# Final Report

# Modeling the decarbonisation of carbon-intensive industries through the integration of CO2 biomethanation: assessment of carbon savings and production costs

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# Executive Summary

$CO_2$ Biomethanation is the biological conversion of carbon dioxide and hydrogen to biomethane via the action of hydrogenotrophic methanogens. In this work biomethanation is integrated into carbon intensive industries using carbon capture technologies which isolate carbon dioxide from industrial flue- and off-gasses, with the hydrogen supplied through the electrolysis of water (Figure S1). The produced biomethane can be used as a drop-in fuel to replace natural gas in industrial processes or can be exported using the natural gas grid and used elsewhere.

In this project, five industries were considered: Cement, steel, distillery (for potable distilled spirits), pulp and paper and ammonia, although biomethanation integration with current commercial ammonia was found to be illogical relative to direct application of electrolysis, so this was not considered further. Although each industry is diverse with a range of processes variants or different technologies, an exemplar **baseline** process for each industry, representing a realistic and/or common version of the industrial process, was developed using data from literature.

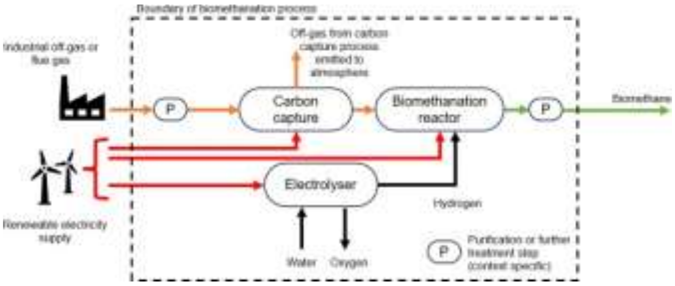

*Figure S1. The biomethanation process.*

Each **baseline** process was extended to produce a high-level design of the integration of biomethanation (the **decarbonised** process) by identifying $CO_2$ containing flue- and off-gasses and opportunities for replacement of natural gas with biomethane. Integration was done whilst making minimal changes to the baseline process such that biomethanation could be considered a potential retrofit upgrade to existing industrial infrastructure. Relevant mass and energy flows were quantified based on reaction stoichiometry and literature data. Subsequently this data used to estimate the carbon footprint (Figure S2) and additional costs associated with the process integration only considering the differences between the **baseline** and **decarbonised** processes.

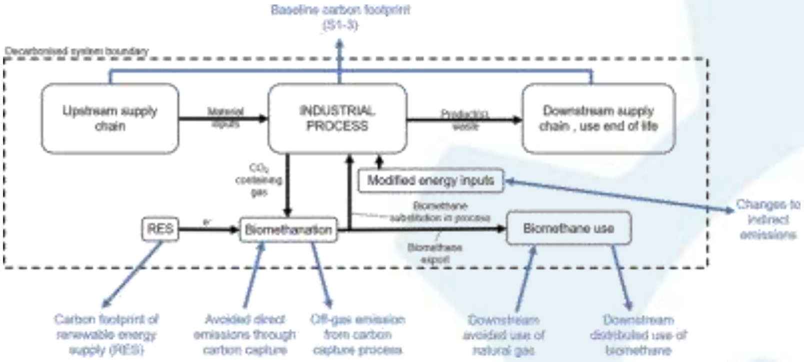

*Figure S2. Generalised methodology for carbon footprint calculation.*

For the other four industries considered, it was found that biomethanation can result in substantial decarbonisation, ranging from 0.70-2.87 $tCO_{2e}/t_{product}$ which could lead to potential global decarbonisation of 4249 $MtCO_{2e}/a$. The **baseline** and **decarbonised** carbon footprints of the four industries were 870 $kgCO_{2e}/t_{Clinker}$ and 166 $kgCO_{2e}/t_{Clinker}$, 2200 $kgCO_{2e}/t_{Liquid\_Steel}$ and 1455 $kgCO_{2e}/t_{Liquid\_Steel}$ , 2.03 $kgCO_{2e}/L_{Alcohol}$ and 0.50 $kgCO_{2e}/L_{Alcohol}$ , 950 $kgCO_{2e}/t_{Air\_Dried}$ and -1915 $kgCO_{2e}/t_{Air\_dried}$ for cement, steel, distillery and pulp and paper respectively. Other important results are summarised in table S1. Where the carbon source was biogenic (pulp and paper, distillery) the decarbonisation replaced all direct fossil emissions with equivalent biogenic emissions. It was found to be critical to achieve decarbonisation that electricity be renewable and ideally to be from the lowest carbon options e.g. wind, solar.

