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Decarbonizing CHP Systems via Hydrogen: Specific Drivers and Hurdles in Highly Industrialized Regions Like Saarland, Germany

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Abstract

The global energy transition demands solutions that balance intermittent renewable energy generation while decarbonizing heat and power sectors. Hydrogen has appeared as a versatile energy carrier, enabling sector coupling across electricity, heat, and industry. This work explores the integration of hydrogen into combined heat and power (CHP) systems, with a regional focus on Saarland, Germany. It depicts H_2-ready technologies including combustion engines, gas turbines, and fuel cells, and introduces a custom Python-based (Version 3.13) techno-economic optimization model to simulate multi-energy system operations. The analysis reveals that high hydrogen costs, electricity price volatility, and market design significantly constrain economic viability. However, Saarland's industrial structure and cross-border infrastructure projects offer strategic opportunities for scalable hydrogen deployment. The article concludes with targeted recommendations for technology development, policy reform, and regional replication, positioning hydrogen CHP as a flexible and decarbonizing solution in energy-intensive regions.

Keywords: hydrogen; combined heat and power; district heating; infrastructure; combustion engine; gas and steam turbine; fuel cell; electrolyser; Saarland

1. Introduction

Achieving climate neutrality by 2050. This is the goal set out in the European Green Deal for Europe's economy and society which is written into law by the European Union (EU). For the EU, this means reducing net greenhouse gas emissions by at least 55% by 2030 and net zero greenhouse gas emissions for EU Member States as a whole by 2050 [1]. As the global energy sector transitions towards decarbonization, hydrogen has appeared as a key energy carrier. Green hydrogen produced via electrolysis powered by renewable energy sources offers a pathway to reduce emissions in hard-to-abate sectors. One of these sectors with ongoing challenges is the electricity and heat sector, accounting for a 0.4% yearly increase in carbon dioxide emissions worldwide [2]. CHP plants, using the idea of cogeneration of heat and power and thus increasing the overall efficiency of generating heat for process heat and/or district heating networks (DHN), still mostly run on fossil fuels. Therefore, incorporating hydrogen in CHP systems is worthy. The IEA [3] forecasts that low-emissions hydrogen production will rise fivefold to 4.2 Mtpa by 2030 (from under 1% to ~4% of the global output), with an additional 6 Mtpa possible if strong demand-side policies are implemented. The successful implementation of a hydrogen economy in CHP systems, however, depends on a clear understanding of the specific characteristics of

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various production and utilization technologies. While existing studies focus on technical or economic feasibility [4], few address the practical challenges of regional implementation.

This contribution analyses technical and economic insights from an industrial transformation using hydrogen as an energy carrier, thereby contributing to a novel regional scaling framework based on heavily industrialized locations and cross-border integration. Unlike most regional studies, which treat regions as closed systems, this work explicitly incorporates the cross-border energy context of Saarland and proposes transferable models such as the concept of "anchor load," in which stable industrial demand enables early infrastructure investment and sector coupling. The identification of cross-border hydrogen corridors as a scaling mechanism extends current regional hydrogen analyses by taking into account the spatial fragmentation between national energy systems.

The methodological integration of technical, economic, and political dimensions was deliberately carried out in three stages in this contribution.

A systematic techno-economic analysis in the first stage forms the core of the work, in which technical performance data from hydrogen CHP systems are linked to cost, revenue, and market assumptions.

These results are then classified within existing market and regulatory frameworks to show how politics, CO_2 pricing, and market design influence economic feasibility.

Finally, the findings are contextualized regionally using the example of Saarland and translated into concrete, policy-relevant recommendations for action.

2. Hydrogen Combined Heat and Power Systems

2.1. The Idea of Cogeneration

The concept of CHP generation represents an efficient approach to the simultaneous production of electrical energy and usable thermal energy, offering significant efficiency advantages over separate electricity and heat generation. In conventional power plants, waste heat is often dissipated into the environment via cooling towers, whereas CHP systems utilize this heat. This results in substantial fuel savings and reduced emissions as shown in Figure 1. CHP, also called Block Heat and Power Plants (BHHP), typically comprises a combustion engine or gas turbine, a generator for electricity production, and heat exchangers to recover thermal energy from exhaust gases and engine-cooling water. The overall efficiency of a CHP is the sum of its electrical and thermal efficiency, yielding total efficiencies above 90%.

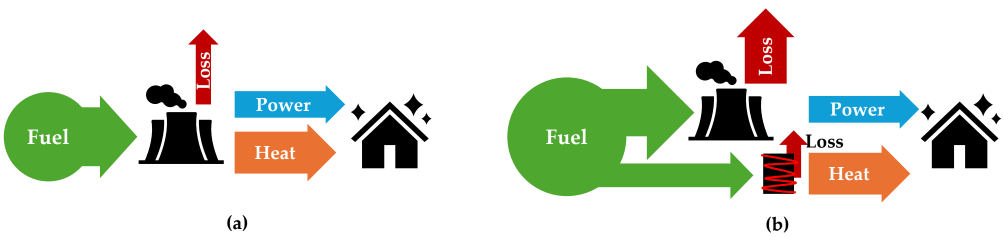

Figure 1. Conceptual comparison of efficiencies for (**a**) combined and (**b**) separate heat and power generation.

The operation of CHP systems is designed to ensure economic viability, requiring precise alignment with the electricity and heat demands of consumers. The most prevalent operational mode is heat-led operation, where the heat demand serves as the primary control parameter, as shown in Figure 2. In this mode, CHP is sized to cover the base thermal load over many hours annually, with peak loads mostly met by supplementary boilers. The generated electricity is either used for on-site consumption or fed into the public grid, without the electricity demand dictating operation. Short-term fluctuations in the thermal base load can be managed by reducing engine output or employing thermal storage systems. Less common is the electricity-led operational mode, where electricity demand directs the system's control. This mode requires a sufficiently large heat sink in the DHN and is typically used to optimize on-site electricity consumption or capitalize on electricity market price fluctuations. A combined heat- and electricity-led mode is suitable for decentralized facilities with consistent energy demands, such as hospitals, where heat demand remains the primary control parameter, but a significant portion of the electrical base load is also covered to maximize system utilization [5].

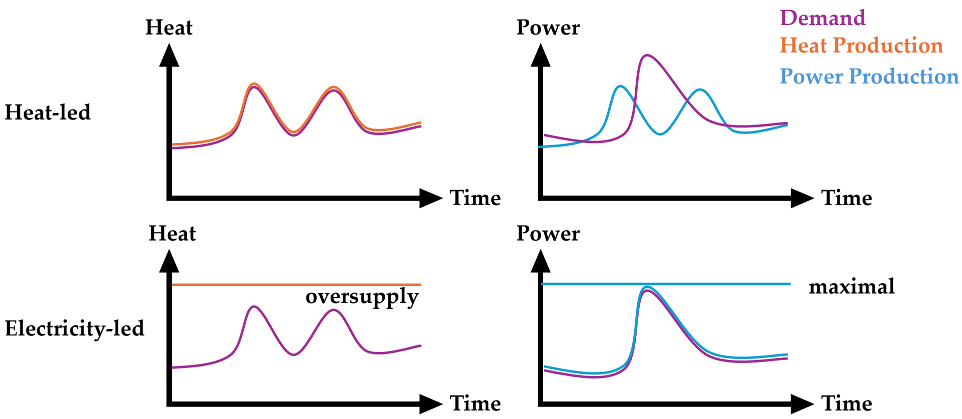

Figure 2. Heat-led and electricity-led operation of CHP plants.

As shown in Figure 3, the planning of CHP systems relies on the sorted annual duration curve of heat demand, which shows how many hours per year a specific heat output is required. This serves as the basis for sizing the CHP plant; characteristic curves of the selected units are integrated into this annual duration curve. Daily profiles of electricity and heat demand are necessary to estimate simultaneous requirements. Heat distribution occurs either through local heating networks, supplying multiple buildings in a confined area, or DHNs, where heat generated in centralized power plants is delivered via extensive, insulated piping systems to consumers in urban or industrial areas. Heat is transferred to consumer heating systems via hydraulically separated heat exchangers. In the context of energy transition, the system-supportive role of CHP plants is increasingly significant. Hydrogen-based CHP systems consider potential consumers or also producers (when integrated with an electrolyser) within a hydrogen supply chain, and can also operate in a market-supportive manner by adjusting load or feed-in based on electricity market prices, contributing to grid stability while generating usable heat or hydrogen. Advantages of modularity include higher availability during maintenance or failure and avoidance of uneconomical part-load operation. There is a target conflict in the number of modules: few large units involve lower investment but fewer operating hours, while small units involve higher investment but more operating hours; larger units typically have better efficiency. Planning objectives include maximum heat coverage with high utilization and as complete as possible own electricity use. Relevant standards in Germany are VDI 3985 for planning, execution, and acceptance of CHP plants, and VDI 2067 (new) for economic efficiency calculations.

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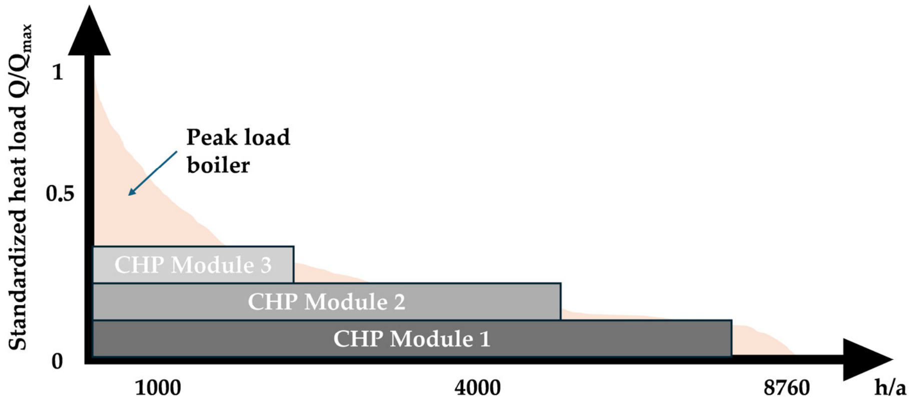

Figure 3. Sorted annual duration curve and CHP planning.

