Transforming carbon-intensive coal-fired power plants into negative emission technologies via biomass-fired calcium looping retrofit

Dawid P. Hanak*

a Net Zero Industry Innovation Centre, Teesside University,
Ferrous Road, Riverside Park Industrial Estate, Middlesbrough, TS2 1DJ, United Kingdom

Corresponding author: *Dawid P. Hanak

d.hanak@tees.ac.uk
ABSTRACT

Calcium looping is a promising CO₂ capture technology due to reduced energy and economic penalties compared to mature solvent scrubbing technologies and the potential for achieving negative emissions. This study examined the potential for transforming coal-fired power plants into negative CO₂ emission technologies via retrofit of calcium looping with biomass co-firing in the calciner. The results confirmed that co-firing 30% biomass with coal in the calciner was sufficient for the retrofitted process to achieve negative CO₂ emissions (-3.9 gCO₂/kWh). Such a retrofit scenario had a net efficiency of 29.9% and a levelised cost of electricity of 81.1–81.4 €/MWh. Alternative approaches to calcium looping design were also explored to maximise the techno-economic viability of the retrofitted process. It was shown that by reducing the CO₂ capture rate in the carbonator to 70%, the retrofitted process maintained the same net efficiency as the reference retrofit scenario. This modification resulted in a 1.8–5.0% reduction in the levelized cost of electricity. Moreover, reducing the fraction of flue gas fed to the carbonator to 80% resulted in a 0.6%-point reduction in efficiency penalty compared to the reference retrofit scenario. Although this adjustment led to specific CO₂ emissions of 109.0 gCO₂/kWh (4.0% higher than the reference retrofit), the emissions remained 86.2% lower than those of the unabated host plant. Notably, the levelized cost of electricity in this scenario was 6.2–7.5% lower than that for the reference retrofit scenario. Overall, this study demonstrated that by incorporating biomass co-firing, the calcium looping retrofits can transform the existing coal-fired power plants into negative CO₂ emission technologies or, at the very least, improve the techno-economic viability of CO₂ capture. Future research should address the broader environmental impact and potential challenges associated with biomass co-firing in coal-fired power plants retrofitted with calcium looping.

Keywords: biomass co-firing, carbonate looping, techno-economic analysis, decarbonisation, coal-fired power plants, carbon capture, climate change, greenhouse gas emissions, negative emissions.
1 INTRODUCTION

Complying with the ambitious aims of the Paris Agreement will require a portfolio of greenhouse gas reduction and mitigation measures that will support the global transition to net-zero emissions. The International Energy Agency has reported that fossil fuel combustion in the power sector alone accounted for nearly 50% of energy-related CO₂ emissions at the global scale. It is because coal is still an important fuel source for power generation, accounting for about 38% of the global power generation fleet [1]. Unfortunately, the demand for coal is still on an increase, achieving an all-time high of 8 billion tonnes per year in 2021. Substantial growth in coal demand was driven by developments in the power sector and switching from natural gas to coal, due to a significant surge in gas prices, in India, China and the European Union, despite substantial reductions in the United States [2]. Therefore, the decarbonisation of coal-fired power plants is more critical now than ever. Implementation of carbon capture, utilisation and storage (CCUS) is expected to provide a substantial driving force for the decarbonisation of the power sector, accounting for about 15% of cumulative CO₂ emission reductions by 2070 [3].

Solvent-based chemical scrubbing technology is currently the technology of choice in power CCUS projects [4], as it has been commercially demonstrated [5]. Yet, such post-combustion capture plants will remove only 85–95% of CO₂ from the flue gas, with the higher end of that range considered the best-available technology [6] and 90% adopted as standard regardless of the technology type [7]. Notably, an increase in the design CO₂ capture rate for the solvent-based chemical scrubbing technology from 90% to 95% would increase the levelized cost of electricity (LCOE) by 3%. A further increase to 99% was shown to increase the LCOE by up to 7.4%. Consequently, most process designs will consider 90% as the target CO₂ capture level; thus, the entire process will remain a net carbon emitter.

Calcium looping (CaL) has emerged as a possible next-generation CCUS technology that can provide better techno-economic performance than conventional solvent scrubbing technologies [8]. Beyond lower energy and economic penalties, CaL can utilise alternative solid fuels, such as biomass, in the calciner and, thus, potentially transform the retrofitted power plant from a net carbon emitter to a net carbon sink. Biomass co-firing in coal-fired power plants has been extensively studied. It was shown to reduce the environmental footprint of coal-fired power plants, assuming that it was locally and sustainably sourced. However, retrofitting the coal-fired boilers for biomass
cofiring can result in fouling, corrosion, slagging and other issues associated with ash characteristics [9]. Although this could pose a challenge in the existing boilers, such challenges can be considered at the design stage of the calciner. Another challenge associated with switching coal with biomass is that the latter is regarded as a lower-quality fuel, primarily due to higher moisture contents and, thus, lower energy density. Nevertheless, the use of lower-quality fuels, such as biomass or waste-derived fuels, in CaL has been proven experimentally. Alonso et al. [10] have used a 300 kW\textsubscript{th} circulating fluidised bed pilot plant to test in-situ combustion and carbonation of biomass. That work demonstrated 550 hours of operation when biomass was used in the calciner, emphasising the need to closely monitor the active CaO inventory in the carbonator. Furthermore, Haaf et al. [11] have used a 1 MW\textsubscript{th} CaL pilot plant to demonstrate that the use of waste-derived fuels poses no significant challenges to the CO\textsubscript{2} capture performance of CaL, which was close to the theoretical maximum over nearly 230 hours of operation. Their experimental campaigns indicated that the process could require close monitoring of inert ash fractions and operational temperatures, as these may influence the hydrodynamics of the dual fluidised bed system. Nevertheless, the experimental trials mentioned above indicate that the use of biomass, especially when co-fired with conventional fuels, should not pose substantial technical challenges.

The current literature offers some insights into the viability of using biomass in the calciner. Hanak et al.[12] considered the CaL retrofit to a coal-fired power plant and evaluated the impact of co-firing 20% biomass with coal and 100% biomass in the calciner. Their work confirmed that co-firing biomass with coal in the calciner enables the CaL design with a lower CO\textsubscript{2} capture level in the carbonator (71%) while maintaining the overall CO\textsubscript{2} capture level of 90%. They have also shown that using 100% biomass in the calciner would result in negative CO\textsubscript{2} emissions. However, that work did not quantify the economic implications of using biomass in the calciner. Martinez et al. [13] evaluated biomass use in the calciner for CaL retrofitted to a coal-fired power plant. In contrast to the work by Hanak et al. [12], the considered CaL layout included a re-carbonator in which part of the CO\textsubscript{2}-rich gas from the calciner is used to increase the carbonation extent of the sorbent leaving the carbonator. It aimed at improving the CO\textsubscript{2} carrying capacity of the sorbent by up to 10% points. That work also considered pure O\textsubscript{2} in the calciner, as it allows for a more compact calciner design [14,15]. Their work demonstrated that although using pure O\textsubscript{2} to combust biomass in the calciner would result in the reduced thermal input to the calciner, and thus the oxygen requirement and fresh limestone requirement, the amount of fuel used in the calciner would still increase.
by 25% compared to a coal-fired calciner. It can be attributed to the lower energy density of biomass (LHV = 19.1 MJ/kg) than that of coal (LHV = 27.5 MJ/kg). Consequently, the net efficiency of CaL with biomass-fired calciner was 0.6% points lower than that of standard CaL where coal was combusted in the calciner. Regardless of reduced energy performance, the use of biomass in the calciner was shown to result in negative CO₂ emissions (-245.3 gCO₂/kWh) and a 17% reduction in the cost of CO₂ avoided. However, the economic benefits reported in that study rely on the assumption that the price of biomass and coal were the same (~1.8 €/GJ), which is rarely the case [16]. Furthermore, Neto et al. [17] analysed a retrofit of CaL to a biomass-fired power plant. Their analysis has shown that the net efficiency penalty of such a retrofit would be 0.9% points. Such a figure is one order of magnitude lower than that reported for the solvent scrubbing retrofit (Cansolv, 8.4% points) for the same host plant. Yet, the rationale for such a low-efficiency penalty has not been provided, as the figures quoted in the literature for similar layouts usually vary between 6–8% points [8]. Moreover, that study reported a cost of CO₂ avoided of 131 €/tCO₂ for the first-of-a-kind CaL plant, which was higher than that for the Cansolv process (90 €/tCO₂). Notably, it could be because the estimated total capital requirement of CaL was significantly higher (5,152 €/kW₉₉) than figures between 1,800–3,000 €/kW₉₉ reported elsewhere [16,18–20].

