



Decarbonising grey hydrogen via bio-hydrogen and carbon capture and storage: a case study in Spain

Luis Yagüe ^a , José Ignacio Linares ^{a,b,*} , Eva Arenas ^{a,c} , José Carlos Romero ^c

^a Rafael Mariño Chair in New Energy Technologies, Comillas Pontifical University, Alberto Aguilera 25, 28015, Madrid, Spain

^b Repsol Foundation Chair in Energy Transition, Comillas Pontifical University, Alberto Aguilera 25, 28015, Madrid, Spain

^c Institute for Research in Technology, Comillas Pontifical University, Rey Francisco 4, 28008, Madrid, Spain

ARTICLE INFO

Keywords:

Biohydrogen
CCS
Grey hydrogen
Net-zero

ABSTRACT

This study assesses the techno-economic feasibility of deploying biohydrogen with carbon capture and storage (HyBECCS) to decarbonise Spain's hydrogen production. The proposed framework replaces natural gas with biomethane while integrating CO₂ capture and storage. Fifteen steam methane reforming (SMR) facilities, representing 90% of national hydrogen production, are characterised. A geospatial analysis matches each facility with the nearest CO₂ storage site, estimating transport and storage costs as functions of distance and capacity. Full substitution of natural gas with biomethane across all facilities requires 28.7 TWh/yr of biomethane and yields up to 4.6 Mt CO₂/yr of negative emissions. Partial substitution across five SMR plants reduces demand to 14.6 TWh/yr of biomethane, achieving net-zero operation. The levelised cost of hydrogen for HyBECCS averages 3.56 €/kg H₂, compared with 2.61 €/kg H₂ under current production conditions. These results confirm HyBECCS as a technically viable and infrastructure-compatible pathway to achieve large-scale hydrogen decarbonisation in Spain.

1. Introduction

In 2023 global demand for hydrogen climbed to an all-time high of approximately 97 Mt. However, the supply chain continues to be overwhelmingly dominated by unabated fossil-derived pathways, with natural-gas-based production routes accounting for close to two-thirds of the global output and entrenching the sector's carbon dependency [1]. At the industrial scale, the main technology remains steam methane reforming (SMR) of natural gas, which single-handedly furnished 66 % of worldwide hydrogen volumes in 2023 [1]. The European Hydrogen Observatory reported that, within the European Union, the share of SMR was even more pronounced: 91.1 % of the 2023 production was generated in conventional SMR units, whilst only three facilities deployed SMR equipped with carbon capture and storage (CCS), collectively contributing a marginal 0.1 % to the regional supply [2]. Spain is the sixth-largest country in the European Union by hydrogen production capacity, with a total installed capacity of 758 kt in 2023 (704 kt from SMR, 48 kt from by-products, and 6 kt from electrolysis). In terms of actual production, Spain ranked fourth in the same year, with 571 kt (531 kt from SMR, 36 kt from by-products, and 4 kt from electrolysis) [1].

SMR is an endothermic, catalytic process operated at 800–1000 °C and 2–3 MPa over a Ni-based fixed-bed, wherein methane reacts with process steam to yield a synthesis gas (syngas) predominantly composed of H₂ (≈75 %) together with residual CH₄ (2–6 %), CO (7–10 %) and CO₂ (6–14 %) [3]. The raw syngas is conventionally subjected to a two-stage water–gas shift (WGS) conversion to maximise the hydrogen fraction and convert CO into additional CO₂, according to Equations (1) and (2). Downstream purification typically by pressure-swing adsorption produces high-purity hydrogen while venting a CO₂-rich tail gas.



When fuelled with fossil natural gas and operated without post-combustion CO₂ abatement, the resulting product is classified as grey hydrogen. Owing to both process-intrinsic CO₂ formation and the firing of additional methane in the reformer furnace to supply the required reaction enthalpy, unabated SMR releases on the order of ~9 kg CO₂/kg H₂ at a net thermal efficiency of ~75.9 % [4]. Integrating a CCS train with an overall capture efficiency exceeding 95 % [5] decreases the cradle-to-gate carbon intensity dramatically, thereby giving rise to

* Corresponding author. Rafael Mariño Chair in New Energy Technologies, Comillas Pontifical University, Alberto Aguilera 25, 28015, Madrid, Spain.

E-mail address: linares@comillas.edu (J.I. Linares).

<https://doi.org/10.1016/j.ijhydene.2026.155447>

Received 21 December 2025; Received in revised form 13 April 2026; Accepted 7 May 2026

Available online 9 May 2026

0360-3199/© 2026 The Authors. Published by Elsevier Ltd on behalf of Hydrogen Energy Publications LLC. This is an open access article under the CC BY-NC-ND license (<http://creativecommons.org/licenses/by-nc-nd/4.0/>).

so-called blue hydrogen. Carbon dioxide can be captured at different points in the process, and capture location affects overall performance [6]. In this work, CO₂ is assumed to be captured from the flue gas using monoethanolamine (MEA), which yields a CO₂ capture efficiency of 90% and an overall energy efficiency of 69.1% [6]. Under these conditions, the reported thermal efficiency without CCS implies that additional firing in the reformer furnace raises methane consumption to 0.397 kmol of methane per kmol of hydrogen (instead of the 0.25 kmol derived from Equations (1) and (2)) [7]. That is, 63% of the overall CO₂ volume is produced by the reforming (Equation (1)) and water-gas shift reactions (Equation (2)), and 37% by methane combustion to maintain the thermal conditions of the reformer. When CCS is incorporated, efficiency decreases to 69.1 % [7] and methane consumption increases to 0.4367 kmol per kmol of hydrogen, leading to 57.25% of the CO₂ volume coming from reforming and 42.75% from methane combustion [7].

Spain exemplifies the carbon footprint of the incumbent hydrogen infrastructure: in 2023 the country produced 531 kt H₂, of which 93 % originated from fifteen SMR installations, collectively emitting 4.7 Mt CO₂ [2].

Achieving the EU's climate-neutrality ambition enshrined in the European Green Deal (December 2019) [8] requires a deep decarbonisation of hydrogen production. One promising lever consists in substituting fossil natural gas with biomethane in the reformer feed, resulting in what is known as biohydrogen [9]. This biohydrogen is classified as renewable [10] or green [11], and it could potentially lead to negative emissions [9]. This phenomenon arises from the fact that biomethane, obtained from organic waste, retains carbon originally absorbed from the atmosphere by plants. Eventually, these plants are transformed into organic waste, with both plants and livestock serving as intermediary agents in this process. In this sense, the capture might be denoted as "pre-combustion" technology. If the CO₂ captured during the SMR process is stored (CCS), negative emissions are achieved because the CO₂ is effectively removed from the atmosphere. These negative emissions might be used by hard-to-abate sectors to offset their unavoidable emissions. The hydrogen produced in this way is referred to as biohydrogen with Carbon Capture and Storage (HyBECCS) [11]. Rosa et al. [12] estimate CO₂ emissions from biomethane-based SMR with CCS in the range -11.6 to -8.84 kg CO₂/kg H₂. Their values are derived from life-cycle analysis of Antonini et al. [13], which accounts for biomethane production and management.

For the development of HyBECCS, the scalability and maturity of the technology associated to SMR with CCS play a pivotal role. Since 2003, when Lipman detailed investment costs for several plants of different scales [3], improvements in SMR with CCS have been notable. Three plants producing blue hydrogen have been reported by IEA from 2013 to 2020 [14]. Investment costs have substantially decreased, as corresponds with the high technological maturity. Rosa et al. [12] recently assigned high technology readiness levels (TRL) to SMR (9) and SMR with CCS (7–8). As an example, a plant of 214,286 kg H₂/day of capacity would require in 2020 an investment of 308.96 million € [4], while a similar size plant would have required around 2.46 times more investment in 2003, reflecting the learning process over nearly two decades [15].