2.2. Hydrogen Technologies

2.2.1. Thermochemical

Combustion engine-based CHP systems convert the chemical energy of a fuel into mechanical power within the combustion chamber, driving a generator to produce electricity. The generated electricity is fed into the power grid via a transformer. Concurrently, the engine's waste heat is transferred through a heat exchanger (to a thermal storage system) and distributed via supply and return lines for space, district or process heating, as shown in Figure 4.

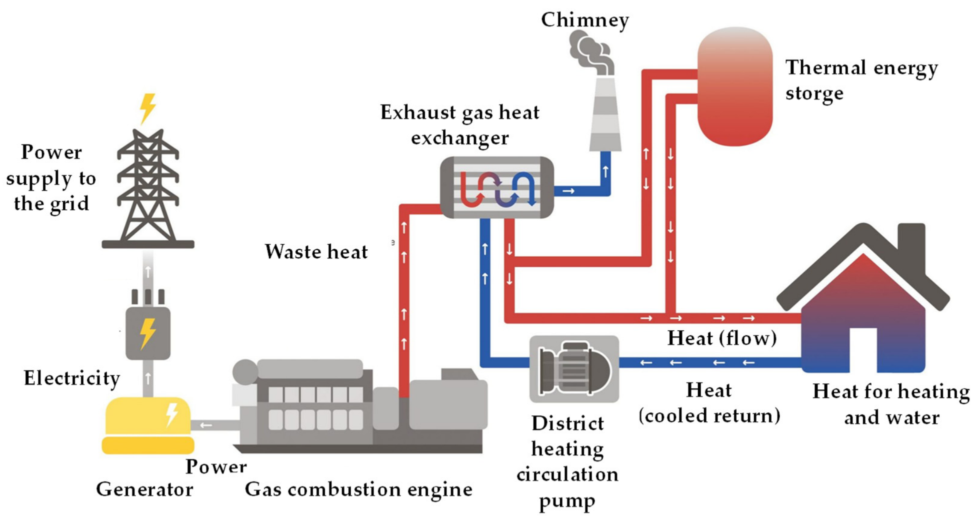

Figure 4. Gas combustion engine plant by *Energie SaarLorLux* in Saarland (translated).

In gas and steam turbine-based CHP systems, gas combustion produces high-temperature gases that drive a gas turbine, which powers a generator for electricity fed to the power grid via a transformer. The turbine exhaust passes through a heat exchanger or heat recovery steam generator to produce steam, which can drive a steam turbine or be stored in a thermal storage system, as shown in Figure 5.

Hydrogen combustion differs fundamentally from natural gas due to its physicochemical properties, as shown in Table 1. The adiabatic flame temperature reaches approximately 2200 °C (versus ~1950 °C for methane), significantly promoting thermal NO_X formation via the Zeldovich mechanism. Hydrogen exhibits faster laminar flame speed (~3 m/s at stoichiometric conditions, ~10× higher than methane's ~0.3 m/s), wide flammability limits (4–75 vol% in air), and low ignition energy (~0.02 mJ), necessitating rigorous prevention of oxyhydrogen formation. As the smallest molecule, H_2 displays high diffusivity and permeability through metals, inducing hydrogen embrittlement in carbon steels. The lower heating value (LHV) is ~120 MJ/kg but only ~10.8 MJ/Nm^3 (≈1/3 of methane's ~35.8 MJ/Nm^3), requiring a threefold increase in volumetric flow for equivalent energy input. The pure H_2 flame is non-luminous with lower overall luminosity, emitting negligible visible radiation but detectable UV emission, while radiative heat transfer is dominated by H_2O bands in the IR, with lower total emissivity than hydrocarbon flames.

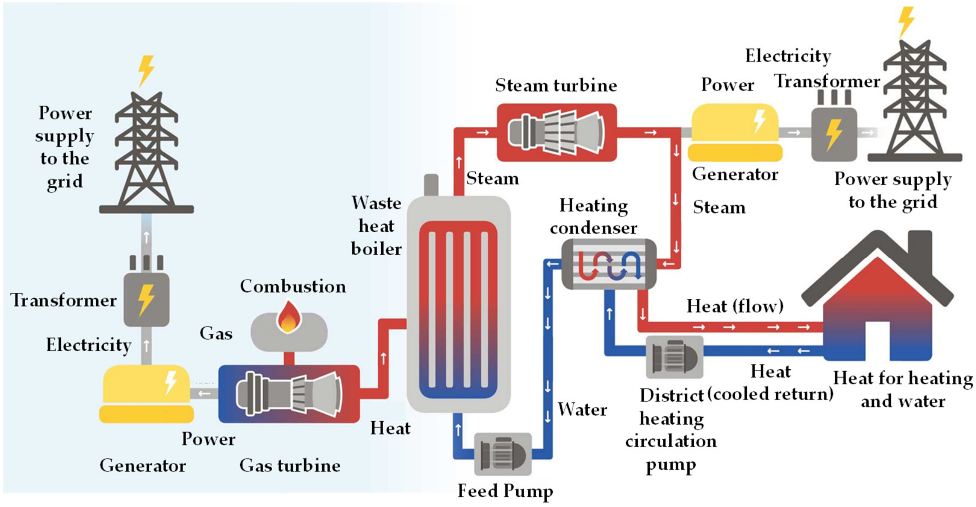

Figure 5. Gas and steam turbine plant by *Energie SaarLorLux* in Saarland (translated).

Table 1. Comparing hydrogen to natural gas.

Property	Unit	Fuel Type	
		Hydrogen	**Natural Gas (Methane)**
Lower Heating Value	(MJ/kg)	~120	~50
Lower Heating Value	(MJ/Nm^3)	~10.8	~35.8
Adiabatic Flame Temperature	(°C)	~2200	~1950
Laminar Flame Speed	(m/s)	~3	~0.3–0.4
Flammability Limits	(% vol in air)	4–75	5–15
Minimum Ignition Energy	(mJ)	~0.02	~0.28
Diffusivity in Air	(cm^2/s at STP)	~0.61	~0.16
Flame Colour		Non-luminous	Blue

Technological adaptations for hydrogen-fired steam and hot-water boilers are well-established in industries with byproduct H_2 (chemical, pharmaceutical, plastics) and emerging green heat applications. Key modifications include [6]:

- Fuel train and burner sizing: pipelines, nozzles, and blower capacity scaled for 3× volumetric flow; combustion chamber volume and port velocity adjusted for higher flame speed and shorter residence time.
- Materials: refractory and heat-exposed components specified for >1800 °C service; avoidance of susceptible alloys to prevent hydrogen attack and embrittlement.
- Burner design: typically premix or diffusion multi-fuel burners with advanced controls for turndown and fuel switching; high excess air or staged combustion to manage flame stability.
- NO_x control: flue gas recirculation (FGR) dilutes O_2 partial pressure, reducing peak flame temperature and NO_x to <100 mg/Nm^3 (at 3% O_2); enables retrofits to maintain rated capacity within regulatory limits.
- Flashback prevention: static arrestors (deflagration/detonation flame arresters) or dynamic quenching via exit velocities > flame speed (e.g., >25 m/s at nozzles).

- Regulatory gap: no dedicated standard exists for hydrogen firing; each installation requires individual hazard and operability (HAZOP) assessment and type examination.
- Condensing technology: fully applicable; exhaust contains high H_2O content (stoichiometric), enabling latent heat recovery. Reducing flue gas from 130 °C to 60 °C via condensing heat exchangers yields fuel savings; system efficiency reaches high levels with low-temperature return (e.g., <57 °C). Caution: FGR plus condensing requires corrosion-resistant materials (e.g., stainless steel or polymer) and control of return temperature to avoid low-temperature corrosion.

2.2.2. Electrochemical

Fuel cells convert chemical energy directly into electrical energy without intermediate mechanical processes, unlike conventional engines. This direct electrochemical conversion enables higher energy efficiency, as fuel cells are not limited by Carnot efficiency, which constrains thermodynamic cycles, as shown in Figure 6. The theoretically usable energy is defined by the Gibbs free energy of the reaction. Fuel cells exhibit only minor efficiency losses under partial load, making them particularly well-suited for variable operating conditions. Although the overall system efficiency may decline at a low load due to the energy consumption of auxiliary components and potential stack heating, well-designed systems maintain a significantly higher partial-load efficiency compared to combustion engines [7].

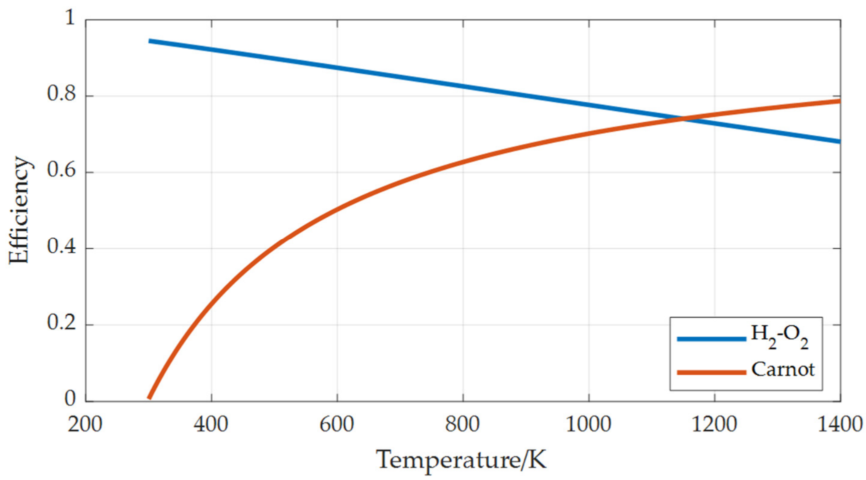

Figure 6. Comparison of Carnot efficiency and maximum theoretical efficiency of an H_2-O_2 fuel cell.

Yu et al. [8] provide a thorough review of hydrogen-based CHP systems, examining key technologies like internal combustion engines, gas turbines, and fuel cells, as well as hydrogen production and storage methods, as shown in Table 2. The study highlights fuel cells' high efficiency, reaching up to 90% for CHP, while pointing out major challenges such as the high cost of renewable hydrogen, limited infrastructure, and NO_x emissions from combustion engines and turbines. It compares fuel cell types, explaining their technical and economic differences, and notes issues like catalyst durability and hydrogen storage density. The paper suggests developing cheaper, non-precious metal catalysts, improving storage safety, and tailoring system designs for specific uses.