The decarbonisation was mainly driven by the substitution of natural gas with biomethane, both in the industrial process and exported to downstream applications. For industries where the carbon source was biogenic (distillery, pulp and paper) this effect was more pronounced such that decarbonisation via biomethanation could be more effective than direct electrification (i.e. removal of direct fossil GHG emissions). Despite substantial gains in terms of decarbonisation potential, these rely strongly on the substitution of fossil fuels, and net-zero emissions cannot be reached by using biomethanation alone unless a biogenic carbon source is used, since the downstream combustion of biomethane results in the emission of the carbon captured as part of the biomethanation process.

Economic assessment predicted increases in production cost for cement (1070%), pulp and paper (561%), steel (182%) and distillery (37%). These were based on nominal estimates of additional costs and revenues after the integration. As for any economic prediction these are subject to large uncertainties and should be treated as indicative. 'Best case' calculations, based on minimum cost and maximum revenues predicted more modest increases in production cost, and are shown in table S1. Additional costs are dominated by hydrogen production cost which is predicted to remain high into the future even where curtailed electricity is targeted, but producing alternative higher value products (compared to methane) could offset high additional net-costs by increasing additional revenue generation.

Overall performance metrics were defined to facilitate external comparison of the **decarbonised** scenarios consider with other decarbonisation options. The **decarbonisation intensity**, defined as the fossil GHG avoided per unit of renewable energy consumed was 0.084-0.096 $tCO_{2e}$/MWh with the industries with biogenic carbon sources being slightly higher. **Cost of decarbonisation**, defined as the additional costs of avoiding GHG emissions s was £773-837/$tCO_{2e}$ for the processes considered.

*Table S1. Summary of results of the biomethanation study (LS – liquid steel, LA – litre of alcohol, ADt – Air dried ton).*

| Industry | **Baseline or Decarbonised** | **Carbon footprint** | **Fossil (F) or Biogenic (B) direct emissions (F:B)** | **Biomethane export (%)** | **Additional (renewable) electricity requirement** | **Production cost Nominal case (best case)** |
|---|---|---|---|---|---|---|
| Cement | Baseline | 870 $kgCO_{2e}/t_{Clinker}$ | Fossil | - | - | £55/ $t_{clinker}$ |
| | Decarbonised | 166 $kgCO_{2e}/t_{Clinker}$ | Fossil | 69% | 1070 MW for 125 $t_{clinker}$/hr | £644/ $t_{clinker}$<br>(£237/ $t_{clinker}$) |
| Steel | Baseline | 2200 $kgCO_{2e}$/tLS | Fossil | - | - | £326/tLS |
| | Decarbonised | 1455 $kgCO_{2e}$/tLS | Fossil | 78% | 5200 MW for 5.3 MtLS/a | £919/tLS<br>(£469/tLS) |
| Distillery | Baseline | 2.03 $kgCO_{2e}$/LA | Mixed (52:48) | - | - | £3.44/LA |
| | Decarbonised | 0.50 $kgCO_{2e}$/LA | Biogenic | 45% | 113 MW for 61 MLA/a | £4.69/LA<br>(£3.93/LA) |
| Pulp and paper | Baseline | 950 $kgCO_{2e}$/ADt | Mixed (3:97) | - | - | £395/ADt |
| | Decarbonised | -1915 $kgCO_{2e}$/ADt | Biogenic | 97% | 5410 MW for 4000 ADt/d | £2609/ADt<br>(£863/ADt) |

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The pulp and paper section of this work includes contributions from Nnaemeka Victor Ezenwaka, University of Hull student in MSc Energy Engineering 2023.