Advanced CaL layouts also were developed for biomass-fired power plants. Ozcan et al. [16] proposed a new layout for a biomass-fired power plant with in-situ CO₂ capture via CaL. It assumed that biomass combustion and CO₂ capture happen simultaneously in a single reactor at 700°C. It also assumed that the price of biomass is three times higher (8.3 €/GJ) than that of coal (2.8 €/GJ). Such a process was shown to result in the cost of CO₂ avoided (43 €/tCO₂) lower than that of an oxy-combustion biomass-fired power plant (45 €/tCO₂). More importantly, the proposed process was shown to result in negative CO₂ emissions of -672 kgCO₂/MWₚₑ, compared to CO₂ neutral characteristics of the reference air-combustion biomass-fired power plant. In addition, Pillai et al. [21] compared the standard process layout for integrated CaL and a biomass-fired power plant with a double CaL layout. The latter uses hot CaO as the heat transfer medium that is heated to >900°C in the air-fired biomass combustor and transfers heat to the calciner. Consequently, this layout did not need the energy-intensive air separation unit for pure O₂ supply to the calciner. Nevertheless, the analysis showed that the standalone CaL

* Average USD to EUR conversion rate of 0.8865 EUR/USD in 2017
layout would result in a lower net efficiency penalty (2% points) than that of the double CaL layout (4% points) with respect to a reference biomass-fired power plant. Unfortunately, the economic benefits of the double CaL layout have not been quantified. Finally, Schakel et al. [22] analysed the environmental impact of using biomass in the calciner in CaL retrofitted to a cement plant. Their work has shown that using biomass in the calciner can reduce the global warming potential by 129%, from 0.87 kgCO$_2$/kg$_{clinker}$ to -0.25 kgCO$_2$/kg$_{clinker}$. This analysis confirmed that the use of biomass in the calciner has the potential to transform a net CO$_2$ emitter into a negative CO$_2$ emission process. However, the trade-off between the energy, economic and environmental performance and the effect of the biomass co-firing fraction has not been well understood yet.

Although the current literature provides some evidence for using biomass in the calciner, understanding how the biomass co-firing fraction influences the process performance and the trade-off between energy, economic and environmental performance is still missing. Therefore, this study aimed to perform a comprehensive techno-economic feasibility assessment of biomass co-firing in the calciner of CaL retrofit to the 580 MW$_{el}$ coal-fired power plant. The high-fidelity process models for the considered process were developed in Aspen Plus®. The resulting energy and mass balances were used to provide process data for the capital cost estimation using a bottom-up approach and economic assessment using the net present value (NPV) method. The trade-off between the key performance indicators has been analysed under different retrofit and operating scenarios, considering the effects of the biomass fraction in the fuel fed to the calciner (Scenario 1), the CO$_2$ capture rate in the carbonator (Scenario 2), and the flue gas fraction fed to the carbonator (Scenario 3). Finally, the key performance indicators of the optimised scenarios have been compared with the reference coal-fired power plant and the reference retrofit scenario.

2 METHODS

2.1 Process model description

This study considers a CaL retrofit to a coal-fired power plant, as illustrated in Figure 1. The host plant is a 580 MW$_{el}$ supercritical coal-fired power plant that was modelled in Aspen Plus® by Hanak et al. [23,24] based on the revised NETL report [25]. It follows a typical plant layout, including a power boiler, flue gas denitrification and desulphurisation units, and a fly ash separator. Coal, for which the composition is presented in Table 1, is combusted in excess air (Table 2) to provide heat for the primary steam cycle. The
feedwater enters the economiser at 289°C and is then superheated in primary and secondary superheaters to 593°C. The superheated steam enters the high-pressure turbine and is expanded from 242.3 bar to 49.0 bar. The steam is then reheated to 593°C in the reheater and expanded to the intermediate pressure of 9.3 bar in the intermediate-pressure turbine. The intermediate-pressure steam is then directed to the low-pressure turbine, where it is expanded to 0.069 bar, a pressure corresponding to the saturation temperature of 38.7°C in the condenser. To ensure high efficiency of the steam cycle, the steam is partially bled from the turbine sections to provide heat for feedwater heating. The feedwater heating train comprises four low-pressure closed feedwater heaters, one mixed feedwater heater, and three closed high-pressure feedwater heaters.

![Figure 1: Process flow diagram of calcium looping retrofit to a coal-fired power plant](image)

CaL was modelled and validated in Aspen Plus® by Hanak et al. [12]. The typical layout of CaL includes an interconnected carbonator and calciner. In this process, CO₂ is removed from the flue gas on contact with CaO in the carbonator at 650°C. The formed CaCO₃ is then regenerated at 900°C in the calciner. The former was modelled as a stoichiometric reactor to account for the sorbent deactivation, whereas the latter was represented as a Gibbs reactor. The average sorbent conversion in the carbonator was accounted for using the semi-empirical correlation proposed by Rodríguez et al. [26].
defined in Eq. (1), the maximum value of the average sorbent conversion in the carbonator depends on the calcination ($f_{\text{calc}}$) and carbonation ($f_{\text{carb}}$) extents, fitting parameters ($a_1, a_2, f_1, f_2, b$), and the amount of fresh limestone make-up ($F_0$), sorbent looping rate ($F_R$) and the fraction limestone that was never calcined ($r_0$). The last variable is defined in Eq. (2). The fitting parameters for the considered semi-empirical correlation were derived based on the experimental data from the 1.7 MWth la Pereda pilot plant [27].

\[
x_{\text{ave}} = (F_0 + F_R r_0) f_{\text{calc}} \left[ \frac{a_1 f_1^2}{F_0 + F_R f_{\text{carb}} f_{\text{calc}} (1 - f_1)} + \frac{a_2 f_2^2}{F_0 + F_R f_{\text{carb}} f_{\text{calc}} (1 - f_2)} + \frac{b}{F_0} \right]
\]

(1)

\[
r_0 = \frac{F_0 (1 - f_{\text{calc}})}{F_0 + F_R f_{\text{calc}}}
\]

(2)

