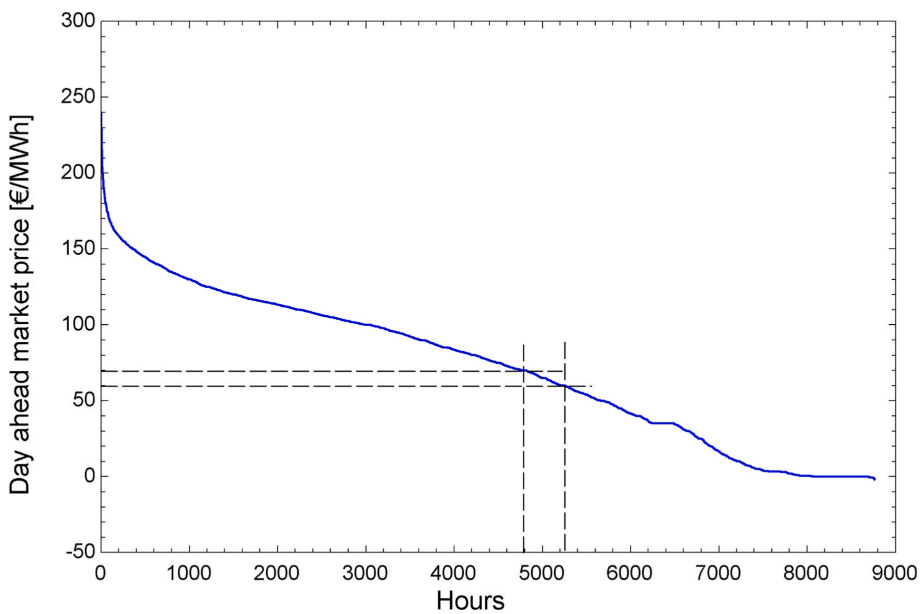

Fig. 1. Price duration curve of day ahead electricity market in Spain from 11 March 2024 to 10 March 2025.

estimates for the Spanish market as noted by Revuelta [48]. However, due to additional taxation in Spain, this cost may escalate to a range of 60 to 70 €/MWh [49].

According to Fig. 1, electricity prices remained below 60 €/MWh for 3,514 h/year and below 70 €/MWh for 3,955 h/year. Therefore, during these periods (representing 40 to 45 % of the year), the LTO NPPs in Spain would have generated revenues that fell below their production costs. As a result, in April 2025, three reactors out of a fleet of seven in Spain were temporarily shut down due to these financial constraints [50]. In contrast, in France, NPPs have the flexibility to modulate their output within a range of 30 % to 100 %, effectively managing low-price periods, thanks to the substantial integration of nuclear power in their electricity generation mix [26].

Therefore, to address the challenge of low electricity prices driven by reduced demand, a common strategy involves decreasing a nuclear plant's electricity output by 50 % through the temporary shutdown of certain reactors or by modulating their production. Based on this rationale, this study proposes the deployment of a PEM electrolyzer at each LTO NPP, sized at half the nominal capacity of the power plant. Assuming a typical 1 GWe LTO NPP [39], the corresponding nominal capacity of the electrolyzer would thus be 500 MWe, which represents the maximum capacity currently designed. Conceptually, the LTO NPP is divided into two equal units: one half continuously exports electricity to the grid while the other half coproduces hydrogen and electricity, allocating the generated electricity either to the electrolyzer or to the grid. The former will be designated as POP while the latter will be referred to as CHyP plant.

Assumptions for the PEM electrolyzer are drawn from the European Hydrogen Observatory (EHO) [51] and are summarized in Table 2. The stack degradation is assumed to be 0.19 % per 1,000 operating hours, with a nominal electricity consumption of 53.3 kWh/kg. The stack is replaced every 60,000 h. Based on [51], the average electricity consumption over the project's lifetime is estimated at 55 kWh/kg.

Regarding electricity costs for electrolyzer operation (feedstock), the LCOE of the nuclear plant is considered to range from 32 €/MWh to 60 €/MWh for an LTO NPP. For a Gen III power plant, it is set at 100 €/MWh. As in a cogeneration project, electricity sales of the CHyP NPP (500 MWe) are accounted for as negative costs in the LCOH,

Table 2
Economic assumptions [51].

Variable	Value	Units
INV_{ELYe}	2,503	€/kW
$\bar{g}$	55	kWh/kg
$LCOE$	32 to 100	€/MWh
f_{om}	0.02	p.u.
N	25	Years
H_{stack}	60,000	H
f_{rs}	0.15	p.u.
wacc	0.06	p.u.

representing revenues from electricity surpluses. Based on the typical operation of NPPs in Spain, an overall (hydrogen plus electricity) capacity factor of 90 % is assumed for the CHyP plant [52]. Equation (1) defines the relationship between the electrolyzer capacity factor (FC_{H2}) and the fraction of electricity exported to the grid (FC_E). The levelized cost of hydrogen includes all cost elements listed in equation (2), with details provided in equations (3) to (8). Equations (2) to (7) are based on [51], whereas equation (8) has been taken from [53].