Table 2. Chemical reactions and characteristics of fuel cells according to [8].

FC Type	AFC	SOFC	PEMFC	PAFC	MCFC
Anode reaction	$H_2 + 2OH^- \rightarrow 2H_2O + 2e^-$	$H_2 + O^{2-} \rightarrow H_2O + 2e^-$ $H_2 \rightarrow 2H^+ + 2e^-$	$H_2 \rightarrow 2H^+ + 2e^-$	$H_2 \rightarrow 2H^+ + 2e^-$	$H_2 + CO_3{}^{2-} \rightarrow H_2O + CO_2 + 2e^-$
Ion	OH^-	O^{2-}, H^+	H^+	H^+	$CO_3{}^{2-}$
Cathode reaction	$½O_2 + H_2O + 2e^- \rightarrow 2OH^-$	$½O_2 + 2e^- \rightarrow O^{2-}$ $½O_2 + 2H^+ + 2e^- \rightarrow H_2O$	$½O_2 + 2H^+ + 2e^- \rightarrow H_2O$	$½O_2 + 2H^+ + 2e^- \rightarrow H_2O$	$½O_2 + CO_2 + 2e^- \rightarrow CO_3{}^{2-}$
Temperature (°C)	60–220	600–1000 (O^{2-}) 400–800 (H^+)	60–85 (LT) 130–220 (HT)	160–220	600–700
Pressure (MPa)	0.5	0.3	1–2	0.1	0.2
Electrolyte	35 wt–85 wt% KOH	Ceramics, e.g., YSZ	Polymer membrane	Phosphoric acid	Carbonates, e.g., Na_2CO_3, Li_2CO_3
Anode catalyst	Ni, Pt/C	Ni, Zr	Pt/C	Pt/C	Ni (Cr, Al)
Cathode catalyst	Ag, Pt/C	$LaMnO_3$	Pt/C	Pt/C	NiO
Electrical efficiency	45–60%	50–60%	40–60%	40–45%	45–55%
CHP efficiency	68–76%	79–87%	60–80%	85–90%	85%
Available fuel	Pure hydrogen	Natural gas, Hydrogen, CO, HC	Hydrogen	Natural gas, Hydrogen, LPG	Natural gas, Hydrogen, LPG
Oxidant	O_2	Air	Air	Air	Air
Sensitive impurity	S, CO_2	S	S, CO, NH_3	S	S
Electrolyte storage matrix	Asbestos	–	–	SiC	$LiAlO_2$
Lifetime (h)	8 k	80 k	80 k	60 k	20 k
Stack output power (kW)	1–100	5–3000	1–100	150–400	300–1000
Start time	1–10 min	>30 min	1–5 s	1–10 min	>30 min
CO tolerance	<10 ppm	<10%	<10 ppm (LT) <1% (HT)	<1%	<10%
CO_2 tolerance	<100 ppm	<10% (O^{2-}) < 5% (H^+)	<15%	<15%	<15%
NH_3 tolerance	–	<0.5%	<0.1 ppm	<4%	–

2.3. Literature Review

2.3.1. Combined Heat and Hydrogen (CHH) Systems

Burrin et al. [9] developed and evaluated a CHH generator system that integrates a PEM electrolyser with a thermal recovery circuit to simultaneously produce green hydrogen and supply heat to DHNs. Using a 1 MW system model, they show that 312 kW of thermal energy can be recovered per MW of electricity input, delivering hot water at 75 °C or 45 °C, suitable for both existing high-temperature and future low-temperature heat networks. This configuration achieved an overall system efficiency of 94.6% and reduced the Levelized Cost of Hydrogen (LCOH) from EUR3.22/kg to EUR2.70/kg through heat sales. Hou et al. [10] demonstrate that a PEMFC-CHP system utilizing methanol reforming and hydrogen permeation alloy membranes can achieve a thermal efficiency of 81.71%, with 44.17% PEMFC unit efficiency and 31.53% system power generation efficiency under optimized conditions, highlighting its potential for efficient hydrogen-based cogeneration. Skordoulias et al. [11] found that a PtH_2tCHP system operating with 100% hydrogen substitution achieved a roundtrip efficiency of 44.21%, a CHP efficiency of 86.88%, and zero CO_2 emissions, indicating strong potential for decarbonizing CHP plants when powered by renewable hydrogen and operated under optimal capacity factors. Sokil et al. [12] conducted a comprehensive review of hydrogen-based heating technologies, highlighting the H_2HEAT project's integration of a hydrogen-fuelled CHP unit with a dual-stage heat pump system. The system uses 101.8 m^3/h of hydrogen to generate 115 kW of electricity and 129 kW of thermal energy, which is further amplified to 350 kW of heat output via sequential air-to-water and water-to-water heat pumps. This configuration shows a renewable, high-efficiency heating solution suitable for commercial buildings, particularly hospitals, and aligns with EU decarbonization goals.

2.3.2. Techno-Economic Optimization and Market Integration in Hydrogen-CHP Systems

A techno-economic optimization model was employed by Öberg et al. [13] to assess the competitiveness of hydrogen-fuelled gas turbines as a flexibility provider in the transition of electricity systems across 15 European countries toward near-zero CO_2 emissions by 2050. The findings indicate that hydrogen-fuelled gas turbines become cost-competitive primarily under stringent CO_2 emission caps, as projected for 2040 and 2050, particularly with high penetration of variable renewable energy (VRE), whereas their role would be minimal in 2030 when higher emissions are permitted. Wang et al. [14] found that a 100% renewable multi-energy microgrid using a stochastic bi-level bidding model can effectively participate in electricity, thermal, and hydrogen markets, to achieve revenue under a 5%

risk tolerance, with strategic bidding improving profitability and reducing renewable energy curtailment. Haakana et al. [15] developed a techno-economic methodology to optimize the daily operation of CHP plants by integrating participation in electricity reserve markets alongside traditional heat and electricity markets. Using a Simulink-based simulation, they showed that reserve market participation—enabled by partial turbine bypass—can increase annual profitability by 16–28% compared to traditional operation. The method allows CHP operators to sell both heat and reserve capacity simultaneously, leveraging DHN flexibility to mitigate minor heat delivery fluctuations. Kander and Häggström Wedding [16] conducted a techno-economic case study on integrating hydrogen systems with the Ortofta CHP plant, evaluating two configurations: a complete hydrogen system (electrolyser, storage, fuel cell) and a power-to-gas (P2G) system (electrolyser, storage). Using the Energy Optima 3 optimization software and historical data from October 2021–2022, they found that the hydrogen system increased profit by 19.9–21.2% and achieved a payback time of 2.86–3.06 years, while the P2G system yielded 13.3–14.8% profit increase with a shorter payback time of 2.15–2.39 years. Most of the profit stemmed from participation in balancing markets, showing strong economic potential for hydrogen integration in CHP operations. Öhman [17] performed a techno-economic optimization of integrating PEM electrolysis for hydrogen production into the Igelsta CHP plant, with full heat recovery to the DHN. Using a mixed-integer linear programming model under two market scenarios, the study found that hydrogen production is economically viable at a retail price of EUR 3.64/kg, yielding a net present value (NPV) of MEUR 5.46 and a LCOH of EUR 2.18/kg in a low electricity price year. The system ran over 7500 h annually, producing 337 tonnes of hydrogen and recovering 5.6 GWh of heat.

2.3.3. Retrofitting and Hydrogen Blending in Existing CHP Plants

Ribeiro et al. [18] analyzed the techno-economic feasibility of decarbonizing a natural gas-fuelled ICE CHP plant in Luxembourg through three scenarios: continuing natural gas use, retrofitting the existing engine for hydrogen (H_2), and installing a new H_2-ready engine. The study modelled CAPEX, operational costs, and technical requirements. Retrofitting for up to 100% H_2 is technically viable with available technologies, offering a practical transition pathway. However, economic barriers are significant, with CAPEX rising from 20% (retrofit) to 60% (new engine) and with high H_2 fuel costs, worsened by underdeveloped regional H_2 infrastructure. The analysis lacks sensitivity to sector coupling, i.e., district heating, future H_2 cost declines or energy price volatility, and is geographically limited, reducing generalizability. The authors advocate policy incentives, financial support, and regional infrastructure projects to address economic gaps and prioritize research. Nazari et al. [19], in their comprehensive review of hydrogen-fired gas turbines, found that adding 10% hydrogen to natural gas in turbine combustors reduces CO emissions by 60% and NO emissions by 14%, while hydrogen-fired turbines integrated with solar PV systems achieve a 22.7% reduction in CO_2 emissions under optimal conditions.

2.3.4. Flexibility Enhancements for CHP Integration with Renewables

Chaudhary et al. [20] conducted a comprehensive review of technologies and retrofitting strategies to improve the operational flexibility of CHP plants, focusing on ramp rate, operation range, and start-up time as key performance indicators. The study found that integrating thermal energy storage with CHPs can increase ramp rates up to five times (e.g., 18 MW/min), reduce minimum load by 5–15%, and enhance overload capacity by 5–10%, thereby enabling participation in ancillary services for power grid frequency regulation in Europe. These improvements are critical for CHPs to operate economically in dynamic electricity markets and support variable renewable energy integration. Although not focused specifically on hydrogen, Wang et al. [21] conducted a comprehensive review of the technical flexibility and operational strategies of CHP systems within integrated energy systems. The study found that integrating heat accumulators, electric boilers, and heat pumps with CHP units significantly expands the operational region of heat and power output, enabling a reduction in wind power curtailment by up to 84% and improving economic performance through market arbitrage. These flexibility enhancements are critical for secure and cost-effective operation under both cost-based and price-based dispatch strategies.

2.3.5. System-Level Planning for Hydrogen-Integrated Multi-Energy Systems

The integration of hydrogen into multi-energy systems is only effective when all links of the hydrogen energy chain are considered. Lu et al. [4] conducted a comprehensive review of 72 studies on collaborative planning of hydrogen energy chain-integrated multi-energy systems (HEC-MESs). They found that incorporating all five HEC links—production, compression, storage, transportation, and application—into MES planning enables cross-time and cross-space energy allocation, improving overall energy efficiency by approximately four times and reducing carbon emissions by nearly 44% compared to traditional electric-heat systems. These results were confirmed through comparative modelling in residential community case studies.