Table 1: Summary of coal and biomass composition

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Coal (Portland) [25]</th>
<th>Biomass (Beech Wood) [28]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Proximate analysis</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Moisture content (%)_{ar}</td>
<td>11.12</td>
<td>19.00</td>
</tr>
<tr>
<td>Fixed carbon (%)_{db}</td>
<td>49.72</td>
<td>14.00</td>
</tr>
<tr>
<td>Volatile matter (%)_{db}</td>
<td>39.37</td>
<td>85.00</td>
</tr>
<tr>
<td>Ash (%)_{db}</td>
<td>10.91</td>
<td>1.00</td>
</tr>
<tr>
<td><strong>Ultimate analysis</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ash (%)_{db}</td>
<td>10.91</td>
<td>1.00</td>
</tr>
<tr>
<td>Carbon (%)_{db}</td>
<td>71.72</td>
<td>50.40</td>
</tr>
<tr>
<td>Hydrogen (%)_{db}</td>
<td>5.06</td>
<td>7.20</td>
</tr>
<tr>
<td>Nitrogen (%)_{db}</td>
<td>1.41</td>
<td>0.30</td>
</tr>
<tr>
<td>Chlorine (%)_{db}</td>
<td>0.33</td>
<td>0.00</td>
</tr>
<tr>
<td>Sulphur (%)_{db}</td>
<td>2.82</td>
<td>0.10</td>
</tr>
<tr>
<td>Oxygen (%)_{db}</td>
<td>7.75</td>
<td>41.0</td>
</tr>
<tr>
<td>Higher heating value (MJ/kg)</td>
<td>27.01</td>
<td>16.21</td>
</tr>
</tbody>
</table>

The calcination reaction is endothermic and, therefore, high-grade heat needs to be added to sustain the desired operating temperature of the calciner. To avoid dilution of CO$_2$, this is usually achieved via oxy-fuel combustion directly in the calciner. In this study, solid fuels (coal and biomass) are considered. This is represented in two stages. First, the decomposition of the solid fuel is represented using a yield reactor. The component yields are adjusted to accurately represent the ultimate analysis of solid fuel, as presented in Table 1. Second, the decomposed fuel is combusted in an O$_2$/CO$_2$ mixture directly in the calciner that, as already mentioned, was modelled as a Gibbs reactor. The complete combustion of solid fuel was achieved by ensuring that an excess amount of
oxygen was maintained in the reactor, which was reflected by the O\textsubscript{2} content of 2.5\%\textsubscript{vol,dry} in the vapour stream leaving the calciner.

Due to a high-temperature operation, high-grade heat can be recovered from the carbonator and the process streams, such as the clean flue gas and high-purity CO\textsubscript{2} streams. This high-grade heat has been used to generate steam for the secondary steam cycle, which had the same steam conditions as the primary steam cycle in the host plant, and pre-heat flue gas and high-purity O\textsubscript{2} streams. The summary of the key process model assumptions for the reference 580 MW\textsubscript{el} coal-fired power plant and CaL are presented in Table 2.
Table 2: Summary of the key process model assumptions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Coal-fired power plant</strong></td>
<td></td>
</tr>
<tr>
<td>Combustor</td>
<td>Excess air ratio (%&lt;sub&gt;vol&lt;/sub&gt;)</td>
</tr>
<tr>
<td>Primary steam cycle</td>
<td>Design live/reheat steam temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Design live/reheat steam pressure (bar)</td>
</tr>
<tr>
<td></td>
<td>Final feedwater temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Feedwater heater terminal temperature difference (°C)</td>
</tr>
<tr>
<td></td>
<td>Feedwater heater minimum temperature approach (°C)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of compressors (%)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of high-pressure steam turbine (%)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of intermediate-pressure steam turbine (%)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of low-pressure steam turbine (%)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of pumps (%)</td>
</tr>
<tr>
<td></td>
<td>Electrical efficiency of generator (%)</td>
</tr>
<tr>
<td>Flue gas treatment</td>
<td>SO&lt;sub&gt;2&lt;/sub&gt; removal efficiency (%)</td>
</tr>
<tr>
<td></td>
<td>Fly ash removal efficiency (%)</td>
</tr>
<tr>
<td></td>
<td>NO&lt;sub&gt;x&lt;/sub&gt; removal efficiency (%)</td>
</tr>
<tr>
<td><strong>Calcium looping CO&lt;sub&gt;2&lt;/sub&gt; capture plant</strong></td>
<td></td>
</tr>
<tr>
<td>Carbonator</td>
<td>Temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Carbonation extent (-)</td>
</tr>
<tr>
<td>Calciner</td>
<td>Temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Calcination extent (-)</td>
</tr>
<tr>
<td></td>
<td>Relative make-up (fresh limestone/sorbent circulation rate) (-)</td>
</tr>
<tr>
<td></td>
<td>O&lt;sub&gt;2&lt;/sub&gt; excess (%&lt;sub&gt;vol,dry&lt;/sub&gt;)</td>
</tr>
<tr>
<td>Secondary steam cycle</td>
<td>Design live/reheat steam temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Design live/reheat steam pressure (bar)</td>
</tr>
<tr>
<td><strong>Auxiliary equipment</strong></td>
<td></td>
</tr>
<tr>
<td>CO&lt;sub&gt;2&lt;/sub&gt; compression unit</td>
<td>Polytropic efficiency of CO&lt;sub&gt;2&lt;/sub&gt; compressors (%)</td>
</tr>
<tr>
<td></td>
<td>Isentropic efficiency of CO&lt;sub&gt;2&lt;/sub&gt; pump (%)</td>
</tr>
<tr>
<td></td>
<td>Intercooling temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>CO&lt;sub&gt;2&lt;/sub&gt; final pressure (bar)</td>
</tr>
<tr>
<td></td>
<td>CO&lt;sub&gt;2&lt;/sub&gt; final temperature (°C)</td>
</tr>
<tr>
<td>Air separation unit</td>
<td>O&lt;sub&gt;2&lt;/sub&gt; purity (%&lt;sub&gt;vol,dry&lt;/sub&gt;)</td>
</tr>
<tr>
<td></td>
<td>Polytropic efficiency of air compressors (%)</td>
</tr>
<tr>
<td></td>
<td>Intercooling temperature (°C)</td>
</tr>
<tr>
<td></td>
<td>Final air pressure (bar)</td>
</tr>
</tbody>
</table>
2.2 Feasibility assessment method

This study aimed to assess whether using biomass as a fuel in the calciner can bring energy, environmental and economic benefits to the CaL retrofit to the 580 MWel coal-fired power plant. The energy performance of the considered process has been quantified considering net efficiency and net efficiency penalty. The net efficiency for the host plant and the CaL retrofit is defined in Eq. (3) and Eq. (4), respectively, as a ratio of the net power output ($W_{net}$) and the chemical energy input from fuel combustion ($Q_{fuel}$).