The production of biogas occurs through anaerobic digestion, serving as the initial stage in biomethane production. Although this is a well-established process, typically achieving efficiencies between 72 and 85 % [16], extensive research is still being conducted. For instance, Nayeri et al. [17] demonstrated that by applying new physical, chemical, and biological pre-treatment techniques, it is possible to improve the overall efficiency of the anaerobic digestion system, maximizing methane yield. Moreover, for distributed production, Zainab B. et al. [18] conducted a study using a small-scale biogas digester to enhance biogas production from the anaerobic digestion process. After the biogas is produced, it is converted into biomethane. This conversion, referred to as upgrading, involves removing impurities and CO₂ from the biogas, resulting in nearly pure methane, indistinguishable from natural gas.

Fig. 1 schematically summarises the HyBECCS concept: biomethane flows to existing or greenfield reformers, whose process and combustion CO₂ is captured and routed to permanent geological storage. Because the captured stream is biogenic, each tonne stored yields a negative-emissions credit that can offset residual emissions from hard-to-abate sectors.

Yagüe et al. [15] developed a parametric levelised cost of hydrogen (LCOH) model for SMR using either natural gas or biomethane, with and without CCS. The affordability of HyBECCS hinges on (i) sustained access to competitively priced biomethane and (ii) proximity to secure CO₂ storage reservoirs. Multiple studies converge on a Spanish biomethane potential ranging from ~44 TWh [19] to 60–90 TWh [20], with a recent bottom-up assessment projecting 163 TWh by 2030 [21]. Presently (2024), nine biomethane upgrading facilities inject 0.64 TWh into the gas grid, and a further 23 plants under construction are expected to lift the volume by an additional 1.04 TWh [22].

The establishment of a robust CO₂ value chain constitutes the other cornerstone of HyBECCS. Recognising this, the European Commission has articulated a strategy for industrial carbon management encompassing capture, compression, transport, utilisation and storage of both fossil and biogenic CO₂ streams [23]. Persistent hurdles include harmonised regulation, cross-border CO₂ quality standards, and the paucity of market incentives arising from the absence of explicit remuneration for negative emissions within the EU Emissions Trading System. Additionally, a recent report from the Commission [24] highlighted the need for a transport network to manage captured CO₂, estimating a required investment range and recommending storage capacities to be located in specific regions to reduce costs. Cross-border issues, particularly concerning quality standards for transport and storage, are also addressed. CO₂ capture, along with its use and storage (CCUS) [14], are key technologies in the global decarbonisation strategy. These technologies not only allow the reduction of CO₂ emissions from large point sources but also offer the possibility of reusing captured CO₂ in various processes, including the manufacturing of building materials [25]. In Europe, there is a strong impulse for the development and implementation of this technology, being considered for incorporation into the National Energy and Climate Plans [26], with initiatives such as the European Union's proposal for an annual CO₂ injection target and the improvement of permitting procedures for CCUS projects [27]. The United Kingdom, for example, announced significant investment for the early deployment of CCUS projects [28]. Additionally, the IEA Greenhouse Gas Programme (IEAGHG) report [29] reviews the status of accelerated mineral carbonation, showing it as a viable option for CO₂ management but with limited commercial maturity due to technical, economic, and environmental challenges.

In order to achieve an appropriate scale of production, guarantee of origin certificates [30] may be employed to link the distributed generation of biomethane with centralized SMR production, situated close to the hydrogen consumer and at an intermediate distance to the CO₂ geological storage site or to the industrial applications that utilize it. Regarding Spain, Sun et al. [31] identified fifteen highly favourable and feasible geological structures after conducting an analysis to assess the potential and feasibility of CO₂ storage. Additionally, the Spanish Geological Survey (IGME) [32] has identified a total of 103 sites with a combined storage capacity of 21 Gt of CO₂. This study includes key details for each site, such as their storage capacity.

Against this backdrop, the present work evaluates the deployment of HyBECCS as a lever to decarbonise Spain's incumbent hydrogen supply. Two transition archetypes are scrutinised: (i) full substitution of natural gas with biomethane across all SMR assets, thereby achieving net-negative hydrogen capable of offsetting emissions from other sectors; and (ii) targeted biomethane use in a subset of plants to attain net-zero hydrogen, wherein fossil CO₂ from natural gas SMRs is balanced by the negative emissions credited to HyBECCS. Both pathways are assessed with respect to LCOH implications, feedstock availability and spatial-temporal alignment with Spanish domestic CO₂ storage capacities. In

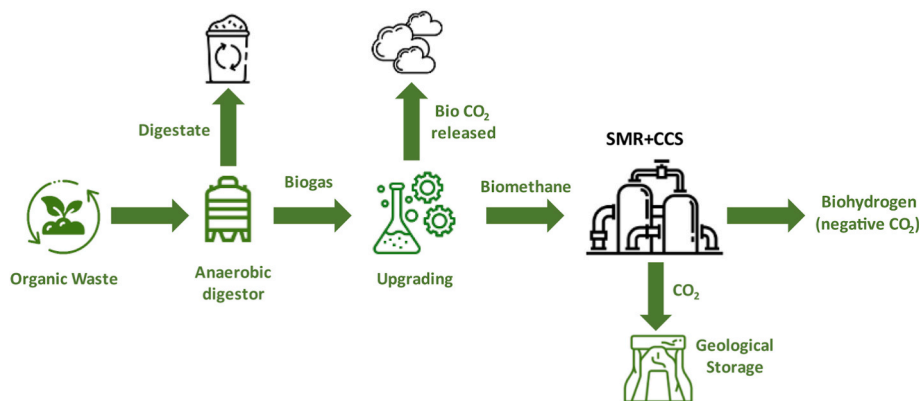


Fig. 1. Biohydrogen with negative emissions (HyBECCS) production stages [15].

doing so, the paper makes three contributions in the Spanish context. First, rather than assuming CCS retrofits on all SMR units, as is implicitly done in most roadmaps, an alternative is assessed in which negative emissions from dedicated HyBECCS plants reduce the number of reformers requiring CCS and the amount of CO₂ handled on site. Second, although Spain has a large technical potential for biomethane, its rollout is slow; this study shows that relying on negative emissions can halve near-term biomethane needs even if full substitution of natural gas remains a long-term goal. Third, a clear planning gap is addressed: while Spain's geological CO₂ storage potential has been estimated, no study has identified optimal source–sink pairings for hydrogen decarbonisation. Here we explicitly match major emission sources to candidate storage sites, providing a concrete blueprint for implementation. Although the analysis is tailored to Spain, the methodological framework and the insights on combining negative emissions, biomethane deployment, and CO₂ storage planning are transferable to other countries with similar storage infrastructures.

2. Methods

Decarbonising hydrogen production in Spain requires a precise characterisation of the current production sources. To achieve this, the European Hydrogen Observatory database [2], which contains information on hydrogen production facilities by country (including capacity, production, and the employed processes) has been utilised. In Spain, 34 facilities have been identified, 15 of which use SMR, and produced 531,497 tons of H₂ in 2023, representing approximately 90% of the total production. Table 1 presents the details of the 15 hydrogen production facilities in Spain based on the reforming route.

2.1. Feedstock substitution: integration of biomethane into reforming facilities

A direct and technically viable pathway to advance the decarbonisation of hydrogen production consists in replacing the natural gas used as feedstock with biomethane. This approach enables the utilisation of existing infrastructure without requiring substantial modifications, thus reducing investment costs and accelerating the transition towards low-carbon hydrogen.

As biomethane is a renewable gas derived from organic, agro-industrial, or municipal waste, its use as feedstock transforms the CO₂ emissions from the process into biogenic emissions. The carbon released during reforming was previously captured from the atmosphere by the biomass. This biomass is the source of the organic waste which feeds the digester, thereby effectively closing the carbon cycle and bringing the net emission balance close to zero. Consequently, the partial or total substitution of natural gas with biomethane represents an immediate decarbonisation measure that complements hydrogen production

Table 1
Details of SMR-based H₂ production facilities in Spain.