2.3.6. LCOH and Breakeven Pricing

Sayed-Ahmed et al. [22] found that dynamic operation of PEM electrolysis can reduce the LCOH by up to 42%, while participation in electricity reserve markets can further reduce LCOH by up to 30%, and selling electrolysis waste heat decreases LCOH by 0.2–0.35 EUR/kg, depending on capital cost and electricity price volatility. Gómez and Castro [23] found that green hydrogen production costs vary significantly (1.12–16.20 EUR/kg), but projected cost reductions in electrolysers and renewable electricity could enable wind-based systems to reach 1.41 EUR/kg and solar-based systems 1.88 EUR/kg by 2050, making them economically viable for large-scale deployment. Osman et al. [24] found that among various hydrogen production pathways, only green hydrogen from wind energy remains within the planetary boundary for climate change, whereas blue hydrogen incurs the highest environmental damage, raising its cost from 1.73 EUR/kg to 4.32 EUR/kg H_2, underscoring the importance of life cycle assessment in sustainable hydrogen planning. Campana et al. [25] evaluated two hydrogen-to-power configurations integrated with CHP systems: fuel cells and gas turbines. In the fuel cell scenario, breakeven hydrogen selling prices ranged from 3.4 to 8.79 EUR/kg when including revenues from electricity generation, heat recovery, and grid services, and increased to 4.41–10.98 EUR/kg when excluding co-product revenues. In the gas turbine scenario, breakeven prices ranged from 3.01 to 7.88 EUR/kg with co-product monetization, and 3.91–9.73 EUR/kg without it. Ibáñez-Rioja et al. [26] found that an off-grid hydrogen system with optimized wind, solar PV, BESS, and a 100 MW electrolyser can achieve an LCOH of 1.72 EUR/kg by 2040, with curtailed energy reduced to 8% and full-load hours increased to 4300 h/year, using real data and evolutionary optimization over a 30-year horizon.

Based on the evaluated literature, the following conclusions can be drawn:

Firstly, there is broad consensus that high overall efficiency through complete heat recovery and sector coupling is crucial. Coupling a PEM electrolyzer with heat recovery has enabled overall efficiencies of 94.6% and significantly reduced LCOH through heat yields.

Secondly, there is a consensus that operational flexibility and multi-market integration are key economic success factors. Hydrogen-fired gas turbines will become increasingly relevant in the future, particularly under strict CO_2 limits and high VRE penetration. Strategic participation in electricity, heat, and hydrogen markets can increase revenues, e.g., by participating in balancing energy markets, by 16–28% and reduce curtailments.

Thirdly, there is consensus that stringent climate policy and appropriate market and subsidy conditions are prerequisites for competitiveness. In particular, scenarios with ambitious emission limits by 2040/2050 have a cost-effective impact on hydrogen technology, although political incentives and infrastructure support are also required.

In summary, sources unanimously confirm the technical feasibility and efficiency advantages of hydrogen CHP, while assessments of its economic attractiveness vary significantly depending on regional energy prices, market integration, infrastructure, and policy frameworks.

Discrepancies are particularly evident in short-term economic efficiency and system selection, which are heavily dependent on location.

2.4. Application to Saarland

The literature review provides a broad foundation of hydrogen CHP systems. Cited papers employ assumptions (CAPEX, electricity prices, load factors) that differ from the specific conditions in Saarland. While absolute cost values are therefore not directly transferable, the cited studies remain useful for illustrating relative trends and sensitivities, which are consistent with the Saarland context. The following synthesis clarifies how prior studies directly inform the regional case analysis:

2.4.1. Relevance of System Designs

Many of the reviewed studies focus on hybrid configurations—specifically, systems coupling CHP units to maximize operational flexibility. These architectures align closely with Saarland's existing district heating plants, which already have thermal storage and grid connectivity. For example, hybrid models discussed in Burrin et al.'s and Ribeiro et al.'s works show cost reductions through dynamic load balancing, a concept transferable to Saarland's industrial and municipal heat networks.

2.4.2. Efficiency and Cost Benchmarks

Reported efficiencies of 60–80% for high-temperature fuel cells and 35–45% for H_2-ready combustion engines provide reference points for the region's prospective retrofits. Compared to Saarland's current CHP efficiencies, these findings suggest achievable improvements through hydrogen integration. Likewise, the LCOH estimates in European pilot studies help frame the cost assumptions in this report's parity analysis.

2.4.3. Lessons for Regional Feasibility

Several studies emphasize the importance of flexible operation and policy support (e.g., carbon pricing, capacity remuneration mechanisms) to make hydrogen CHP viable. These insights underpin the following Saarland analysis by justifying the focus on market design, cost recovery mechanisms, and anchor industrial loads as key enablers. Thus, the literature not only informs technological feasibility but also confirms the strategic policy recommendations derived later in this report.

3. Saarland

3.1. Overview

As a historically industrial and geographically compact region, Saarland presents a compelling model for examining hydrogen-based CHP integration into district heating systems. The region's unique energy landscape—characterized by significant industrial heat demand, a growing share of intermittent renewables, and proximity to two transnational hydrogen initiatives—positions Saarland as a critical testbed for understanding how hydrogen technologies can address the dual imperatives of decarbonization and energy resilience. Figure 7 shows Saarland's unique infrastructure.

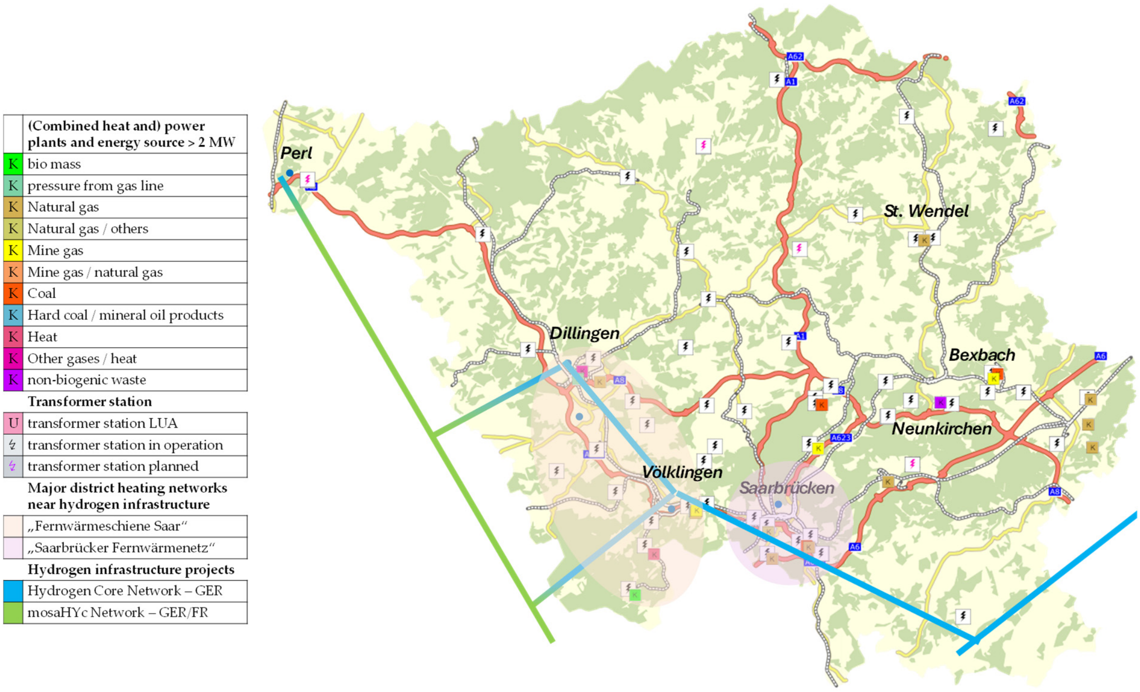

Figure 7. Hydrogen, heat, and power infrastructure in Saarland.

Saarland's industrial structure is still dominated by energy-intensive sectors, particularly steel, chemicals, and automotive manufacturing. The proximity of such industries to urban heat sinks creates conditions conducive to CHP deployment. However, decarbonization pressures—including the EU's Fit-for-55 package and the looming expansion of the EU Emissions Trading System (EU ETS II)—are making fossil-based CHP solutions increasingly untenable. In response, Saarland has become a focal point for hydrogen infrastructure development. The Bundesnetzagentur's approved Szenariorahmen for the Netzentwicklungsplan Strom 2025–2037/2045, which integrates climate goals under the §12a energy law and aligns power and gas/hydrogen systems, foresees up to 42.5 GW of installed electricity capacity in Saarland by 2045 in the highest scenario, underscoring the region's pivotal role in grid expansion [27]. Complementing this, the "Saarländische Wasserstoffstrategie 2025–2032" outlines a roadmap to set up Saarland as a model region for a hydrogen-based economy by 2032. Structured around four action fields—production, infrastructure, utilization, and supply chain—it integrates with regional climate and innovation strategies to drive decarbonization and economic competitiveness. Six strategic measures, including project implementation and regulatory reform, aim to position Saarland as a global leader in hydrogen technologies and services [28].

A critical enabler of Saarland's hydrogen integration is the mosaHYc project (Moselle-Saar Hydrogen Conversion) [29], a cross-border infrastructure initiative led by Creos

Deutschland, NaTran, and the Encevo Group, under the umbrella of the Grande Région Hydrogène. The project aims to convert ~94 km of existing natural gas pipelines between Saint-Avold (France) and Merschweiller (France) into a dedicated hydrogen backbone, with key links to Dillingen and Völklingen via the Creos network. mosaHYc is designed to establish an open-access transport network for renewable hydrogen across the Greater Region (including parts of Germany, France, Luxembourg, and Belgium), with first deliveries targeted for Q4 2028. Its initial use will serve the heavy industry, particularly the Dillinger Hütte steelworks, and projected capacity stands at 5.5 GWh/day. Included on the EU's list of Projects of Common and Mutual Interest (PCI/PMI) and supported by France's France 2030 programme, mosaHYc exemplifies how infrastructure conversion and cross-border coordination can accelerate industrial decarbonisation—potentially avoiding up to 0.7 Mt CO_2 annually in hard-to-abate sectors.

