Exploring the feasibility of low-carbon fuel blends in CCGTs for deep decarbonization of power systems

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Keywords Deep decarbonization, low-carbon fuels, fuel-blending, combined-cycle gas turbines (CCGT)

JEL Classification Q42, Q48

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Highlights

- Techno-economic assessment of low-carbon fuel blending for decarbonizing CCGTs.
- Relative to hydrogen or ammonia, biomethane reduces capital investment requirements substantially.
- Marginal costs for low-carbon fuels exceed 120 €/MWh, limiting market competitiveness.
- Fuel blending enhances flexibility but raises retrofitting capital costs.
- Retrofitting strategy should consider plant age, fuel supply proximity, and available infrastructure.

Keywords

Deep decarbonization, low-carbon fuels, fuel-blending, combined-cycle gas turbines (CCGT)

Abstract

Retrofitting gas-fired power plants to accommodate low-carbon fuel blends offers a promising pathway to achieving deep decarbonization while leveraging the existing infrastructure and maintaining electricity supply reliability. This study presents a comprehensive techno-economic assessment of low-carbon fuel options for decarbonizing combined cycle gas turbines (CCGTs), evaluating both fuel switching and blending strategies using green hydrogen, green ammonia, and biomethane. We estimate capital investment requirements for retrofitting existing fleets and building new CCGT capacity in Germany and the UK, featuring a case study case of retrofitting a relatively new CCGT power plant (Keadby2 in the UK). Our findings reveal that retrofitting increases the levelized cost of electricity (LCOE) by about 6–13 €/MWh, with storage infrastructure representing a key cost driver. Fuel blending enhances operational flexibility but raises retrofitting costs. Biomethane emerges as the most cost-effective option due to its compatibility with existing infrastructure and negligible retrofitting needs, potentially cutting capital investments by up to €16.5 and €12 billion in Germany and the UK, respectively. However, even under the most favorable conditions, the marginal cost of electricity using low-carbon fuels exceeds 120 €/MWh, leaving natural gas more competitive at current market conditions. Strategic retrofitting decisions must be pursued selectively, considering plant age, proximity to fuel supply, and storage infrastructure. Policy frameworks ensuring simultaneous supply and infrastructure development are critical to realizing the potential of fuel blending and retrofitting strategies.

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Introduction

The transition to low-carbon energy systems requires innovative solutions to manage the weather-driven intermittency in grids dominated by renewable energy sources (RES). Given the limited control over their fluctuating generation, and the inevitable need for an affordable and reliable electricity supply, the demand for greater system flexibility is of paramount importance [1, 2]. In many power systems, gas-fired power plants are the largest source of flexibility in today's electricity systems and are seen as a bridge tool offering short-to-medium term benefits in the energy transition [3, 4]. However, their role will likely diminish in a low-carbon future [5, 6]. In this context, the use of low-carbon fuels in gas turbines offer a promising pathway for the "last-mile" decarbonization while maintaining reliability, particularly during periods of peak demand and low RES-infeed.

Despite growing interest, the financial uncertainties and techno-economic trade-offs of co-firing or converting gas turbines to low-carbon fuels remain sparsely examined. This study evaluates the economic viability of converting combined-cycle gas turbines (CCGTs) to operate on low-carbon fuels for winter-peaking capacity and quantifies the benefits of co-firing low-carbon solutions. The fuels considered are green hydrogen, green ammonia, and biomethane, analyzed within the context of decarbonizing the German and British CCGT fleets. This research also features a case study of retrofitting a relatively new CCGT power plant (Keadby2 in the UK) for low-carbon fuels. By analyzing the whole low-carbon fuels supply chain, while accounting for infrastructure requirements and cost uncertainties, this analysis offers valuable insights for policymakers and stakeholders into the prospective role of low-carbon fuels in decarbonizing the electricity sector.

The share of natural gas use in the electricity mix is projected to decrease in the upcoming years, globally [7], including in the United States [8], China [9], Europe [10], UK [11], and in Germany [12]. Nevertheless, as coal plants retire and RES penetration levels increase, gas-fired generation remains critical for meeting peak demand while operating at low utilization rates [13, 14]. Consequently, generation assets and associated infrastructure must be sized to accommodate peak demand yet remain underutilized for much of the year. Such a situation may challenge the neoclassical economic principles of cost-optimal emissions reduction, which typically favor assets with high utilization rates and low average costs.

The neoclassical principle of cost-optimal emissions reduction relies on the assumption that market-based mechanisms (i.e., carbon taxes or emissions cap-and-trade systems) will allocate resources efficiently by minimizing total system costs. However, this principle may not fully hold in a decarbonized power system that requires substantial dispatchable capacity to cover rare but extreme peak demand events. Energy-only markets often fail to provide adequate investment signals for such backup capacity (known as the missing money problem [15, 16]). Consequently, this reduced utilization poses economic challenges and could hinder investment in new capacity without targeted policy interventions to ensure a secure and flexible power supply [17]. These facts demonstrate that the high costs of a fully decarbonized power system must not be overlooked and highlight the importance of aligning economic realities with decarbonization goals.

Renewable electricity is expected to decarbonize a large share of the electricity system, but not all of it. In this context, an ever-increasing number of studies are viewing low-carbon fuels as a promising solution for filling this residual gap and substituting fossil-based generation. One of the major advantages of gas-fired power plants lies in their fuel flexibility, which allows them to operate on a broad spectrum of alternative gaseous fuels with some technical modifications [18]. Currently, gas turbines can tolerate up to 30% (by volume)[2] low-carbon fuel mixtures without any modifications [19]. However, achieving 100% low-carbon fuel operation requires significant infrastructural modifications [20]. In addition, there is a significant supply chain dedicated to the production of gas turbine technology [21].

The full range of fuel flexibility includes both fossil-based (natural gas, LPG, coalbed methane) and low- or zero-carbon options (biomethane, ammonia, and all shades of hydrogen) [22]. Despite their potential, the higher marginal costs associated with low-carbon hydrogen continue to hinder its widespread deployment [23, 24]. Nevertheless, with decreasing levelized costs of renewable energy [25], rising demand [26], and different policy interventions such as subsidies, [27], carbon pricing [28], high decarbonization levels [29], or geopolitical conflicts [30], the marginal costs of low-carbon hydrogen might become more economically attractive.

A further advantage of using zero-carbon gases in CCGTs is that the establishment of technical feasibility and conversion costs allows the green use of CCGTs to be the default pathway to fully decarbonizing the electricity sector. While the foundation of long-term decarbonization can be more efficiently achieved through electrification, renewable energy, and battery storage, certain hard-to-abate segments of the power system will remain. In these cases, retrofitted CCGTs and the use of low-carbon fuels can serve a vital, complementary role. Consequently, higher costs can be incurred in the late 2040s once alternative and cheaper sources of decarbonization have been exhausted. Quantifying the total upfront investment costs is therefore critical, not because they are the primary pathway to net zero, but because they are essential enablers of the last-mile decarbonization of power systems.

Despite its high relevance for national decarbonization strategies, this topic remains underexplored in existing literature. This study addresses a critical gap in understanding the economic trade-offs and system implications of low-carbon fuels in CCGTs, with a focus on retrofitting feasibility and marginal electricity costs across different blending scenarios. In the context of ongoing debates about the role of dispatchable generation, we use levelized cost of electricity (LCOE), adjusted for expected utilization, to evaluate the economics of retrofitting existing plants versus building new low-carbon CCGT capacity. The analysis also evaluates the capital requirements for the future CCGT fleet in the UK and Germany to accommodate low-carbon fuels, with a case study on Keadby2, Europe's newest and most efficient CCGT plant.

While the research focuses on the CCGT fleet in UK and Germany, the findings are globally relevant. According to the Global Energy Monitor, most gas-fired power plants currently in operation will remain technically viable beyond 2040, with even more capacity under

[2] Volumetric share does not equate to energy share due to varying energy densities. The energy shares can be estimated by weighting the volumetric fractions of the blended fuels according to their respective heating values.

construction or in the planning stage [31]. This is particularly true in emerging economies due to recent investments [32]. Retrofitting these assets for low-carbon fuel use can reduce the risk of asset stranding, improve the investment case for flexible generation, and accelerate the global shift toward net-zero electricity systems. By positioning our results within this international context, this paper offers a global outreach for the research outcomes on the potential of low-carbon fuels to many energy systems who share the same energy transition goals.

Background and Literature Review

Overview of low-carbon fuels

Low-carbon fuels encompass a wide array of synthesized alternatives, each derived through distinct chemical and thermochemical pathways. The literature offers a broad classification of these fuels based on their production routes [33, 34]. Hydrogen (H_2) typically serves as the starting point for synthetic fuels as the basic molecule[3]. Beyond hydrogen, several synthetic low-carbon fuels have emerged as promising alternatives. Hydrogen can be further synthesized into renewable natural gas (RNG), methanol, or ammonia (NH_3) [35, 36][4]. Besides their fundamental role as industrial and agricultural feedstock, these synthetic fuels can be used in gas power plants [37]. Here, it is important to note that some synthetic fuels processes have been historically linked with high GHG emissions due to the usage of hydrogen from fossil-fuel based reforming [38]. To be classified as a low-carbon fuel, both the hydrogen used in these synthetic pathways and the energy used in the synthesis processes must be produced using renewable electricity [39].

RNG is produced through the pyrolysis of carbonaceous compounds [38], or through the methanation process by chemically mixing hydrogen and carbon monoxide [40]. Similarly, methanol is synthesized through catalytic CO_2 hydrogenation, where hydrogen reacts with captured carbon dioxide [41]. Ammonia, on the other hand, is produced by combining hydrogen and nitrogen over a bed of catalyst via the well-established Haber-Bosch (HB) process [42]. Biomass-derived fuels, or biofuels, represent another important class of low-carbon fuels. These are extracted from organic feedstocks through mechanical or chemical conversion methods [43]. When upgraded into biomethane (CH_4), they serve as a direct substitute for fossil-based natural gas and can be injected into existing natural gas networks or used in power generation [34, 44].

Although these conversion processes are generally energy-intensive [45], they offer unique systemic and logistical advantages. RNG and biomethane, for example, can be utilized within the existing natural gas infrastructure, presenting a cost-effective option for decarbonization. However, it remains uncertain whether future demand levels will be sufficient to justify maintaining such infrastructure. In contrast, fuels like ammonia and methanol offer easier long-term storage and transport, positioning them as critical enablers in the broader hydrogen economy.