Facility	End-use	Production capacity [t/year]	Output [t/year]
San Roque/Algeciras CEPSA	Refining	17,520	13,688
Huelva Fertiberia	Ammonia	71,021	47,584
Huelva/La Rábida CEPSA	Refining	86,262	67,393
Cartagena Repsol	Refining	146,000	122,506
Puertollano Fertiberia	Ammonia	35,511	21,343
Puertollano Air Liquide	Refining	42,000	29,976
Puertollano Repsol	Refining	17,000	11,450
Castellón de la Plana BP	Refining	81,904	63,989
Tarragona Air Products	Refining	52,774	41,231
Tarragona Repsol	Refining	26,000	18,479
Sabiñánigo	Ammonia	1598	1071
Muskiz Repsol	Refining	70,000	50,645
La Coruña Air Liquide	Refining	24,528	19,163
La Coruña Repsol	Refining	24,000	17,110
Aviles Nippon Gases Europe	Other chemicals	7879	5870
TOTAL		703,997	531,497

through renewable electrolysis, while this latter approach is in its deployment phase.

To implement the substitution of natural gas with biomethane, it is necessary to determine both the required amount of biomethane and its available supply potential. To meet the Spanish annual hydrogen production (531,497 t H₂), approximately 26.1 TWh of natural gas is required, assuming a SMR efficiency of 75.9% (20.26 kg H₂/MWh-HHV) [15]. In the case of HyBECCS production, the efficiency drops to 69.1% due to the inclusion of CCS (18.54 kg H₂/MWh-HHV) [15]. Assuming a 90% carbon capture efficiency [15], the total biomethane demand would increase to approximately 28.7 TWh. These figures are well within the Spanish biomethane potential, which has been estimated at 163 TWh per year according to the SEDIGAS report [21]. Other institutions report different values, from 44 TWh in EBA (2022) [19] to 60–90 TWh in Naturgy (2019) [20]. Nevertheless, the SEDIGAS report [21] is more recent and offers the highest level of detail by substrate and region. It includes cover crops, assigning them a potential close to 60 TWh, although their use in Spain is still rare. If cover crops are excluded, the potential reported by SEDIGAS [21] falls to roughly 100 TWh, close to the upper end of Naturgy's estimate [20]. Since both sources are Spanish, this value can be taken as a conservative potential for Spain, and it is about 3.5 times the biomethane required to fully replace current natural gas used in hydrogen production. However, current biomethane production in Spain is only around 64 GWh per year [22], highlighting

the significant scale-up challenge required to unlock this potential.

Average values of 68.7 €/MWh-HHV for biomethane and 25 €/MWh-HHV for natural gas have been used. The chosen natural gas cost corresponds to a typical pre-Ukraine-war value, ensuring that the relative cost of the proposed solutions versus current fossil-based options remains conservative. The CO₂ tax has been set at 80 €/t CO₂, with a nominal escalation rate of 3.5%.

The proposed model for integrating biomethane into reforming facilities is based on a decentralised–centralised scheme. In this configuration, biomethane production occurs in a decentralised manner near sources of organic waste — such as agricultural, livestock, or urban residues — where anaerobic digestion is performed to generate biogas, followed by upgrading to biomethane. Once produced, the biomethane is injected into the existing natural gas grid, with Guarantees of Origin certifying its renewable origin and ensuring traceability throughout the gas network, enabling its transport and distribution to SMR plants. At these centralised facilities, biomethane is used as feedstock for hydrogen production. This configuration combines the advantages of local renewable gas generation with the operational efficiency of large-scale hydrogen production.

Investment and maintenance costs for the facilities have been taken from Yagüe et al. [15]. Equation (3) gives the investment (INV, €) for an SMR facility without CCS as a function of its capacity (TPA, tonnes/year), whereas Equation (4) gives the corresponding investment with CCS. In plants without CCS, maintenance costs are 0.096 €/kg H₂, increasing to 0.148 €/kg when CCS is applied. The weighted average capital cost is set to 8% and the project lifespan to 25 years.

The previous formulation for investment and maintenance correspond to new assets. In other words, retrofitting of existing plants has not been considered in the CCS scenarios. This choice yields conservative cost estimates and avoids the need for detailed information on the current condition of each facility.

$$INV_{no\ CCS} = 56,884 \cdot TPA^{0.713} \quad (3)$$

$$INV_{CCS} = 56,884 \cdot TPA^{0.713} + 8,347 \cdot TPA^{0.8592} \quad (4)$$

2.2. Integration of carbon capture and storage (CCS)

The steam reforming process inherently generates CO₂-rich streams, facilitating their separation and subsequent capture through mature technologies such as amine absorption, adsorption, or membrane separation. This feature makes reforming plants particularly suitable candidates for the implementation of Carbon Capture and Storage (CCS) or Carbon Capture, Utilisation and Storage (CCUS) systems.

Within this framework, the proposed model considers the capture of CO₂ from all or part of the existing facilities, followed by its transport to suitable geological storage sites. Depending on the extent of natural gas substitution by biomethane, the overall system could achieve net-zero or even negative emissions. This approach enhances the role of biomethane as a key energy transition vector while reinforcing the technical and economic feasibility of hydrogen decarbonisation in the short and medium term.

Life-cycle analysis of hydrogen produced from biomethane-based SMR with CCS report net negative emissions in the range –11.6 to –8.84 kg CO₂/kg H₂ when the full value chain is considered [13]. To avoid this variability, only direct negative emissions from the CCS step have been considered in this study, set at –8.64 kg CO₂/kg H₂ [7], consistent with the lowest absolute value reported in Ref. [13].

2.3. Cost optimisation and geospatial assessment

The described process involves additional costs associated with both the use of biomethane in place of natural gas and the transport and storage of captured CO₂. In the study by Yagüe et al. [15], the levelised cost of hydrogen (LCOH) for a HYBECCS system was analysed under

standard assumptions for CO₂ transport and storage costs. In contrast, the present work focuses on the specific optimisation of these costs for a real-case scenario, defined by a set of existing reforming facilities — and thus CO₂ emission sources — in relation to different geological storage alternatives. To achieve this, a geospatial analysis was carried out to identify potential CO₂ storage sites located in proximity to the reforming plants. Parameters such as transport distance, storage capacity, geological formation type, and the technical and economic feasibility of each option were evaluated.

This methodological framework enables the identification of optimal transport–storage configurations that minimise the total system cost while maximizing the net emission reduction potential of the HYBECCS process.

Since the CO₂ generated during hydrogen production from biomethane needs to be captured and transported to the storage site, the storage facilities closest to the production points were analysed. Fig. 2 shows the location of the SMR production facilities and the storage sites identified by IGME.

The proposed model considers CO₂ capture at reforming facilities, followed by its transport and storage at selected locations. Transport costs depend mainly on pipeline length and average annual CO₂ mass flow rate while storage costs depend on the storage site capacity.

To estimate CO₂ transport costs, an open-source tool, supported by the U.S. Department of Energy's Office of Fossil Energy and Carbon Management (FECM), known as the FECM/NETL CO₂ Transport Cost Model (CO2_T_COM), was employed [33]. The model estimates CO₂ pipeline costs as a function of several variables. In the present work, specific values of pipeline length and average annual CO₂ mass flow rate for each pipeline, connecting every H₂ production facility to its closest storage site, were used.

For CO₂ storage costs, they have been derived from the data provided by Navigant [34], which reports costs as a function of the total storage capacity. The study presents reference values for sites with capacities of 200, 66, and 40 Mt CO₂, representing different geological formations and scales of operation (Table 2). Based on these data a relationship between storage capacity and specific storage cost (€/t CO₂) has been derived.

To incorporate this relationship into the modelling framework, storage costs were modelled as a function of capacity Q , using reference values from Ref. [34] (ranging between 200 Mt CO₂ and 40 Mt CO₂). This correlation yields Equation (5).

$$\text{Storage cost} \left[\frac{\text{€}}{\text{t CO}_2} \right] = 655.93 \times Q[\text{Mt CO}_2]^{-1.107} \quad (5)$$

Since reforming facilities are already in place, the economic analysis focused on identifying the best alternative, namely either prioritising transport to minimise the distance to the nearest storage site or prioritising storage by selecting sites with the highest capacity, even if this involves greater distances.

