Uncovering the economic tipping point between H_2-based gas turbines and CCS-enhanced gas turbines

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Abstract. In the pursuit of carbon neutrality, decarbonizing electricity production is a central yet complex challenge. While renewable sources like wind and solar are increasingly viable, their intermittency necessitates reliable and dispatchable alternatives. Gas turbines (GTs) can provide this flexibility, and two main pathways exist to make them carbon neutral: H_2-based GTs and CCS-enhanced GTs using amine-based carbon capture. Both options are compared technically and economically. It evaluates the feasibility of burning pure hydrogen and capturing 100 % CO_2, and examines their impact on efficiency, CAPEX, and OPEX. Simulations using Aspen Plus and economic modelling reveal that CCS-enhanced CCGTs, despite higher CAPEX, outperform H_2-based CCGTs due to currently prohibitive hydrogen costs. The study finds a LCOE of 140 €/MWh for CCS versus 1660 €/MWh for hydrogen, and payback of 23 years for CCS with EGR while no payback for hydrogen. A user-friendly online tool was also developed to assess scenarios based on real-world parameters. These findings underscore the current economic advantage of CCS-enhanced turbines, while highlighting the need for hydrogen cost reductions to make H_2-based systems viable.

Introduction

The decarbonization of electricity generation represents both a critical objective and a hard challenge. While renewable energy sources like wind and solar have become central to reducing emissions, their intermittency induce crucial needs in reliability and dispatchability. Gas turbines (GTs), and more specifically Combined-Cycle Gas Turbines (CCGTs), can provide the flexibility and stability required by modern grids. However, decarbonizing gas turbines remains a pending issue.

During past years, two main pathways have emerged to make CCGTs carbon neutral: H_2-based CCGTs, aiming at burning hydrogen instead of methane, and CCS-enhanced CCGTs, using amine-based carbon capture to mitigate CO_2 emissions. These two solutions are investigated from both technical and economic perspectives, addressing key questions such as achievable efficiencies, feasibility in current energy markets, levelized cost of electricity (LCOE), payback, and the economic tipping point between the two technologies.

To compare the technologies properly, the first step is to find relevant techno-economic studies on both subjects with potential economic data on power plants. This part is crucial to have consistent base cases around which the economic models are performed.

After getting data from literature, an Aspen model of the CCGT+CCU has been made to cross-validate technical data and price ranges from Aspen Economics.

Based on data gathered, an economic model was developed to assess the economic viability of both technologies by determining the LCOE and payback.

Finally, the model has been integrated into an online tool application where the end user could vary the parameters and see the evolution of the results depending on these variations. This allows the readers of this study to get a tool that could be useful to evaluate results for their own power plant data.

In conclusion, by developing a techno-economic model and validating it against literature data and process simulations, this work aims to provide an informed comparison and actionable insights on the role of these technologies in a decarbonized power sector.

Note that cycle performances of CCGTs will be evaluated at design conditions in this paper, and off-design conditions are out of scope.

1 Literature Review

Studies made on CCS-enhanced CCGTs generally cover a wide range of technical aspects influencing the efficiency of the CCGT while including a capture process. Gülen et al. [1] investigated supplementary firing in the HRSG and EGR implementation on an 800 MW CCS-enhanced CCGT, leading to a lower capture penalty on the efficiency and a lower CAPEX of the power plant. Adams et al. [2] evaluated efficiency penalty of CCS on a 420 MW CCGT under full and part load operations, also investigating the impact of EGR on

the results. Mullen et al. [3] evaluate the impact of a high capture rate CCS-enhanced CCGT on the LCOE by performing a techno-economic analysis on a 660 MW CCGT, also investigating on different amine-based carbon capture configurations to optimize the results.

On the other side, studies performed on hydrogen fuelled CCGT stay focused on technological breakthroughs allowing a higher hydrogen content in the fuel mix of a gas turbine due to improved and adapted burner configurations [4,5,6]. In fact, lower TRL of H_2-based CCGTs induces a higher interest for purely technical studies rather than techno-economical studies which should be a more representative part in a near future. However, some researches still include an economical part in their work, like the study of Öberg et al. [7], which considers a local green hydrogen production with electrolysers, including assumptions made on the reduction of emissions caps in different countries.