Complementing mosaHYc, the HY4Link [30] project represents the next phase of cross-border hydrogen infrastructure development in the Greater Region. Led by Creos Luxembourg, Fluxys Hydrogen (Belgium), and GRTgaz (France), the project was recently included in the European hydrogen network development plan, marking a preliminary step toward official designation as a PCI. HY4Link aims to connect industrial hydrogen demand clusters in Saarland, Luxembourg, and Grand Est, with green hydrogen import hubs in Antwerp, Zeebrugge, Dunkirk, and Rotterdam. The initiative supports both transit capacity and decentralized production, with planned links from Bouzonville (France) through Thionville to Frisange (Luxembourg) and onward to Belgium via Bras (Belgium). Strategically, it reinforces mosaHYc by establishing infrastructure continuity across Luxembourg, enabling future integration into broader EU corridors such as H_2Med. By enhancing regional connectivity and securing access to competitively priced hydrogen, HY4Link is poised to accelerate decarbonisation across industry and mobility in Saarland and its neighbouring regions.

At the European level, the European Hydrogen Backbone (EHB) [31] provides the strategic context for regional infrastructure projects like mosaHYc and HY4Link, embedding them within a long-term vision for a connected, competitive, and decarbonised hydrogen economy. Spearheaded by a consortium of 33 future hydrogen network operators, the EHB envisions a 58,000 km hydrogen pipeline network by 2040, with approximately 60% of hydrogen repurposed from existing natural gas infrastructure, significantly lowering costs and implementation time. By connecting low-cost renewable hydrogen production—particularly from the North Sea import hubs—with industrial demand centres across inland Europe, the EHB is designed to create a liquid, cross-border hydrogen market and enhance EU energy security. For regions like Saarland, alignment with the EHB strengthens both the bankability and scalability of local projects by linking them to a larger European supply–demand corridor. Moreover, the backbone supports the cost-efficient decarbonisation of hard-to-abate sectors such as steel and chemicals, while enabling access to competitively priced hydrogen through infrastructure that ensures resilience, flexibility, and long-term affordability. As most EHB projects have advanced beyond the pre-feasibility phase, accelerated permitting and targeted public support are now key to achieving timely deployment.

As mentioned above, a cornerstone of Saarland's hydrogen strategy is the Power4Steel [32] project, led by the SHS—Stahl-Holding-Saar Group, comprising Dillinger, Saarstahl, and ROGESA. With a total investment volume of EUR1.7 billion, it represents one of Europe's largest industrial decarbonisation initiatives. The project will replace conventional blast furnaces with hydrogen-based direct reduction units and electric arc furnaces, enabling a projected 55% reduction in CO_2 emissions by the early 2030s. In 2024, SHS signed a long-term offtake agreement with Verso Energy for at least 6000 tonnes of Renewable Fuels of Non-Biologic Origin (RFNBO)-certified green hydrogen annually, to be supplied via the MoSaHYc cross-border pipeline from Carling, France. This marks a key step in establishing a regional hydrogen market, with SHS aiming to scale up to 120,000 tonnes per year, making it one of the largest future consumers in the area. As a stable, large-scale hydrogen off-taker, Power4Steel enhances the bankability of adjacent infrastructure, including hydrogen-powered CHP systems. The project exemplifies how integrated industrial transformation, supported by cross-border cooperation and multi-level financing, can drive the development of a resilient hydrogen economy.

The integration of hydrogen-fuelled CHP systems into Saarland's district heating grid can simultaneously address multiple regional energy challenges. First, hydrogen CHP offers dispatchable generation, ideal for compensating the variability of solar and wind energy, which now comprise over 90% of the regional renewable electricity mix [33]. Second, hydrogen combustion or fuel cell CHP units provide a direct pathway to decarbonize existing gas-based heating networks while retaining legacy infrastructure—a pragmatic solution compared to complete electrification. Third, the compact urban form and industrial clustering of Saarbrücken, Völklingen, and Neunkirchen enable efficient heat distribution and integration of industrial waste heat, allowing hydrogen CHP to function as a flexible buffer that balances both power and thermal loads.

Despite its technical feasibility, hydrogen CHP in Saarland is constrained by systemic barriers:

- High LCOH: Even under optimistic electrolysis cost curves, hydrogen remains significantly more expensive than natural gas [28]. The companies surveyed in Saarland in [28] considered prices above 10 EUR/kg to be unattractive.
- Electricity Price Volatility: Electrolysis-based hydrogen production is sensitive to electricity prices, which are increasingly volatile due to renewable intermittency and fluctuating carbon prices. This undermines the business case for on-site hydrogen generation and necessitates long-term power purchase agreements (PPAs) or grid-friendly operating strategies.
- Fragmented Market Design: Existing market mechanisms fail to adequately reward the grid-stabilizing and decarbonization benefits of hydrogen CHP. Current regulatory frameworks, especially in Germany's energy law, do not prioritize fuel-flexible or hydrogen-ready CHP units in district heating tenders or funding schemes [28].

Despite these hurdles, Saarland is well-positioned to capitalize on several emerging opportunities.

- Technological Investments: The region is actively investing in H_2-ready technologies, increasing the value proposition of hydrogen in distributed CHP applications.
- Hydrogen Infrastructure: The HY4Link and MoSaHYc corridors offer unique synergies. By leveraging transnational funding mechanisms (e.g., IPCEI Hydrogen), Saarland can lower infrastructure costs while gaining early-mover advantages in regional hydrogen markets. These corridors could also unlock access to lower-cost hydrogen produced in the Grand Est region.
- Supportive Policy Signals: The German and EU hydrogen strategies offer significant funding for regional pilots and infrastructure buildouts. Saarland has already been identified as a "Hydrogen Model Region," granting access to technical assistance and early-stage capital.

3.2. Economic Ratio for Hydrogen Integration Examplified in Saarland

To better understand the cost dynamics, a simplified cost–benefit comparison was conducted. As an example, for the regional context of the Saarland case, the following system will be analyzed: Stadtwerke Saarbrücken GmbH operates a CHP plant to supply electricity and district heating into the DHN of Saarbrücken. The bus depot site as listed in Table 3 hosts three Caterpillar CHP units (packaged by Zeppelin), each producing 2 MW_{el} and 2.4 MW_{th}, totalling 6 MW_{el} and 7.2 MW_{th}. Based on a methane content of approximately 50% from the ground, natural gas (93% CH_4) is used to enrich the methane gas mixture to almost 60% CH_4 for full-load operation, with 39% electrical efficiency and 87% total efficiency [34].

Table 3. Natural gas CHP plant that supplies the DHN in Saarbrücken.

Parameter	Bus Depot CHP Plant
Plant Type	Combustion Engine (3 units)
Manufacturer	Caterpillar (packaged by Zeppelin)
Electrical Output	3×2 MW_{el} = 6 MW_{el} total
Thermal Output	3×2.4 MW_{th} = 7.2 MW_{th} total
Fuel Type	Methane (50% CH_4) enriched. with natural gas (93% CH_4)
Fuel Consumption	~500 m^3/h natural gas per unit at full load
Electrical Efficiency	39%
Total Efficiency	87%
NO_x Emissions	500 mg/m^3, TA-Luft compliant
Air–Fuel Ratio (Lambda)	1.76
Engine/Turbine Details	20 cylinders, 3 bar boost pressure
Thermal Storage	None
Grid Connection	10 kV transformer

For this comparison, only the fuel and carbon emission costs are compared under different fuel cost ratios r. It is assumed that the same amount of MWh fuel is needed for both fuel types and all efficiencies remain the same.

$$\frac{Total\ Cost\ with\ H_2}{Total\ Cost\ with\ NG} = \frac{[CO_2\ per\ MWh \cdot Price\ per\ kgCO_2] + [NG\ price\ per\ MWh \cdot r]}{[CO_2\ per\ MWh \cdot Price\ per\ kgCO_2] + [NG\ price\ per\ MWh]} \quad (1)$$

The analysis of the cost ratio (base NG price: 30 EUR/MWh [35]; NG emissions: 0.18 kg CO_2/kWh; Higher heating value (HHV)) reveals that, at a hydrogen to natural gas fuel price ratio (H_2/NG) of 2 and zero CO_2 cost, hydrogen engines are twice as expensive as seen in Figure 8. However, as CO_2 prices rise, the relative cost declines systematically: at 100 EUR/t CO_2, the ratio falls to 1.3; at 200 EUR/t CO_2, to 0.9; and at 300 EUR/t CO_2, hydrogen achieves cost parity or superiority (ratio ≤ 1) for $H_2/NG \leq 2.8$. The breakeven analysis underscores that hydrogen-fuelled engines achieve cost parity (relative cost ratio ≤ 1.0) with natural gas counterparts only under stringent conditions of both low hydrogen-to-natural gas fuel price ratios (H_2/NG) and elevated CO_2 pricing. At the current H_2/NG ratio of approximately 9—reflecting green hydrogen costs near 270 EUR/MWh against natural gas at ~30 EUR/MWh—even extreme CO_2 costs of 1000 EUR/t (more than tenfold current EU ETS levels of ~80 EUR/tonne) reduce the relative cost to only ~1.4, which is far from competitive, even if realistic efficiency variations would be included in the analysis. Such CO_2 price levels are economically and politically implausible, highlighting that carbon pricing alone cannot render hydrogen engines cost-effective while production cost gaps persist. Sustained high H_2/NG ratios above 6–7 maintain relative costs >2.0 regardless of CO_2 pricing within realistic bounds (<300 EUR/t), reinforcing that technological advancements in electrolysis, renewable energy integration, and scale-up of green hydrogen supply chains—targeting lower ratios—are indispensable for viability in decarbonized power applications.