3. Results

3.1. Evaluation of alternative CO₂ storage allocation strategies

To assess the feasibility and cost-effectiveness of different CO₂ storage configurations, two alternative allocation strategies were evaluated. The first strategy assigns each reforming facility to the nearest geological storage site, thereby minimising transport distance. The second strategy explores the potential benefits of directing emissions to a smaller number of higher-quality storage sites with larger capacities.

Table 3 presents the results of the first strategy, matching of reforming facilities to the nearest geological storage sites. The table reports the selected storage location, the distance from each project to that site, and the number of years of storage capacity the reservoir would provide if required to store all the CO₂ emitted by the identified facilities. This strategy results in an average transport and storage cost of

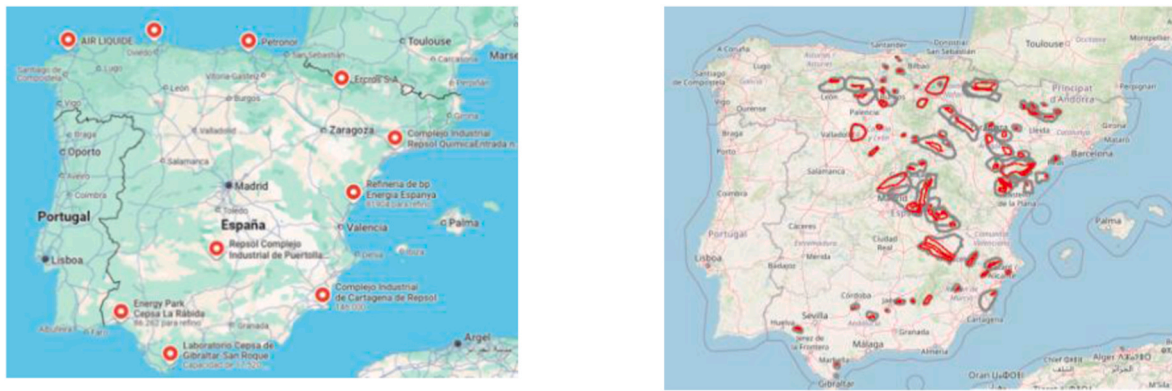


Fig. 2. On the left, SMR hydrogen production facilities [2]; on the right, geological storage sites [32].

Table 2

Reference values for CO₂ storage cost reported by Navigant [34].

Storage Capacity (Mt CO ₂)	200.0	66.0	40.0
Storage cost (€/t CO ₂)	2 €/t CO ₂	5 €/t CO ₂	13 €/t CO ₂

17.5 €/t CO₂.

Table 4 examines the same facilities under the second strategy assumptions, where CO₂ is transported to one of four higher-quality, larger-capacity storage sites rather than to the closest storage site. This strategy results in a very similar average cost (18.2 €/t CO₂).

Since the costs of both scenarios are very similar, non-economic feasibility criteria must be used to select the preferred option. These include social acceptance, permitting and equity. Optimising storage reduces the number of sites to characterise, permit and monitor, but concentrates activity at fewer hubs that may face stronger opposition or legal limits on onshore storage. Optimising transport can shorten pipelines but may require more storage sites and widen right-of-way negotiations. Equity issues also differ: pipelines spread local impacts across regions, whereas storage hubs concentrate perceived risks, so benefit-sharing mechanisms may be needed in both cases to balance local burdens and system-wide decarbonisation gains.

Given these trade-offs, the latter scenario is considered more viable because it reduces the number of required storage sites. Geological CO₂

Table 3

Assignment of reforming facilities to nearest geological CO₂ storage sites: selected location, transport distance, and estimated years of storage capacity assuming all CO₂ from the identified facilities is injected.

Facility	SMR facilities		Storage				Transport	
	H ₂ production [t]	CO ₂ emissions [kt]	Storage	Capacity [Mt CO ₂]	Reserves [years]	Storage Cost [€/t CO ₂]	Distance [km]	Trans. Cost [€/t CO ₂]
San Roque/Algeciras CEPSA	13,688	119.63	BG-GF-02	11.91	100	42.25	22	8,83
Huelva Fertiberia	47,584	415.88	BG-GF-01	216.81	216	1.70	34	3,98
Huelva/La Rábida CEPSA	67,393	589.01						3,21
Cartagena Repsol	122,506	1070.7	BG-GE-08	413.48	386	0.83	50	2,84
Puertollano Fertiberia	21,343	186.54	BG-GE-	57.02	104	7.46	142	25,63
Puertollano Air Liquide	29,976	261.99	10C					18,41
Puertollano Repsol	11,450	100.07						45,11
Castellón de la Plana BP	63,989	559.27	IT-GF-04	86.08	154	4.73	70	6,04
Tarragona Air Products	41,231	360.36	PE-GF-04	21.32	41	22.18	11	1,98
Tarragona Repsol	18,479	161.50						4,67
Sabiñánigo	1071	9.36	PE-GE-13	318.6	34.05	1.11	67	239,38
Muskiz Repsol	50,645	442.64	CD-GE-03	47.25	107	9.19	69	7,07
La Coruña Air Liquide	19,163	167.48	CD-GF-03	139.97	380	2.76	248	44,13
La Coruña Repsol	17,110	149.54					248	49,94
Aviles Nippon Gases Europe	5870	51.30					91	61,61
TOTAL	531,497	4645						

storage—particularly onshore—can face high social acceptance risks and permitting complexity, as local communities may perceive storage as a long-term environmental liability (e.g., concerns about leakage, induced seismicity, and groundwater impacts) and may question the fairness of concentrating perceived risks in a single “host” region. For this reason, an infrastructure design that reduces the number of storage locations, even at the expense of additional pipeline length, can be advantageous in practice: it limits the number of communities directly exposed to storage-related concerns, reduces the number of site-characterisation and storage-permit processes that must be successfully completed, and may therefore lower schedule risk. Thus, the storage-optimisation scenario is chosen as the basis for the following sections. Fig. 3 shows both alternatives in terms of storage sites.

3.2. Calculation of LCOH

The LCOH of each of the 15 SMR hydrogen production facilities have been determined based on the previously calculated costs and the LCOH framework of Yagüe [15]. Whereas that analysis used generic transport and storage costs, the calculations presented here consider the specific distances between each facility, the mass flow rate of the CO₂ emissions and the available geological storage sites, allowing for a more tailored and precise estimation of the LCOH.

The analysis assesses the technical and economic feasibility of hydrogen decarbonisation in Spain. The initial step is to estimate the

Table 4
Assignment of reforming facilities to one of the four strategically located geological storage sites of higher quality and capacity.

Facility	SMR facilities		Storage					Transport	
	H ₂ production [t]	CO ₂ emissions [kt]	Storage	Location	Capacity [Mt CO ₂]	Reserves [years]	Storage Cost [€/t CO ₂]	Distance [km]	Trans. Cost [€/t CO ₂]
San Roque/Algeciras CEPSA	13,688	119.63	BG-GF-01	Almonte	216.81	193	1.70	156	40,81
Huelva Fertiberia	47,584	415.88						34	3,98
Huelva/La Rábida CEPSA	67,393	589.01							3,21
Cartagena Repsol	122,506	1070.70	BG-GE-08	Murcia B-1	413.48	368	0.83	50	2,84
Puertollano Fertiberia	21,343	186.54						193	33,42
Puertollano Air Liquide	29,976	261.99							24,35
Puertollano Repsol	11,450	100.07							59,12
Castellón de la Plana BP	63,989	559.27	PE-GE-06	Zona Enlace - Bunt	1212.5	1078	0.25	70	6,04
Tarragona Air Products	41,231	360.36						170	17,24
Tarragona Repsol	18,479	161.50							33,60
Sabiñánigo	1071	9.36						250	745,50
Muskiz Repsol	50,645	442.64	CD-GF-03	Boñar	139.97	124	2.76	207	19,31
La Coruña Air Liquide	19,163	167.48						248	44,13
La Coruña Repsol	17,110	149.54							49,94
Aviles Nippon Gases Europe	5870	51.30						91	61,61
TOTAL	531,497	4645							