In the CaL retrofit, the chemical energy input considers the host plant and CaL, distinguishing between coal ($m_{coal,CaL}$) and biomass ($m_{biomass,CaL}$) fuels. The efficiency penalty is defined in Eq. (5) as the difference between the net efficiency of the host plant ($\eta_{th,host}$) and of the CaL retrofit ($\eta_{th,CaL}$). Moreover, it is worth exploring the potential increase in the fuel handling rates due to a lower higher heating value of biomass (Table 1). Thus, a specific fuel requirement ($b_{fuel}$) is defined in Eq. (6) as a ratio of the total fuel consumption and the net power output of the CaL retrofit.

$$\eta_{th,host} = \frac{W_{net,primary}}{HHV_{coal}m_{coal,host}}$$ (3)

$$\eta_{th,CaL} = \frac{W_{net,primary} + W_{net,secondary}}{HHV_{coal}(m_{coal,host} + m_{coal,CaL}) + HHV_{biomass}(m_{biomass,CaL})}$$ (4)

$$\Delta\eta_{th} = \eta_{th,host} - \eta_{th,CaL}$$ (5)

$$b_{fuel} = \frac{m_{coal,host} + m_{coal,CaL} + m_{biomass,CaL}}{W_{net,primary} + W_{net,secondary}}$$ (6)

The environmental performance of the considered process has been evaluated using the specific CO$_2$ emissions ($e_{CO2}$), as defined in Eq. (7). It is defined as the ratio of the net CO$_2$ mass flow rate emitted into the atmosphere and the net power output. The former can be determined as the difference between the CO$_2$ mass flow rate leaving the carbonator with the clean gas ($m_{CO2,carb}$), which is of fossil origin, and the CO$_2$ mass flow rate resulting from biomass combustion in the calciner. Due to the nearly carbon-neutral character of biomass, permanent storage of that CO$_2$ will result in negative CO$_2$ emissions that can be used to partially offset the fossil CO$_2$ still present in the clean gas.

$$e_{CO2,CaL} = \frac{m_{CO2,carb} - m_{CO2,biomass,CaL}}{W_{net,primary} + W_{net,secondary}}$$ (8)
The economic performance of the considered process has been quantified using LCOE and the cost of CO₂ avoided (AC). The LCOE is defined in Eq. (9) and determines the minimum cost of electricity at which the project becomes profitable. It correlates the thermodynamic performance indicators of the considered systems, including the net power output (\(W_{\text{net}}\)) and net efficiency (\(\eta_{\text{th}}\)), with the economic performance indicators. These include total capital requirement (TCR), fixed operating and maintenance costs (FOM), variable operating and maintenance costs (VOM) and specific fuel cost (SFC).

In addition, parameters such as the capacity factor (CF), which represents the fraction of the time the considered system is operating in a year, and the fixed capacity factor (FCF), which is used to annualise the TCR considering project lifetime (t) and discount rate (r), as defined in Eq. (10). In addition, the AC is defined in Eq. (11).

\[
L_{\text{COE}} = \frac{\text{TCR} \times \text{FCF} + \text{FOM}}{W_{\text{net}} \times \text{CF} \times 8760} + V_{\text{OM}} + \frac{\text{SFC}}{\eta_{\text{th}}} 
\]

\[
\text{FCF} = \frac{r(1 + r)^t}{(1 + r)^t - 1} 
\]

\[
\text{AC} = \frac{L_{\text{COE}}_{\text{Cal}} - L_{\text{COE}}_{\text{Host}}}{e_{\text{CO}_2,\text{Host}} - e_{\text{CO}_2,\text{Cal}}} 
\]

The TCR represents the total capital cost of the host plant and Cal. The cost component for the host plant has been determined based on the NETL report [29], whereas the cost component for Cal was determined using Eq. (12) from Romano et al. [30]. This correlation is based on the scaling law and uses the oxy-fuel circulating fluidised bed system as the reference capital cost (Co) [31]. Heat input to the calciner (\(Q_{\text{calc}}\)) and reactor volume (V) are considered as the scaling parameters, along with the relevant scaling factors for heat input (SF,Q) and reactor volume (SF,V).

\[
C_{\text{Cal}} = C_0 \left[ \alpha \left( \frac{Q_{\text{calc}}}{Q_{0,\text{calc}}} \right)^{SF,Q} + (1 - \alpha) \left( \frac{V_{\text{calc}}}{V_{0,\text{calc}}} \right)^{SF,V} \right] 
\]

Finally, the FOM and VOM are defined as a fraction of the TCR. The operating expenditure is determined based on the energy and mass balance from Aspen Plus® model outputs and the assumed specific costs for CO₂ emission, CO₂ storage and transport, sorbent make-up and fuel consumption. The economic assumptions considered in this study are summarised in Table 3.
Table 3: Summary of the key economic model assumptions

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scale and size variables</td>
<td></td>
</tr>
<tr>
<td>Scaling factor of coal-fired power plant (-) [31]</td>
<td>0.67</td>
</tr>
<tr>
<td>Scaling factor for the heat transfer surfaces (-) [30]</td>
<td>0.85</td>
</tr>
<tr>
<td>Scaling factor for the heat rate in the calciner (-) [30]</td>
<td>0.9</td>
</tr>
<tr>
<td>Scaling factor for the volume of the reactors (-) [30]</td>
<td>0.67</td>
</tr>
<tr>
<td>Superficial velocity (m/s) [32,33]</td>
<td>5</td>
</tr>
<tr>
<td>Height-to-diameter ratio (-) [34]</td>
<td>3</td>
</tr>
<tr>
<td>Economic variables</td>
<td></td>
</tr>
<tr>
<td>Variable operating and maintenance cost rate (%/year) [19,35]</td>
<td>2</td>
</tr>
<tr>
<td>Fixed operating and maintenance cost rate (%/year) [19,35]</td>
<td>1</td>
</tr>
<tr>
<td>Carbon tax (€/tonne)</td>
<td>25</td>
</tr>
<tr>
<td>Specific cost of CO₂ transport and storage (€/tonne) [30]</td>
<td>7</td>
</tr>
<tr>
<td>Specific cost of sorbent (€/tonne) [19,35]</td>
<td>6</td>
</tr>
<tr>
<td>Specific cost of coal (€/GJ) [35,36]</td>
<td>1.5</td>
</tr>
<tr>
<td>Specific cost of biomass (€/GJ) [37]</td>
<td>4.5</td>
</tr>
<tr>
<td>Project discount rate (%) [19,35]</td>
<td>8.78</td>
</tr>
<tr>
<td>Project expected lifetime (years) [19,35]</td>
<td>25</td>
</tr>
<tr>
<td>Capacity factor (%) [19,35]</td>
<td>80</td>
</tr>
<tr>
<td>Reference specific capital cost of coal-fired power plant (€/kW) [29]</td>
<td>1100</td>
</tr>
<tr>
<td>Reference specific capital cost of calcium looping process (€/kW) [31]</td>
<td>1252.3</td>
</tr>
</tbody>
</table>

2.3 Feasibility assessment scenarios

The techno-economic viability of using biomass in the calciner of CaL has been assessed under different retrofit and operating scenarios (Table 4):

- In Scenario 1, biomass fraction in the fuel fed to the calciner was varied between 0% and 100%. It aimed to understand how various coal-biomass mixtures influence the techno-economic performance of the CaL retrofit in the calciner.

- In Scenario 2, the biomass fraction was fixed at 30%, which is often used when co-firing biomass with coal to meet electric efficiency standards [38–40], and the CO₂ capture rate in the carbonator was varied between 50% and 90%. It aimed to understand how the carbonator design influences the techno-economic performance of the CaL retrofit.

- In Scenario 3, the biomass fraction was also fixed at 30% and the flue gas fraction fed to the carbonator was varied between 50% and 100%. It aimed to understand how the scale of CaL influences the techno-economic performance of the retrofitted system.
Table 4: Summary of the scenario assumptions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass fraction in the calciner (%)</td>
<td>0-100</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>CO₂ capture rate in the carbonator (%)</td>
<td>80</td>
<td>50-90</td>
<td>80</td>
</tr>
<tr>
<td>Flue gas fed to the carbonator (%)</td>
<td>100</td>
<td>100</td>
<td>50-100</td>
</tr>
</tbody>
</table>

3 RESULTS AND DISCUSSION

3.1 Effect of biomass fraction in the fuel mixture fed to the calciner

In Scenario 1, the fraction of biomass in the calciner fuel mixture was varied between 0 and 100%. The CO₂ capture rate in the carbonator and the fraction of the flue gas fed to the carbonator were 80% and 100%, respectively. Figure 2 presents the influence of the biomass fraction in the calciner fuel mixture on the key technical performance indicators of the retrofitted system.