[3] Hydrogen here is defined as an energy vector, its carbon content (color) depends on the source of electricity (see Fig. 1 from Yu, et al., 2021 [79] and Fig. 16 from Molière 2023 [19])

[4] Some synthetic fuels processes have been historically linked with high GHG emissions due to non-green hydrogen from fossil-fuel based reforming (see Ruth & Stephanopoulos, 2023 [36])

Nevertheless, certain synthetic fuels such as RNG require a CO_2 supply chain, including capture, transport, and storage infrastructure, which is beyond the scope of this study.

Given the diversity of low-carbon fuel types, each with distinct production methods, infrastructure requirements, and performance trade-offs, a comparative approach is essential for assessing the economic and technical viability of decarbonized energy systems. Considering these various synthesis routes is crucial in evaluating the feasibility of a low-carbon energy transition centered on flexible, dispatchable generation.

A key point of interest is the scope for blending and substituting low carbon fuels in the light of fluctuations in fuel costs and in the physical availability of different fuels. Thus, if local biomethane is both variable in supply and often insufficient to fully power peaking CCGTs, it may be necessary to blend it or substitute it for hydrogen or ammonia, both of which could be locally or globally sourced.

Fuel blending and co-firing of low-carbon fuels

Gas turbines are widely recognized for their flexibility in accommodating a range of fuel mixtures [46]. Many existing turbines can co-fire blends with up to 50% by volume (50%-Vol) of hydrogen [47, 48] or ammonia [49, 50], often with minimal or no hardware modifications. Additionally, ammonia can be catalytically cracked into nitrogen (N_2) and hydrogen before combustion, with the resulting hydrogen subsequently used as fuel [46]. Biomethane, on the other hand, can be directly utilized in gas turbines without requiring any modifications [51]. However, achieving full decarbonization of combined-cycle gas turbines (CCGTs) necessitates complete low-carbon fuel firing capability, which remains currently under development. Gas turbines capable of operating on 100% low-carbon fuels are currently being tested and are expected to reach commercial availability by 2030 [52, 53, 54]. Several studies are also investigating the operational and technical conditions in hydrogen [48, 55] and ammonia [56, 57] combustion.

In principle, fuel blending of various compositions is technically possible. The scientific literature has extensively explored the combustion characteristics and technical aspects of binary blends in gas turbines such as CH_4/H_2 [58, 59], CH_4/NH_3 [60, 61], and NH_3/H_2 [62, 63]. Ternary fuel blends such as $H_2/NH_3/CH_4$ have also been studied in detail [64, 65, 66, 67]. While the technical aspects of these blends are well-documented, there remains a significant gap in understanding the economic implications and capital investment required for retrofitting existing turbines. For instance, fuel blending poses specific combustion challenges, particularly related to NO_x emissions, flame stabilization, varying flame speeds, and flashback risks [68]. As such, blending higher level of hydrogen or ammonia in fuel blends requires post-combustion catalytic systems for emissions control [69] or comprehensive retrofitting of burner and fuel systems [70]. Many of these fuel mixes remain untested at scale due to the inability to run a large-scale test (i.e. co-firing for several hours) on a conventional CCGT without the necessary fuel supply adjustments or sufficient low carbon gas and in the presence of output loss due to the time taken to switch between fuel mixes.

Low-carbon fuels blending is viewed as a transitional step toward CCGT decarbonization, the same cannot be said about the supply infrastructure, which presents more limitations.

Existing infrastructure and appliances were not designed to accommodate high levels of low-carbon fuels. Due to differences in volumetric energy density (see Table 1), the existing natural gas grid can accommodate only small amounts of hydrogen or ammonia [71, 72]. This means that full decarbonization would likely require repurposing or replacing large parts of the current gas transmission infrastructure [44].

Table 1: Material properties of selected low-carbon fuels

Parameter	Unit	Ammonia (NH_3)	(Bio-) methane (CH_4)	Hydrogen (H_2)
Volumetric higher heating value	MJ/m3	15.6	39.8	12.7
Volumetric lower heating value	MJ/m3	13.8	35.8	10.7
Mass-specific higher heating value	MJ/kg	22.5	55.5	141.8
Mass-specific lower heating value	MJ/kg	18.6	50.01	119.9
Density	kg/m3	0.73	0.657	0.0899

Hydrogen's extremely low volumetric density also presents major challenges for storage, necessitating high-pressure containment or significantly larger volumes to match the energy content of other low-carbon fuels [73]. Contrary to that, both ammonia and biomethane offer more practical options for storage and transport. Ammonia benefits from an existing infrastructure, a mature market, and a well-established global supply chain, making it a viable candidate for a hydrogen carrier and a shortcut solution toward a low-carbon economy [74]. Biomethane, being chemically identical to methane, can be directly injected into the natural gas grid and used as a drop-in renewable substitute for natural gas to supply traditional end-users [75, 76].

Despite their potential, the global scale-up of low-carbon fuels is constrained primarily by the high production costs of the fuel itself. For instance, current green hydrogen production costs average between \$6.25–\$12.20/kgH_2 (equivalent to 187–366 \$/MWh$_{fuel}$) [77], whereas grey hydrogen is considerably cheaper, ranging from \$1.03–\$2.08/kgH_2 (30.9–62.4 \$/MWh$_{fuel}$) [78]. Green ammonia is currently produced at a 700-1000 \$/tNH_3 (136-195 \$/MWh$_{fuel}$) [79], where grey ammonia rages from \$159 to \$450/tNH_3 (31-87 \$/MWh$_{fuel}$) [80]. Biomethane cost is between 50 and 100 \$/MWh$_{fuel}$ [81], whereas European gas prices already reverted to less than 40 \$/MWh$_{fuel}$ after the 2022 energy crisis [82], with long-term projections remaining under 50 \$/MWh$_{fuel}$ [83].

Next to the low cost-competitiveness of low-carbon fuels, other challenges are hindering the widespread acceptance of low carbon gases. A key obstacle to scaling up the low-carbon economy is the mismatch between the cost of hydrogen production and the current level of hydrogen demand [84]. Nevertheless, growing ambitions to achieve deep decarbonization, alongside mandated policy measures are expected to create opportunities for the production and transport of green hydrogen at lower costs [83, 85, 86]. The biomethane sector, meanwhile, remains underdeveloped, largely due to spillover effects from green electricity support schemes and inconsistent policy signals [76, 87], while the case of green ammonia is further complicated as it faces financing barriers due to its dependence on long-term, fixed-price offtake contracts, directly clashing with established market norms [88].

Finally, an uptake of hydrogen economy requires the simultaneous development of the entire value chain, including production, transport, storage, and end-use [89, 90]. This systemic coordination challenge is further complicated by the incompatibility of existing infrastructure to accommodate any of hydrogen's chain due to distinct physical properties (see Table 1).

Methodology

We compare fuel supply chains, retrofit costs, and operational costs across three firing modes (single, binary, ternary) of low-carbon fuels in CCGT. Based on established literature, the technology for fuel blending is assumed to be technically and commercially available in the future, with an efficiency factor of 63% for such CCGTs. This study evaluates the techno-economic performance of low-carbon co-firing strategies for gas turbine-based power generation using three fuels: green hydrogen (H_2), green ammonia (NH_3), and biomethane (CH_4). The entire value chain is considered, with each fuel following a distinct supply route up to the firing in CCGT, including international shipping, distribution as well as on-site storage. Next to the global market, the use of hydrogen and ammonia locally produced is considered. Finally, the retrofitting costs for CCGT accommodate low-carbon fuel co-firing. This section describes the system boundaries, which are then summarized in Table 2.

Importantly, we assume uniform financial parameters of energy projects across both the UK and Germany. This simplification allows for a generalized comparison of systemic and policy-related differences, without conflating results with cost variations due to local return expectation, market risks, or technology adaptation [91]. This approach is also supported by existing literature, which empirically shows the similarity of the cost of capital for energy projects in developed countries [92, 93]. While this assumption may not fully reflect local market conditions, we address this through a sensitivity analysis of all key cost parameters in Appendix A. This ensures that our findings remain robust across a reasonable range of cost scenarios.

Increasing aspirations to achieve net-zero emissions will create opportunities to reduce the cost of low-carbon fuels. Hydrogen production costs are estimated at 40-50 Eur/MWh$_{fuel}$ by 2050 from the global market, while locally produced (in Europe) hydrogen is estimated to cost 80-90 Eur/MWh$_{fuel}$ by 2050 [84, 25]. Ammonia follows the same production costs of hydrogen to ensure consistency, with extra cost requirements to represent the hydrogen-to-ammonia synthesis [94], while biomethane costs are estimated to be around 87 Eur/MWh$_{fuel}$ [10].

Hydrogen can be transported in different mediums, such as compressed or liquid hydrogen (LH_2), ammonia, or liquid organic hydrogen carrier (LOHC) [95]. Previous research identified liquid hydrogen and ammonia as the most promising technologies for international hydrogen shipping [96, 97], with significant future cost-reduction potential [98, 99]. In our calculations, transport costs include seaborn international shipping costs, terminal operational cost at both export and import harbors for both hydrogen [100] and ammonia [101]. Moreover, hydrogen transport costs include liquefaction cost [100].

Inland distribution of hydrogen and ammonia from the harbor to the power plant (CCGT in this case) can happen via pipelines, rail, or truck delivery [102]. For biomethane, we only consider distribution using the current natural gas infrastructure [103]. On-site storage takes place in the form of standard storage tanks for ammonia [101], and pressurized biomethane tanks [10], while hydrogen storage can be in the form of liquefied hydrogen tanks [25] or underground salt caverns [104]. Finally, on-site fuel storage is assumed to be with a capacity sufficient for three days of power plant operation to ensure supply security and prevent fuel interruptions [105].

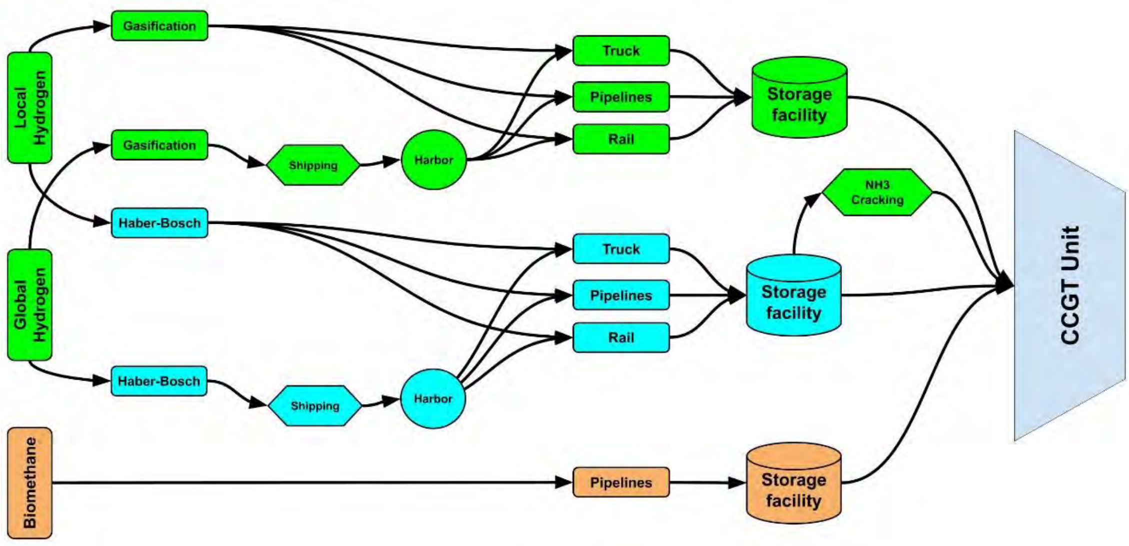

Figure 1: Overview of system functional diagram and analyzed fuel routes.