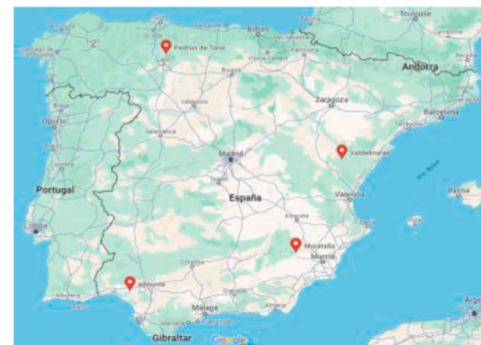
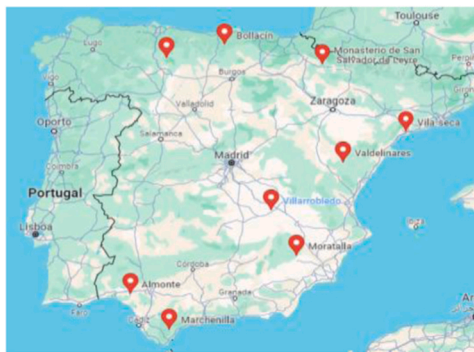


Fig. 3. On the left, storage sites selected for transport optimisation; on the right, sites selected for storage optimisation.

levelised cost of hydrogen (LCOH) for unabated grey hydrogen and compare it with the HyBECCS option. As outlined in the Methods section, HyBECCS accounts for the price premium of biomethane over natural gas and all CO₂ capture, transport and storage costs.

Fig. 4 shows the breakdown of the average LCOH for grey hydrogen, weighted by the production of each facility, while Fig. 5 shows the corresponding breakdown for biohydrogen production with CO₂ capture and storage, also weighted by facility output. The results reveal a clear cost difference between grey hydrogen and biohydrogen with CO₂ capture and storage. The main driver is the higher cost of biomethane relative to natural gas, only partially offset by the carbon credits received, compared to the CO₂ emission costs associated with grey hydrogen. Tables A1 and A2 in the Annex collect the data for each facility.

3.3. Cost for decarbonisation of H₂ production in Spain

Decarbonising hydrogen production in Spain requires a comprehensive assessment of both the technical pathways and their associated economic implications. This section evaluates the cost impacts of substituting natural gas with biomethane and applying carbon capture and storage (CCS) to achieve low-carbon or net-zero hydrogen.

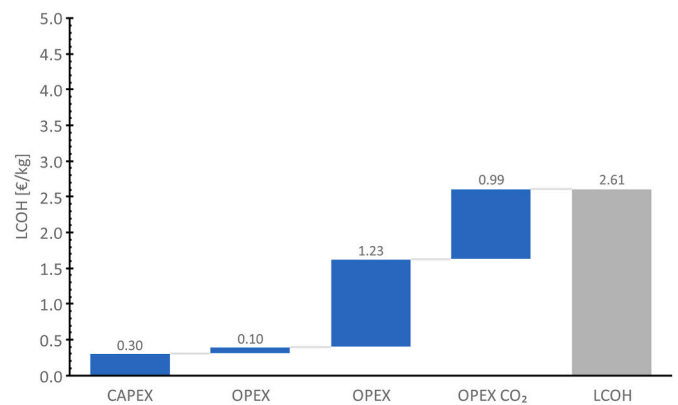


Fig. 4. Breakdown of average LCOH for grey hydrogen, weighted by facility production.

Building on the estimated hydrogen production levels, the corresponding CO₂ emissions are quantified to determine the mitigation potential of each pathway. Two scenarios have been compared: (A) full

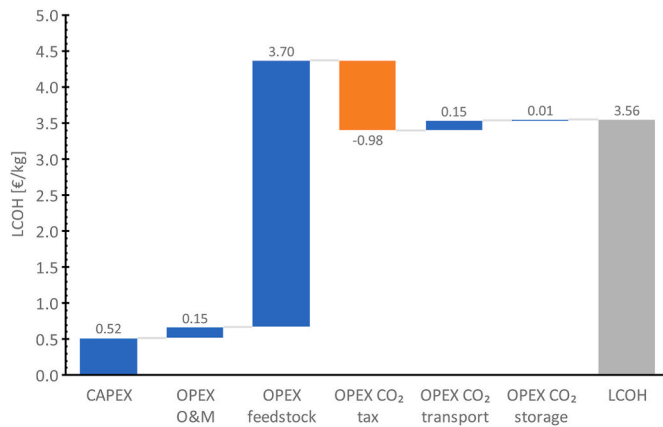


Fig. 5. Breakdown of average LCOH for biohydrogen with CO₂ capture and storage, weighted by facility production.

replacement of natural gas with biomethane, and (B) partial replacement, enough to achieve net zero hydrogen production. In both scenarios, the analysis includes CO₂ transport and storage costs for the selected site, investment costs scaled to facility size, and feedstock prices for biomethane and natural gas.

The average LCOH obtained in scenario A was previously shown in Fig. 5, with a total annual cost of 1889 M€ (about 500 M€ above current grey hydrogen production). Fig. 6 presents the CO₂ tax required to keep the LCOH of grey hydrogen unchanged, which is 157.23 €/t CO₂. The resulting negative emissions offset for unabated sectors amount to -4.59 Mt, which can be readily stored in the four previously mentioned storage sites, whose combined capacity is 1982 Mt CO₂. The biomethane required reaches 28.7 TWh, a value consistent with Spain's long-term production potential. Table A3 in the Annex provides facility-level details.

In scenario B, only five production facilities switch to biomethane and are retrofitted with CCS, which is enough to achieve net-zero hydrogen production. These five facilities are selected on the basis of their lowest LCOH once CO₂ transport and storage costs are included. i.e. those where substitution with biomethane and CCS is most economically viable. Under this criterion, only two geological storage sites are required: Almonte (BG-GF-01) and Murcia B-1 (BG-GE-08), which together provide a total storage capacity of 630 Mt CO₂. This configuration enables a net-zero solution (in fact, a negative emission of -52 kt CO₂). The average LCOH for the selected facilities is 3.44 €/kg, compared with 2.58 €/kg for their current grey hydrogen. Their total annual cost therefore raises from a current value of 698 M€ to 928 M€. Table A4 in the Annex gives facility-level details.

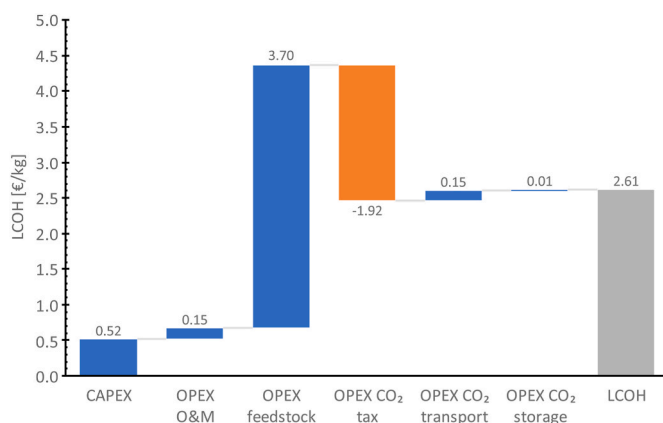


Fig. 6. Breakdown of average LCOH weighted by production facility in scenario A if CO₂ tax reaches 157.23 €/t CO₂.

Scenario B is technically feasible but requires enabling policy to prevent asymmetric cost incidence across producers. In liberalised markets, early adopters of HyBECCS may face a first-mover disadvantage if competing grey producers remain at lower costs; a CO₂ price alone may therefore be insufficient to ensure implementation. Scenario B is instead conceived as a policy-enabled pathway in which the incremental cost is socialised (e.g., via a low-carbon hydrogen obligation and a levy-funded settlement mechanism or “contract for difference” (Cfd)-style premium), ensuring that the overcost is spread across hydrogen consumers rather than borne only by the plants that decarbonise first. Fig. 7 shows the required incentive to maintain the current LCOH at the selected facilities where HyBECCS would be produced. This premium corresponds to 69.91 €/t CO₂, implying an equivalent CO₂ tax of 149.91 €/t CO₂.