$$FC_{H2} + FC_E + 0.1 = 1 \tag{1}$$

$$LCOH = CAPEX_{ELY} + CAPOPEX_{feedstock} + OPEX_{omELY} + OPEX_{repstack} + REVENUES_{surpluses} \tag{2}$$

$$CAPEX_{ELY} = \frac{INV_{ELYe} \bullet \overline{g} \bullet CRF}{H} \tag{3}$$

$$CAPOPEX_{feedstock} = \frac{LCOE \bullet \overline{g} \bullet 0.9}{1000 \bullet FC_{H2}} \tag{4}$$

$$OPEX_{omELY} = \frac{INV_{ELYe} \bullet \overline{g} \bullet f_{om}}{H} \tag{5}$$

$$OPEX_{repstack} = \frac{floor\left(\frac{H \bullet N}{H_{stack}}\right) \bullet INV_{ELYe} \bullet \overline{g} \bullet f_{rs}}{H \bullet N} \tag{6}$$

$$REVENUES_{surpluses} = -\overline{T}_{mp} \bullet \left(\frac{\overline{g}}{1000}\right) \bullet \left(\frac{0.9 - FC_{H2}}{FC_{H2}}\right) \tag{7}$$

$$CRF = \frac{wacc \bullet (1 + wacc)^N}{(1 + wacc)^N - 1} \tag{8}$$

The proposed operational strategy involves defining a minimum market price (at least equal to the LCOE), above which the electricity generated by the CHyP power plant is exported to the grid. When market prices fall below this threshold, electricity is diverted to the electrolyzer to produce hydrogen. The selected minimum market price determines the average electricity price during profitable hours, which is used to assess surplus revenue. By ensuring that the selected minimum price is greater than or equal to the LCOE, the profitability of the CHyP configuration is guaranteed. In addition, revenues from hydrogen sales at market price may offset lower revenues from grid electricity sales by the POP unit. The Iberian hydrogen index [54] is used as the hydrogen market price, with an average value of 5.86 €/kg during the period considered.

The impact of hydrogen revenues on the POP's economics is expressed by equation (9), where the second term on the right-hand side can be interpreted as a feed-in tariff above the average market price.

$$\overline{P}_{e,POP} = \overline{P}_{market} + \frac{(P_{H2market} - LCOH) \bullet \dot{W}_{ELY} \bullet H \bullet \left(\frac{1000}{\overline{g}}\right)}{\dot{W}_{POP} \bullet 8760 \bullet 0.9} \tag{9}$$

3. Results and discussion

Given a selected minimum day-ahead market price, Fig. 2 shows the number of annual hours during which the market price exceeds this threshold (left axis) and the corresponding average price during those hours (right axis). Assuming that hydrogen is produced when the market price is less than or equal to the chosen minimum, the electrolyzer capacity factor is assessed. Using the average electricity price given in Fig. 2 as the sale price for surplus electricity, Fig. 3 is obtained. It shows a family of *iso*-LCOE curves ranging from 32 to 60 €/MWh, representing typical values for LTO NPPs. An additional curve at LCOE = 100 €/MWh has been included to represent Gen III power plants [39]. It can be observed that each *iso*-LCOE curve begins at a minimum market price equal to its corresponding LCOE. The different trends between isolines at low LCOE (LTO) and high LCOE (Gen III) is explained in Fig. 4. For low LCOEs, the dominant contributor to the LCOH is the revenue from surplus electricity sales. However, as LCOE increases, this component becomes less significant, with the breakeven point slightly above 60 €/MWh.

Thereafter, two relevant scenarios are explored. The first scenario assumes a common LCOE of 45 €/MWh for LTO NPPs. The second considers an increased LCOE of 65 €/MWh, representative of current Spanish nuclear generation costs. Fig. 5 shows the variation in the average equivalent price perceived by the POP unit, including the feed-in tariff effect from CHyP plant hydrogen revenues (equation (9). The figure represents this price as a function of the minimum day-ahead

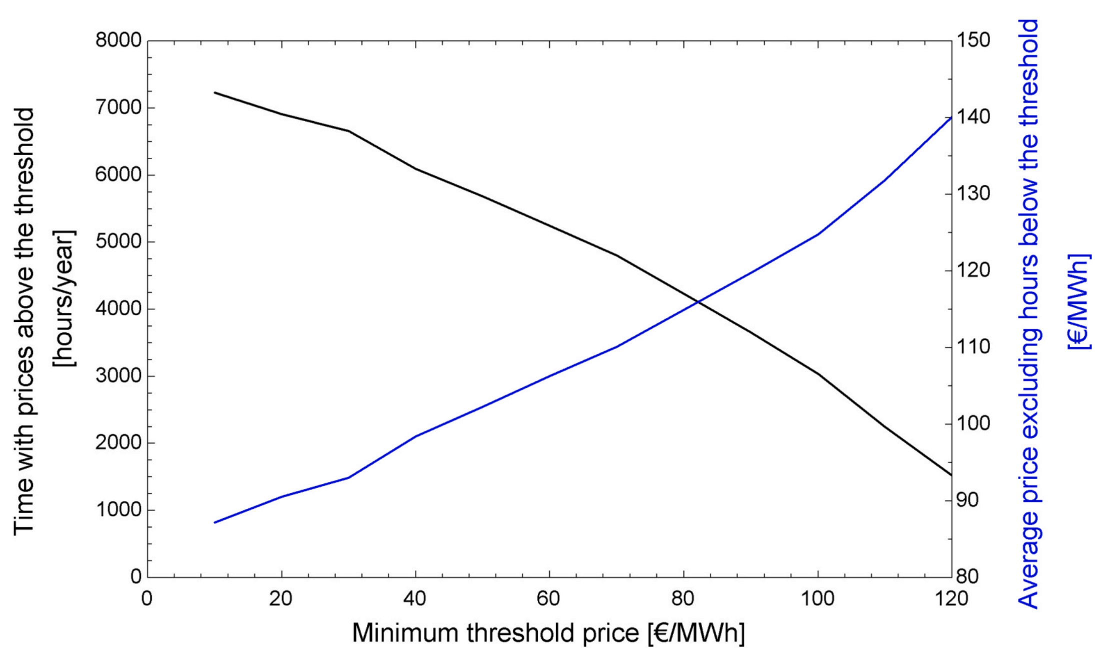

Fig. 2. Left axis: annual hours with day-ahead prices above the selected minimum threshold. Right axis: annual average day-ahead electricity price excluding hours below the threshold.