https://doi.org/10.3390/hydrogen7020046

H_2/NG Price Ratio (NG base price 30EUR/MWh)	CO_2 Price [EUR/tCO2]																										
	0	20	40	60	80	100	120	140	160	180	200	220	240	260	280	300	350	400	450	500	550	600	650	700	750	800	850	900	950	1000
1,0	1	0,9	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,1	0,1
1,1	1,1	1	0,9	0,8	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2
1,2	1,2	1,1	1	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2
1,3	1,3	1,2	1	1	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2
1,4	1,4	1,3	1,1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2
1,5	1,5	1,3	1,2	1,1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,6	0,6	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,3	0,2	0,2	0,2	0,2
1,6	1,6	1,4	1,3	1,2	1,1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,2	0,2
1,7	1,7	1,5	1,4	1,3	1,1	1,1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,3	0,3	0,2
1,8	1,8	1,6	1,5	1,3	1,2	1,1	1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,3	0,3
1,9	1,9	1,7	1,5	1,4	1,3	1,2	1,1	1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,7	0,6	0,6	0,5	0,5	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3	0,3
2,0	2	1,8	1,6	1,5	1,4	1,3	1,2	1,1	1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3	0,3
2,1	2,1	1,9	1,7	1,5	1,4	1,3	1,2	1,1	1,1	1	1	0,9	0,9	0,8	0,8	0,8	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,3	0,3	0,3	0,3
2,2	2,2	2	1,8	1,6	1,5	1,4	1,3	1,2	1,1	1,1	1	0,9	0,9	0,9	0,8	0,8	0,7	0,6	0,6	0,6	0,5	0,5	0,4	0,4	0,4	0,4	0,4	0,3	0,3	0,3
2,3	2,3	2,1	1,9	1,7	1,6	1,4	1,3	1,3	1,2	1,1	1	1	0,9	0,9	0,9	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4	0,3	0,3
2,4	2,4	2,1	1,9	1,8	1,6	1,5	1,4	1,3	1,2	1,2	1,1	1	1	0,9	0,9	0,9	0,8	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4	0,3
2,5	2,5	2,2	2	1,8	1,7	1,6	1,5	1,4	1,3	1,2	1,1	1,1	1	1	0,9	0,9	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4
2,6	2,6	2,3	2,1	1,9	1,8	1,6	1,5	1,4	1,3	1,3	1,2	1,1	1,1	1	1	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4
2,7	2,7	2,4	2,2	2	1,8	1,7	1,6	1,5	1,4	1,3	1,2	1,2	1,1	1,1	1	1	0,9	0,8	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,4	0,4	0,4	0,4
2,8	2,8	2,5	2,3	2,1	1,9	1,8	1,6	1,5	1,4	1,3	1,3	1,2	1,1	1,1	1	1	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4	0,4
2,9	2,9	2,6	2,3	2,1	2	1,8	1,7	1,6	1,5	1,4	1,3	1,3	1,2	1,1	1,1	1	0,9	0,9	0,8	0,7	0,7	0,6	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4
3,0	3	2,7	2,4	2,2	2	1,9	1,7	1,6	1,5	1,4	1,4	1,3	1,2	1,2	1,1	1,1	1	0,9	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,5	0,5	0,4	0,4
4,0	4	3,6	3,2	2,9	2,7	2,5	2,3	2,2	2	1,9	1,8	1,7	1,6	1,6	1,5	1,4	1,3	1,2	1,1	1	0,9	0,9	0,8	0,8	0,7	0,7	0,7	0,6	0,6	0,6
5,0	5	4,5	4	3,7	3,4	3,1	2,9	2,7	2,6	2,4	2,3	2,2	2	2	1,9	1,8	1,6	1,5	1,4	1,3	1,2	1,1	1	1	0,9	0,9	0,8	0,8	0,7	0,7
6,0	6	5,4	4,8	4,4	4,1	3,8	3,5	3,3	3,1	2,9	2,7	2,6	2,5	2,3	2,2	2,1	1,9	1,8	1,6	1,5	1,4	1,3	1,2	1,2	1,1	1	1	0,9	0,9	0,9
7,0	7	6,3	5,6	5,1	4,7	4,4	4,1	3,8	3,6	3,4	3,2	3	2,9	2,7	2,6	2,5	2,3	2,1	1,9	1,8	1,6	1,5	1,4	1,3	1,3	1,2	1,1	1,1	1	1
8,0	8	7,1	6,5	5,9	5,4	5	4,7	4,3	4,1	3,8	3,6	3,4	3,3	3,1	3	2,9	2,6	2,4	2,2	2	1,9	1,7	1,6	1,5	1,5	1,4	1,3	1,3	1,2	1,1
9,0	9	8	7,3	6,6	6,1	5,6	5,2	4,9	4,6	4,3	4,1	3,9	3,7	3,5	3,4	3,2	2,9	2,6	2,4	2,3	2,1	2	1,8	1,7	1,6	1,6	1,5	1,4	1,3	1,3
10,0	10	8,9	8,1	7,4	6,8	6,3	5,8	5,4	5,1	4,8	4,5	4,3	4,1	3,9	3,7	3,6	3,2	2,9	2,7	2,5	2,3	2,2	2	1,9	1,8	1,7	1,6	1,6	1,5	1,4

Figure 8. Cost ratio hydrogen-based to natural-gas-based relative to fuel price and carbon emission cost.

3.3. Optimization Model for Hydrogen CHP

This section provides an overview of the methodological basis and implementation approach for the Python optimization model developed to analyze hydrogen-integrated combined heat and power (CHP) systems within a multi-energy-system (MES) context. The conceptual orientation of the model follows established MES planning frameworks such as those outlined in Lu et al.'s work [4], which emphasizes temporal and spatial system boundaries, sectoral coupling, uncertainty treatment, and optimization structure. Positioning the model within this conceptual landscape clarifies how the approach integrates electricity, heat, and hydrogen processes—including electrolysis, CHP operation, storage, and market interactions—into a unified decision framework.

A first version of the model has been implemented in Python using Pyomo (version 6.9.3) and formulated as a mixed-integer linear optimization problem with an hourly temporal resolution. The system representation includes:

- An electrolyser
- A fuel cell
- A combustion-based CHP unit
- Thermal storage
- Battery storage
- Hydrogen storage
- Ancillary material storage
- Market interfaces for electricity, hydrogen, oxygen, and water.

A schematic representation of the overall model with fluid and energy flows is shown in Figure 9 as a block diagram. The diagram shown here includes additional components, such as reformers, PV systems, and ammonium crackers, which are not considered in this article. The input variables are shown on the left side of the figure and the output variables on the right side, with the conversion paths of the fluids and energy forms in between.

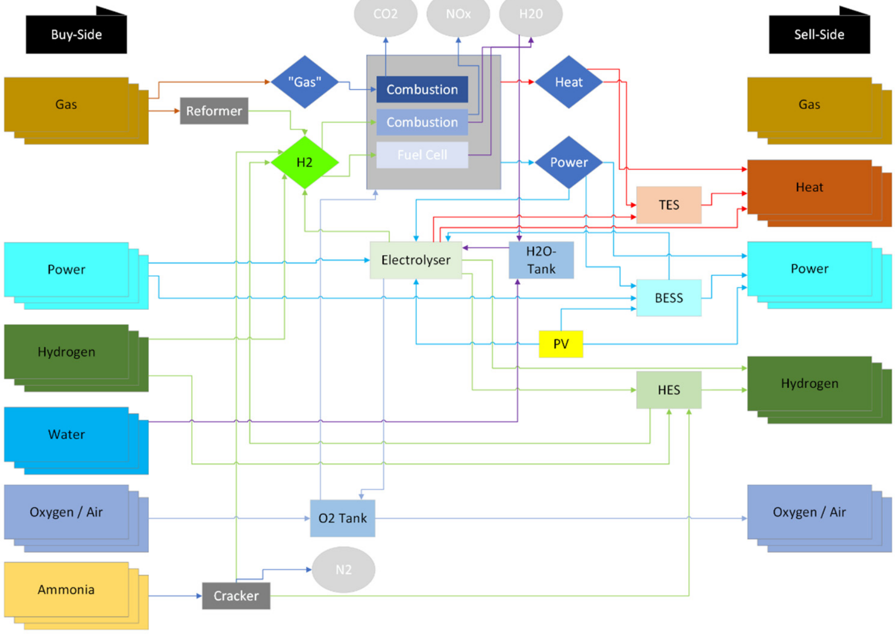

Figure 9. Multi-energy system energy and material flows.

The heat demand time series is obtained from an open-source dataset [36] and proportionally scaled to match a target annual energy supply of 314,400,000 kWh, representing the *SaarLorLux* region. Electricity prices are imported from an open-source wholesale market dataset [37]. In contrast, commodity prices for hydrogen (H_2), water (H_2O), and oxygen (O_2) are currently generated stochastically using random or Gaussian distributions for testing purposes, and the heat price is synthetically defined. In a production environment, these synthetic price assumptions are intended to be replaced by observed historical data or forecasted time series. Conversions between hydrogen mass and energy are based on a higher heating value of $HHV_{H2} = 39.40$ kWh/kg.

The electrolyzer consumes electrical power $P_{EL,E}$ subject to on/off binary $x_{EL,on}$ and minimum/maximum power constraints, producing hydrogen at a rate of $M^{H_2}_{EL,out}$ in kg/h

$$M^{H_2}_{EL,out} = \frac{P_{EL,E} \cdot \eta_{EL}}{HHV_{H_2}} \tag{2}$$

with efficiency η_{EL}, consuming water $M^{H_2O}_{EL,in}$, and producing oxygen $M^{O_2}_{EL,out}$ stoichiometrically according to:

$$M^{H_2O}_{EL,in} = 9 \cdot M^{H_2}_{EL,out} \tag{3}$$

$$M^{O_2}_{EL,out} = 8 \cdot M^{H_2}_{EL,out} \tag{4}$$

alongside a minor thermal output Q_{EL} according to

$$Q_{EL} = P_{EL} \cdot \eta_{EL,Q} \tag{5}$$

The fuel cell and CHP consume hydrogen $M^{H_2}_{FC,in}$ and $M^{H_2}_{CHP,in}$ respectively, generating electrical power $P_{EL,FC}$ and $P_{EL,CHP}$ with their efficiency $\eta_{P,FC}$ and $\eta_{P,CHP}$ according to:

$$P_{EL,FC} = M^{H_2}_{FC,in} \cdot HHV_{H_2} \cdot \eta_{P,FC} \tag{6}$$

$$P_{EL,CHP} = M^{H_2}_{CHP,in} \cdot HHV_{H_2} \cdot \eta_{P,CHP} \tag{7}$$

and producing thermal power to the following equation:

$$Q_{EL,FC} = M_{FC,in}^{H_2} \cdot HHV_{H_2} \cdot \eta_{Q,FC} \quad (8)$$

$$Q_{EL,CHP} = M_{CHP,in}^{H_2} \cdot HHV_{H_2} \cdot \eta_{Q,CHP} \quad (9)$$

with respective efficiencies $\eta_{Q,FC}$ and $\eta_{Q,CHP}$, subject to on/off binaries x_{FC} and x_{CHP} and minimum and maximum electrical ($P_{EL,FC,min}$, $P_{EL,FC,max}$) and thermal power $Q_{EL,FC,max}$

$$P_{EL,FC} \leq P_{EL,FC,max} \cdot x_{FC} \quad (10)$$

$$P_{EL,FC} \geq P_{EL,FC,min} \cdot x_{FC} \quad (11)$$

$$Q_{EL,FC} \leq Q_{EL,FC,max} \cdot x_{FC} \quad (12)$$

where the equations for CHP correspond to Equations (10)–(12).