Figs. 4 and 5 show that feedstock price and the CO₂ tax strongly influence the LCOH. To quantify this effect, a sensitivity analysis has been carried out. The average LCOH, weighted by the hydrogen production of each facility, has been assessed for different feedstock costs (both biomethane and natural gas) and CO₂ tax levels. Transport distance and capture efficiency have not been varied as their contribution to the LCOH is very small. Fig. 8 summarises the result of this analysis. For HyBECCS, the LCOH increases by 0.54 €/kg for each 10 €/MWh-HHV increase in biomethane cost, and decreases by 0.12 €/kg for each 10 €/t CO₂ increase in the CO₂ tax. For grey hydrogen, LCOH rises by 0.49 €/kg for each 10 €/MWh-HHV increase in natural gas cost and by 0.12 €/kg for each 10 €/t CO₂ increase in the CO₂ tax.

4. Conclusions

The analysis demonstrates the potential of biohydrogen production from biomethane combined with CO₂ capture and storage as a technically and economically viable pathway for decarbonising the current grey hydrogen production in Spain. This approach takes advantage of the existing natural gas infrastructure for the transport of biomethane to reforming plants, while enabling significant reductions in CO₂ emissions. From a technical and resource feasibility perspective, the required amount of biomethane to support this transition lies well within Spain's renewable gas potential; however, it remains well above current production levels, which underlines the need to accelerate biomethane deployment rather than posing a resource constraint.

Two alternative scenarios were evaluated to assess the scale and impact of this transition. In Scenario A, all natural gas used in current reforming facilities is replaced by biomethane (28.7 TWh/year), assuming the retrofit of all existing plants to incorporate CCS and the transport and injection of 4.59 Mt CO₂/year into geological storage. In Scenario B, only five reforming facilities are retrofitted to include CCS

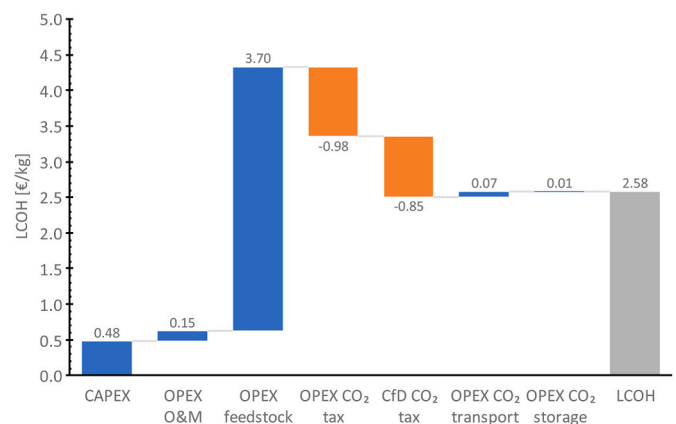


Fig. 7. Breakdown of average LCOH in selected facilities to produce HyBECCS in scenario B (policy-enabled), including the incentive to maintain the current grey hydrogen cost.

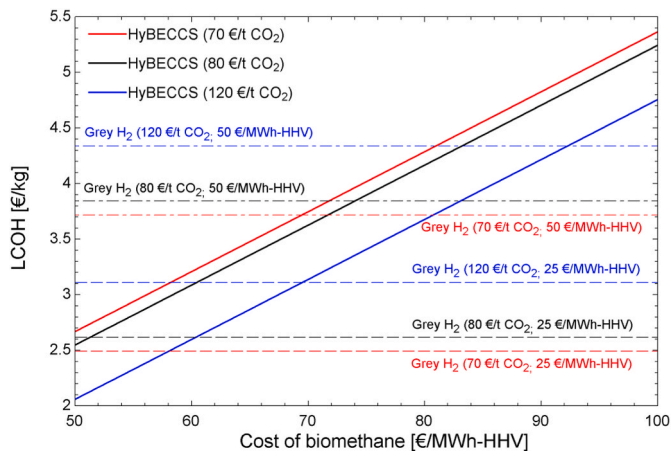


Fig. 8. Sensitivity analysis of LCOH to feedstock cost and CO₂ tax.

and operate with biomethane —sufficient to achieve net-zero hydrogen production across the system. This second configuration requires 14.6 TWh/year of biomethane and involves the transport and injection of 2.34 Mt CO₂/year into just two geological storage sites, substantially reducing the CCS infrastructure required.

Technically, Scenario B is preferred because it reaches climate neutrality with fewer retrofitted plants and a smaller CCS network, thereby reducing infrastructure complexity and exposure to permitting and social acceptance constraints associated with multiple storage locations.

Regarding economic competitiveness, Scenario B entails an incremental cost of 0.43 €/kg H₂, (230 million € per year), corresponding to a 17% increase over current production costs (1388 million €/year) while delivering negative emissions of 52 kt CO₂/year. These results indicate that HyBECCS can be economically plausible under the assumptions applied, but its competitiveness remains sensitive to biomethane availability and pricing, as well as to the monetisation of avoided/negative emissions. Transportation distance and capture efficiency have not been included in the sensitivity analysis; however, these limitations do not alter the general conclusions.

The investment and maintenance costs considered for the CCS-equipped facilities correspond to new assets and therefore yield a conservative cost estimate. Future work should consider the specific characteristics of each facility, including layout constraints, age and other site-specific restrictions, in order to better represent real-world implementation conditions.

The analysis of CO₂ transport costs further shows that pipelines operating at very low flow rates are penalised by high specific transport costs. To mitigate this effect, emitters should be clustered and connected through shared pipelines and hubs, favouring trunk-line configurations

Annex.

Table A1
Breakdown of the LCOH by facility for grey hydrogen production.

SMR facilities		LCOH [€/kg H ₂]				
Facility	H ₂ production [t]	OPEX feedstock (Natural gas)	OPEX O&M	CAPEX	OPEX CO ₂ tax	TOTAL
San Roque/Algeciras CEPSA	13,688	1.23	0.10	0.41	0.99	2.73
Huelva Fertiberia	47,584			0.32		2.64
Huelva/La Rábida CEPSA	67,393			0.26		2.57
Cartagena Repsol	122,506			0.21		2.52
Puertollano Fertiberia	21,343			0.44		2.75
Puertollano Air Liquide	29,976			0.35		2.66

(continued on next page)

over many small, under-utilised pipelines. In practice, this means that both the selection of storage sites and the grouping of emitting plants into transport corridors are key design levers for improving the overall cost-effectiveness of HyBECCS.

Finally, the deployment of this pathway is policy- and regulation-dependent. CCS remains at an early stage of development in Spain, with no dedicated regulatory framework yet established to facilitate its large-scale implementation. At present, negative emissions are not credited for compliance under the EU ETS. However, EU policy is evolving through the adoption of the CRCF Regulation (EU) 2024/3012 [35] on how negative emissions could potentially be accounted for under emissions trading; therefore, the carbon-credit term in our scenario analysis should be read as a forward-looking policy case.

Overall, the findings confirm the technical soundness and economic plausibility of HyBECCS as a complementary route for the decarbonisation of hydrogen production in Spain, provided that biomethane deployment and CO₂ infrastructure planning advance in parallel. They also highlight the need for regulatory development, coordinated planning of CO₂ transport and storage networks (including emitter clustering), and targeted policy support to unlock the full potential of this approach within Spain's broader energy transition strategy. The methodological framework developed here can be readily adapted to other countries with suitable biomethane potential, existing gas infrastructure and geological storage options, offering a transferable tool for comparative assessment of national HyBECCS pathways.

CRediT authorship contribution statement

Luis Yagüe: Writing – original draft, Visualization, Software, Investigation, Conceptualization. **José Ignacio Linares:** Writing – review & editing, Validation, Supervision, Methodology, Funding acquisition, Formal analysis, Conceptualization. **Eva Arenas:** Writing – review & editing, Validation, Supervision, Methodology, Funding acquisition, Formal analysis, Conceptualization. **José Carlos Romero:** Writing – review & editing, Validation, Supervision, Methodology, 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.

Acknowledgements

Authors acknowledge to Rafael Mariño Chair on New Energy Technologies and Repsol Foundation Chair in Energy Transition of Comillas Pontifical University for its support.