Three firing configurations are assessed in the analysis. The first configuration involves single-fuel firing, where only one fuel is used at a time. The second explores binary co-firing, allowing two of the three fuels to be mixed at varying proportions. The third considers ternary co-firing, where simultaneous use of all three fuels takes place. Hydrogen may come from catalytic ammonia cracking, in which the associated energy losses are incorporated into the fuel supply chain based on reported cracking plant performance [106]. For each configuration, the energy content of the fired fuel is normalized based on the lower heating values (LHV) of the blended fuels. A schematic overview of the entire low-carbon fuel supply chain is presented in Figure 1.

Retrofitting gas-fired power plants to accommodate fuel blending[5], while technically possible, comes with significant capital investments. To this end, Freitag et al. [107] quantified the increase in capital costs required for hydrogen firing, including costs related to burner replacement, auxiliary mechanical systems, and enhanced emissions control systems. Ammonia firing, on the other hand, results in elevated NOx emissions, even more than hydrogen-fired turbines, necessitating more advanced selective catalytic reduction (SCR) [6] systems to meet stringent emission standards [108].

The capital cost of standard SCR systems typically varies between 15 Eur/kW and 36 Eur/kW with low NOx reduction efficiencies while advanced SCR with 90% removal efficiency is estimated at an additional cost of up to 60 Eur/kW [109]. Literature on binary and ternary co-firing low carbon fuels is scarce. To this extent, few studies suggested a 15% cost increase for blending, yet, their suggestions were based on assumptions not a detailed cost analysis [70, 110, 111]. Due to the scarcity of detailed cost studies on binary and ternary co-firing configurations, conservative cost estimates are adopted in our study.

[5] Combined cycle consists of two interconnected thermodynamic cycles; gas turbine (Brayton cycle) and steam turbine (Rankine cycle), as such, retrofitting costs will affect only the gas turbine.
[6] SCR converts nitrogen oxides (NOx) into harmless nitrogen gas and water.

Specifically, we assume a capital cost increase of 7.98% for hydrogen co-firing, 11.34% for ammonia, 13.41% for ternary co-firing that does not include ammonia in the blend, and 16.77% for ternary co-firing that includes ammonia in the blend. The rationale behind those increases stems from the fact that SCR requirements are higher in case of ammonia co-firing or ternary co-firing [112], while fuel and burner systems modifications[7] are costlier in case of ternary co-firing. That said, large-scale commercial deployment of low-carbon turbines may reduce these costs over time as major material cost is in the turbine itself [70], however, potential learning effects are excluded from our analysis as a conservative assumption.

By considering different pathways for low-carbon fuels, the tradeoffs between different shipping routes and firing modes are evaluated. Ammonia, while offering advantages in transport and storage over hydrogen, may impose higher retrofitting costs due to its higher emission profile. Conversely, biomethane appears attractive due to compatibility with existing infrastructure, yet future competition for its use in other hard-to-abate sectors could constrain its availability and cost-effectiveness for co-firing [44].

Table 2: Cost assumptions for components within system boundary in €$_{2025}$

Variable	**Value**	**Description & unit**	**Reference**
CCGT OCC	942.14	Overnight capital cost [Eur/kW]	[101]
FLH	1000	Full load hours [h]	Assumption based on [113]
FOM $_{CCGT}$	14	Fixed Operation & Maintenance Cost [Eur/kW/a]	[114, 115, 116]
VOM $_{CCGT}$	3	Variable Operation & Maintenance Cost [Eur/MWh]	[114, 115]
LH_2-Storage tank OCC	945	Hydrogen on-site storage tank - overnight capital cost [Eur/MWh[8]]	[25]
H_2-Storage cavern OCC	292	Hydrogen on-site salt cavern storage - overnight capital cost [Eur/MWh[8]]	[104]
NH_3-Storage tank OCC	143	Ammonia on-site storage tank - overnight capital cost [Eur/MWh[8]]	[101]
CH_4-Storage tank OCC	164	Biomethane on-site storage tank - overnight capital cost [Eur/MWh[8]]	[10]
FOM $_{Storage}$	14	Fixed Operation & Maintenance Cost [% of capex[9]/a]	[25]
Reserve fuel capacity	3	Days of backup fuel supply to account for supply disruption	[105]
Global H_2-Production cost	50	Production cost of green hydrogen from the global market [Eur/MWh]	[25, 84]
Global H_2-Production cost	86.1	Production cost of green hydrogen from the local market [Eur/MWh]	[25, 84]
H_2-Liquefaction cost	9.7	Cost of hydrogen liquefaction [Eur/MWh]	[25]
H_2-Shipping	24.3	Cost of international long-distance hydrogen shipping [Eur/MWh]	[117]
H_2-Truck distribution	32.8	Cost of hydrogen in-land[10] distribution by truck [Eur/MWh]	[118]
H_2-Pipeline distribution	34	Cost of hydrogen in-l1.and[10] distribution by pipelines [Eur/MWh]	[118]
H_2-Rail distribution	22.2	Cost of hydrogen in-land[10] distribution by rail [Eur/MWh]	[119]
H_2-Gasification	8.5	Cost of hydrogen gasification process [Eur/MWh]	[120]

7 Includes piping and tubing.
8 Overnight capital cost of storage units is per MWh of fuel.
9 CAPEX here is defined as in Eq. 4
10 Assuming a distribution distance of 500km within the land.

NH_3-Synthesis	32.7	Cost of hydrogen to ammonia synthesis via Haber-Bosch process [Eur/MWh]	[94]
NH_3-Shipping	11.8	Cost of international long-distance ammonia shipping [Eur/MWh]	[101]
NH_3-Truck distribution	23.2	Cost of ammonia in-land distribution by truck [Eur/MWh]	[121]
NH_3-Pipeline distribution	7.5	Cost of ammonia in-land[10] distribution by pipelines [Eur/MWh]	[119]
NH_3-Rail distribution	3.3	Cost of ammonia in-land[10] distribution by rail [Eur/MWh]	[121]
NH_3 to H_2 cracking	20%	Energy losses due to ammonia cracking to hydrogen [%]	[106]
Biomethane production cost	87.8	Production cost of biomethane [Eur/MWh]	[10]
Biomethane pipeline distribution	4.3	Cost of biomethane in-land[10] distribution by rail [Eur/MWh]	[103]

The main economic assessment indicator used in this study is the levelized cost of electricity (LCOE), which captures the discounted average cost per megawatt-hour of electricity over the lifetime of the asset and reflects the break-even price that must be achieved to yield a zero-net-present value. The LCOE (Eq. 1) is calculated by incorporating the capital requirements (CAPEX), the annual fixed operation and maintenance cost (FOM), the variable operation and maintenance cost (VOM), and the electricity output in year y.

$$LCOE = \frac{CAPEX + \sum_{y=0}^{n} \frac{FOM+VOM}{(1+discount\ rate)^y}}{\sum_{y=0}^{n} \frac{Electricity_y}{(1+discount\ rate)^y}} \qquad \textit{Eq. 1}$$

As the LCOE represents the minimum cost per MWh that must be covered by the market price to break even, discounting the fixed costs and energy with the weighted average cost of capital (WACC) is appropriate (Eq. 2 & 3) [122]. In literature, discount rates may be nominal or real. However, short-term studies typically apply current monetary values, whereas long-term studies are frequently computed in real monetary values to adjust for inflation over extended periods [123].

$$WACC_{nominal} = V(Equity) \cdot r_E + V(Debt) \cdot r_D(1 - tax_{rate}) \qquad \textit{Eq. 2}$$

$$WACC_{real} = \frac{1+WACC_{nominal}}{1+i} - 1 \qquad \textit{Eq. 3}$$

The capital cost is calculated using the overnight capital costs (OCC) and the fixed charge rate (FCR) as shown in Eq. 4, which includes the capital recovery factor (CRF), the project finance factor (PFF), as well as the construction finance factor (CFF) as shown in Eq. 5.

$$CAPEX = OCC * (1 + FCR) \qquad \textit{Eq. 4}$$

$$FCR = CRF * PFF * CFF \qquad \textit{Eq. 5}$$

The capital recovery factor represents the present value of the uniform annual payments required to repay the initial investment (Eq. 6). The project finance factor captures the present value of depreciation and tax shields over a standard tax depreciation period of 15 years[11] (Eq. 7 and 8), while the construction finance factor accounts for additional project development costs incurred during construction (Eq. 9 and 10).

[11] FD is the depreciation factor based on 150% declining-balance depreciation method (15 years)

$$CRF = WACC * \left[\frac{1}{1-\frac{1}{(1+WACC)^n}}\right] \qquad Eq.\ 6$$

$$PFF = \frac{1 - PVD * tax_{\text{rate}}}{1-tax_{\text{rate}}} \qquad Eq.\ 7$$

$$PVD = \sum_{y=0}^{y=M} FD_y \ * \ \frac{1}{(1+WACC)*(1+i)^y} \qquad Eq.\ 8$$

$$CFF = \sum_{y=0}^{y=C} FC_y \ * (1 + IDC)^{(y+0.5)} + \sum_{y=0}^{y=C} FC_y \ * (1 + r_{EDC})^{(y+0.5)} \ * V(Equity) \qquad Eq.\ 9$$

$$r_{EDC} = V(Equity) + IDC \qquad Eq.\ 10$$

The LCOE calculations in our study follow largely from the conventions in literature [124, 114, 115, 125]. The market-standard financing costs and risk premiums are taken into account in detail and shown in Table 3. For our analysis, all costs are calculated in real monetary terms and shown in $€_{2025}$ with an exchange rate of 0.925 is used from \$ to €[12].