The oxygen demand ($M_{FC,in}^{O_2}$) and water production ($M_{FC,out}^{H_2O}$) result from the stoichiometric ratio as follows:

$$M_{FC,in}^{O_2} = 0.5 \cdot M_{FC,in}^{H_2} \quad (13)$$

$$M_{FC,out}^{H_2O} = 1.0 \cdot M_{FC,in}^{H_2} \quad (14)$$

Storage dynamics for HESS track mass level $M_{HESS,t}$ at time t in kg from an initial value within bounds, with charge/discharge flows $M_{HESS,in}$, $M_{HESS,out}$ adjusted by efficiencies $\eta_{HESS,in}$, $\eta_{HESS,out}$ and mutual exclusivity enforced via binaries, alongside market flows M_{HESS}^{buy}, M_{HESS}^{sell} similarly bounded and exclusive:

$$M_{HESS,t} = M_{HESS,t-1} + (\eta_{HESS,in} \cdot M_{HESS,in,t} - \frac{M_{HESS,out,t}}{\eta_{HESS,out}}) \quad (15)$$

The storage capacity is within limits (Equation (16)), whereby charging and discharging, or buying and selling hydrogen, cannot be done simultaneously (Equation (10)).

$$M_{HESS,min} \leq M_{HESS,t} \leq M_{HESS,max} \quad (16)$$

$$x_{HESS,in} + x_{HESS,out} \leq 1 \quad (17)$$

$$x_{HESS,buy} + x_{HESS,sell} \leq 1 \quad (18)$$

For the TESS, O_2 storage and H_2 storage, mass or energy balance formulations with inflows, outflows, efficiencies, and market interactions under mutual exclusivity are analogous.

The BESS model maintains energy level $E_{BESS,t}$ in kWh at time t with charge/discharge powers $P_{BESS,t}^{ch}/P_{BESS,t}^{disch}$ under round-trip efficiency and binary exclusivity, with degradation [38] quantified via full equivalent cycles (FEC) and a per-cycle cost $C_{BESS,cyc}^{FEC}$:

$$C_{BESS,cyc}^{FEC} = \frac{C_{BESS}^{CAPEX,kWh} \cdot E_{BESS,max}}{n_{BESS,EOL}} \quad (19)$$

with CAPEX costs per kWh, $C_{BESS}^{CAPEX,kWh}$, and the number of full cycles until end of life $n_{BESS,EOL}$, applied to FEC accumulation from charge/discharge energy.

Grid interactions use $P_{GRID,t}^{buy}$, $P_{GRID,t}^{sell}$ with binaries $x_{GRID,buy}$ and $x_{GRID,sell}$, preventing simultaneous transactions and power exchanges are bounded by maximum values $P_{GRID,max}^{buy}$, $P_{GRID,max}^{sell}$ respectively.

$$x_{GRID,buy} + x_{GRID,sell} \leq 1 \quad (20)$$

$$P_{GRID,t}^{buy} \leq P_{GRID,max}^{buy} \cdot x_{GRID,t}^{buy} \tag{21}$$

$$P_{GRID,t}^{sell} \leq P_{GRID,max}^{sell} \cdot x_{GRID,t}^{sell} \tag{22}$$

Physical balances enforce zero net flow hourly: electricity balance sums grid buys minus sells plus CHP and FC generation minus EL consumption plus BESS discharge minus charge to zero. Heat balance includes CHP, FC, and EL thermal outputs plus TESS discharge minus charge minus DHN supply plus slack variables $Q_{DHN,t}^{undersupply}$ and $Q_{DHN,t}^{oversupply}$ for infeasibility with penalties $Q_{DHN,t}^{oversupply,pen}$ and $Q_{DHN,t}^{undersupply,pen}$.

$$Q_{DHN,t}^{supply} \leq Q_{DHN,t}^{demand} + Q_{DHN,t}^{oversupply} \tag{23}$$

$$Q_{DHN,t}^{supply} \geq Q_{DHN,t}^{demand} - Q_{DHN,t}^{undersupply} \tag{24}$$

The objective J maximizes cumulative profit via tracked revenue and cost variables:

$$J = \max(R_{total} - C_{total}) \tag{25}$$

Revenues R_{total} comprise electricity sales (power $P_{GRID,t}^{sell}$ and selling price $p_{GRID,t}^{sell}$) or grid purchases at negative prices (power $P_{GRID,t}^{buy}$ and buying price $p_{GRID,t}^{buy,<}$), hydrogen sales M_{HESS}^{sell} with selling price $p_{H_2,t}^{sell}$, oxygen byproduct sales with mass $M_{EL,out}^{O_2}$ and $p_{O_2,t}^{sell}$, and heat supply $Q_{DHN,t}^{supply}$ and $p_{DHN,t}^{sell}$:

$$\begin{aligned} R_{total} = P_{GRID,t}^{sell} \cdot p_{GRID,t}^{sell} + P_{GRID,t}^{buy} \cdot p_{GRID,t}^{buy,<} + M_{HESS}^{sell} \cdot p_{H_2,t}^{sell} \\ + M_{EL,out}^{O_2} \cdot p_{O_2,t}^{sell} + Q_{DHN,t}^{supply} \cdot p_{DHN,t}^{sell} \end{aligned} \tag{26}$$

Costs C_{total} include hourly CAPEX amortization as sum of CAPEX-per-unit capacity $C_{i,p.u.}^{CAPEX}$, its per-unit capacity $cap_{p.u.}$ and lifetime in hours $t_{i,life,h}$. Here, i represents the individual energy and fluid flows of the considered system components, $i \in \{HESS,\ BESS,\ TESS, H_2OT, O_2T, CHP, FC, EL\}$. Fixed OPEX costs as an annual fraction $f_{i,life,h}$ of CAPEX-converted hourly costs are also taken into account.

In addition, commodity purchase costs with per-unit capacity $cap_{i,p.u.}$ and per-unit price $p_{i,p.u.,t}$, as well as DHN undersupply/oversupply penalties are considered in the objective function.

Start/stop costs $C_i^{start-stop}$ scaled by maximum capacity $cap_{i,max}$ and event count $n_{i,start-stop}$ are also taken into account.

$$\begin{aligned} C_{total} = \sum_i C_{i,p.u.}^{CAPEX} \cdot \frac{cap_{i,p.u.}}{t_{i,life,h}} + \sum_i C_{i,p.u.}^{CAPEX} \cdot cap_{i,p.u.} \cdot f_{i,life,h} + \sum_i (cap_{i,p.u.} \cdot p_{i,p.u.,t}) + Q_{DHN,t}^{oversupply,pen} \cdot Q_{DHN,t}^{oversupply} \\ + Q_{DHN,t}^{undersupply,pen} \cdot Q_{DHN,t}^{undersupply} + \sum_i n_{i,start-stop} \cdot C_i^{start-stop} \cdot cap_{i,max} \end{aligned} \tag{27}$$

The model is solved using Gurobi through Pyomo with options *TimeLimit* = 600 s and *MIPGap* = 0.1, checking for infeasibility or unboundedness and exporting irreducible inconsistent subsystem (IIS) when infeasible.

The objective function maximizes operational profit based on revenues from energy and commodity sales and costs related to CAPEX amortization, OPEX, start/stop events, storage losses, battery degradation, and imbalance penalties. All energy and mass flows are modelled under linear balance constraints, fixed conversion efficiencies, and mutually exclusive operational states for charge/discharge and buy/sell interactions.

A preliminary simulation has been conducted to evaluate the internal consistency and solvability of the model, using open-source heat demand (When2Heat Heating Profiles [36]) and price time series (SMARD—Strom- und Gasmarktdaten für Deutschland [37]) alongside synthetic price signals for hydrogen, oxygen, and water. Figures 10 and 11 illustrate the hourly (left side) and cumulative (right side) economic performance of a test simulation run, showing how the model continuously adapts operational decisions in response to cost and revenue signals. The cumulative curves confirm stable long-term behaviour of the optimization framework, while the hourly fluctuations reflect the dynamic interaction of market prices, component operation, and system constraints.

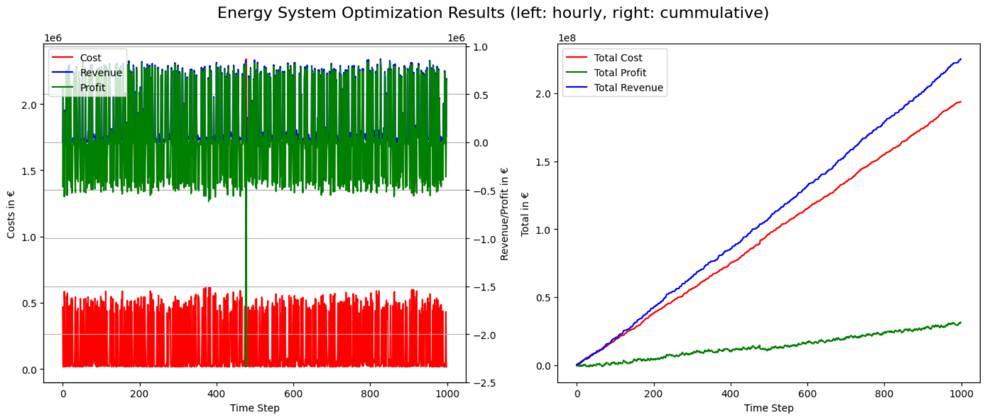

Figure 10. Financial results for optimization with fuel cell OFF and combustion.