# Abbreviations

| | |
|---|---|
| a | year |
| AD(t) | Air dried (ton) |
| BAT | Best available technology |
| BD(t) | Bone dry (ton) |
| BF(G) | Blast furnace (gas) |
| BM | Biomethanation |
| BOF(G) | Basic oxygen furnace (gas) |
| CC(S) | Carbon Capture (and storage) |
| CO(G) | Coke oven (gas) |
| Cr-Ga | Cradle-to-Gate system boundary |
| d | day |
| DS | Dry solids |
| GGSS | Green gas support scheme |
| GHG | Greenhouse Gas |
| HM | Hot metal |
| LA | Litre of alcohol |
| LS | Liquid steel |
| MOLA | Million litres of original alcohol |
| PFD | Process flow Diagram |
| PSA | Pressure swing absorption |
| SMR | Steam methane reforming |
| t | Ton or tonne |
| WGS | Water gas shift |
| WL | White liquor |

# Contents

# 1 Introduction

$CO_2$ Biomethanation has recently emerged as a competitive technology for recycling industrial sources of $CO_2$ into $CH_4$. In this configuration, carbon dioxide sourced from different off-gas streams is reduced to methane through a biologically mediated reaction with hydrogen, which can be produced from renewable electricity through electrolysis. The process has mainly been studied and applied to the upgrading of biogas produced from the anaerobic digestion (AD) of biowastes, where it results in a variety of benefits: increased carbon efficiency and methane production from the biowastes, upgraded biogas quality to biomethane with potential contribution towards the decarbonisation of the gas grid, long-term storage of renewable electricity in the form of high energy density fuel.

$CO_2$ Biomethanation has also been proposed as an enabling technology for the recycling and utilisation of $CO_2$ from other carbon intensive industrial processes, such as steel, cement, fermentation, ammonia production etc. (Naims 2016). The recycling of $CO_2$ emissions into biomethane could lead to a displacement of fossil fuel use in the processes themselves, and also in downstream applications as a drop-in replacement for natural gas use in domestic, industrial or transport applications. This, in principle, can result in reduction of greenhouse gas (GHG) emissions which could contribute to the mitigation of anthropogenic climate change. Furthermore, methane, as an energy storage mechanism for excess renewable electricity, could facilitate the transition to a high penetration of renewables in the power system. The biomethanation process is also very tolerant to impurities in gas streams, an advantage when compared to alternative thermo-chemical routes for $CO_2$-based electrofuels.

While carbon recycling through biomethanation is an attractive approach for the decarbonization of energy systems, it is not yet widely recognised as such and there are several technical, economic, and legislative uncertainties regarding its future role and scale. This work seeks to address some of these through a conceptual study of the engineering integration of biomethanation with a group of carbon intensive industries, and to attempt to quantify the associated potential carbon savings and costs.

Five industries are considered in this work: steel, cement, pulp and paper, distillery (for potable distilled spirits) and ammonia. These were not chosen with any strict criteria but instead based on the balance of several factors which make them potentially suitable targets for decarbonisation through biomethanation e.g.;

- Significant emitters of fossil GHGs with ‘point-source’ emission of large quantities of $CO_2$ containing gases (all industries to varying degrees)
- Significant emitters of biogenic GHG, for which biomethanation may result in enhanced GHG reduction through internal or downstream displacement of fossil fuels (i.e. pulp and paper, distillery)
- Part or all of the thermal demand of the process is provided by natural gas (or can be easily switched to natural gas), which makes fuel swapping to biomethane and recycling of carbon through biomethanation a potential decarbonisation route (all industries to varying degrees)

Note that direct emissions from fossil fuel power plants was not considered as part of this study, since instead the focus was on emissions from industries that are unavoidable (economically due to long life of infrastructure or technically due to lack of alternative process availability).

It is hoped that the results of this work can provoke informed discussion and debate surrounding the current and future applications of biomethanation and therefore better guide the UK Government policy and ongoing R&D efforts within the research community.