It was shown that an increase in the biomass fraction in the calciner resulted in an increased efficiency penalty of the retrofitted system (Figure 2a). Notably, the efficiency penalty increased from 7.7% points for no biomass in the calciner to 8.1% points for 30% biomass co-fired with coal in the calciner. An exponential growth in the efficiency penalty was observed above 50% biomass co-fired with coal in the calciner, resulting in the efficiency penalties of 8.4% points and 9.4% points at biomass fraction in the calciner of 50% and 100%, respectively. Notably, the net power output of the retrofitted system (Figure 2b) has only been marginally influenced. On the increase from 0% to 100% biomass in the calciner fuel mixture, the net power output of the retrofitted system increased from 835.7 MWₑ₁ to 841.0 MWₑ₁. Such a performance of the retrofitted system under varying biomass fraction in the calciner fuel mixture can be explained by the differences in composition and fuel properties of biomass and coal. The considered biomass composition has a substantially higher moisture content (19.00%ₐₑ) and lower heating value (16.21 MJ/kg) than coal (11.12%ₐₑ; 27.01 MJ/kg). As a result, the fuel mixtures with a higher biomass content imposed a higher heat load on the calciner necessary to evaporate moisture. Thus, more fuel was needed in the calciner per unit amount of electricity produced by the retrofitted system (Figure 2c). This analysis also revealed that the increase of the biomass content in the calciner fuel mixture from 0% to 30% would increase the fuel consumption by 7.7%, from 439.6 g/kWh to 473.5 g/kWh. A further increase in the biomass content to 50% and 100% would substantially increase the fuel consumption by 14.4% (503.0 g/kWh) and 41.7% (622.9 g/kWh), respectively,
compared to the case with no biomass cofiring. A combination of higher efficiency penalties and fuel consumption makes co-firing more than 50% of the biomass in the calciner unattractive from the thermodynamic standpoint.

The only benefit of co-firing biomass with coal in the calciner is that it is often considered a carbon-neutral fuel [41]. It implies that any biogenic CO₂ captured from the biomass combustion in the calciner will result in negative CO₂ emissions that can offset the residual fossil CO₂ emissions in the clean gas leaving the carbonator. Considering that the entire volume of flue gas from the coal-fired power plant is fed to the carbonator and that 80% of CO₂ is removed from the flue gas in the carbonator, the specific CO₂ emissions of the retrofitted system became negative when the biomass fraction in the calciner fuel mixture was higher than 29%. Notably, at 30% biomass fraction, the specific emissions were -3.9 gCO₂/kWh. It implies that there is no need for a substantial amount of biomass to be co-fired in the calciner for the entire process to become carbon neutral. Hence, biomass co-firing can be implemented in line with the current practice, limiting the impact on the thermodynamic performance to meet electric efficiency standards [38–40].
Figure 2: Effect of biomass fraction in the calciner on a) net efficiency penalty, b) net power output, c) fuel consumption, and d) specific CO₂ emissions

Having proven the technical and environmental viability of co-firing biomass with coal in the calciner, it is crucial to understand its implications on the economic viability of the retrofitted process. Figure 3 presents the impact of the biomass fraction in the calciner fuel mixture on the LCOE and the AC. Furthermore, the impact of the market conditions, represented by the carbon tax, coal price and biomass price, was also considered.
The economic analysis has revealed that co-firing biomass with coal in the calciner can have potential cost benefits, especially for high carbon tax scenarios (Figure 3a). The price for the carbon permits on the EU Emission Trading System reached 100 €/tCO₂ in February 2023 [42]. At such carbon tax, the LCOE would reduce from 85.4 €/MWh for...
no biomass co-firing to 82.8 €/MWh and 55.4 €/MWh for 30% and 100% biomass fraction in the calciner fuel mixture. It is important to emphasise that such a reduction in the LCOE can be achieved even though the considered price of biomass is three times higher (4.5 €/GJ) than that for coal (1.5 €/GJ). However, such economic benefits of biomass co-firing were only observed when the carbon tax was higher than 50–60 €/tCO₂. Below this range, the increase in the biomass fraction in the calciner fuel mixture resulted in an increase in the LCOE. It can be attributed to a higher cost of biomass considered in the analysis, as mentioned above. For each level of carbon tax considered, the AC increased with an increase in biomass content from 0% to 30% (Figure 3b). For biomass fraction in the calciner fuel mixture above 30%, the retrofitted system became carbon negative and the cost of CO₂ avoided reduced. Notably, the AC increased from -43.1 €/tCO₂ to -42.6 €/tCO₂ between 0% and 30% of biomass fraction in the calciner fuel mixture at the carbon tax of 100 €/tCO₂. It then reduced to -42.9 €/tCO₂ and -44.6 €/tCO₂ at 50% and 100% biomass content. The negative figures indicate that the carbon tax payments were higher than the cost of avoiding CO₂ emissions, contributing to the revenue.

Considering the volatility of the energy market, the fluctuations in fuel prices can significantly impact the economic viability of the retrofitted process. Considering the carbon tax of 25 €/tCO₂ (Table 3), an increase in the coal price from 1.5 €/GJ to 4.5 €/GJ when no biomass was co-fired in the calciner can result in a 45.9% increase in the LCOE from 77.6 €/MWh to 113.2 €/MWh (Figure 3c). Such an increase in the LCOE is limited to 37.0% when 30% of biomass is co-fired in the calciner. It indicates that using biomass in the calciner can reduce the economic implications of the variability of fossil fuel prices on the viability of the retrofitted system, provided the biomass price is not subject to similar variability. Under the same biomass co-firing conditions (30% biomass co-firing), an increase in the biomass price from 4.5 €/GJ to 8.0 €/GJ, which represents a typical range of biomass prices [43], would only result in a 7.8% increase in the LCOE from 81.4 €/MWh to 87.8 €/MWh (Figure 3e). The same increase in biomass price would cause a more substantial impact on the LCOE at 50% (13.3% increase in LCOE) and 100% biomass co-fired in the calciner (25.8% increase in the LCOE). Notably, the data presented in Figure 3c and Figure 3e indicate that the change in the coal price has a more significant impact on the LCOE than the change in the biomass price, especially for low biomass co-firing fractions. It is because coal is used in both the host plant and CaL, and any increase in the coal price would influence the operating expenditure of the entire retrofitted system. Conversely, the variation in the biomass price would only impact the operating expenditure of CaL. Notably, the correlation between the coal price and...
the biomass price needs to be further explored, but this was considered out of this study scope. Finally, Figure 3d and Figure 3f demonstrated that the price of coal and biomass, respectively, have a moderate effect on the AC. An increase in the coal price from 1.5 €/GJ to 4.5 €/GJ when no biomass was co-fired in the calciner resulted in a 32.9% increase in the AC from 31.9 €/tCO$_2$ to 45.5 €/tCO$_2$ (Figure 3e). Such an increase in the AC was limited to 6.5% when 30% of biomass was co-fired in the calciner (34.6 €/tCO$_2$). It is essential to highlight that the AC reduced below 31.9 €/tCO$_2$ when more than 40% of biomass was co-fired in the calciner. The increase in the biomass price from 4.5 €/GJ to 8.0 €/GJ resulted in the AC increase of 16.8% when 30% of biomass is co-fired in the calciner (40.4 €/tCO$_2$), with respect to the case when no biomass is co-fired in the calciner (31.9 €/tCO$_2$).