Table A1 (continued)

SMR facilities	LCOH [€/kg H ₂]			
Puertollano Repsol	11,450		0.48	2.80
Castellón de la Plana BP	63,989		0.27	2.58
Tarragona Air Products	41,231		0.30	2.61
Tarragona Repsol	18,479		0.41	2.72
Sabiñánigo	1071		0.96	3.27
Muskiz Repsol	50,645		0.30	2.61
La Coruña Air Liquide	19,163		0.37	2.69
La Coruña Repsol	17,110		0.41	2.73
Aviles Nippon Gases Europe	5870		0.54	2.86
TOTAL	531,497			2.61*

* The value corresponds to the weighted average of the LCOH and hydrogen production of the different facilities.

Table A2

Breakdown of the LCOH by facility for biohydrogen production with CO₂ capture and storage.

SMR facilities	LCOH [€/kg H ₂]							TOTAL
Facility	H ₂ production [t]	OPEX feedstock (Biomethane)	OPEX O&M	CAPEX	OPEX CO ₂ tax	OPEX CO ₂ Transport	OPEX CO ₂ Storage	
San Roque/Algeciras CEPSA	13,688	3.70	0.15	0.67	-0.98	0.35	0.015	3.91
Huelva Fertiberia	47,584			0.57		0.03	0.015	3.49
Huelva/La Rábida CEPSA	67,393			0.47		0.03	0.015	3.38
Cartagena Repsol	122,506			0.39		0.02	0.007	3.29
Puertollano Fertiberia	21,343			0.74		0.29	0.007	3.91
Puertollano Air Liquide	29,976			0.60		0.21	0.007	3.69
Puertollano Repsol	11,450			0.78		0.51	0.007	4.17
Castellón de la Plana BP	63,989			0.47		0.05	0.002	3.40
Tarragona Air Products	41,231			0.52		0.15	0.002	3.55
Tarragona Repsol	18,479			0.67		0.29	0.002	3.84
Sabiñánigo	1071			1.37		6.44	0.002	10.69
Muskiz Repsol	50,645			0.53		0.17	0.024	3.59
La Coruña Air Liquide	19,163			0.62		0.38	0.024	3.90
La Coruña Repsol	17,110			0.68		0.43	0.024	4.01
Aviles Nippon Gases Europe	5870			0.84		0.53	0.024	4.28
TOTAL	531,497							3.56*

* The value corresponds to the weighted average of the LCOH and hydrogen production of the different facilities.

Table A3

Current H₂ production, emissions and cost compared to scenario A (fully full replacement of natural gas by biomethane).

Facility	H ₂ production [t]	Fossil hydrogen (current situation)			HyBECCS (Scenario A)		
		Natural gas [GWh-HHV]	CO ₂ emissions [kt]	Cost [M€]	Biomethane [GWh-HHV]	CO ₂ emissions [kt]	Cost [M€]
San Roque/Algeciras CEPSA	13,688	672	119.63	37.27	738	-118.26	53.50
Huelva Fertiberia	47,584	2335	415.88	125.26	2565	-411.13	166.03
Huelva/La Rábida CEPSA	67,393	3308	589.01	173.30	3633	-582.28	227.89
Cartagena Repsol	122,506	6012	1070.70	308.63	6604	-1058.45	403.21
Puertollano Fertiberia	21,343	1048	186.54	58.66	1151	-184.40	83.40
Puertollano Air Liquide	29,976	1471	261.99	79.79	1616	-259.00	110.60
Puertollano Repsol	11,450	562	100.07	31.98	617	-98.93	47.76
Castellón de la Plana BP	63,989	3141	559.27	164.80	3450	-552.87	217.49
Tarragona Air Products	41,231	2024	360.36	107.65	2223	-356.23	146.13
Tarragona Repsol	18,479	907	161.50	50.18	996	-159.66	70.89
Sabiñánigo	1071	53	9.36	3.50	58	-9.25	11.44
Muskiz Repsol	50,645	2486	442.64	132.17	2730	-437.57	181.85
La Coruña Air Liquide	19,163	941	167.48	51.45	1033	-165.57	74.68
La Coruña Repsol	17,110	840	149.54	46.60	922	-147.83	68.60
Aviles Nippon Gases Europe	5870	288	51.30	16.76	316	-50.72	25.08
TOTAL	531,497	26,085	4645	1388	28,652	-4592	1889

Table A4

H₂ production, emissions and cost in the scenario B (partial replacement of natural gas by biomethane).

Facility	H ₂ production [t]	Natural gas [GWh-HHV]	Biomethane [GWh-HHV]	CO ₂ emissions [kt]	Cost [M€]
San Roque/Algeciras CEPSA	13,688	672		119.63	37.27
Huelva Fertiberia	47,584		2565	-411.13	166.03
Huelva/La Rábida CEPSA	67,393		3633	-582.28	227.89
Cartagena Repsol	122,506		6604	-1058.45	403.21
Puertollano Fertiberia	21,343		1151	-184.40	83.40

(continued on next page)

Table A4 (continued)

Facility	H ₂ production [t]	Natural gas [GWh-HHV]	Biomethane [GWh-HHV]	CO ₂ emissions [kt]	Cost [M€]
Puertollano Air Liquide	29,976	1471		261.99	79.79
Puertollano Repsol	11,450		617	−98.93	47.76
Castellón de la Plana BP	63,989	3141		559.27	164.80
Tarragona Air Products	41,231	2024		360.36	107.65
Tarragona Repsol	18,479	907		161.50	50.18
Sabiñánigo	1071	53		9.36	3.50
Muskiz Repsol	50,645	2486		442.64	132.17
La Coruña Air Liquide	19,163	941		167.48	51.45
La Coruña Repsol	17,110	840		149.54	46.60
Aviles Nippon Gases Europe	5870	288		51.30	16.76
TOTAL	531,497	12,821	13,953	−52.1	1606