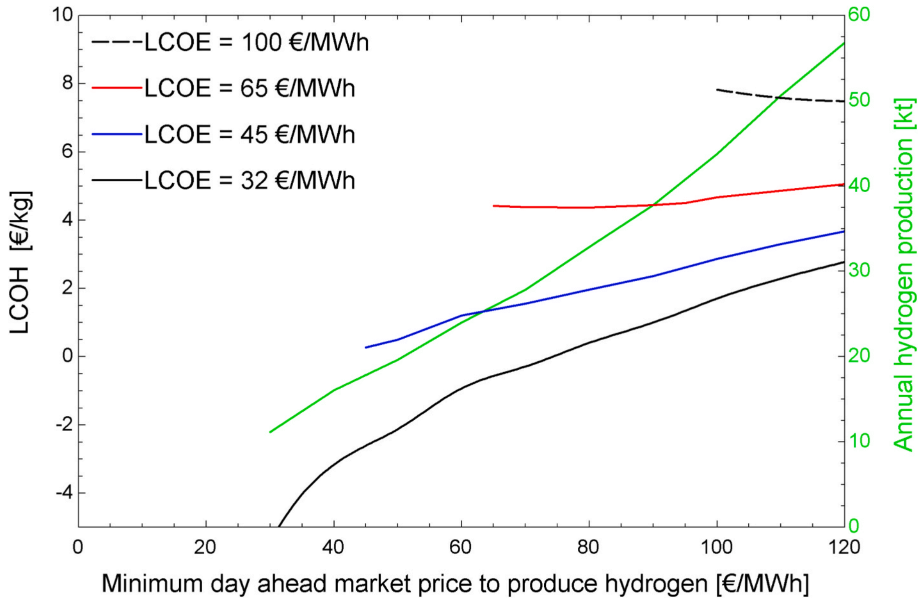

Fig. 3. Levelized cost and hydrogen production for various nuclear plant LCOE values and market price thresholds used to operate the electrolyzer.

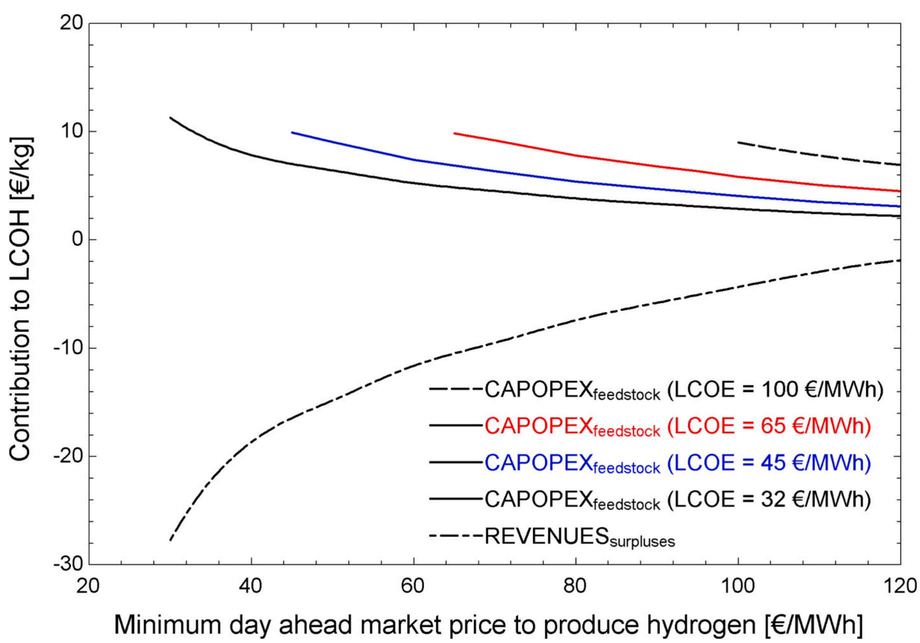

Fig. 4. Contribution to the LCOH of the electricity generation cost ($CAPOPEX_{feedstock}$) and the surplus electricity revenues ($REVENUES_{surpluses}$).

electricity market price selected for hydrogen production for the two proposed scenarios. Subtracting the average annual market price (72.28 €/MWh) from this value the effective feed-in tariff is obtained.

A maximum average equivalent price is observed in both cases: 106 €/MWh for LCOE = 45 €/MWh and 86 €/MWh for LCOE = 65 €/MWh. These maximum values occur at a high electricity market price and correspond to electrolyzer capacity factors of 48.29 % and 51.62 % respectively, indicating that approximately half of the CHyP plant's operational time would be devoted to produce hydrogen. Achieving such capacity factors would require sufficient energy storage to accommodate intermittent renewables. In the absence of such storage, lower minimum electricity market prices should be selected, leading to electrolyzer capacity factors ranging between 20 % and 30 %. As expected, hydrogen production increases with higher minimum electricity market prices. In any case, Fig. 5 highlights that the equivalent average price perceived by the POP is clearly enough to ensure economic viability, even under high LCOE conditions.

Fig. 6a provides a detailed LCOH breakdown for a scenario where LCOE = 65 €/MWh and hydrogen is produced when the market price is below 65 €/MWh. This scenario yields an electrolyzer capacity factor of 32.72 %, with an average surplus electricity of 108.3 €/MWh and annual hydrogen production of 26 kt. Given the current lack of energy storage in Spain to avoid curtailments, this scenario can be seen as a proxy for actual national conditions. The resulting LCOH is 4.42 €/kg, and the equivalent average market price perceived by the POP is 81.78 €/MWh.