Overall, the analysis presented in this scenario has demonstrated that biomass co-firing in the calciner can be a viable route to convert existing coal-fired power plants into carbon-neutral or even carbon-negative technologies. The analysis showed that the impact on the thermodynamic economic performance would be relatively limited when up to 30% of biomass was co-fired in the calciner. The key challenge of using biomass in the calciner was increased efficiency penalty and specific fuel consumption. Although these were limited up to a 30% co-firing fraction, it is worth exploring how this negative impact can be limited through alternative CaL designs.

3.2 Effect of the CO$_2$ capture rate in the carbonator

In Scenario 2, the fraction of biomass in the calciner fuel mixture was fixed at 30%, and the CO$_2$ capture rate in the carbonator was varied between 50% and 90%. Moreover, the fraction of the flue gas fed to the carbonator was 100%. Figure 4 presents the effect of the CO$_2$ capture rate in the carbonator on the key technical performance indicators of the retrofitted system.
The analysis of the thermodynamic performance has shown that an increase in the CO$_2$ capture rate in the carbonator will result in a higher efficiency penalty (Figure 4a). Notably, the efficiency penalty increased from 7.3% points to 7.7% points at the CO$_2$ capture rate in the carbonator between 50% and 70% (0.18% points per 1% increase in the CO$_2$ capture rate). For higher CO$_2$ capture levels, the efficiency penalty increased at the rate of 0.36% points per 1% increase in the CO$_2$ capture rate, from 7.7% points at 70% to 8.4% points at 90%. Notably, the net power output was shown to increase nearly linearly from 702.9 MW to 876.1 MW for the CO$_2$ capture levels in the carbonator of 50%
and 90%, respectively (Figure 4b). Therefore, higher efficiency penalty levels at higher CO₂ capture rates can be associated with higher specific fuel consumption (Figure 4c). When more CO₂ was removed in the carbonator, more sorbent needed to be circulated between the carbonator and the calciner. In addition, the considered layout of CaL described in Section 2 (Figure 1) does include neither waste heat recovery from the purge stream nor pre-heating of the fresh sorbent make up. As a result of a higher sorbent circulation rate and make-up rate, the energy demand in the calciner will be higher at higher CO₂ capture rates, leading to a higher efficiency penalty. Finally, the specific CO₂ emissions of the retrofitted system reduced from 230.8 gCO₂/kWh to -66.6 gCO₂/kWh for the CO₂ capture levels in the carbonator of 50% and 90%, respectively (Figure 4d). Considering that the unabated host plant has specific CO₂ emissions of 792.3 gCO₂/kWh, the retrofit of CaL with 30% biomass co-fired in the calciner would result in 70.9% lower specific CO₂ emissions even if only 50% of CO₂ was removed from the flue gas in the carbonator. If 90% of CO₂ were removed in the carbonator, the retrofitted system would become carbon negative. The optimum CO₂ capture rate in the carbonator needs to be determined based on the economic analysis.

Figure 5 presents the impact of the CO₂ capture rate in the carbonator on the economic viability of the CaL retrofit. Similarly to the previous analysis, the impact of the market conditions was also considered. It can be observed that the LCOE increases with the increase in the CO₂ capture rate in the carbonator for the carbon tax below 70 €/tCO₂ (Figure 5a). Above this figure, the increase in the amount of CO₂ removed from the flue gas results in a reduction of the LCOE. For example, at the initial carbon tax of 25 €/tCO₂, the LCOE would increase from 67.6 €/MWh to 87.0 €/MWh on an increase of the CO₂ capture rate from 50% to 90%. However, at the carbon tax of 100 €/tCO₂, the LCOE would reduce from 85.0 €/MWh to 82.0 €/MWh. It implies that under current carbon tax conditions in the UK and the EU, it will be more economically viable to design CaL for CO₂ capture rates between 80% and 90%. Furthermore, the analysis presented in Figure 5b revealed that the AC becomes negative for the carbon tax above 50 €/tCO₂ at the CO₂ capture rates below 60%, above 55 €/tCO₂ at the CO₂ capture rates between 70-80%, and above 65 €/tCO₂ at the CO₂ capture rate of 90%. It indicates that a higher carbon tax is required to offset the additional cost associated with larger capital and operational costs of CaL needed to achieve higher CO₂ capture rates. It is also worth highlighting that competitive LCOE values (below 70 €/MWh) can be achieved at the low values for CO₂ capture rate in the carbonator (below 60%; Figure 5a) and carbon tax (below 30 €/tCO₂) result in competitive LCOE values (below 70 €/MWh). Under such
conditions, the AC fluctuated between 20 €/tCO₂ and 40 €/tCO₂. Notably, the design of CaL for the CO₂ capture rate in the carbonator of 50–60% may still be viable in other parts of the world, such as China where the average carbon tax is about 9 €/tCO₂ [44]. Such a design would reduce the environmental footprint of the existing host plant and leave space for further expansion of the CO₂ capture capacity once the market conditions become more favourable.

Furthermore, the variation in fuel prices has been shown to have a substantial impact on the economic viability of the retrofitted system. Considering that only 30% of biomass was co-fired with coal in the calciner, the change in the coal price from 1.5 €/GJ to 4.5 €/GJ resulted in an LCOE increase of 45.3% (from 67.6 €/MWh to 98.3 €/MWh) and 34.5% (from 82.0 €/MWh to 117.1 €/MWh) for the CO₂ capture rates of 50% and 90%, respectively (Figure 5c). Under the same conditions, the AC increased by 18.9% (from 21.5 €/tCO₂ to 24.8 €/tCO₂) and 5.4% (from 36.6 €/tCO₂ to 38.6 €/tCO₂) for the CO₂ capture rates of 50% and 90%, respectively (Figure 5d). It can be observed that although the retrofitted system with a higher CO₂ capture rate in the carbonator had higher LCOE, which can be attributed to higher capital and operating expenditure, it was less sensitive to a fluctuation in the coal price. It can be explained by the fact that the fraction of biomass in the total fuel supply to the retrofitted system will increase with the CO₂ capture rate in the carbonator, shielding the LCOE and the AC from the coal price increases. Moreover, an increase in the biomass price from 4.5 €/GJ to 8.0 €/GJ resulted in the LCOE increase of only 7.1% and 7.8% for the CO₂ capture rates of 50% and 90%, respectively (Figure 5d). Hence, the increase in the biomass price will only have a marginal influence on the LCOE. However, such an increase in the biomass price will increase the AC by 40% (from 21.5 €/tCO₂ to 30.0 €/tCO₂) and 21.6% (from 36.6 €/tCO₂ to 44.5 €/tCO₂) for the CO₂ capture rates of 50% and 90%, respectively (Figure 5f). Such an increase in the AC is caused by the fact that any change in the biomass price only influences the operating expenditure of CaL. In contrast, any change in the coal price will influence the operating expenditure of both CaL and the host plant resulting in a lower impact on the AC.