Beyond the LCOE, this study also evaluates total system investments and capacity sizing implications for the British and German energy systems, with a closer look at Keadby2 CCGT. According to the latest UK carbon budget, 38 GW of new low-carbon dispatchable[13] capacities will be required to reach net-zero emissions [126]. Similarly, the German Network Development Plan (NDP) shows a need for 51.9 GW of low-carbon dispatchable generation by 2045, with 25.2 GW expected to come from new investments [127][14]. Considering the backup role and high operational flexibility of these CCGTs, an annual full-load hours (FLH) of 1,000 is assumed, in line with values reported in [113]. Importantly, unlike conventional natural gas fired-plants, low-carbon fueled CCGTs can operate flexibly without increasing the CO_2 emissions[15], making them valuable for system balancing during high renewable variability [128].

The rationale for presenting total upfront investment costs is to quantify the financial requirements for achieving the "last mile" of decarbonization. Since these retrofitted power plants are primarily expected to operate in backup or peaking modes, it is crucial to emphasize that they should not be viewed as the cornerstone of decarbonization strategies. Rather, they serve as a complementary solution for enabling deep decarbonization. While long-term decarbonization is more efficiently achieved through electrification, renewable energy deployment, and battery storage, low-carbon fuels and CCGT retrofitting offer a practical means of eliminating the residual emissions from the hardest-to-abate segments of the power system. In this context, they represent a critical enabler for accelerating the final stages of the energy transition.

Table 3: Financial assumptions

Variable	Value	Description & unit	Reference
$WACC_{Real}$	5.61%	Weighted Average Cost of Capital - Real	Calculated from Eq. 3
Efficiency	63%	CCGT Efficiency	[129]

[12] investing.com: Average of the year 2024 from commodities trading
[13] Low-carbon dispatchable capacity refers to generation from hydrogen or gas with carbon capture and storage.
[14] It is important to note that the NDP of Germany [122] reports a potential of retrofitting of 26.7 GW from the current gas fleet of 32.3 GW yet offers no explanation how this number was obtained.
[15] Flexible operation of natural gas-fired plants increases the CO_2 emissions intensity of the generated electricity.

V(Equity)	40%	Share of equity [%]	[114, 115, 130]
r_E	11.3%	Return on Equity [%]	[114, 115, 130]
V(Debt)	60%	Share of debt [%]	[114, 115, 130]
r_D	6%	interest on debt [%]	[115, 130]
tax_{rate}	25.7%	Tax rate [%]	[131]
i	1.5%	Long-term inflation rate [%]	[115, 132]
$\text{WACC}_{\text{Nominal}}$	7.2%	Weighted Average Cost of Capital – Nominal [%]	Calculated from Eq. 2
USD to Eur	0.925	Average exchange rate	investing.com
PVD	60.8%	Present Value of Depreciation [%]	Calculated from Eq. 8
FD	-	Annual deductions for depreciation [16] [%/year]	[133]
M	15	Depreciation period [years]	[133]
PFF	113.6%	Project Finance Factor [%]	Calculated from Eq. 7
C	3	Construction years	[134, 116]
IDC	8%	Interest during construction – Nominal [%]	[135]
IDC_{Real}	6.4%	Interest during construction – Real [%]	Calculated from Eq. 3
r_{EDC}	17.7%	Return on Equity during construction [%]	Calculated from Eq. 10
FC	-	Fraction of capital at construction year 80% at year 0, 10% at year 1, 10% at year 2	[124]
CFF	108.9%	Construction Finance Factor [%]	Calculated from Eq. 9
CRF_{CCGT}	6.6%	Capital Recovery Factor [%]	Calculated from Eq. 6
CCGT lifetime (n)	35	Technical service lifetime of CCGT	[115, 134]
$\text{CRF}_{\text{Storage}}$	8.4%	Capital Recovery Factor [%]	Calculated from Eq. 6
Storage lifetime (n)	20	Technical service lifetime of on-site storage	[136]
$\text{FCR}_{\text{Storage}}$	10.4%	Fixed Charge Rate – Storage [%]	Calculated from Eq. 5

The lifetime of CCGT is assumed to be 35 years [115, 134]. While life extension repowering or retrofitting measures can increase that up to 50 years, estimating the costs of extending the life of power plant beyond the original design intent is very difficult [137]. As such, CCGT capacities that have not yet reached a technical life of more than 10 years are assumed to be economically viable to retrofit it.

Huge uncertainties lie in the future energy systems. As seen in Figure 1, the model incorporates various key parameters affecting the feasibility of low-carbon fuels in CCGTs that are subject to huge uncertainty. Therefore, the uncertainties of low-carbon fuels are evaluated with a sensitivity analysis of ±20% to test the robustness of the results and outline key factors affecting their feasibility. Moreover, the analysis explores the cost efficiency of the infrastructural requirements sized for peak demand but operating at lower average loads, providing insights into whether infrastructure investments are justifiable under varying conditions.

While the FLH used in our study is set to represent a modest weather year where CCGT operates in a back-up mode, recent experience has shown that the impact of weather years on electricity prices can be extreme, especially with higher shares of renewables. As such, different operating modes for CCGTs are investigated, where it can be operated in a super-peaking mode to represent a good weather year (FLH of 500 hours) or with a moderate base-load mode (FLH of 3000 hours) to represent a bad weather year.

Importantly, this analysis aims to determine whether the required investments for converting CCGTs to low-carbon fuels are economically viable, specifically whether market mechanisms can deliver sufficiently high price signals to recover levelized costs, or whether public intervention is necessary through subsidies or adjustments to market design. By examining these variables, the analysis will provide insights into the uncertainties and potential risks associated

[16] The reader is referred to the appendix for the complete tabular values.

with converting CCGTs to low-carbon fuels, helping to inform decision-making about the economic feasibility and cost optimality of low-carbon fuels in CCGT.

Results & Discussion

This section presents the findings from our analysis of low-carbon fuel use in CCGTs. First, we examine the marginal and levelized costs associated with firing different low-carbon fuels and their blends, exploring how fuel composition and storage impact overall cost. Next, we quantify the total system investment costs for deploying low-carbon dispatchable capacity in the UK and Germany, with a closer look on Keadby2 power plant in the UK, including retrofitting and infrastructure requirements. Together, these results provide a comprehensive picture of the economic feasibility of transitioning gas-fired power plants to low-carbon fuel use.

Plant-Level Economics: Firing of Low-Carbon Fuels and Fuel Blending

Through the different fuels that can be used in a gas turbine and their routes, we investigate the marginal cost of electricity (MCOE) and the needed capital for retrofitting. Figure 2 illustrates the marginal cost of electricity for different fuel routes, with a detailed breakdown of individual cost components and a ±20% sensitivity range. The robustness of our results through a sensitivity analysis is explored in Appendix A. The routes analyzed include locally produced biomethane, hydrogen and ammonia traded globally and locally. To benchmark the results, natural gas traded at 50 €/MWh_{fuel} and a carbon price range of 100 to 400 €/tCO_2 is used to capture the substantial uncertainty surrounding future prices of natural gas and ambition of policies around carbon budgets [138, 139][17].

Liquid hydrogen and ammonia-based routes (NH_3 and NH_3-Cracking) start with a similar production cost but diverge significantly due to the processing steps involved. Despite the advantages in the NH_3-cracking route of cheaper logistics costs, the additional cost of cracking increases the cost by 20%, raising the total marginal cost to the highest among the evaluated options, with a minimum of 146 €/MWh_{el}. LH_2 incurs the highest shipping and delivery costs, accounting for about 45% of its total cost, with an additional regasification cost of 13 €/MWh_{el}, making LH_2 the second-most expensive route after NH_3-Cracking. NH_3, while similar to LH_2 in production costs, avoids the high shipping and distribution costs, however, it still bears significant synthesis expenses accounting for more than 30% of its cost. The uncertainty range for the hydrogen-based routes is also considerable, underscoring the compounded risks of complex supply chains and technological dependency. Under aggressive cost reduction scenarios, the marginal cost of electricity from ammonia could reach 122 €/MWh_{el}, biomethane could be a bit more expensive at 129 €/MWh_{el}, while hydrogen and cracked ammonia remain north of 145 €/MWh_{el}.

[17] Assuming a CO_2 intensity of 187 kg CO_2/MWh_{fuel}

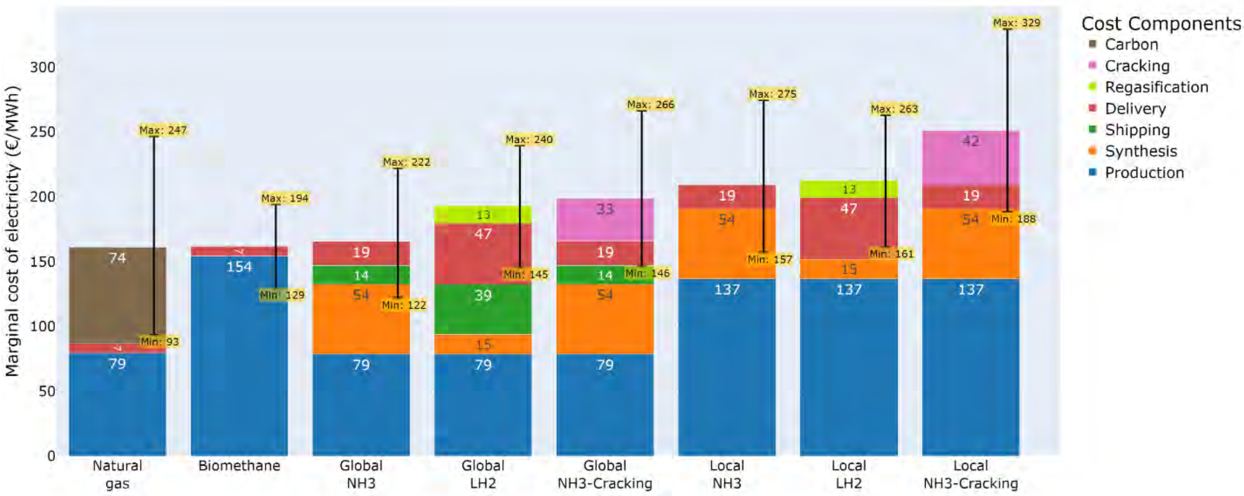

Figure 2: Breakdown of average marginal cost of electricity for single-firing fuels. The error ranges represent the cost uncertainty of the supply chain with a ±20% sensitivity range. Moreover, several inland distribution options for low-carbon fuels are included in the error ranges.