Even if there is already a consequent number of studies made on CCS-enhanced and H_2-based CCGTs, there is still a need for a consistent comparison between the two technologies to determine which solution would be economically more interesting. In addition, even if some studies have already made a LCOE computation of their respective technologies, these computations may seem inconsistent due to some relaxations in the economic model. Finally, most of the studies are based on a simple case analysis while there is a need for flexible studies allowing the reader to adapt the model and get different results based on its own data.

In conclusion, while other studies are more focused on technical aspects of both technologies, this paper will assess the economic potential of these power plants using a flexible model based on reference studies. LCOE will be computed using a simulation of the whole lifespan of the plants rather than a simplified equation. Another economic indicator known as the payback will also be computed to give an overview of the economic viability of the two solutions. This indicator is missing in other studies but it ensures an effective representation of the economical readiness of technologies. To conclude, the comparison of these solutions in a flexible way, using a more precise economic model and determining interesting economic indicators such as LCOE and payback, brings an additional useful breakthrough towards the selection of the future CO_2 neutral peak generation units.

2 Methodology

2.1 CAPEX Determination

In this study, capital expenditure (CAPEX) is dissected into three distinct components to ensure a detailed and objective economic comparison between CCS-enhanced and H_2-based gas turbines. These components are:

1. the base CAPEX of a standard Combined-Cycle Gas Turbine (CCGT),
2. the additional CAPEX for retrofitting a carbon capture and storage (CCS) system,
3. the retrofit CAPEX to enable 100% hydrogen combustion.

2.1.1 CCGT CAPEX

The baseline CAPEX for a simple CCGT unit was established using literature data, primarily from Christoph Kost et al. [8] and the U.S. Energy Information Administration (EIA) [9]. These sources provided a Total Overnight Cost (TOC) estimate between 850 and 1150 €/kW for new installations. Additionally, a case study by the University of Edinburgh [3] evaluating a 663.3 MW CCGT with 64% efficiency and 4.9% mol CO_2 in the flue gas estimated a CAPEX of 946 €/kW, aligning well with the predefined range. This consistent base model was crucial to maintaining parity in subsequent comparisons between the two decarbonization pathways.

2.1.2 CCS Retrofit CAPEX

To model the cost of retrofitting amine-based CCS systems, a comprehensive simulation was developed in Aspen Plus using a reference model from Verhaeghe et al. [10]. The process included a Direct Contact Cooler (DCC), absorber and stripper columns, compression units, and water/MEA make-up systems. The absorber height was adjusted to achieve either 90% or 96% capture efficiency with 20 m for the former and 24 m for the latter. The design followed a step-by-step methodology:

- Gas cooling to 40° C in the DCC.
- Amine absorption with a target of 0.1 mol CO_2/mol MEA.
- Pressure recovery via compression.
- Lean/rich heat exchange and reboiler duty optimization.
- Product purity enhancement to 99.6% CO_2.
- Compression of captured CO_2 to 30 bar for transport.

The following key operational data were collected from the step-by-step methodology depicted above:

- amine recirculation flow of 1284.2 kg/s for 96% capture,
- reboiler duty of 182 MW,
- cooling water flow of 5.628 m³/s.

Using Aspen Economics, the Bare Erected Costs (BEC) were converted to total overnight cost via a standard multiplier, resulting in CAPEX values of 454.28 M€ for 90% capture and 513.9 M€ for 96%. In addition of a 100 M€ investment in the EGR loop equipment.

For comparison, the study by Mullen et al. [3] showed substantially higher costs: 722 M€ for 96% and

769 M€ for 100% capture. The discrepancy is attributed to differences in CO_2 flue gas concentration (4.9% vs. 8%) and TOC calculation methods. Studies with Exhaust Gas Recirculation (EGR), such as presented by Verhaeghe et al. [11], showed lower CAPEX due to reduced gas flow and absorber dimensions.

2.1.3 Hydrogen Retrofit CAPEX

Hydrogen-capable gas turbines require significant upgrades due to combustion challenges like flashback, flame speed, and NO_x emissions. Costs depend on whether the plant is newly built or retrofitted. Literature data from sources including Walter et al. [12] report a price increase of 13–45% for new H_2-GTs and 25–72% for retrofits, depending on the hydrogen volume share.