Overall, the analysis presented in this scenario demonstrated that the optimum CO₂ capture rate in the carbonator would depend on the actual market conditions. Considering the current carbon tax figures (i.e. >100 €/tCO₂ via EU ETS), it is more economically viable to design CaL to capture 80–90% of CO₂ from the flue gas. This is because the retrofitted process becomes carbon negative at such CO₂ capture rates.
Assuming that the plant operator can be paid to use the negative emissions to offset someone else's emissions, the additional revenue stream from carbon tax payments would compensate for the increased efficiency penalty and fuel consumption observed at high CO₂ capture rates. Nevertheless, the optimum CO₂ capture rate was shown to be highly influenced by the fuel price. The analysis indicated that the high CO₂ capture rates would only be viable under low fuel cost scenarios. Further optimisation of this scenario is required, considering the uncertainty due to carbon tax and fuel price fluctuation.
Figure 5: Effect of the CO\textsubscript{2} capture rate in the carbonator and carbon tax (a,b), coal price (c,d), and biomass price (e,f) on levelised cost of electricity (a,c,e) and cost of CO\textsubscript{2} avoided (b,d,f).
3.3 Effect of the flue gas fraction fed to the carbonator

In Scenario 3, the fraction of flue gas from the host plant to CaL was varied between 50% and 100%. The fraction of biomass in the calciner fuel mixture was 30% and the CO₂ capture rate in the carbonator was 80%. Figure 6 presents the effect of the flue gas fraction fed to the carbonator on the key technical performance indicators of the retrofitted system.

![Graphs showing the effect of flue gas fraction on efficiency, power output, fuel consumption, and CO₂ emissions.]

Figure 6: Effect of biomass fraction in the calciner on a) net efficiency penalty, b) net power output, c) fuel consumption, and d) specific CO₂ emissions
The analysis of the thermodynamic performance has revealed that the increase in the volume of flue gas treated in the carbonator will result in a higher efficiency penalty (Figure 6a). The efficiency penalty increased at the rate of 0.06–0.07% points per 1% increase in the flue gas fraction when 50–70% of flue gas was treated in CaL. For higher flue gas fractions, the efficiency penalty increased at the rate of 0.04–0.05% points per 1% increase in the flue gas fraction. Overall, the efficiency penalty increased from 5.3% points to 8.1% points for the flue gas fractions fed to the carbonator of 50% and 100%, respectively. Such a change will also result in a 24.6% increase in the net power output (Figure 6b) and a 5.6% increase in fuel consumption (Figure 6c). Furthermore, a reduction in the flue gas fraction fed to the carbonator from 100% to 80% would result in specific CO$_2$ emissions of 109.0 gCO$_2$/kWh (Figure 6d). Such a figure is comparable to that for CaL with no biomass co-firing in the calciner discussed in Scenario 1 (104.8 gCO$_2$/kWh). Notably, the efficiency penalty for the retrofitted system with 30% biomass co-firing in the calciner and 80% of flue gas treated in the carbonator will be 0.6% points (7.1% points) lower than that of the retrofitted system with no biomass co-firing (7.7% points). It implies that considering a flue gas bypass, rather than designing CaL for a lower CO$_2$ capture rate, would be a more viable approach. It also implies that multi-variable optimisation of the retrofitted system is required to arrive at the optimum set of operating conditions. It is, however, out of the scope of this work.

Figure 7 presents the impact of the flue gas fraction fed to the carbonator on the economic viability of the CaL retrofit, under variable market conditions. It can be observed that the lowest figures for the LCOE were obtained for the carbon tax below 70 €/tCO$_2$ and the flue gas fraction fed to the carbonator below 80% (Figure 7a). Under such conditions, the LCOE varied between 56.6 €/MWh and 77.1 €/MWh. A similar trend was observed in Scenario 2. However, under current carbon tax conditions (i.e. €100/tCO$_2$), CaL should be designed to treat 80–100% of flue gas from the host plant. Under such carbon tax conditions, the LCOE would be 84.6 €/MWh and 81.1 €/MWh at the flue gas fraction fed to the carbonator of 50% and 100%, respectively. Furthermore, the AC was shown to become negative for the carbon tax values above 40 €/tCO$_2$ when 50–80% of flue gas is fed to the carbonator and above 50 €/tCO$_2$ for more than 80% of flue gas fed to the carbonator (Figure 7b). These figures are lower than those in Scenario 2, indicating that the economic penalties associated with the retrofit of CaL will be lower in Scenario 3.
Finally, a similar effect of fuel prices on the economic viability of the retrofitted system to that in Scenario 2 was observed. Namely, the change in the coal price from 1.5 €/GJ to 4.5 €/GJ resulted in an LCOE increase of 47.8% (from 61.3 €/MWh to 90.6 €/MWh) and 36.9% (from 81.4 €/MWh to 111.5 €/MWh) for the flue gas fraction fed to the carbonator of 50% and 100%, respectively (Figure 7c). Such a change resulted in an increase in the AC of 16.5 % (from 11.8 €/tCO$_2$ to 13.8 €/tCO$_2$) and 6.5% (from 32.5 €/tCO$_2$ to 34.6 €/tCO$_2$). Moreover, an increase in the biomass price from 4.5 €/GJ to 8.0 €/GJ resulted in the LCOE increase of only 6.4% and 7.8% for the flue gas fraction fed to the carbonator of 50% and 100%, respectively (Figure 7d). Such a change resulted in an increase in the AC of 68.9 % (from 11.9 €/tCO$_2$ to 20.1 €/tCO$_2$) and 24.6% (from 32.5 €/tCO$_2$ to 40.4 €/tCO$_2$). Notably, the AC for low coal and biomass prices and low flue gas volumes treated in the flue gas (<70%) fell below 20 €/tCO$_2$.

Overall, the analysis presented in this scenario demonstrated that the optimum fraction of the flue gas to be treated in CaL would be about 70–80%, considering that 30% of biomass is co-fired with coal in the calciner. Such operating conditions were shown to minimise efficiency penalty, LCOE and AC, while keeping the specific CO$_2$ emissions of the entire process of about 100 gCO$_2$/kWh.
3.4 Discussion

The key outputs from the techno-economic analysis presented above are summarised in Table 5. The results confirmed that when 30% of biomass is co-fired with coal in the calciner (Scenario 1), the overall process will become carbon negative. It is worth
mentioning, however, that this analysis focused solely on the carbon footprint associated with the operation of the host plant and CaL. Further work is required to determine the global warming potential using the cradle-to-grave life cycle assessment.

The transition from carbon positive process in the reference retrofit scenario (104.8 gCO₂/kWh) to the carbon negative process in Scenario 1 (-3.9 gCO₂/kWh) resulted in an inferior thermodynamic performance. Namely, the efficiency penalty has increased from 7.7% points to 8.1% points, primarily because of the lower higher heating value and higher moisture content of biomass. This has directly translated into an increase in the LCOE from 77.6 €/MWh to 81.4 €/MWh at a carbon tax of 25 €/tCO₂. However, the LCOE was lower in Scenario 1 (81.1 €/MWh) than that in the reference retrofit scenario (85.4 €/MWh) and the reference host plant without CO₂ capture (115.0 €/MWh) when the carbon tax was 100 €/tCO₂. It can be assigned to the carbon-negative character of the process in Scenario 1. A further improvement in the thermodynamic and economic performance was achieved by reducing the CO₂ capture level in the carbonator (Scenario 2) and the fraction of flue gas fed to the carbonator (Scenario 3).