To put this into perspective, during the 2022 energy crisis[18], wholesale electricity prices exceeded 200 €/MWh$_{el}$ for 4691 hours in Germany, with the 21st percentile at 122 €/MWh$_{el}$. In the UK, prices surpassed 200 €/MWh$_{el}$ for nearly 5000 hours, with the 14th percentile also at 122 €/MWh$_{el}$. By contrast, in 2024, such price levels were observed for only 111 hours in Germany (89th percentile at 122 €/MWh$_{el}$) and just 53 hours in the UK (91% quantile of 122 €/MWh$_{el}$). Periods of high prices typically happen with low RES-infeed and high demand, conditions in which dispatchable generation sets the market clearing price. In a decarbonized power system, where low-carbon fuels displace gas power plants, wholesale electricity prices could remain structurally elevated without major market reforms or policy interventions.

Among the routes, natural gas shows the lowest marginal costs, however with the widest uncertainty range, spanning from 93 €/MWh$_{el}$ to 247 €/MWh$_{el}$. This suggests that while natural gas may currently appear economically attractive, its sensitivity to price fluctuations, geopolitics, or regulatory changes is significant. The carbon cost component is substantial, indicating its high vulnerability in decarbonization scenarios. Biomethane, in contrast, shows a higher cost pattern compared to natural gas, however it is largely dominated by production costs alone. This reflects the simplicity of the supply chain but also highlights the high intrinsic cost of biomethane production. The cost range for biomethane is narrower, suggesting cost stability but less potential for cost reduction in the current configuration.

Locally produced hydrogen (and derivatives) exhibits the highest marginal cost amongst the other routes, averaging north of 200 €/MWh$_{el}$. However, long-term contracts could in principle hedge against significant uncertainties associated with the global market fluctuations, making these high costs relatively manageable. Moreover, the previous conclusion holds in showing that cracking hydrogen, despite its lower infrastructural requirements, will result in the highest marginal cost of electricity. This makes NH_3-cracking the least feasible option in our analysis.

[18] Ember European Wholesale Electricity Price Data: https://ember-energy.org/data/european-wholesale-electricity-price-data/

The retrofitting of CCGT to accommodate low-carbon fuels reveals several noteworthy aspects, as illustrated in Figure 3. The LCOE of an unmodified CCGT is estimated at around 93 €/MWh$_{el}$. Switching to hydrogen increases the LCOE by 6 €/MWh$_{el}$ for retrofitting purposes. In contrast, using ammonia requires a more advanced emissions control system, leading to an LCOE increase of 8.6 €/MWh$_{el}$. Ternary fuel blending results in an even higher increase of 12.7 €/MWh$_{el}$ due to the even higher costs for retrofitting and emissions control system.

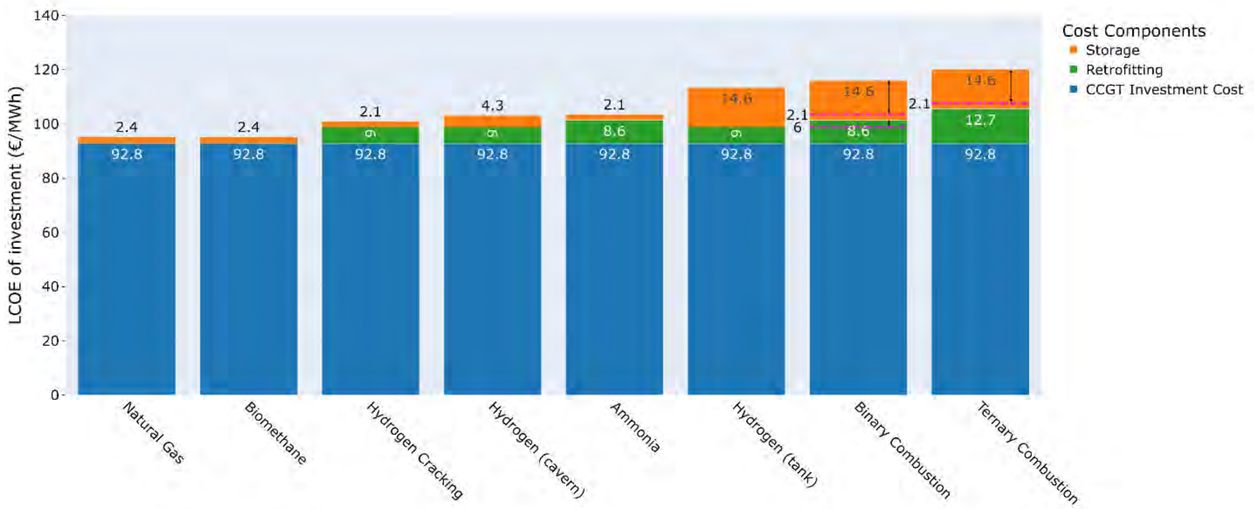

Figure 3: Breakdown of LCOE and retrofitting of CCGT for different blends.

Interestingly, the impact of storage capacity on the LCOE is more nuanced than the retrofitting costs. Hydrogen storage tanks increase the LCOE by 14.6 €/MWh$_{el}$, while salt caverns are less than a third of that, increasing the LCOE only by 4.3 €/MWh$_{el}$. While previous assessments of salt caverns in Europe show a massive technical potential [140], this would require a separate assessment based on the location of CCGT itself to investigate its suitability. Biomethane on-site storage would increase the LCOE by 2.4 €/MWh$_{el}$, while ammonia storage results in the lowest on-site storage increase by 2.1 €/MWh$_{el}$.

The case for binary fuel mixtures depends heavily on the mix composition. Figure 4 shows the MCOE and LCOE, offering a holistic perspective to analyze both short-term operational costs and long-term investment costs associated with different binary fuel blending strategies. The analysis reveals a wide range of marginal cost values, from around 152 to over 180 €/MWh$_{el}$, with divergent behavior of different blends. Higher hydrogen shares become incrementally more expensive. Conversely, higher biomethane and ammonia in the blends demonstrate a decreasing marginal cost while cracked ammonia implies a consistently higher marginal cost.

A key observation is the significant impact of storage on the LCOE as shown in Figure 4. Blends involving hydrogen tank storage consistently show higher LCOE values and steeper increases as the share of H_2 increases, compared to their salt cavern counterparts. For instance, the "H_2-tank_NH_3" blend exhibits the highest LCOE, reaching nearly 116 €/MWh$_{el}$ when hydrogen constitutes 100% of the mix, underscoring the substantial cost contribution of hydrogen storage tank. Conversely, hydrogen stored in caverns leads to lower LCOE values, highlighting the cost efficiency of large-scale geological storage. In contrast, ammonia and biomethane present more moderate increases of 2.1-2.4 €/MWh$_{el}$, making them comparatively cost-effective.

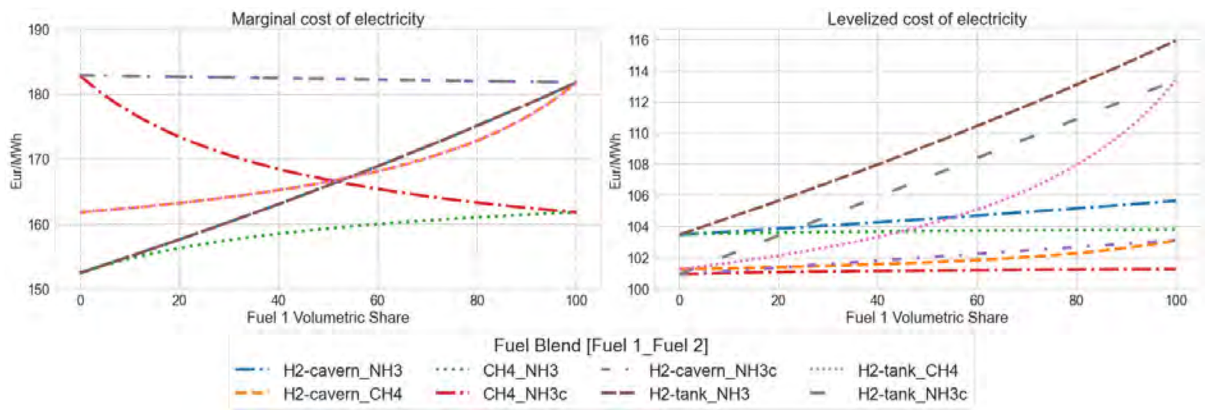

Figure 4: Marginal cost of electricity (left) and levelized cost of electricity (right) as a function of Fuel 1 volumetric share for different binary fuel blends.

Furthermore, the fuel blends in Figure 4 indicate varying cost sensitivities to the blend composition. Blends with biomethane and ammonia show relatively flat LCOE curves, implying that their LCOE is less sensitive to the fuel blending. In contrast, blends involving hydrogen, especially with tank storage, exhibit a strong positive correlation between the share of H_2 and LCOE. In terms of marginal cost, the biomethane-ammonia blend shows a slightly flat curve as both fuel costs are relatively close, resulting in the cheapest marginal cost. In the same context, hydrogen-cracked ammonia blend shows a flat curve, however with the most expensive marginal cost. Among these routes, ammonia cracking stands out due as the cheapest retrofitting option. While the marginal cost of electricity from cracked ammonia is estimated to be the highest, this pathway requires the least retrofitting cost as eventually hydrogen is combusted in CCGT, along with cheap storage requirements of ammonia.

Due to the complex nature of displaying the results of ternary fuel mixtures, the results are reported with ternary contour plots in Figure 5, with working examples on how to read the results. The three corners of the triangle represent the three fuels. Points exactly on the corner represent pure substances (e.g., point 4 with pure H_2 fuel), while points on the axis border represent binary blends (e.g., point 2 of 70% H_2 and 30% NH_3, and point 3 of 60% CH_4 and 40% NH_3). Other points that represent a ternary fuel blending (e.g., points 1 and 5) are read using the gridlines as a guide to determine fuel mixtures. Parallel lines of each axis and their intersection with the third axis refer to the composition share of the third fuel. For instance, a parallel line to the CH_4 axis is used to determine the composition of NH_3, a parallel line to the H_2 axis is used to determine the composition of CH_4, and a parallel line to the NH_3 axis is used to determine the composition of H_2. As such, point 1 is composed of 60% H_2, 10% NH_3, 30% CH_4, and point 5 is composed of 10% H_2, 70% NH_3, and 20% CH_4.

Figure 5 identifies the optimal blending strategies to minimize the marginal cost of electricity production. A significant observation is the direct proportional relation between the marginal cost and the proportion of hydrogen in the blend. As the proportion of H_2 increases, the marginal cost rises, suggesting that hydrogen is the most expensive component within this blending scheme. The highest marginal cost values are observed in regions with high hydrogen content, particularly towards the pure H_2 blends.