Fig. 6b analyzes a second case with LCOE = 45 €/MWh, where hydrogen is produced when the market price dips below 85 €/MWh. In this scenario, the electrolyzer capacity factor increases to 45.23 %, the average surplus electricity price for generating revenues is 117.53 €/MWh, and annual hydrogen production reaches 35.5 kt. This

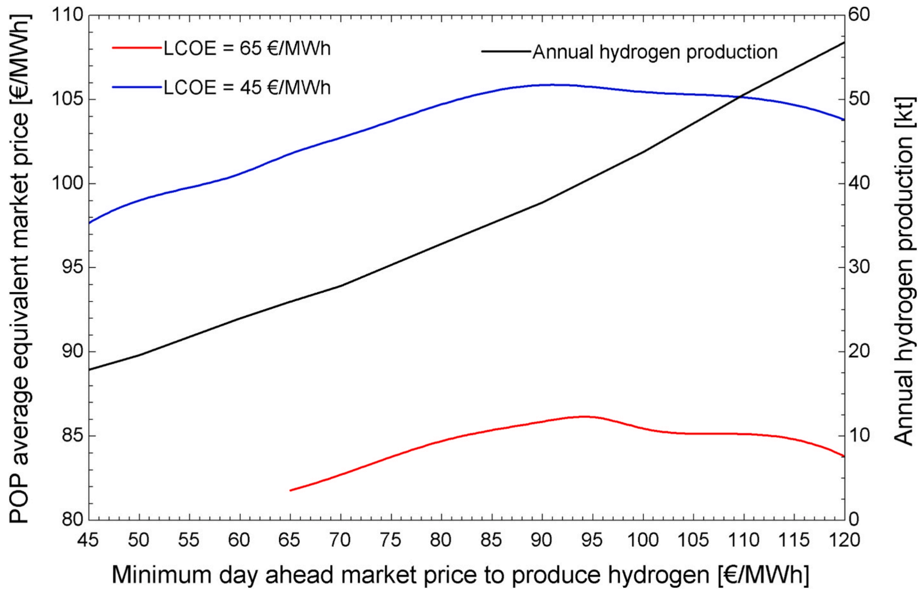

Fig. 5. Average equivalent electricity price perceived by the POP as a result of the feed-in tariff from hydrogen revenues generated by the CHyP plant.