This study adopts a conservative 25% increase assumption for retrofitting. Using the previously defined CCGT CAPEX of 946 €/kW, a 25% increase yields a TOC of approximately 784.4 M€ for a 663.3 MW plant. This aligns with the retrofit scenario where CAPEX is balanced against reduced hydrogen readiness complexity, making it a practical baseline for techno-economic modelling.

In summary, while CCS systems incur higher CAPEX due to process complexity and auxiliary systems, H_2 retrofits remain costly largely because of immature combustion technology and infrastructure adaptation. These values are critical for calculating LCOE and payback in further sections.

2.2 OPEX Determination

Operating expenditure (OPEX) in power plants is divided into two components: Fixed Operation and Maintenance costs (FOM) and Variable Operation and Maintenance costs (VOM). The total annual OPEX can be calculated with Equation (1).

$$OPEX\ [€/\text{year}] = FOM\ [€/\text{year}] + VOM[€/\text{kWh}] \times E[\text{kWh/year}] \quad (1)$$

Where E represents the annual electricity production.

2.2.1 FOM Determination

FOM includes labour, maintenance, insurance, and overhead, typically calculated as a percentage of CAPEX. For gas turbines, values usually range between 3–4%. In this study, CCS-enhanced GTs are assigned a FOM of 3.5%, while H_2-based GTs have 4% due to greater complexity.

2.2.2 VOM Determination

VOM is subdivided into key cost components:

- **Fuel**: Depends on efficiency and price (e.g., 4.5 ct/kWh for methane and 3.62 €/kg for H_2).
- **Cooling and Make-Up Water**: required in CCS and steam cycles (e.g., 0.05 €/m³ and 3.15 €/m³ respectively).
- **Chemicals (MEA)**: 1.2 €/kg to maintain CO_2 capture.
- **CO_2 Transport and Storage (T&S) costs and Carbon Tax (ETS)**: 40 €/ton and 85 €/ton respectively.

The VOM cost formula for CCS-enhanced CCGTs is retrieved in Equation (2).

$$VOM\ \left[\frac{€}{kWh}\right] = \left(\frac{Fuel\ Price}{\eta_{CCGT}}\right) + q_{cooling\ water} * Price_{cooling\ water} + q_{make-up\ water} * Price_{make-up\ water} + q_{MEA} * Price_{MEA} + q_{CO_2\ emitted} * (CO_2\ T\&S + ETS) \quad (2)$$

With collected data, calculated VOMs are as shown in Figure 1. Hydrogen fuel accounting for 99.9% of the VOM in H_2- based GTs.

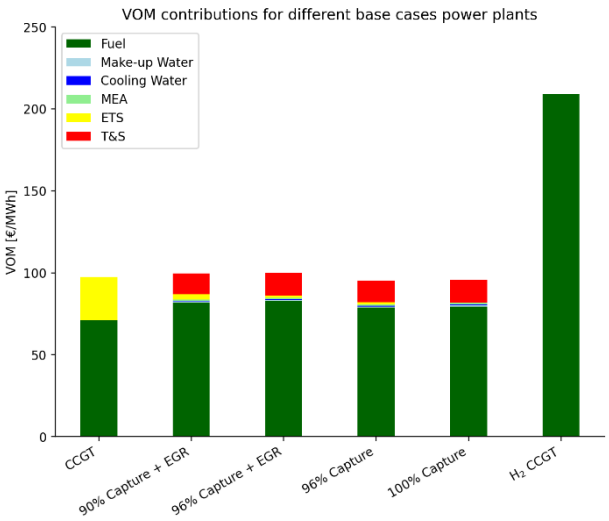

Fig. 1. VOM breakdown for all base cases power plants

2.2.3 Electricity Production Estimation

Electricity production E is determined via capacity factors (CF) from two models:

- **Fixed Load Method**: Estimates average CF of 50%.
- **Merit Order Model**: Uses actual hourly electricity price data to determine CF where VOM is inferior to the price. Table 1 shows CF for 3 base cases considered later.

Table 1. Load Factors based on the Merit Order attribution mechanism

Power plant	Load Hours (CF)
CCGT	4541 (51.8%)
CCGT + CCS 96% + EGR	4760 (54.3%)
H_2-CCGT	87 (0.99%)

The H_2-CCGT is barely dispatched due to its high VOM, resulting in minimal operation.

2.2.4 Final OPEX computation

By inserting FOM, VOM, and E into the OPEX formula, one obtains the results shown on Table 2 for the annual OPEX of the corresponding power plants.