# 2 Methodology

In this report biomethanation (BM) is defined as a collection of processes/technologies that are combined to convert a $CO_2$ containing gas to biomethane through the action of hydrogenotrophic methanogens in a biomethanation reactors, supplied with hydrogen produced by water electrolysis as per the following reaction:

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O$$

Biomethanation can be performed as an ex- or in-situ process which refers to whether the conversion of hydrogen to methane occurs in a dedicated reactor along with a functionally simple culture of hydrogenotrophic methanogens (in-situ), or within an existing anaerobic digestion (AD) system where hydrogen is injected into the main digester along with optional further supplementation of $CO_2$, taking advantage of the existing (or enriched) hydrogenotrophic methanogens within an AD system.

This work does not make a distinction between ex- or in-situ since for its purpose the overall reaction of hydrogen and carbon dioxide remains the same. However, for industries that may already have AD on their sites, there may be a benefit to investigating whether in-situ biomethanation may be a beneficial option since it can increase utility of existing assets, despite its lower volumetric productivity and fixed scale relative to the biomass input. However, in-situ biomethanation is less technologically mature compared with ex-situ (where some commercial operations exist) and so this process requires further development before its technical feasibility is confirmed.

Industrial flue – and off-gasses usually require a capture (to avoid emission) and separation process to increase the concentration of $CO_2$, commonly denoted as carbon capture, and depending on the impurities in the source gas may also require other purification steps (not considered in this work). The three major elements of the BM process are powered by (usually renewable) electricity (in the absence of other energy sources). Water electrolysis produces oxygen which is not considered in this work but could have opportunities for additional revenue or process integration in some cases.

The process is shown in Figure 1 (a). To simplify and harmonize the process flow diagrams in this work, a subsystem mask is used (Figure 1 (b)) and a common key is used to represent mass and energy flows (Figure 1 (c)).

Throughout this report we define biomethane as methane produced through a biomethanation process to differentiate it from methane in natural gas. However, this definition could be misinterpreted for a more specific definition of biomethane, which is methane derived from a biogenic carbon source. By our definition biomethane (from a biomethanation process) could come from a fossil carbon source (e.g. flue gas from a fossil fuel power plant). To avoid ambiguity this report will denote biogenic biomethane (B) and fossil biomethane (F). In future versions of this work we may reconsider this nomenclature for clarity and/or consistency with other studies.

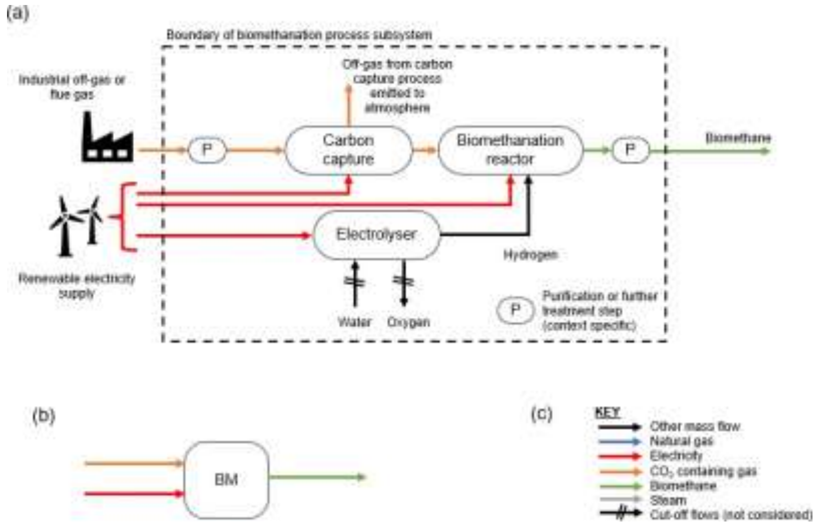


*Figure 1 (a) Generalised process flow diagram for a biomethanation process, (b) Simplified biomethanation (BM) subsystem incorporating elements in (a), and (c) key used for mass and energy balance diagrams*

The following is a summary of methodology for each industrial process. Each point is explored in more detail in the following sections:

1. Identify an example of the predominant or common configuration of the industrial process and use literature to define a **baseline** process flow diagram (PFD) (section 2.1)
2. Develop a PFD for a modified process that integrates the biomethanation process, denoted as the **decarbonised** process using a fixed set of principles (section 2.2)
3. Develop a relevant mass and energy balance for the **baseline** process focusing on the flows that are relevant to biomethanation integration (section 2.3).
4. Further develop the mass and energy balance for the **decarbonised** process, to include the integrated biomethanation process elements; electrolysis, carbon capture, biomethanation reactor etc., considering any other nuances of the process integration (section 2.3)
5. Use mass and energy balance data, along with best and most relevant data from literature/public domain to perform two major **system assessments**:
    a. the GHG emissions (or carbon footprint) of the **decarbonised** process (section 2.4).
    b. the additional costs associated with the **decarbonised** process (section 2.5)
6. For both 5a and 5b, perform a sensitivity analysis based on the most influential assumptions and variables to illustrate the inherent uncertainty of the results (also sections 2.4 and 2.5).

While the methodology followed can produce data that can inform future developments of industrial integration of $CO_2$ biomethanation, this approach is associated with inherent weaknesses of, for example, overgeneralization or oversimplification of the integration process. A SWOT analysis of the approach is provided (see section 2.6) to elaborate on the various qualities of the proposed approach. The aim throughout this work is for full transparency in terms of the assumptions and weaknesses of the approach such that an informed reader can fully appreciate the implications and importance of the conclusions reached.

All calculations and modelling were done in Microsoft Excel, and these files can be shared for collaboration or published as a dataset alongside future versions of this work.

## 2.1 Industrial processes – Baseline PFDs

For each of the five industries considered, a **baseline** PFD was produced to enable the subsequent steps of the integrated process design, mass and energy balances and eventually the system assessments. The principle of this part of the methodology was to produce **baseline** flowsheets that were as folllows;

- Specific and with sufficient granularity i.e. a single process that included the relevant mass and energy flows to allow design of the **decarbonised** process.
- representative of the predominant (or at least a common) process configuration, and of an appropriate scale, compared to real world installations such that relevance of the results was maximised.
- possible to quantify the relevant mass and energy flows with evidence from a reliable, consistent, and sufficiently comprehensive data source (or at least minimising inconsistency where multiple data sources were needed)

This development involved trade-offs surrounding data availability/consistency, against the eventual relevance (and limits of generalisation) of the results.

## 2.2 Biomethanation integration – Decarbonised PFDs

For each industry the **baseline** PFD was modified to develop a **decarbonised** PFD through the integration of BM with the industrial process. Integration with biomethanation could take different forms associated with different requirements of modification of the baseline industrial process. In this work the integration philosophy is one of a drop-in retrofit, i.e. no modification (or minimal modification) of the original process. The logic of this decision is that a strong argument for industrial integration using biomethanation over direct electrification (or conversion to hydrogen), is that in can extend the life current infrastructure (both industrial facilities and the natural gas grid) whilst still delivering progress on decarbonisation. The integration design follows the following principles;

- Emissions of carbon dioxide containing gasses e.g. post-combustion flue gasses, off-gasses from other processes were completely redirected to carbon capture, with the captured $CO_2$ going to the biomethanation reactor.
- Carbon capture also produced an off-gas containing the non-$CO_2$ components of the original flue- or off-gas as well as a slippage flux of $CO_2$ which was emitted to atmosphere.
- All natural gas inputs could be substituted with biomethane (B or F) as a drop-in fuel (where available in sufficient quantity)
- Replacement of other fuels with biomethane was only done where possible with minimal process adjustment (and where this could be justified with evidence)
- For post-combustion carbon capture, and where there was excess high-grade thermal energy in the **baseline** process, this could be used to satisfy the energy demand for carbon capture process (Since amine-based technology has a significant thermal energy demand (Chauvy et al. 2020a)).
- Existing excess electrical energy generation in the **baseline** process could be used to satisfy the energy demand for either hydrogen production through electrolysis or for the carbon capture process.
- Remaining demand for energy to the electrolysis, carbon capture and biomethanation reactor were met using externally sourced renewable energy supply (RES) on the basis that meeting thermal demands of these processes using biomethane would lead to higher RES consumption due to efficiency losses in the electrolysis and biomethanation processes.