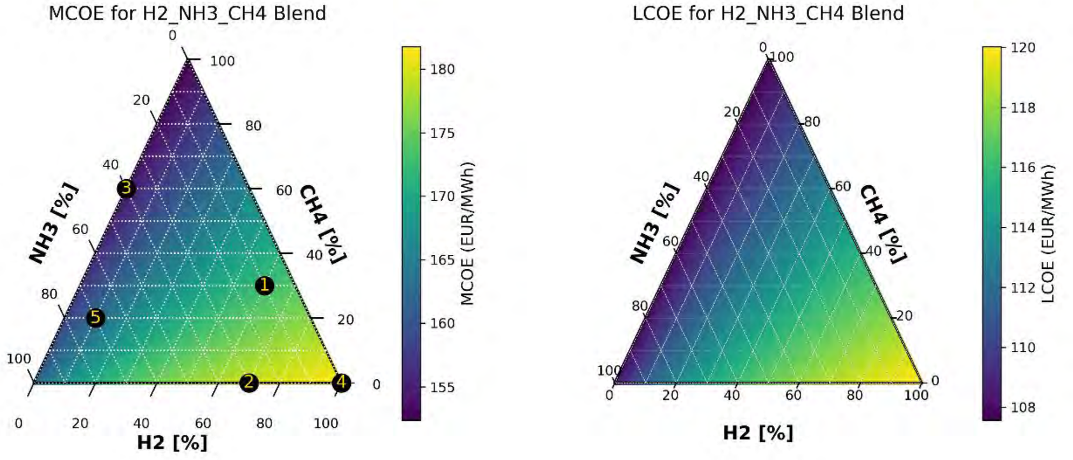

Figure 5: Marginal cost of electricity (left) and levelized cost of electricity (right) for ternary fuel blends based on their volumetric share in the mix. The color gradient indicating the associated marginal cost in €/MWh, with darker shades indicating lower marginal costs values and lighter shades indicating higher costs.

Conversely, the overall trend indicates a preference for ammonia and biomethane as primary constituents for achieving lower electricity costs, making them attractive options for blending, with a slight advantage for ammonia due to its lower marginal cost (Figure 2). Furthermore, a relatively smooth gradient across the ternary diagram is revealed, suggesting a continuous change in LCOE with varying blend compositions. While Figure 5 shows no sign of abrupt shifts or discontinuities, implying a predictable relationship between the fuel mixture and the resulting LCOE, yet the main difference remains in the higher LCOE for blends with higher H_2 share. The main reason behind the higher LCOE costs for blends with higher H_2 share is their higher storage capital requirements compared to those of ammonia and biomethane.

System-Level Investments: The case of Germany and the UK

As discussed in the Methodology section, 38 and 51.9 GW of low-carbon dispatchable capacities will be required to reach net-zero emissions in the UK [126] and Germany [127], respectively. In the UK, the 38 GW will be newly invested capacities, while for Germany 25.2 GW is expected to come from new investments and 26.7 GW will be retrofitted from the current CCGT fleet[14]. To benchmark the additional investment needs for various blending strategies, we define a baseline scenario where CCGTs operate solely on natural gas without low-carbon fuel co-firing. The baseline scenario describes a pathway where the CCGT fleet is kept running on natural gas, without any low-carbon fuel co-firing. Based on our capital cost assumptions of 1039 €/kW of CCGT, €39.5 billion would be required to build 38 GW of new CCGT capacity in the UK. For Germany, 26.7 GW of new CCGT capacity would require a capital investment of €26.2 billion. The detailed breakdown of additional investments for blending is shown in Figure 6.

The sizing of the infrastructural requirements in the case of total investment costs differs from the case of levelized cost. The basic idea of fuel flexibility is that power plants are given the flexibility to switch between fuels depending on the market, either traded locally or globally. Moreover, biomethane production (and cost) fluctuates seasonally. As such, total investment cost should include both the retrofitting cost and the on-site storage sized to the peak of all fuels depending on the blending scenario. For instance, single-firing scenarios include only the cost of one on-site storage facility sized to the peak demand, while binary firing includes both on-site storage options.

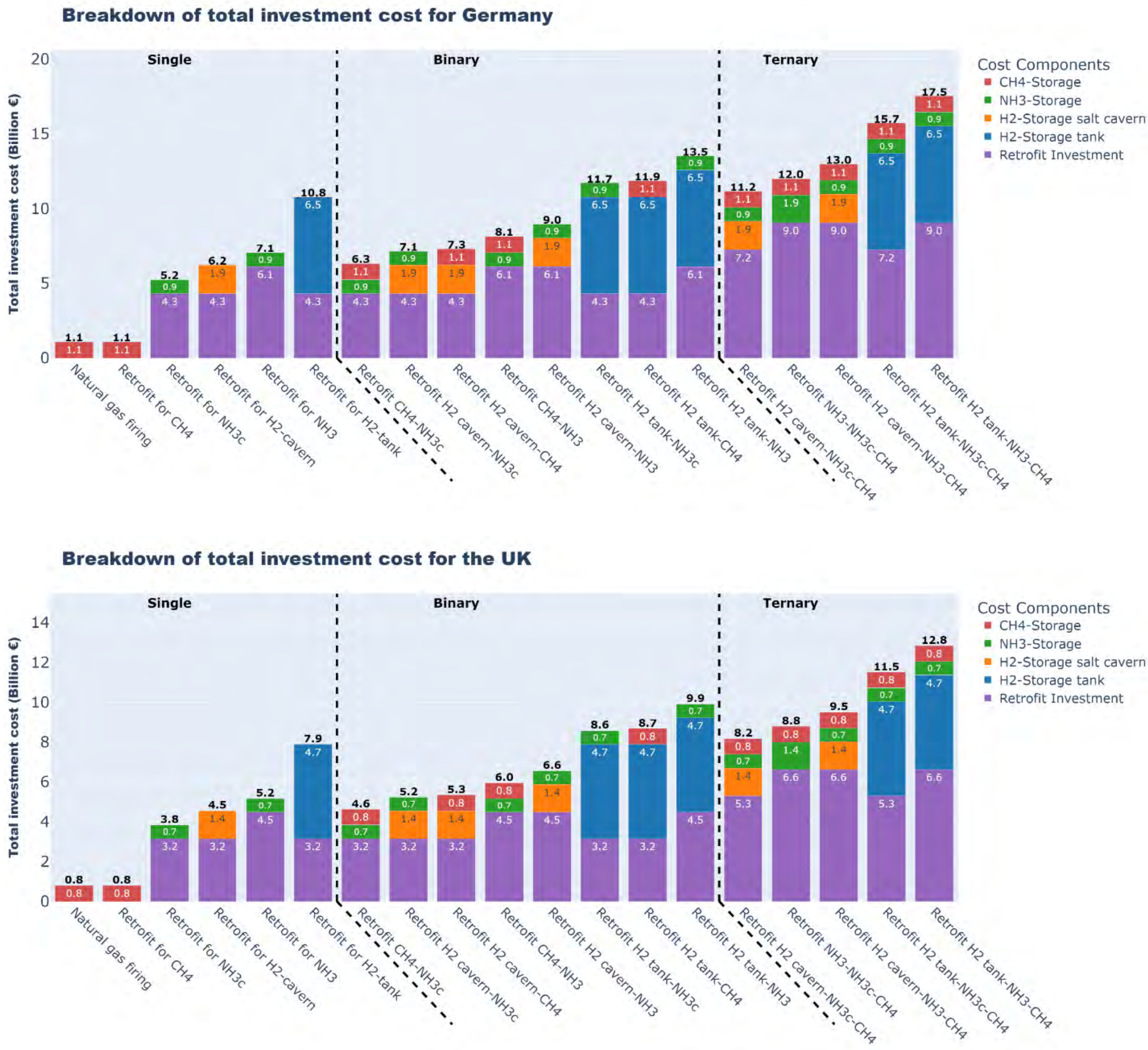

Figure 6: Breakdown of the additional investment costs for the low-carbon dispatchable CCGT capacities in Germany (top) and the UK (bottom)

The CCGT fleet in the UK has a higher capital requirement, despite having lower capacity, as the whole fleet is based on new investments not retrofits. For instance, the baseline scenario requires a €39.5 billion for the CCGT capital investment in addition to a €0.8 billion for on-site storage facility. Consequently, at least €40.3 billion would need to be invested (approximately 1.18% of the UK's GDP_{2024}[19]) to build this CCGT fleet, even if it was operating solely on natural gas. The addition of low-carbon fuel co-firing would require an additional 3-12 billion euros (0.09-0.35% of the UK's GDP_{2024}) for retrofitting costs depending on blending strategy. For Germany, to reach the 51.9 GW of CCGT capacity, at least 27.3 billion euros would need to be invested (approximately 0.62% of Germany's GDP_{2024}), while retrofitting that fleet would increase the cost between 4.2-16.5 billion euros (0.09-0.1% of the Germany's GDP_{2024}).

[19] GDP values are taken from The World Bank: https://data.worldbank.org/indicator/NY.GDP.MKTP.CD

Another interesting aspect is the suitability of retrofitting for countries with different system structures. For instance, in the UK, the additional investments represent an increase of 8-30% from the baseline scenario, while for Germany they represent an increase of 15-60% from the baseline scenario, due to the larger potential of retrofitting within its fleet. This indicates that for countries that are planning to invest in new CCGT capacities for their future power systems, retrofitting their new fleet to accommodate low-carbon fuels can be more viable than countries who aim to retrofit their existing fleet. While the costs to invest in CCGT dominate the required capital, retrofitting and storage costs make up a small part of the total investment.

Moreover, while the retrofitting costs to decarbonize the last few percentage points of carbon emissions from the power system are estimated to high, these costs do not need to be born immediately as the power plants are being built. If plans towards reaching net-zero are to be realized or higher decarbonization levels are achieved, the additional retrofitting costs would make those power plants continue working on low-carbon fuels without risk of stranded assets and help maintain a secure supply of electricity.

Interestingly, while the results quantify the total capital investment, this does not imply that the entire CCGT fleet should be retrofitted for biomethane firing, even if it appears to be the least costly option. Instead, retrofitting decisions should consider location-specific factors. Plants located near biomethane production sites may be well-suited for biomethane or co-firing with hydrogen or ammonia to compensate for limited fuel availability. In contrast, plants near ports or local hydrogen/ammonia production facilities could be fully retrofitted to operate on those fuels. Moreover, the storage requirements in the case of hydrogen tanks show a clear indication that geological storage options should be pursued as the only option to store hydrogen. Consequently, parts of the fleet near geological storage locations could be retrofitted to accommodate hydrogen storage. Finally, while the previous analysis showed the higher marginal cost in case of hydrogen cracking, the results show that the capital investments to accommodate cracked ammonia are the cheapest next to biomethane.