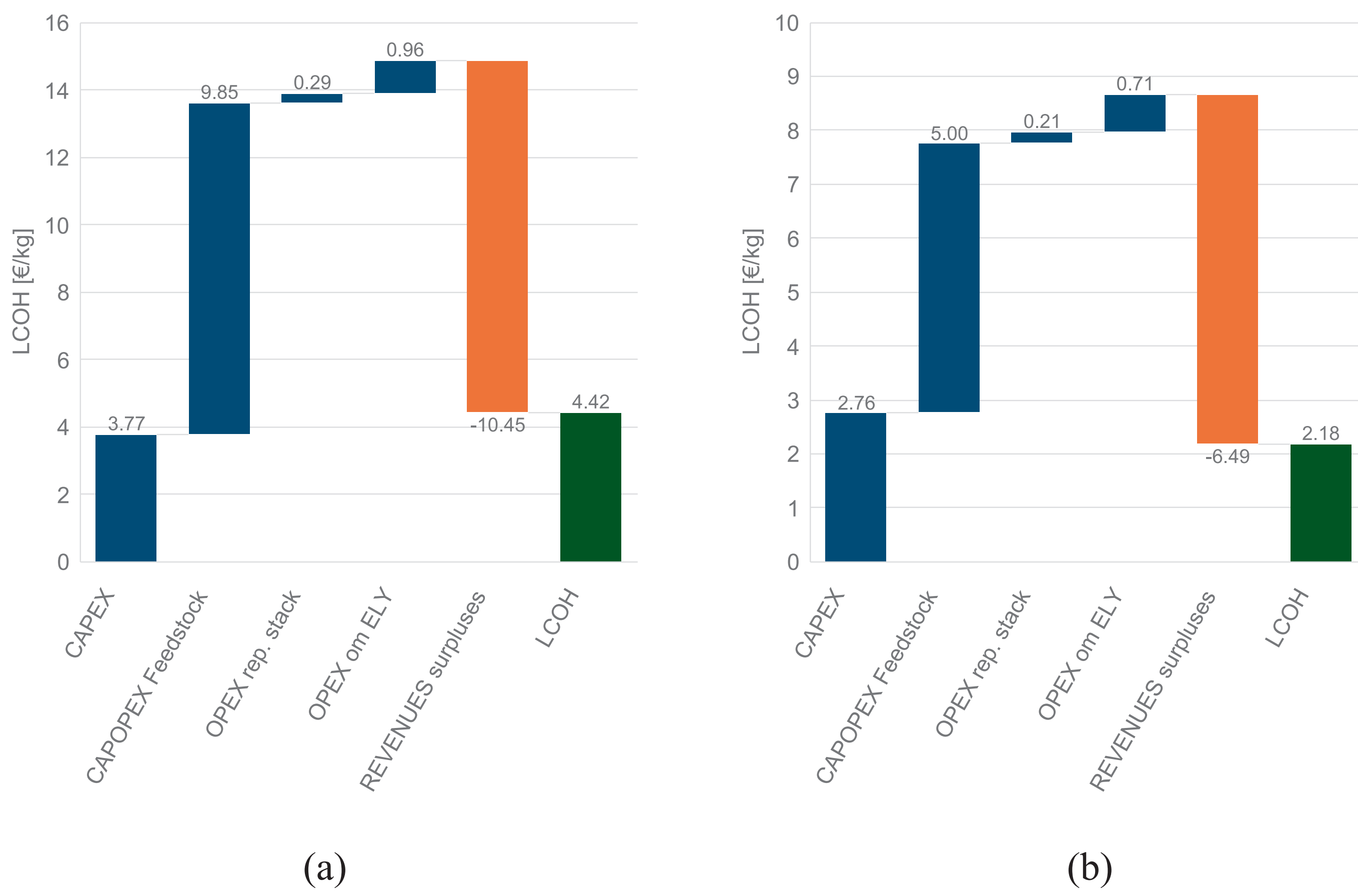

Fig. 6. LCOH breakdown for an electrolyzer operating: (a) when the market price is below 65 €/MWh, with LCOE = 65 €/MWh; (b) when the market price is below 85 €/MWh, with LCOE = 45 €/MWh.

configuration is reflective of countries with typical LCOEs alongside sufficient installed energy storage capacity to fully leverage the potential of intermittent renewables. Consequently, the resulting LCOH drops significantly to 2.18 €/kg, whereas the average equivalent market price perceived by the POP reaches 105.4 €/MWh.

The values of LCOH obtained, ranging from 2.2 €/kg to 4.4 €/kg, are consistent with reported values from projects such as Nine Mile Point, Davis-Besse, and Palo Verde with costs between 3.09 and 4.85 $/kg, [40]. It is important to note that the value of 2.18 €/kg in this study is based on a market with high storage capacity, which is not a common situation. Nevertheless, such low values are projected by the IEA in future scenarios [39].

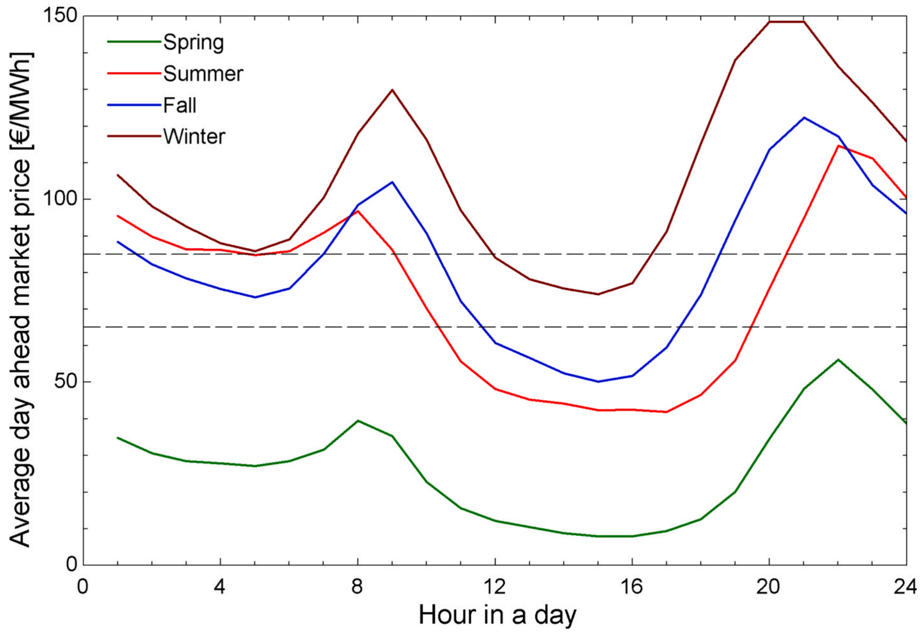

Fig. 7. Seasonal daily average day-ahead market price.

Fig. 7 displays the average day-ahead market price by season, with thresholds of 65 €/MWh and 85 €/MWh indicated by dashed lines. Across all seasons, prices are lower during solar hours as a consequence of PV production. Two price peaks appear immediately before and after solar hours, corresponding to higher demand. Night-time demand decreases, and while wind farm (WF) production does contribute, it is lower in Spain compared to PV generation.

It can be observed that in spring, hydrogen production is feasible throughout the day under both thresholds, as prices remain entirely below 65 €/MWh. In winter, the pattern reverses: no hydrogen production is feasible at the 65 €/MWh threshold, and only a few hours are feasible at 85 €/MWh. Summer and fall present an intermediate scenario, with higher hydrogen production under the higher threshold. These patterns imply a need for both intraday and seasonal storage, except in winter at the 65 €/MWh threshold, when no production occurs.

Fig. 8 illustrates the hourly hydrogen production and supply profiles for both thresholds in each season. A constant delivery of hydrogen to demand throughout the year has been assumed. According to these profiles, the minimum storage required is 11,898 t at the 65 €/MWh threshold, whereas 8,787 t are required when the threshold is raised to 85 €/MWh. The higher threshold reduces storage needs because of the increased production schedule.

A lifespan of 60,000 h has been assumed, based on hypothesis from [51]. However, this value is expected to increase as electrolysis technology evolves. To evaluate the impact of lifespan on LCOH, a sensitivity analysis has been conducted. An extended lifespan correlates with increased degradation, which in turn affects consumption and reduces production, as illustrated in Fig. 9. The step changes in the graphs result from the need for stack replacement which decreases with longer lifespans, leading to higher degradation and consumption. Fig. 10 presents the implications on hydrogen production cost of stack lifespan at the threshold of 65 €/MWh, where some categories considered in the cost breakdown detailed in Fig. 6 have been aggregated. On one hand, CAPEX and maintenance OPEX of the electrolyzer increase with lifespan due to the reduced production resulting from the higher consumption. On the other hand, the net electricity costs (CAPOPEX and REVENUES) remain nearly constant at approximately −0.6 €/kg. This value offsets the cost of stack replacement for lifespans below 35,000 h, but leads to a negative value for longer spans, thus gradually reducing the LCOH. The overall reduction from the initially assumed 60,000 h to 100,000 h amounts to 0.15 €/kg.