Two areas of potentially beneficial process integration were not considered in this work:

- Detailed thermal integration beyond the supply of high-grade heat to carbon capture was not considered. This was mainly because the biomethanation/electrolysis processes have no other high grade heat requirements, nor do they produce a high-grade heat source. Beyond this, while it is possible that low-grade thermal integration may give some benefits (e.g. use of electrolysis cooling water), it is thought that this will have low impact on the results and could require significant investment to be integrated into the industrial processes.
- Oxygen production from the electrolysis process was not considered for integration or as a revenue source. On the former, although integration of electrolysis sourced oxygen to displace externally sourced oxygen or air-separation may be viable in some industrial process, the overall impact on the analysis is expected to be small due to the large disparity between supply and demand. On the latter, while assigning revenue to excess oxygen production would be possible in the assessment framework, it was thought that assuming a selling price for oxygen where a sufficient market demand may not exist within a reasonable distance would be questionable.

## 2.3 Mass and Energy Balance

For the **baseline** process the mass and energy fluxes relevant to the biomethanation integration, as well as the overall productivity of the industrial process, were quantified using data from academic literature (maximising data consistency where possible) as identified in the **baseline** PFD development step.

The mass and energy balance of the **decarbonised** process was performed based on the integration principles, using the data from Table 1. All gas volumes were quoted at standard conditions of 1 bar and 0°C. The biomethanation reaction was represented with the following stoichiometry:

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$$

The reaction was assumed to reach 99% completeness (i.e. 99% of $H_2$ consumption) in the biomethanation reactor. The composition of resulting biomethane mixture was calculated by mass balance. Carbon capture was assumed by default to be 90% effective, with 10% of the incoming $CO_2$ emitted as in the off- gas (this variable was explored through sensitivity analysis).

*Table 1 Mass and energy data used in all scenarios*

| **Quantity** | **Value** | **Unit** | **Source/Note** |
|---|---|---|---|
| Carbon capture energy demand | 3.5 | $GJ/tCO_2$ | (Chauvy et al. 2020a) |
| Biomethanation reactor electricity demand | 0.44 | $kWh/m^3_{CH4}$ | (Alfaro et al. 2018) |
| Electrolysis electricity demand | 4.9 | $kWh/m^3_{H2}$ | (Bhandari and Shah 2021) |
| Methane lower heating value (LHV) | 35.8 | $MJ/m^3$ | (The Engineering ToolBox 2003) |
| Methane higher heating value (HHV) | 39.8 | $MJ/m^3$ | (The Engineering ToolBox 2003) |
| Hydrogen LHV | 10.2 | $MJ/m^3$ | (The Engineering ToolBox 2003) |
| Biomethanation reaction completeness | % | 99 | Assumed |
| Carbon capture effectiveness | % | 90 | Assumed |

## 2.4 Carbon footprint calculations

The approach to the emissions calculations avoids the development of a comprehensive full lifecycle-based carbon footprint but instead focusses only on the differences between the **baseline** and **decarbonised** systems. The methodology is represented diagrammatically in Figure 2. The carbon footprint of the baseline system (Figure 2 (a)) is obtained from literature, with the scope of the source assessment defining the system boundary for the subsequent calculations. In the example shown a cradle-to-grave assessment is used including both the upstream and downstream supply chain, use phase and end-of life of any products, co-products and waste streams.

Based on the **decarbonised** process**,** the additional (arrows leaving the system) and avoided (arrows entering the system) GHG emissions are identified, as shown in Figure 2 (b) and then quantified based on the mass and energy balance, using the relevant emissions intensities to calculate their GHG equivalence (i.e. $CO_{2e}$). The final carbon footprint of the decarbonised process is simply the sum of all the produced and avoided emissions crossing the system boundary in Figure 2 (b) after conversion to some common unit (e.g. $kgCO_{2e}/t_{product}$).

Emission scopes are consistent with the GHG Protocol guidance (GHG Protocol 2015), and where lifecycle data was used, best efforts were made to align for consistency of system boundaries. In brief, scope 1 (S1) refer to direct emissions of GHG, scope 2 (S2) to indirect emissions due to electricity supply and scope 3 (S3) are indirect emissions from elsewhere in the supply chain.