A case study of retrofitting an existing plant: Keadby2 in the UK

Further results on the study case of Keadby2 are shown in Figure 7. Keadby 2 Power Station in North Lincolnshire, UK, is an 893MW power plant with a Guinness World Records title holder for the most efficient CCGT of 64.18% [141]. The plant entered commercial service in March 2023, with a lifetime of 25 years[20]. Ongoing work at the powerplant is exploring different decarbonization pathways, with low-carbon fuel blending emerging as a promising technology to reduce the plant's emissions. Based on our capital cost assumptions of 1039 €/kW of CCGT, Keadby2 has a total base cost of 928 million euros.

[20] Through communication with the corporate affairs department at SSE Thermal (owner of Keadby2), the business model for Keadby2 was adapted to 25 years.

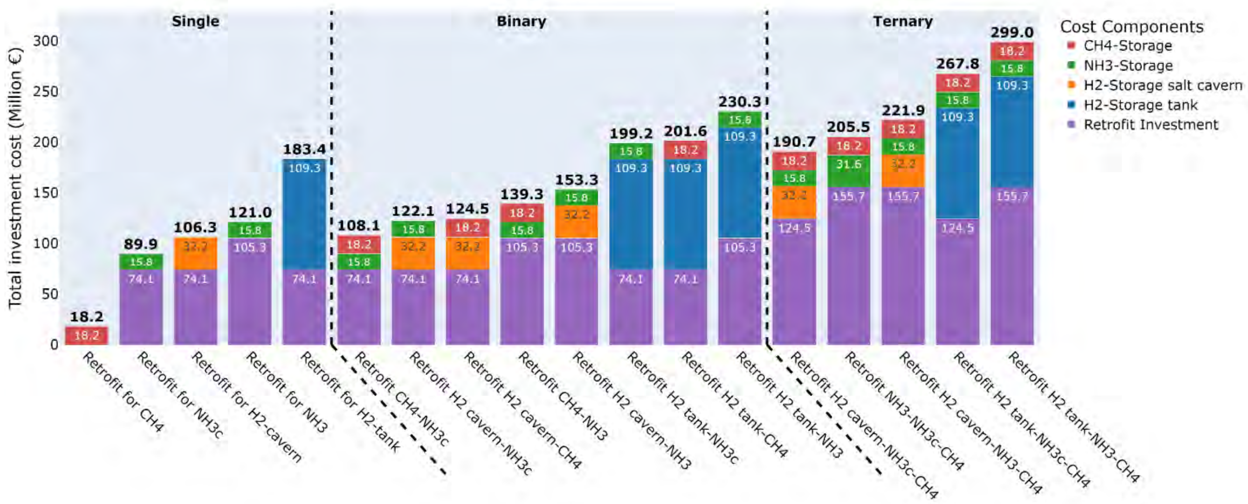

Figure 7: Breakdown of the investment costs for decarbonizing Keadby2 CCGT powerplant.

The results highlight two main cost components of the total investments. Retrofitting costs make up a significant part of the total investment cost, especially for ternary co-firing, ranging from 117-146 million Euros. In terms of single firing, retrofitting for ammonia costs around 99 million euro, while the cheapest retrofitting option is for hydrogen firing, of around 70 million euros. Biomethane firing requires no additional retrofitting investments, with on-site storage making the only cost addition of 17.1 million euros.

Another significant factor is the storage requirements, particularly in the case of hydrogen tanks. Hydrogen tanks for Keadby2 would cost more than 100 million euros, making the case nearly infeasible for retrofits in case of absence of geological storage facilities i.e., salt caverns. Ammonia cracking presents itself as a very promising solution. Storing hydrogen as ammonia is the cheapest option and firing cracked hydrogen requires the lowest capital investments.

Currently, the plant has secured a capacity agreement contract of 15 years with the UK government through the T-4 capacity auction. This means that a retrofitting option might only be considered from 2038 on, with a lifetime up to 2048. Investing 84-281 million euros to decarbonize Keadby 2 might not be a very viable solution given the short residual lifetime after the expiry of the capacity contract. In contrast, biomethane presents a compelling alternative towards decarbonizing the power plant due to its compatibility with existing infrastructure and minimal capital requirements. If biomethane supply to Keadby2 can be secured, the plant can be completely decarbonized with minimal capital costs.

To operate as a peaking unit, Keadby2 would require approximately 1.4 TWh of biomethane annually, equivalent to around 20% of the UK's current biomethane production. Typical large-scale biomethane plants with a capacity of 5 MW can produce up to 19-29 GWh of biomethane annually [142, 143]. Consequently, 60-90 biomethane plants of such size would be required to meet this demand. This underscores the importance of developing the biomethane sector and designing targeted policies that prioritize its use for dispatchable electricity generation.

Conclusion

This study provided a comprehensive techno-economic assessment of low-carbon fuel options for gas-fired power plants, focusing on their role in supporting decarbonized electricity systems through fuel flexibility and blending strategies. The analysis also estimated the capital requirements for future CCGT fleet in the UK and Germany to accommodate low-carbon fuels, with a case study on Keadby2, Europe's newest and most efficient CCGT plant. A major advantage of the use of low carbon gases in CCGTs is the maintenance of the current manufacturing supply chain for CCGTs and all the equipment export opportunities this provides.

Our results show that retrofitting CCGTs to accommodate single or blends of low-carbon fuels increases the LCOE by 6-12.7 €/MWh. Interestingly, the storage cost shows a more nuanced impact on LCOE. For example, storing hydrogen in pressurized tanks can add about 15 €/MWh (LCOE), while using salt caverns cuts that cost down to nearly 4 €/MWh. Similar cost gaps exist for ammonia and biomethane. This underscores the need for coordinated infrastructure development. National and regional energy planners should identify suitable storage sites and invest in infrastructure for cost-effective fuel storage and transport. Policy design should incorporate proximity to fuel supply and storage as part of the retrofitting decision. Plants near ports or ammonia production sites might be ideal for ammonia retrofits, while those in rural areas with access to biogas or biomethane could opt for those fuels with simpler configurations. Importantly, retrofitting CCGTs must go hand in hand with strategies to scale up infrastructure and fuel supply.

Our study reveals that the marginal costs of electricity using hydrogen, ammonia, or biomethane exceed 120 €/MWh even under the most favorable circumstances, and typically far exceed 150 €/MWh. Natural gas remains the lowest-cost option under currently foreseeable carbon prices. However, natural gas price volatility and carbon price exposure suggest that there could be a role for low carbon gases under future deep decarbonization. Biomethane can offer a more stable but expensive alternative, however, competition with other sectors might increase its costs further. Hydrogen-based pathways represent flexible but costly options, even with high-cost reduction in the future, their viability will largely depend on infrastructure development, technological maturity, and regulatory support. Retrofitting for ammonia cracking requires fewer capital investments yet has the highest marginal cost.

Biomethane stands out among the other low-carbon fuels as a promising solution. It is costly to produce and its supply chain is underdeveloped, but it can run in existing CCGTs without modification and uses the current gas infrastructure. Our analysis suggests using biomethane as a reserve fuel could cut capital investment needs by up to €12 billion in the UK and €16.5 billion in Germany compared to using hydrogen or ammonia blends. Therefore, policymakers should seriously consider locally produced biomethane for peak electricity use in a decarbonized energy system rather than let it be consumed in sectors where electrification or efficiency could achieve decarbonization at lower costs. A policy framework that guarantees biomethane for dispatchable generation could improve cost-efficiency and reduce the risk of stranded assets.

Fuel blending emerges as a crucial strategy for enhancing the flexibility of low-carbon CCGTs. By enabling the use of multiple fuels in varying proportions, operators can optimize fuel supply based on cost, availability, and infrastructure constraints. This flexibility can reduce reliance on a single fuel source, mitigate supply risks, and improve overall system reliability. Our results show that the marginal cost of electricity for fuel blending ranges from 152 to 183 €/MWh depending on the blend. Moreover, accommodating a higher degree of fuel flexibility leads to increased capital for retrofitting, with an LCOE of 101-116 €/MWh. Strategic decisions on retrofitting the CCGT fleet for blending should be tailored to each specific plant, taking into account proximity to fuel supplies, storage infrastructure, and plant's remaining lifetime, rather than applying a uniform high fuel-flexibility retrofit across the entire fleet. This targeted approach helps optimize investment costs and operational flexibility where it matters most.

Long-term energy sovereignty security may become a stronger policy driver. This suggests that using a locally (European) produced low-carbon solution – both in terms of fuel and equipment –may be attractive. Our solution allows flexibility with respect to how, when, and if, low carbon gases are utilized. Achieving the "last mile" of power sector decarbonization requires targeted and pragmatic solutions. Our results show that low-carbon fuels and CCGTs retrofitting is a currently expensive solution but is worth investigating more carefully for deep decarbonization (versus other possible routes to deep decarbonization, such as via intermittent renewables).

Several areas warrant further research. With the high marginal costs of low-carbon fuels, the market design questions seem to remain open. In our methodology, the availability of shared infrastructure in future power systems is assumed (e.g., hydrogen hubs), however, failure to scale up infrastructure would raise the costs even further. Future research should investigate the impact of local infrastructure availability around existing CCGT plants. Low-carbon fuel blending and retrofit options are often overlooked or oversimplified in energy models and strategies, despite their importance in balancing the grid when renewables fall short. We suggest integrating these options explicitly into models to capture their technical and economic trade-offs.

Finally, the technical aspects of fuel blending are well understood in literature, but there is little real-world experience on scale. Questions remain about benchmarking in-lab tests with large-scale ones, and how retrofitted systems perform under real grid conditions. Demonstration projects may provide valuable technical insights, reduce investor uncertainty, and inform future standards and regulations. To this extent, SSE and Siemens Energy have recently launched a multi-million-pound co-investment mission to test large-scale low-carbon fuels[21]. Such projects can further develop best practices for retrofitting and operation of flexible low-carbon plants.

Data Availability

No new data has been produced in this study. All data used is properly cited. The analysis and plotting codes to reproduce the study's results are publicly available on Zenodo https://doi.org/10.5281/zenodo.16342110 and maintained on GitHub https://github.com/AnasAbuzayed/H2_CCGT.

[21] https://www.ssethermal.com/news-and-views/2024/12/sse-and-siemens-energy-announce-hydrogen-power-acceleration-partnership/

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Appendix A

Our cost parameters in the main part of the paper represent 2050 costs. In this section, we quantify the effects of divergent tecno-economic assumptions on different parameters on our main results. While prices for renewable technologies have fallen in the past and will continue to do so in the future, including low-carbon fuel costs, as a result of technical improvements and economies of scale, the extent of this trend is surrounded by huge uncertainty. Hence, we complement our paper with a systematic exploration of the parameter space.