Fig. 11 is similar to Fig. 10 but addresses a threshold of 85 €/MWh. In this scenario, the CAPEX and maintenance OPEX of the electrolyzer remain nearly constant, due to the limited effect of higher consumption as production increases. The CAPOPEX and REVENUES are also nearly constant in this scenario, now at −1.5 €/kg. As the CAPEX and maintenance OPEX of the electrolyzer are stable, the replacement cost is fully reflected in the LCOH. In any case, the gap between lifespans of 60,000 h to 100,000 is 0.12 €/kg.

For consistent comparison, the LCOH from electrolysis under different electricity supply options is assessed using the EHO model [51], with the same assumptions adopted in this study (Table 2). Three electricity sources have been considered: the wholesale market (grid-supplied electricity), a dedicated PV plant, and a dedicated WF plant. Electricity prices of 65 €/MWh and 85 €/MWh have been considered for the wholesale market, using the same operating hours as in the nuclear case. For PV and WF, operating hours and cost data were derived from the default values for Spain assumed in the EHO model. Table 3 summarizes the findings, revealing LCOH values ranging from 6.28 €/kg to 6.95 €/kg. The LCOH values from the wholesale market are relatively similar across the two prices assumptions, while the values for PV and WF show greater variability. For reference, the LCOH from natural gas is between 3 and 6 €/kg when carbon taxes are considered, and 1.5–4 €/kg when they are excluded [55].

To conclude, an additional comparative analysis has been performed. The electrolysers CAPEX is expected to decline, with the IEA projecting a range of 620 to 960 €/kW by 2030. Based on anticipated costs for FV and WP in Spain, this results in an LCOH of 2.5 to 3 €/kg, assuming a WACC of 6 % [56]. For the proposed nuclear-based solution, lower CAPEX significantly reduces the LCOH, potentially yielding negative values due to high revenues from surplus electricity. To standardize the comparison, the analysis sets the LCOH to zero at the IEA's highest projected CAPEX (960 €/kW). With an LCOE of 45 €/MWh, hydrogen is produced when market prices fall below 103.2 €/MWh, achieving an electrolyzer capacity factor of 58.1 % (45.9 kt) and an average equivalent price for the POP of 140.5 €/MWh. At an LCOE of 65 €/MWh, hydrogen production becomes viable below 74.3 €/MWh, yielding a capacity factor of 37.9 % (29.9 kt) and an equivalent POP