Despite lower OPEX for H_2-CCGT, this is due to its minimal operating time, not cost-efficiency. Hence, high VOM and low CF render it economically uncompetitive under current conditions.

Table 2. Annual OPEX of power plants

Power plant	OPEX [M€/year]
CCGT	281.29
CCGT + CCS 96% + EGR	318.14
H_2-CCGT	36.78

This OPEX summary is foundational for calculating the Levelized Cost of Electricity (LCOE) and payback in the following sections.

2.3 LCOE and payback computation

One of the most commonly used economic indicators in power plant studies is the Levelized Cost of Electricity (LCOE). It calculates the average cost of generating one MWh of electricity over a plant's lifetime. It also represents the break-even price for selling electricity when accounting for all costs. LCOE is mathematically defined as in Equation (3).

$$LCOE[€/\text{MWh}] = \frac{\Sigma\, (CAPEX_t + OPEX_t)/(1+r)^t}{\Sigma\, E_t/(1+r)^t} \quad (3)$$

Where $CAPEX_t$ and $OPEX_t$ are yearly capital and operating expenditures, E_t is yearly electricity produced, and r is the inflation rate, assumed at 4% (Belgian average in the past five years). CAPEX is distributed over a 3-year construction phase using a payment curve of [20%, 45%, 35%], after which the plant starts producing electricity. An alternative LCOE formula used for sensitivity is retrieved in Equation (4).

$$LCOE[€/\text{MWh}] = LF * \left(\frac{\beta * CAPEX + FOM}{E} + VOM\right) \quad (4)$$

Where LF is a leveling factor (1.268 for IOUs) and β a capital charge factor (typically 10–13%).

While LCOE provides a good benchmark for technology comparison, it ignores cash flows and profitability for investors. For this, payback is calculated to consider revenues from electricity sales and CRM (Capacity Remuneration Mechanism), which rewards dispatchable flexibility. CRM is valued at 25.7 k€/MW/year. Revenue is calculated using an updated capacity factor algorithm.

The algorithm accumulates hourly earnings and calculates the total energy dispatched (in hours). This produces both capacity factor and total revenue.

The final payback is computed by subtracting expenses (OPEX + CAPEX) from total revenues, annually. In this study, future benefits are not discounted since prices are assumed to grow with inflation. The model remains flexible with an optional discount factor in the online tool for user customization.

LCOE and payback values are fully analyzed and compared in the next section, forming the basis for final conclusions and recommendations.

3 Results

The main objective of this study, as written in its title, is to give an economic tipping point between CCS-enhanced and H_2-based gas turbines. To ensure a consistent comparison of the two technologies, it was chosen to compare a 100% capture rate CCS-enhanced CCGT with a 100% hydrogen H_2-based CCGT. This ensures a comparison of technologies both nullifying CO_2 emissions. This comparison was first made using an inflation rate of 4% and excluding CRM revenues. Additionally, a construction time of 3 years followed by a power plant lifespan of 25 years was considered.

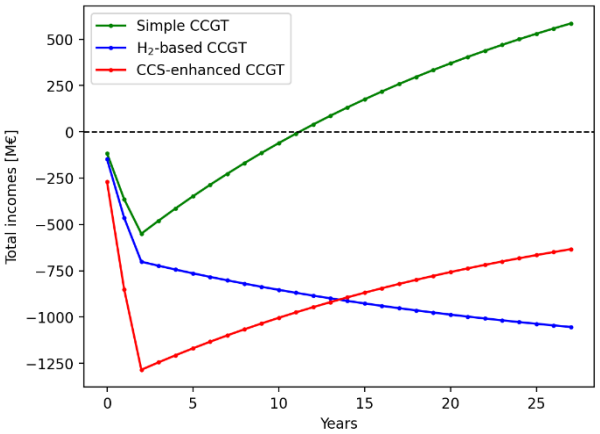

Fig. 2. Final comparison between a simple CCGT with carbon taxes, a 100% capture rate CCS-enhanced CCGT and 100% H_2-based CCGT without CRM revenues and with 4% inflation rate.