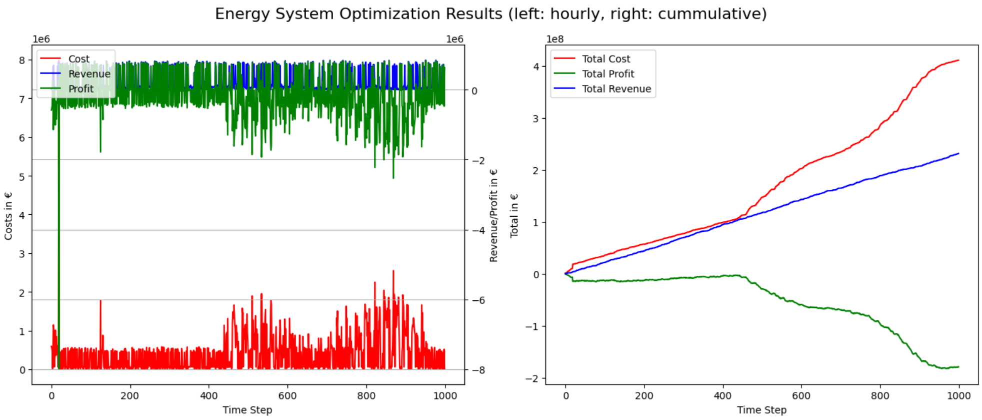

Figure 11. Financial results with fuel cell ON and combustion.

Even though the maximum power and heat of each version is alike, costs due to CAPEX, OPEX and penalties make the fuel cell-based version unprofitable. This result is only an example, to show that the model runs, because prices and equipment data are approximated and not verified through real data, which can make a significant difference. These exploratory runs confirm that the framework operates as intended and adjusts system behaviour in accordance with economic incentives and physical constraints. More detailed analyses, including validated techno-economic parameters, scenario studies, and comparative assessments of combustion-based and fuel-cell-based CHP operation, are part of subsequent work.

3.4. Comparative Analysis

To draw meaningful insights from the Saarland case, it is essential to systematically compare its regional characteristics with the broader findings from the literature on hydrogen-based CHP systems.

The literature consistently identifies infrastructure limitations as a primary technical barrier to hydrogen deployment in district energy systems. Many model-based studies assume isolated national or urban networks, often omitting cross-border dynamics. In contrast, Saarland's participation in MoSaHYc and HY4Link offers a rare example of transnational hydrogen integration, potentially addressing the scalability and distribution constraints that remain under-theorized in much of the existing work.

Moreover, while the technical feasibility of hydrogen-based CHP is well established—especially in pilot configurations involving micro-CHP fuel cells or hydrogen co-firing [39]—these studies often focus on standalone applications. Saarland distinguishes itself through its dense coupling of industrial heat demand, DHNs, and electricity balancing needs within a compact territorial scale. This intersectoral convergence supports more efficient hydrogen utilization, aligning with theoretical calls for system-level integration, yet few empirical examples exist to date.

Across the literature, the economic viability of hydrogen in CHP is portrayed as questionable. Reported LCOH range between 147 and 357 EUR/MWh depending on the production pathway, electricity price, and capacity utilization [40]. These figures are largely consistent with those observed in Saarland, where electrolysis-based hydrogen remains significantly costlier than fossil gas alternatives [28].

However, the concentration of industrial demand in Saarland provides a distinct economic opportunity not frequently emphasized in the literature. Industrial clusters often serve as "anchor loads" that can stabilize hydrogen demand and justify the scale-up of infrastructure, thereby improving capacity utilization and lowering average costs. In this context, hydrogen-based CHP could be co-located with industrial users to maximize thermal efficiency and reduce waste, contributing to the economics of integrated energy systems.

Policy frameworks are often cited in the literature as either enablers or inhibitors of hydrogen deployment. A recurring theme is the misalignment of market design with hydrogen's system value. Most regulatory systems prioritize lowest-cost generation or carbon mitigation in isolation, without fully accounting for hydrogen's role in grid balancing, sector coupling, or resilience. Saarland exemplifies this policy gap. Despite participation in high-profile hydrogen corridors, national and EU-level frameworks have yet to adequately internalize the co-benefits of hydrogen-based CHP, such as flexible load management and decarbonization of distributed heating. Stopped projects in Saarland [41] reinforce this mismatch, revealing a strong interest in hydrogen-ready technologies but hesitancy to invest without clearer regulatory signals or long-term price guarantees. Additionally, Saarland's cross-border context introduces a level of regulatory complexity that is absent from domestic-focused analyses. Harmonizing grid access, gas quality standards, and subsidy structures across three jurisdictions (Germany, France, and Luxembourg) remains a non-trivial barrier that is insufficiently addressed in current policy literature.

4. Discussion

4.1. Conclusions

Building on the comparative analysis, which highlights Saarland's alignment with and extensions of existing literature on hydrogen-based CHP systems, this chapter synthesizes these findings into broader implications. It emphasizes how systemic challenges—such as high costs and regulatory misalignments—interact in practice, while proposing targeted, forward-looking strategies for overcoming them. The discussion draws on Saarland's unique cross-border and industrial context to inform scalable models, incorporating supplementary insights from recent studies and stakeholder perspectives for enhanced applicability.

In the following, conclusions are divided into separate subsections: key technical findings, economic implications, and policy and market-related conclusions.

A. Technical Key Findings

1. Validation of literature-identified technical barriers for hydrogen-based CHP systems in the Saarland context, including system integration and performance constraints
2. Technical Recommendations
    - Accelerated development of fuel cells and H2-ready engines or turbines optimized for CHP applications in dense urban or industrial areas
    - Evaluation of hybrid system architectures (e.g., electrolysis + storage + CHP) in real-world settings to assess their dynamic performance under fluctuating renewable inputs and thermal demand
3. Role of the Python Optimization Model
    - Methodological foundation through integrated modelling of hydrogen, heat, and electricity subsystems within a unified environment for dynamic evaluation of operational strategies under varying market, policy, and cost conditions.
    - Modular structure enables the inclusion of additional technologies (e.g., hydrogen storage, district heating expansions) and policy instruments (e.g., carbon pricing, CfDs), facilitating analysis of their impact on system economics and emissions.
    - Potential for future validation of model performance via dynamic multi-year simulations using real data from Saarland's CHP plants
    - Exploring scalability across other industrial regions

B. Economic Implications:

1. Persistent Cost Barriers: Even in regions with renewable potential and industrial demand, high costs remain a key challenge, underscoring the need for parallel evolution in market mechanisms alongside technological cost reductions
2. Market Design Inefficiencies: Undervaluation of ancillary services, such as grid balancing, represents a structural hurdle for hydrogen CHP adoption
3. Economic and Policy Recommendations (economic dimension):
    - Introduction of targeted subsidies or Contracts for Difference (CfDs) for hydrogen-based CHP to close the current cost gap with natural gas. These instruments should reflect not only energy output but also system services and decarbonization value.
    - Internalization of externalities (e.g., CO_2, NO_x, and methane emissions from fossil fuels) via dynamic carbon pricing to improve hydrogen's competitiveness, particularly in industrial applications

C. Policy and Market Design Conclusions:

1. Confirmation of policy and regulatory gaps identified in the literature, with Saarland illustrating how these gaps manifest in practice
2. Economic and Policy Recommendations (policy dimension):
    - Reform of balancing markets and capacity mechanisms to allow hydrogen CHP units to bid based on their full value stack—including heat production, peak shaving, and flexibility.
3. Regional Scaling Strategies:
    - Replicating of Saarland's "anchor load" model using large, stable industrial consumers to justify early infrastructure investment and help aggregate demand across sectors.

- Development of cross-border hydrogen corridors in regions where energy systems are fragmented across national borders but integrated in practice (e.g., North Rhine-Westphalia–Belgium–Netherlands; Upper Austria–Czech Republic).
- A more proactive role for regional governments in stakeholder coordination, permitting and alignment with national and EU hydrogen strategies and roadmaps.

A common hydrogen market does not yet exist in the EU. For these reasons, it is important that uniform regulations are created at the EU level in a timely manner. Therefore, a future EU regulation on the hydrogen network must take into account liberalization, decarbonization, and security of supply for all stakeholders.

The biggest barriers lie in different gas quality and hydrogen blending standards (with purity targets between 98 mol%, 99.5 mol%, and 99.97 mol%), which make it difficult to use existing infrastructure across borders. In addition, there are different network access rules, which hinder uniform operational management across national borders. While other European countries usually have only one gas network operator, in Germany, according to the German Energy Industry Act (EnWG §28q) (https://climate-laws.org/document/energy-industry-act-enwg_863f (accessed on 5 November 2025)), the 16 transmission system operators of the gas networks are responsible for the operation of future hydrogen networks in Germany, which further complicates joint, cross-border harmonization and coordination.

4.2. Limitations and Future Research

While this report provides valuable insights, several limitations must be considered:

- Geographic Scope: Focusing on a single region inherently limits generalizability. Although Saarland offers a rich case, its specific industrial structure, governance culture, and infrastructure legacy may not be directly transferable to other contexts.
- Data Availability: Infrastructure cost assumptions and technology performance metrics rely on secondary sources or ranges reported in the literature, rather than proprietary or empirical datasets specific to Saarland.
- Temporal Constraints: The analysis assumes a static cost and policy environment. Incorporating dynamic modelling of hydrogen price trajectories and policy shifts (e.g., EU Green Deal implementation, fit for 55 revisions [1]) would enable more robust long-term projections.

4.3. Directions for Future Research

- Comparative Case Studies: Investigating other industrial regions implementing hydrogen CHP systems to enable cross-contextual learning and evaluate transferability of findings.
- Dynamic Techno-Economic Modelling: Expanding optimization to incorporate renewable variability, hydrogen storage economics, and market response to policy changes, providing more realistic and robust system projections.
- Stakeholder-Based Analysis: Engaging utilities, regulators, and industry players through interviews and decision-making frameworks to assess real-world feasibility, adoption barriers, and practical implementation strategies.

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Abbreviations

The following abbreviations are used in this manuscript:

BHHP	Block Heat and Power Plant
CfD	Contracts for Difference
CHP	Combined heat and power
CHH	Combined Heat and Hydrogen
DHN	District heating network
EHB	European Hydrogen Backbone
ETS	Emissions Trading System
FGR	Flue gas recirculation
HHV	Higher heating value
HEC-MES	Hydrogen energy chain-integrated multi-energy systems
LHV	Lower heating value
NG	Natural gas
NPV	Net present value
PCI	Projects of Common Interest
PMI	Projects of Mutual Interest
PPA	Power purchase agreement
P2G	Power to gas
RFNBO	Renewable Fuels of Non-Biologic Origin
TLA	Three letter acronyms
VRE	Variable renewable energy

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