References

- [1] Paris. In: IEA global hydrogen review 2024. IEA; 2024. Available online: <https://www.iea.org/reports/global-hydrogen-review-2024>. [Accessed 28 November 2024].
- [2] European hydrogen observatory. Hydrogen lanscape. 2023. Available online: <http://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/production-trade-and-cost/hydrogen-production>. [Accessed 6 May 2025].
- [3] Lipman T. What will power the hydrogen economy? Present and future sources of hydrogen energy. University of CaliforniaDavis; 2004. July Available online: https://itspubs.ucdavis.edu/download_pdf.php?id=172. [Accessed 14 May 2025].
- [4] Techno-economic evaluation of SMR based standalone hydrogen plant with CCS. IEAGHG Technical Report 2017-02; 2017. February. Available online: 2017-02 Techno - Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS.pdf, [Accessed 9 May 2025].
- [5] Zang G, Graham EJ, Mallapragada D. H₂ production through natural gas reforming and carbon capture: a techno-economic and life cycle analysis comparison. Int J Hydrogen Energy 2024;49(Part A):1288–303. Available online: H2 production through natural gas reforming and carbon capture: A techno-economic and life cycle analysis comparison - ScienceDirect, [Accessed 6 May 2025].
- [6] IEAGHG. Techno-economic evaluation of SMR based standalone (merchant) hydrogen plant with CCS. 2017/02, February, <https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/>. [Accessed 20 February 2026].
- [7] Lefranc L, Linares JI, Santos AM, Arenas E, Martín C, Moratilla Y. Biohydrogen with negative CO₂ emissions from municipal solid waste for decarbonising the public bus fleet. Application to the municipality of Madrid. J Environ Manag 2024; 371:123258. <https://doi.org/10.1016/j.jenvman.2024.123258>. [Accessed 16 February 2026].
- [8] European green deal. Available online: european green deal - consilium (accessed on 8 May 2025).
- [9] Lou Y, Fan Z, Friedmann J, Corbeau A, Agrawal M, Khatri A. The potential role of biohydrogen in creating a net-zero world. Columbia Center of Global Energy Policy 2023. January. Available online: Biohydrogen-CGEP_Report_110723.pdf, [Accessed 6 May 2025].
- [10] Green Hydrogen Coalition. Green hydrogen guidebook. 2022. Available online: <https://www.ghcoalition.org/guidebook>. [Accessed 9 May 2025].
- [11] Velazquez Abad A, Dodds PE. Green hydrogen characterisation initiatives: definitions, standards, guarantees of origin, and challenges. Energy Policy 2020; 138: 111300, Available online: Green hydrogen characterisation initiatives: Definitions, standards, guarantees of origin, and challenges - ScienceDirect, [Accessed 6 May 2025].
- [12] Rosa L, Mazzotti M. Potential for hydrogen production from sustainable biomass with carbon capture and storage. Renew Sustain Energy Rev 2022;157:112123. <https://doi.org/10.1016/j.rser.2022.112123>. [Accessed 9 May 2025]. Available online: Potential for hydrogen production from sustainable biomass with carbon capture and storage - ScienceDirect.
- [13] Antonini C, Treyer K, Streb A, van der Spek M, Bauer C, Mazzotti M. Hydrogen production from natural gas and biomethane with carbon capture and storage—A techno-environmental analysis. Sustain Energy Fuels 2020;4:2967–86. <https://pubs.rsc.org/en/content/articlelanding/2020/se/d0se00222d>. [Accessed 16 February 2026].
- [14] IEA, CCUS. In: Clean energy transitions. Paris: IEA; 2020. Available online: CCUS in clean energy transitions, [Accessed 7 May 2025].
- [15] Yagüe L, Linares JI, Arenas EM, Romero JC. Levelized cost of biohydrogen from steam reforming of biomethane with carbon capture and storage (golden hydrogen)—Application to Spain. Energies 2024;17:1134. Available online: Levelized Cost of Biohydrogen from Steam Reforming of Biomethane with Carbon Capture and Storage (Golden Hydrogen)—Application to Spain, [Accessed 16 October 2025].
- [16] Rawoof S, Kumar P, Vo D, Subramanian S. Sequential production of hydrogen and methane by anaerobic digestion of organic wastes: a review. Environ Chem Lett 2020;19:1043–63. <https://doi.org/10.1007/s10311-020-01122-6>. [Accessed 6 May 2025].
- [17] Nayeri D, Mohammadi P, Bashardoust P, Eshtiaghi N. A comprehensive review on the recent development of anaerobic sludge digestions: performance, mechanism, operational factors, and future challenges. Results Eng 2024;22:102292. <https://doi.org/10.1016/j.rineng.2024.102292>. Available online: [Accessed 7 May 2025].
- [18] Zainab B M, Mohammed Y F, Ali G S. Investigation of solid waste generation rate of biogas production. Results Eng 2024;23:102531. Available online: <https://www.sciencedirect.com/science/article/pii/S2590123024007862>. [Accessed 6 May 2025].
- [19] EBA. Biomethane production potentials in the EU. Guidehouse; July 2022. Available online: https://www.europeanbiogas.eu/wp-content/uploads/2022/07/GfC_national-biomethane-potentials_070722.pdf. [Accessed 9 May 2025].
- [20] Feliu A, et al. Renewable gases. An emerging energy vector. Naturgy Foundation 2019. Available online: Los gases renovables. Un vector energético emergente - Fundación Naturgy, [Accessed 14 May 2025].
- [21] SEDIGAS. Estudio de la capacidad de producción de biometano en España. 2023. Available online: <https://estudio-biometano.sedigas.es/wp-content/uploads/2023/01/sedigas-informe-potencial-biometano-2023-resumen-ejecutivo.pdf>. [Accessed 29 November 2024].
- [22] GASNAM. Map of biomethane production plants in Spain. Available online: Mapa de plantas de producción de biometano - Gasnam (accessed on 14 November 2025).
- [23] European Commission. Towards an ambitious industrial carbon management for the EU. COM. 2024. 62 Final, 2024. Strasbourg, 6.02. Available online: eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52024DC0062, [Accessed 6 May 2025].
- [24] Tumara D, Uihlein A, Hidalgo González I. Shaping the future CO₂ transport network for Europe. European Commission: Joint Research Centre; 2024. Available online: <https://publications.jrc.ec.europa.eu/repository/handle/JRC136709>. [Accessed 6 May 2025].
- [25] Defining the value of carbon capture, utilisation and storage for a low- carbon future. IEAGHG Technical Report 2022-09; 2022. August. Available online: Defining the Value of Carbon Capture, Utilisation and Storage for a Low-Carbon Future - IEAGHG, [Accessed 7 May 2025].
- [26] Clean Air Task Force (CATF). Carbon capture and storage and the national energy and climate plans. Available online: [CATF_NECF_CCS_PolicyBrief.pdf](https://www.catf.org/publications/CATF_NECF_CCS_PolicyBrief.pdf) (accessed on 7 May 2025).
- [27] Itul A, Diaz Rincon A, Eulaerts OD, Georgakaki A, Grabowska M, Kapetaki Z, Ince E, Letout S, Kuokkanen A, Mountraki A, et al. Clean energy technology observatory: carbon capture storage and utilisation in the European Union—2023 status report on technology development, trends, value chains and markets. Luxembourg: Publications Office of the European Union; 2023. Available online: <https://publications.jrc.ec.europa.eu/repository/handle/JRC134999>. [Accessed 7 May 2025].
- [28] CCUS-Enabled Production Working Group, Hydrogen UK. CCUS-enabled production report. 2023. Available online: [HUK-CCUS-Enabled-Hydrogen-Production.pdf](https://www.hydrogen-uk.org/wp-content/uploads/2023/07/CCUS-Enabled-Hydrogen-Production.pdf), [Accessed 7 May 2025].
- [29] Mineral carbonation using mine tailings—a strategic overview of potential and opportunities. IEAGHG Technical Report 2022-10; 2022. July. Available online: 2022-10 Mineral Carbonation using Mine Tailings – A Strategic Overview of Potential and Opportunities.pdf, [Accessed 6 May 2025].
- [30] Haszeldine RS, Flude S, Johnson G, Scott V. Negative emissions technologies and carbon capture and storage to achieve the Paris agreement commitments. Philos Trans R Soc A 2018;376:20160447. Available online: Negative emissions technologies and carbon capture and storage to achieve the Paris Agreement commitments, [Accessed 6 May 2025].
- [31] Sun X, Alcalde J, Bakhtbidar M, Elío J, Villarrasa V, Canal J, Ballesteros J, Heinemann N, Haszeldine S, Cavanagh A, Vega-Maza D, Rubiera F, Martínez-Orio R, Johnson G, Carbonell R, Marzan I, Travé A, Gomez-Rivas E. Hubs and clusters approach to unlock the development of carbon capture and storage – case study in Spain. Appl Energy 2021;300:117418. Available online: Hubs and clusters approach to unlock the development of carbon capture and storage – Case study in Spain - ScienceDirect, [Accessed 6 May 2025].
- [32] Spanish Geological Survey (IGME). Potential geological storages for CO₂ in Spain. Available online: Almacenes potenciales de CO₂ (accessed on 9 May 2025).

- [33] National Energy Technology Laboratory, FECM/NETL CO₂ transport cost model (2024), National Energy Technology Laboratory, Last Update: Aug 2024 (Version 5), <https://netl.doe.gov/energy-analysis/search?search=CO2TransportCostModel>.
- [34] Navigant. Gas for Climate. Extended analysis on the optimal role for gas in a net zero emissions energy system. <https://gasforclimate2050.eu/wp-content/uploads/2020/03/Navigant-Gas-for-Climate-The-optimal-role-for-gas-in-a-net-zero-emissions-energy-system-March-2019.pdf>. [Accessed 7 May 2025].
- [35] European Union. Regulation (EU) 2024/3012 of the European parliament and of the council of 27 November 2024 establishing a union certification framework for permanent carbon removals, carbon farming and carbon storage in products (CRCF). Off J Eur Union 6 December 2024. OJ L, 2024/3012 Available online: <https://eur-lex.europa.eu/eli/reg/2024/3012/oj/eng>. [Accessed 14 February 2026].