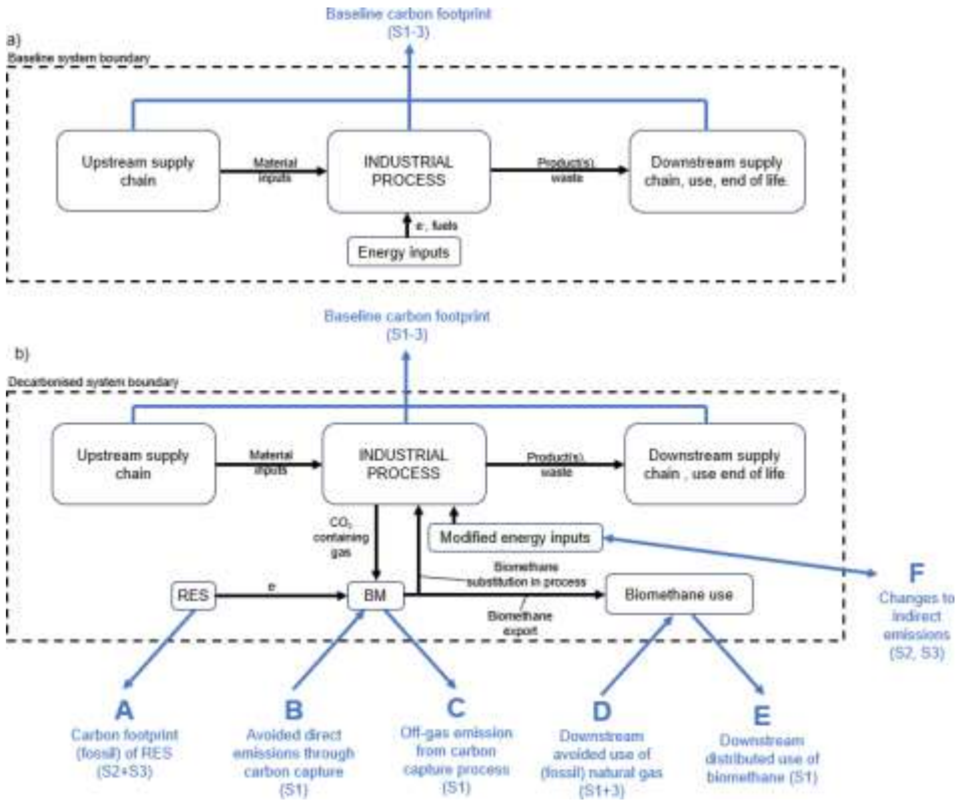


*Figure 2 Generalised methodology for calculation of decarbonised carbon footprints of integration of industrial processes with biomethanation showing (a) baseline and (b) decarbonised carbon footprints. S1-3 refer to emissions scope. Black arrows are material/energy flows, blue arrows are fossil GHG emissions. A-F relate to emissions described in Table 2*

Table 3-Table 7 show the data required to calculate the GHG emissions in $CO2e$ for each of the emissions A-F above. Note that B and C are direct emissions of $CO2$ and therefore do not require an emission factor. Table 3 gives the emissions factors of various fuels as direct emissions (S1) and indirect (S3, or WTT) and are used to calculate the GHG emissions associated with D, E and F. Table 4 gives emissions factors of electricity supply in the UK as S2 and S3 (indirect) for both generation and T&D used to calculate GHG emissions associated with A and F. Table 5 gives emission factors used for renewable electricity supply as recommended by the IPCC (Intergovernmental Panel on Climate Change) which are used, along with the weightings in Table 6 and Table 7 to calculate the emissions

factors for renewable energy generation in the UK used to calculate GHG emissions associated with A.