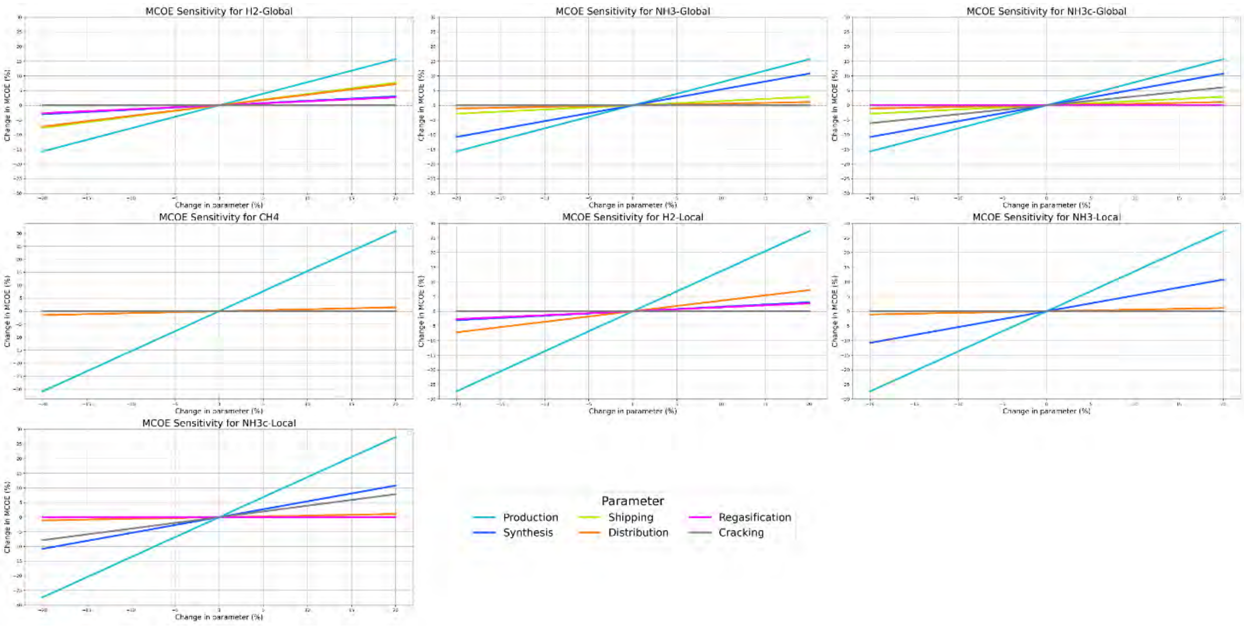

Figure A. 1: MCOE sensitivity analysis for all fuel routes with a ±20% sensitivity range.

Figure A. 1 shows a view of MCOE changes with single parameter values altered by up to -20% to +20%. Production, shipping, and distribution costs exhibit steep, linear trends, implying a significant drive on MCOE variation. These are especially dominant in biomethane, where fuel production costs are very high. Different parameters have various impacts on MCOE depending on the route. For instance, synthesis costs highly affect ammonia routes, while they have less impact on hydrogen routes. In the same sense, shipping and distribution have bigger impact on liquid hydrogen as they have on ammonia. Some parameters such as cracking or regasification only affect routes like NH_{3c} or LH_2, respectively, and are excluded from other cases due to being zero in base values.

The sensitivity analysis for the LCOE for single-fired CCGTs is shown in Figure A. 2. Common to all routes, the full load hours (FLH) of CCGT and the capital costs have a very high impact on the LCOE, where FLH shows an exponential relation. In contrast, parameters like VOM, FOM or retrofit increase have gentler slopes, showing a comparatively smaller effect on LCOE.

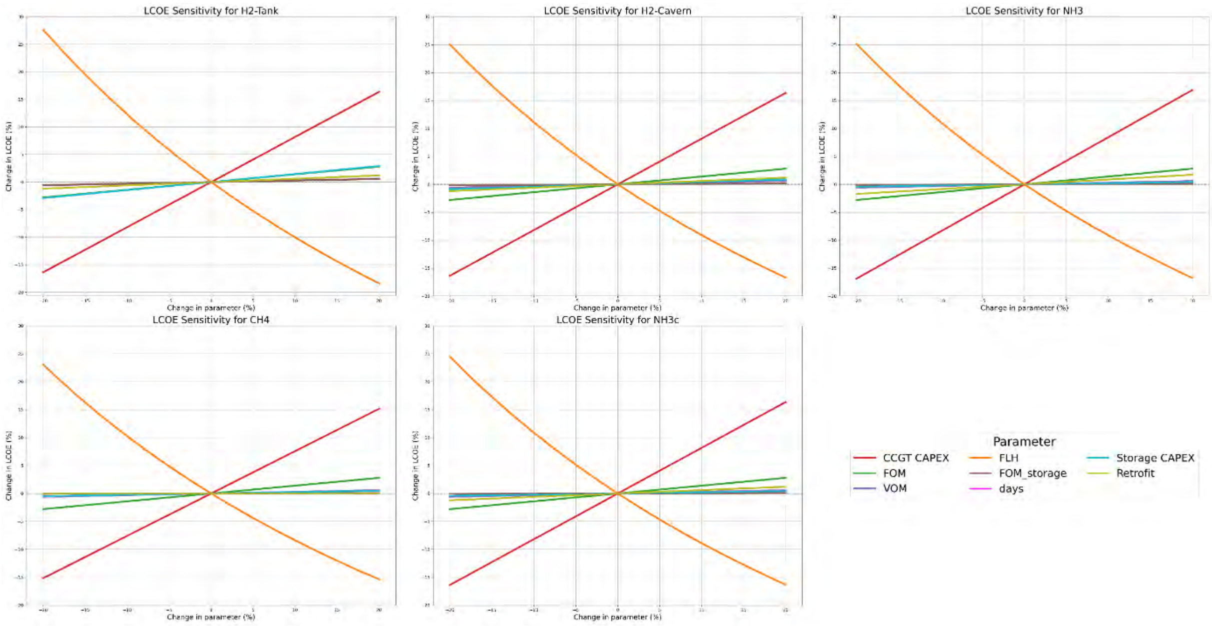

Figure A. 2: LCOE sensitivity analysis for single-fired CCGTs with a ±20% sensitivity range.

Reserve capacity (through parameter *days*) shows a minimal impact on the LCOE, however, as the baseline scenario considers a storage reserve of 3 days, a ±20% range is not completely realistic in terms of reserve capacity. Future CCGTs could have longer storage period requirements, especially in case of absent infrastructures to transport low-carbon fuels, as such, the LCOE in such cases will be higher. The same applies to FLH, where different operating modes can highly affect the LCOE, especially with different weather conditions. Such conditions (e.g., longer cold periods) must be taken into account, particularly when sizing the on-site storage facility. We explore a wider range of sensitivity for FLH and storage duration in Figure A. 3.

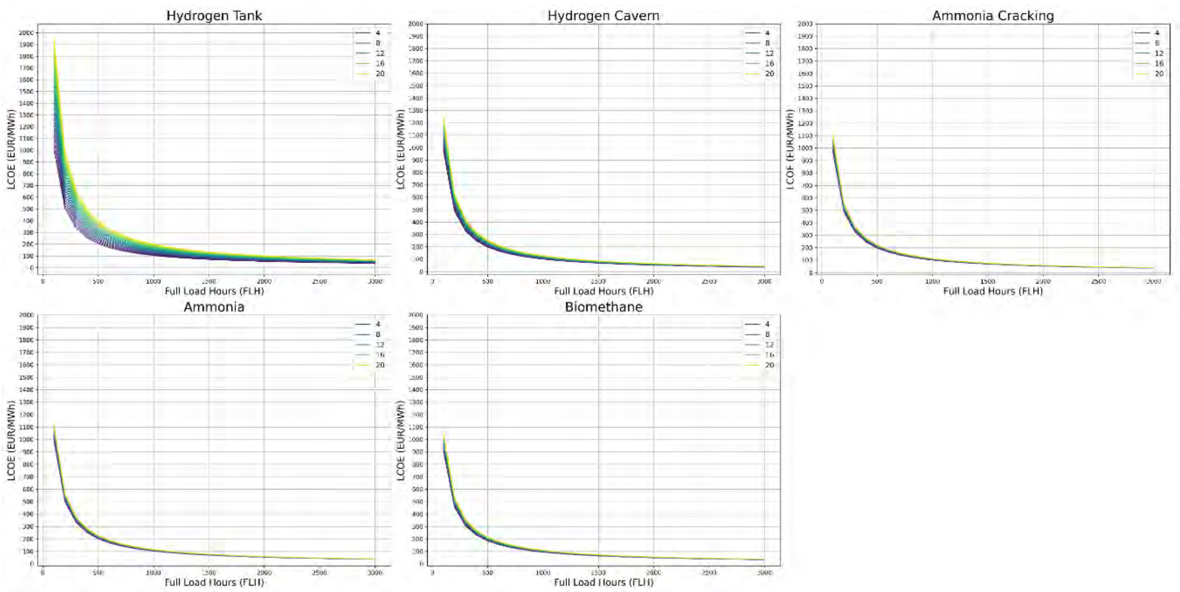

Figure A. 3: LCOE sensitivity analysis for single-fired CCGTs against different FLH modes.

The utilization level of CCGTs massively changes its LCOE. CCGTs operating in a super-peaking mode (less than 500 FLH) have an LCOE of at least double that of the baseline scenario ranging from 187-1980 €/MWh_{el}. The LCOE drastically increases with lower FLH.

However, the composition of the LCOE changes with the reserve capacity and the storage technology. For instance, for a FLH of 100 hours, hydrogen firing has an LCOE of 961 €/MWh_{el}. Depending on the on-site storage duration, hydrogen tanks have a cost ranging between 49-1019 €/MWh_{el}, hydrogen cavern ranges from 14-301 €/MWh_{el}, while cracked hydrogen ranges from 7-147 €/MWh_{el}. These results from the sensitivity analysis support our claims that geological storage options or ammonia storage should be pursued as the main option to store hydrogen.

For a moderate baseload CCGT (more than 2500 FLH), the LCOE of firing drops down to a maximum of 42 €/MWh_{el} and could go as low as 33 €/MWh_{el}. As such, while those powerplants are mainly designed to operate in a backup mode to accommodate the high renewable energy shares in future power systems, the massive investment behind such technologies would encourage the operators to achieve higher utilization factors. Moreover, we design the baseline scenario with 1000 FLH to represent a modest weather year, however, climate induced changes in demand and supply of intermittent renewables could well increase the utilization of such powerplants.

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