Payback curves can be seen in Figure 2, where two main observations can be made. Firstly, there is an economic tipping point as the curves cross after 14 years and 188 days. This means a CCS-enhanced gas turbine becomes economically more attractive after that lifespan. Secondly, both technologies are still not economically viable. Neither can provide a payback for potential investors. Although an increased lifespan may

eventually benefit CCS, it does not for hydrogen, as the low annual electricity sold is insufficient to counteract the Fixed O&M expenses. This makes the H_2-based CCGT curve going down even when the power plant is operating. In addition, comparing both technologies with a simple CCGT curve shows that reducing emissions induce a negative impact on the payback of a CCGT.

A second analysis includes CRM revenues and assumes no inflation. The results are shown in Figure 3. The tipping point appears earlier - after 11 years and 285 days. Additionally, CCS-enhanced CCGT becomes economically viable, achieving payback in 25 years and 121 days.

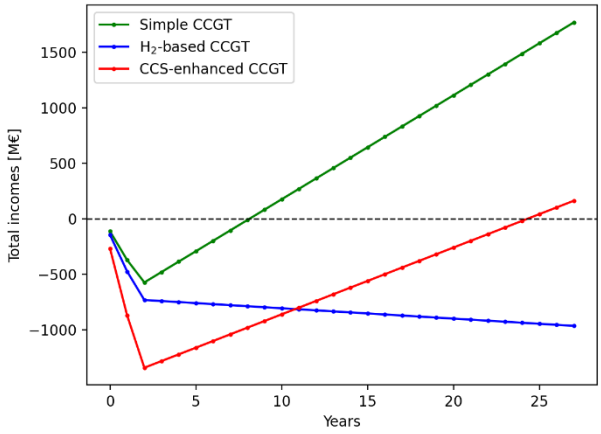

Fig. 3. Final comparison between a simple CCGT, 100% capture rate CCS- enhanced CCGT and 100% hydrogen H_2-based CCGT with CRM revenues and no inflation rate.

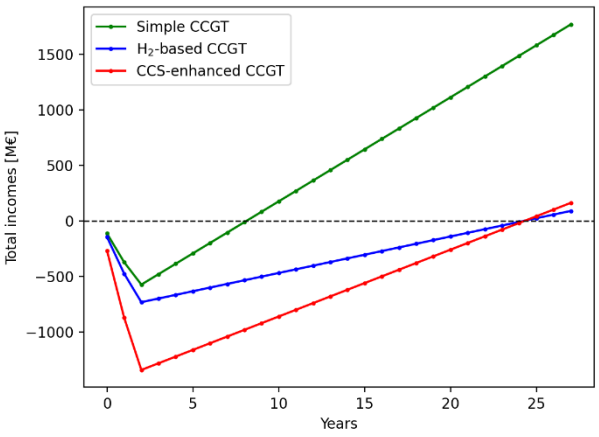

Fig. 4. Final comparison between a simple CCGT, 96% capture rate CCS-enhanced CCGT and 100% hydrogen H_2-based CCGT with hydrogen price reduced by 45%, CRM revenues and no inflation rate.

Another useful representation is the comparison of LCOE and payback, as shown in Table 3. The LCOE increases by about 20 €/MWh when adding CCS (approx. +17%), and payback is roughly doubled. In contrast, high hydrogen prices make the H_2-CCGT economically non-viable, yielding extremely high LCOE and no payback. Additionally, implementing EGR has both positive and negative effects: while it reduces CAPEX (by increasing CO_2 concentration in flue gases), it also reduces efficiency, raising fuel costs and VOM. As a result, payback and LCOE remain similar or slightly increase.

Table 3. LCOE and payback of each base case power plant

Power plant	LCOE [€/MWh]	payback [years]
CCGT	119.13	10
CCGT + CCS 90% + EGR	139.65	26.1
CCGT + CCS 96% + EGR	142.59	27.8
CCGT + CCS 96%	131.19	23.3
CCGT + CCS 100%	131.88	25.3
H_2-CCGT	1664.22	None

To make H_2-CCGT competitive, hydrogen price must be reduced. Figure 4 shows a comparison between a H_2-based CCGT with hydrogen priced at 2 €/kg (instead of 3.62 €/kg), and a 96% capture CCS-enhanced CCGT. Under this scenario, both technologies reach payback simultaneously, but the CCS-enhanced CCGT ends with a better economic profile. This is reinforced by the LCOE breakdown in Figure 5.