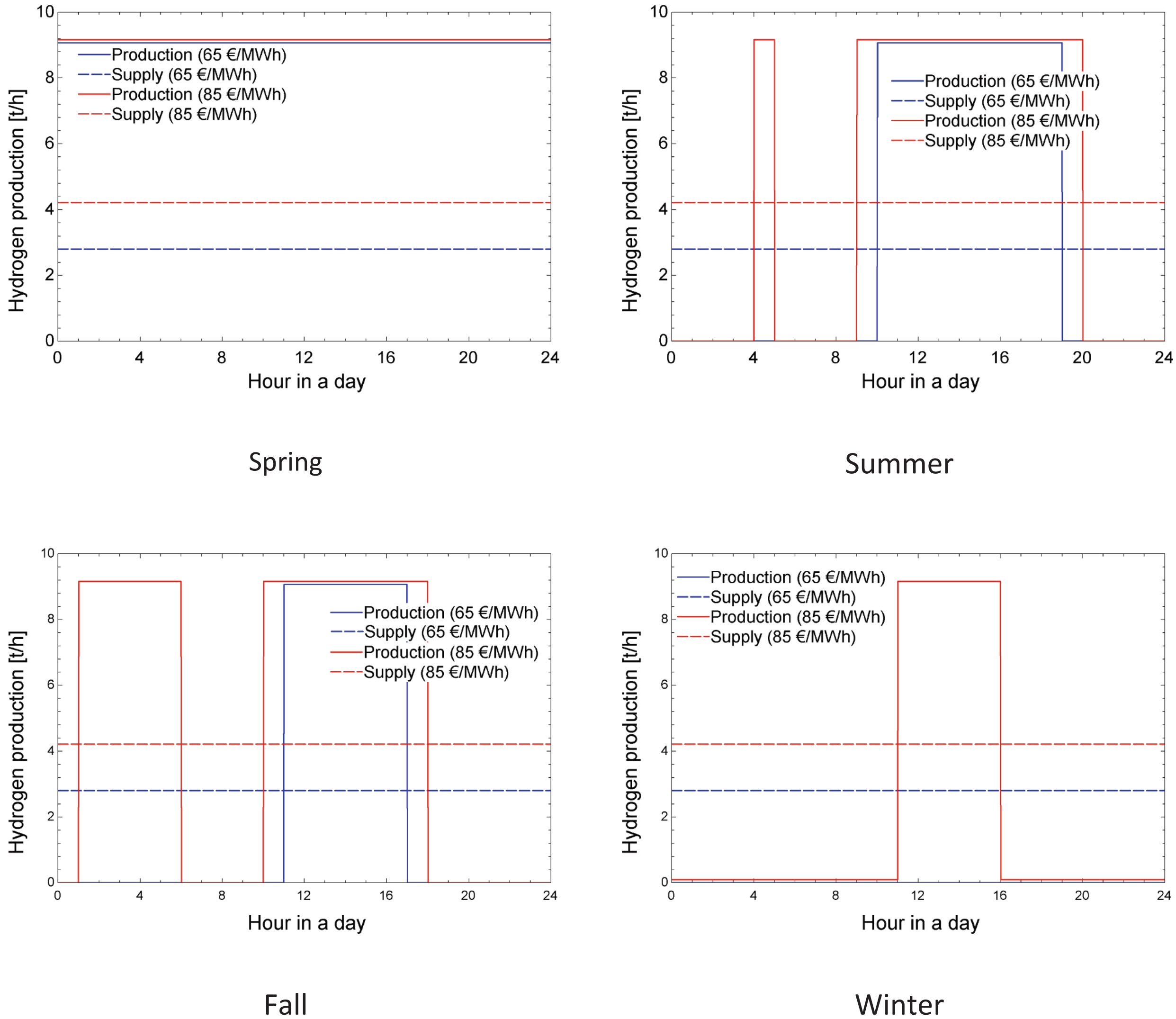

Fig. 8. Daily hydrogen production and supply by season. Production at the 85 €/MWh threshold has been increased by 2% to avoid the graphical overlay with the output at 65 €/MWh threshold.

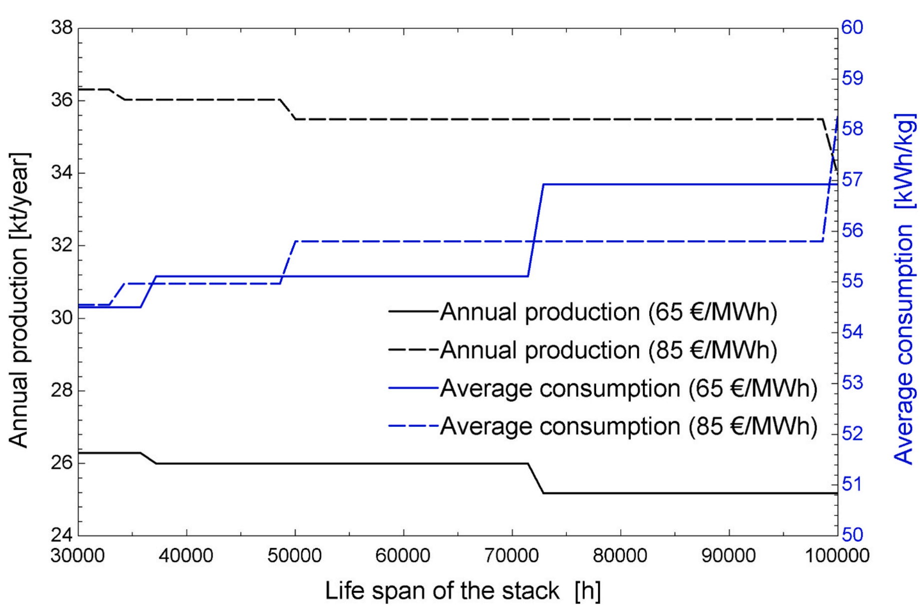

Fig. 9. Effect of the stack lifespan in the annual production and consumption.

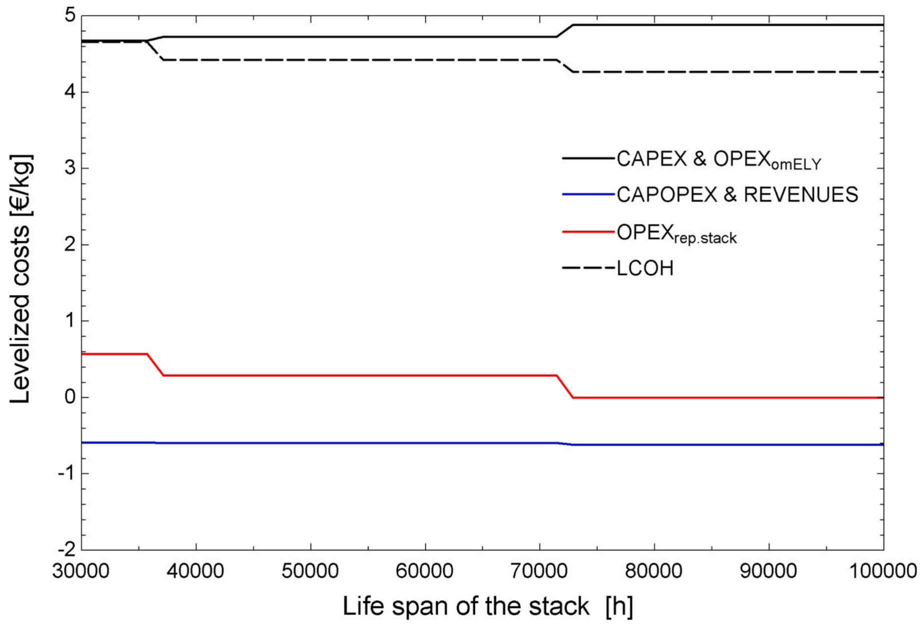

Fig. 10. Effect of the lifespan of the stack in the hydrogen production costs for the threshold of 65 €/MWh.