In Scenario 2, the net efficiency of the retrofitted process was the same as that in the reference retrofit scenario. It was achieved by reducing the CO₂ capture rate in the carbonator from 80% (Scenario 1) to 70% (Scenario 2). Even though this resulted in an increase in the specific CO₂ emissions from -3.9 gCO₂/kWh to 65.2 gCO₂/kWh, the latter figure is still 37.8% lower than that in the reference retrofit scenario (104.8 gCO₂/kWh) and 91.8% lower than that in the host plant without CO₂ capture (792.3 gCO₂/kWh). The

---

Table 5: Summary of the optimised scenarios

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference coal-fired power plant</th>
<th>Reference retrofit scenario</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Assumptions</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biomass fraction in the calciner (%)</td>
<td>-</td>
<td>0</td>
<td>30</td>
<td>30</td>
<td>30</td>
</tr>
<tr>
<td>CO₂ capture rate in the carbonator (%)</td>
<td>-</td>
<td>80</td>
<td>80</td>
<td>70</td>
<td>80</td>
</tr>
<tr>
<td>Flue gas fed to the carbonator (%)</td>
<td>-</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>80</td>
</tr>
<tr>
<td>Carbon tax (€/tCO₂)</td>
<td>25</td>
<td>100</td>
<td>25</td>
<td>100</td>
<td>25</td>
</tr>
<tr>
<td><strong>Key performance indicators</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Efficiency penalty (% points)</td>
<td>7.7</td>
<td>8.1</td>
<td>7.7</td>
<td>7.1</td>
<td>7.1</td>
</tr>
<tr>
<td>Net efficiency (%)</td>
<td>38.0</td>
<td>30.3</td>
<td>29.9</td>
<td>30.3</td>
<td>30.9</td>
</tr>
<tr>
<td>Specific emissions (gCO₂/kWh)</td>
<td>792.3</td>
<td>104.8</td>
<td>-9.9</td>
<td>65.2</td>
<td>109.0</td>
</tr>
<tr>
<td>Specific fuel consumption (g/kWh)</td>
<td>350.3</td>
<td>439.6</td>
<td>473.5</td>
<td>465.5</td>
<td>456.0</td>
</tr>
<tr>
<td>Net power output (MW)</td>
<td>552.7</td>
<td>835.7</td>
<td>836.2</td>
<td>796.0</td>
<td>779.5</td>
</tr>
<tr>
<td>Levelised cost of electricity (€/MWh)</td>
<td>55.8</td>
<td>115.0</td>
<td>77.6</td>
<td>81.4</td>
<td>81.1</td>
</tr>
<tr>
<td>Cost of CO₂ avoided (€/tCO₂)</td>
<td>-</td>
<td>-</td>
<td>31.9</td>
<td>-43.1</td>
<td>32.5</td>
</tr>
</tbody>
</table>

The transition from carbon positive process in the reference retrofit scenario (104.8 gCO₂/kWh) to the carbon negative process in Scenario 1 (-3.9 gCO₂/kWh) resulted in an inferior thermodynamic performance. Namely, the efficiency penalty has increased from 7.7% points to 8.1% points, primarily because of the lower higher heating value and higher moisture content of biomass. This has directly translated into an increase in the LCOE from 77.6 €/MWh to 81.4 €/MWh at a carbon tax of 25 €/tCO₂. However, the LCOE was lower in Scenario 1 (81.1 €/MWh) than that in the reference retrofit scenario (85.4 €/MWh) and the reference host plant without CO₂ capture (115.0 €/MWh) when the carbon tax was 100 €/tCO₂. It can be assigned to the carbon-negative character of the process in Scenario 1. A further improvement in the thermodynamic and economic performance was achieved by reducing the CO₂ capture level in the carbonator (Scenario 2) and the fraction of flue gas fed to the carbonator (Scenario 3).
LCOE in Scenario 2 was also shown to be 1.8% and 5.0% lower than that in the reference retrofit at a carbon tax of 25 €/tCO₂ and 100 €/tCO₂, respectively. It demonstrated that the use of biomass in the calciner and reduced CO₂ capture level in the carbonator can bring environmental and economic benefits.

In Scenario 3, the efficiency penalty of the retrofitted process was 0.6% points and 1.0% points lower than that in the reference retrofit scenario and Scenario 1, respectively. This was achieved by reducing the fraction of flue gas fed to the carbonator from 100% (Scenario 1) to 80% (Scenario 3). Such a design of the retrofit scenario resulted in the specific CO₂ emissions of 109.0 gCO₂/kWh, which is 4.0% higher than that in the reference retrofit scenario. Yet, the specific CO₂ emissions in this scenario are still 86.2% lower than that in the reference host plant without CO₂ capture. More importantly, the LCOE was shown to be 7.5% and 6.2% lower than that in the reference retrofit scenario at a carbon tax of 25 €/tCO₂ and 100 €/tCO₂, respectively.

Overall, this study demonstrated that the co-firing of biomass in the calciner provides more flexibility in the design of CaL for the decarbonisation of coal-fired power plants. Notably, when up to 30% of biomass is co-fired with coal in the calciner, the process can offer negative emissions and better economic performance than the process without biomass co-firing under current EU ETS conditions. Further improvement to the techno-economic performance was achieved by reducing the amount of CO₂ captured by CaL, via reducing either the CO₂ capture rate or the amount of flue gas processed. Although this was achieved at the expense of the residual CO₂ emissions, the net specific emissions were still about 90% lower than those of the unabated host plant. The main limitation of this study is that it only considered the carbon footprint associated with the operation of CaL and did not apply the cradle-to-grave approach to environmental impact assessment. Such analysis is recommended as future work to understand the potential benefits and challenges of co-firing biomass in the calciner.

4 CONCLUSIONS

This study aimed to assess the techno-economic feasibility of biomass co-firing in CaL retrofitted coal-fired power plants and understand whether such retrofit can transform the host plant into a carbon-negative process. The analysis was performed considering different retrofit and operating scenarios. In Scenario 1, the effect of biomass fraction in the fuel fed to the calciner was evaluated. It was
found that at 30% biomass co-fired in the calciner, which is considered as a technically viable limit for biomass co-firing with coal in the current combustion processes, the process achieved negative CO₂ emissions with a net efficiency of 29.9%. This resulted in a higher LCOE of 81.4 €/MWh, compared to the reference retrofit scenario (77.6 €/MWh) and the host plant without CO₂ capture (55.8 €/MWh) at a carbon tax of 25 €/tCO₂. However, the process considered in Scenario 1 was shown to become more economically viable than reference retrofit scenario and the host plant without CO₂ capture at the current carbon tax of €100/tCO₂ due to the ability to achieve negative CO₂ emissions. The economic viability of the biomass co-firing in the calciner was shown to be further improved when CaL was designed either for lower CO₂ capture rates in the carbonator or for lower flue gas feed rates. Although the process remains net CO₂ emitter under such conditions (>~100 gCO₂/kWh), a combination of biomass co-firing and reduced CO₂ capture capacity resulted in lower LCOE (72.2 €/MWh–81.1 €/MWh) compared to the reference retrofit scenario (77.6 €/MWh–85.4 €/MWh) at a carbon tax of 25 €/tCO₂ and 100 €/tCO₂, respectively, and the host plant (115 €/MWh) at a carbon tax of 100 €/tCO₂. Optimising the CO₂ capture rate and the fraction of flue gas fed to the carbonator can further enhance the economic and environmental performance of the retrofitted process. Future research should focus on comprehensive life cycle assessments to better understand the overall environmental impact. By leveraging different biomass types and considering land use changes, a more holistic assessment of the feasibility and sustainability of large-scale implementation can be achieved.
REFERENCES


44. Lushan H. Rebooting China’s carbon credits: What will 2022 bring?. China Dialogue.