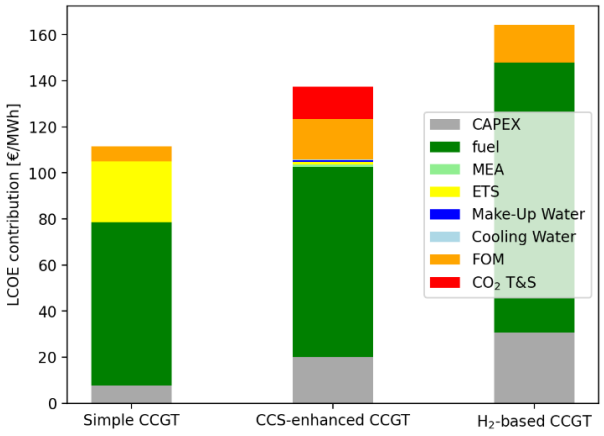

Fig. 5. LCOE breakdown comparison between 96% capture rate CCS-enhanced CCGT and 100% hydrogen H_2-based CCGT with hydrogen price reduced by 45%, CRM revenues and no inflation rate.

Figure 5 provides key insights on the LCOE structure. The LCOE breakdown of a simple CCGT shows a major contribution of fuel cost and carbon tax (ETS in yellow), with a smaller contribution for CCGT CAPEX and FOM costs, and a negligible contribution for cooling and make-up water. The LCOE breakdown of a CCS-enhanced CCGT has a reduced contribution of the carbon tax due to the high capture rate (96%) while having a higher contribution of fuel cost because of the lower CCGT efficiency, a higher contribution of CAPEX and FOM, and an additional contribution from

CO_2 transport and storage costs (CO_2 T&S in red) and MEA, which is nevertheless 20 times less impacting than CO_2 T&S costs.

As explained, ETS price is highly impacting the results of the study by increasing the LCOE and payback for a simple CCGT. Nowadays, this tax averages 85 €/ton and is supposed to remain constant in the future. However, an increase in this tax up to 130 €/ton could give an additional perspective to the results. While Figure 6 shows a comparable LCOE between simple and CCS-enhanced CCGTs, Figure 7 shows that a simple CCGT keeps a twice faster payback compared to the carbon neutral units.

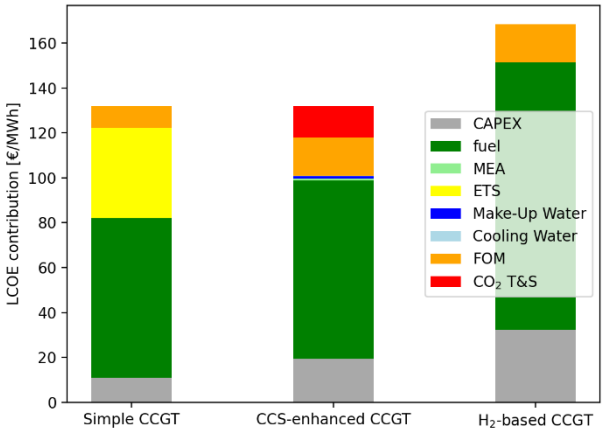

Fig. 6. LCOE breakdown comparison between a simple CCGT, 100% capture rate CCS-enhanced CCGT and 100% hydrogen H_2-based CCGT with hydrogen price reduced by 45%, CRM revenues and no inflation rate.

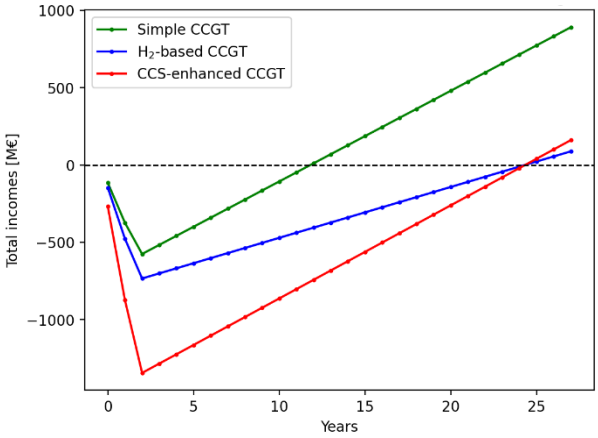

Fig. 7. Final comparison between a simple CCGT, 100% capture rate CCS-enhanced CCGT and 100% hydrogen H_2-based CCGT with hydrogen price reduced by 45%, CRM revenues and no inflation rate.