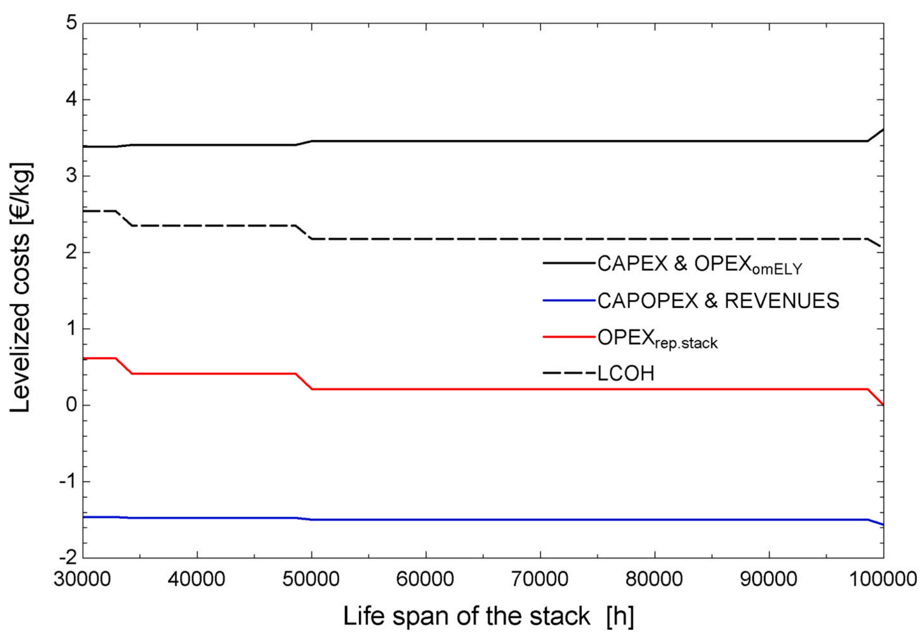

Fig. 11. Effect of the lifespan of the stack in the hydrogen production costs for the threshold of 85 €/MWh.

electricity price of 116.7 €/MWh.

4. Conclusions

The decarbonization of the energy sector, combined with increasing penetration of renewable sources, has led to more frequent episodes of low electricity market prices. These dynamics pose a challenge to the profitability of baseload technologies such as nuclear power. In this context, the integration of flexible loads such as hydrogen production presents an opportunity to mitigate market exposure while adding value through the creation of a storable, low-carbon energy carrier.

To evaluate this concept, the co-production of hydrogen has been proposed to provide flexibility to an existing NPP. A typical size of 1 GW has been chosen for the NPP, which is divided into two operational units. The POP unit continuously delivers electricity to the grid, whereas the CHyP unit dynamically allocates its electricity either to a PEM electrolyzer or to the grid based on real-time market prices. The electrolyzer, sized at 500 MW (50 % of the nominal plant capacity), produces hydrogen during periods of low electricity prices, thus providing an alternative revenue stream and avoiding nuclear plant's output curtailment.

Considering current electricity market prices and LTO costs conditions in Spain, it is possible to produce 26 kt of hydrogen at a LCOH of 4.42 €/kg by operating the electrolyzer only when market price is below 65 €/MWh. Assuming a hydrogen selling price of 5.86 €/kg, the resulting equivalent electricity price achieved by POP operating 24/7 is 81.79 €/MWh, well above the assumed LCOE (65 €/MWh in Spain). This illustrates the effectiveness of the proposed approach in addressing the economic challenge posed by low electricity market prices. For conventional LTO costs (45 €/MWh) and hydrogen production when the

Table 3
Electrolysis LCOH breakdown for other electricity sources [51].

	Wholesale market (threshold 65 €/MWh)	Wholesale market (threshold 85 €/MWh)	Dedicated PV	Dedicated WF
Electricity price [€/MWh]	23.97	35.60	28.66	44.77
Electrolysis hours [h/year]	3742	4838	2803	3277
CAPEX [€/kg]	2.92	2.28	3.92	3.34
OPEX feedstock [€/kg]	1.34	2.01	1.6	2.5
OPEX others [€/kg]	0.97	0.93	1.3	1.11
Grid Fees & Taxes [€/kg]	1.06	1.06	0	0
LCOH [€/kg]	6.29	6.28	6.82	6.95

market price is below 85 €/MWh, the LCOH drops to 2.18 €/kg, and the equivalent electricity price perceived by the POP unit increases to 105.4 €/MWh. Those LCOH values are lower than those obtained using the EHO model under the same basic assumptions. When electricity is supplied from the wholesale market, a dedicated PV plant, or a dedicated WF, the resulting LCOH falls in the range of 6.28 to 6.95 €/kg.

To assess the effect of lifespan on LCOH, a sensitivity analysis was conducted. Increasing the lifetime from 60,000 to 100,000 operating hours reduces LCOH by only 0.12–0.15 €/kg, indicating a marginal impact. The storage required to fully utilize hydrogen production under a constant-supply assumption was also estimated, showing a need for both intraday and seasonal storage.

The proposed solution has demonstrated to be economically viable in Spain, which has been explicitly assessed. In addition, a broad range of LCOE values feasible for LTO NPPs has also been considered, encompassing countries or markets with high renewable penetration where prices fall below generation costs for substantial periods of the year.

However, this approach becomes economically unfeasible for new Gen III NPPs, whose LCOE is expected to be substantially higher than that of LTO NPPs. At such cost levels, the implied electricity price renders electrolytic hydrogen uncompetitive.

Regarding the regulatory framework, hydrogen derived from nuclear energy does not meet the criteria to be classified as "green," as outlined by the Delegate Act that governs renewable fuels of non-biological origin [57]. Nevertheless, the European Union has established a standard for "low carbon hydrogen," which explicitly includes hydrogen produced from nuclear sources [58].

CRediT authorship contribution statement

José Ignacio Linares: Writing – original draft, Investigation, Funding acquisition, Conceptualization. **José Rubén Pérez-Domínguez:** Writing – review & editing, Supervision, Methodology, Formal analysis. **Eva Arenas:** Writing – review & editing, Validation, Investigation, Funding acquisition, Formal analysis. **Yolanda Moratilla:** Writing – review & editing, Supervision, Investigation, 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.

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Data availability

Data will be made available on request.

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