4 Online Tool Implementation

To complement the results presented in the previous section, this paper introduces a Streamlit-based web application designed to enable customizable economic analysis of hydrogen-based and CCS-enhanced gas turbines.

Fig. 8. QR code linking to the online tool

The tool addresses the challenge of variability in power plant configurations and local market conditions by allowing users to input their own technical and economic parameters.

4.1 Data Selection

Users begin by selecting regional electricity and fuel price data from predefined databases (Belgium, Norway, Netherlands, Poland, Sweden) or uploading their own hourly price profiles. This step also affects hydrogen and methane pricing. The selected dataset is visualized with hourly load and price curves.

4.2 Flexibility integration

Interactive sliders and inputs allow for extensive customization:

- Price parameters (methane, hydrogen, CO_2 T&S, etc.).
- Technical parameters (plant capacity, capture efficiency, water and MEA flowrates).

4.3 Application output

After configuration, the tool computes and displays key metrics:

- CAPEX/OPEX breakdown,
- payback curve,
- marginal cost, capacity factor, yearly OPEX, and LCOE.

4.4 Graphical Comparison

To visualize the economic tipping point between both technologies, the tool plots:

- payback curves of both CCGTs side-by-side with tipping point
- LCOE breakdown comparison.

4.5 Sensitivity Analysis

Multiple parameters have been varied to see their impact on the results of the study. Notable insights include:

- methane price variations significantly affect CCS-enhanced CCGTs, with payback ranging from 22 to 28 years due to small price shifts,
- CAPEX sensitivity for CCS has a lesser effect on payback due to unchanged OPEX and marginal cost,

- hydrogen price has a strong influence on H_2-based CCGTs, requiring a drop below 2 €/kg to become viable.

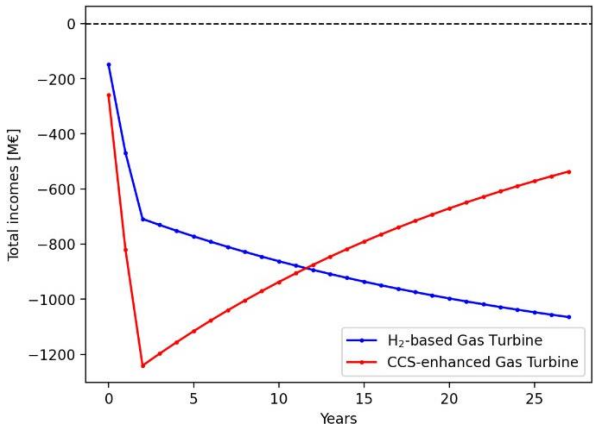

Fig. 9. Comparative payback curves.

Conclusion

To conclude, two decarbonization pathways for combined-cycle gas turbines (CCGT): CCS-enhanced CCGT with amine- based capture, and 100% hydrogen-fuelled CCGT have been compared. From a technical point of view, both solutions come with significant challenges: while CCS-enhanced CCGTs experience an efficiency penalty of about 7.3% for achieving 100% CO_2 capture, hydrogen-fuelled CCGTs remain limited to a lower efficiency of around 51.9%. Economically, despite a higher CAPEX for CCS units, the high price of hydrogen makes the H_2-based CCGT less competitive due to its high VOM costs, resulting in no realistic payback under current conditions.

Sensitivity analyses showed that reducing hydrogen prices by 45% would be critical to making H_2-based CCGTs feasible, whereas implementing Exhaust Gas Recirculation (EGR) in CCS-enhanced CCGTs surprisingly tends to increase both payback and LCOE of the power CCS-enhanced CCGTs due to a high EGR ratio of 45%, which seems not to be economically worth it in addition of being technically more complex.

Furthermore, the economic tipping point, where CCS-enhanced CCGTs surpass H_2-based CCGTs in profitability, was found around 12 years under base assumptions, and around 11 years with CRM revenues and zero inflation.

In addition, an increase in the carbon tax would make the LCOE of simple and CCS-enhanced CCGTS comparable, but the payback of a simple CCGT remains twice faster.

Overall, CCS-enhanced CCGTs show more favorable long-term economic potential under current market conditions, while hydrogen-based solutions will rely heavily on significant hydrogen price reductions and technological improvements.

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