*Table 2 description of additional and avoided GHG emissions shown in Figure 2(b)*

| **GHG emission name (see Figure 2 (b))** | | **Emission Description** |
|---|---|---|
| **A** | **Carbon footprint (fossil) of RES (S2 and S3)** | Lifecycle GHG emissions from the supply of renewable energy and thus includes both S2 and S3 emissions. Included within this item are also the indirect emissions associated with transmission and distribution of electricity (T&D). |
| **B** | **Avoided direct emissions through carbon capture (S1)** | Avoided GHG emissions relative to the baseline carbon footprint and is an avoided direct emission and therefore S1. |
| **C** | **Off-gas emissions from carbon capture process (S1)** | Direct emissions contained in the slippage gas from the carbon capture process and are emitted directly and so S1. |
| **D** | **Downstream avoided use of (fossil) natural gas (S1+3)** | Avoided direct and indirect emissions since the produced biomethane substitutes for the use of natural gas elsewhere in the economy. The indirect emissions (representing emissions associated with extraction, processing, transport, distribution) are accounted for using the WTT (Well-To-Tank) emissions provided by the UK government as shown in Table 3. |
| **E** | **Downstream distributed use of biomethane (S1)** | Direct emission of GHG from the combustion of biomethane by the downstream user, assumed to be 100% emitted directly to atmosphere (i.e. not subject to a downstream carbon capture process). |
| **F** | **Changes to indirect emissions (S2, S3)** | Indirect emissions associated with differences) in energy consumption caused by the process integration. If the reduction is in electricity, then the emissions include S2 and S3 and also both generation and T&D. If the emissions relate to a fossil fuel, then only the indirect emissions (S3) are accounted for since direct emissions changes are already accounted for in the '**A - Avoided direct emissions through carbon capture (S1)**'. These are again accounted for using WTT figures as shown in Table 3. |

### 2.4.1 Discussion of 'Downstream avoided use of (fossil) natural gas'

Avoided emissions (D) arises when biomethane (B or F) exported from the industrial process displaces natural gas taken from the UK grid and therefore is assumed to contain 0.65% of biomethane (B) already, as shown in Table 3. This allows the calculation of an 'avoided' GHG emission by the substitution which is then 'credited' back to the industrial process with emissions intensity of 0.2378 kgCO$_{2e}$/kWh (see Table 3). This is an important assumption since:

(a) It relies on a system boundary for the decarbonised flowsheet that includes the downstream usage of biomethane (B or F), i.e. the downstream user becomes part of the system, and any emissions savings are 'credited' back to the industrial process. This approach is taken to avoid any questionable allocation (or weighting) of the carbon savings between the producer of biomethane (B or F) and the downstream user, which could become a contentious topic.

(b) It assumes the gas grid is an independent entity which remains unchanged despite that we propose a large-scale introduction of biomethane into it (which would result in its partial decarbonisation) and additionally, in the future, the wider gas grid is expected to contain an increasing amount of 'green gas'. Substituting biomethane (B or F) for a fully or partially blended non-fossil 'green gas' results in less reduction (or even an increase) in GHG emissions. The effect of this is explored as an important sensitivity variable and is denoted '% of biomethane in gas grid' in sensitivity results.

### 2.4.2 Discussion of the ‘decarbonised carbon footprint’

Due to the assumptions around the substitution discussed above, it is possible that the results of the **decarbonised** carbon footprint results in a negative value. It is important to note that this does not (necessarily) signify a carbon-negative process. This potentially misleading outcome is a product of the system expansion process which considers avoided emissions through the substitution of predominantly fossil fuels. A negative value of carbon footprint should be instead interpreted as the total carbon emission avoided in the broader economy (specifically referring to downstream use of biomethane). It is possible that future versions of this work present the results differently to avoid this ambiguity, although consideration of the alternatives was discussed and considered at length.

### 2.4.3 Carbon footprint sensitivity analysis

The aim of the sensitivity analysis was to serve multiple purposes in adding value to the carbon calculations, namely:

a) Understanding the impact of sources of uncertainty in the input data.
b) Test the impact of important methodological assumptions made.
c) Elaborate on variations of **decarbonised** scenario chosen as an alternative to having multiple sub-scenarios to answer questions of ‘what if…?’.

The selected sensitivity variables were chosen qualitatively through an iterative process once the calculation models were developed. Sensitivity ranges were selected based on the judgement of the authors based on the amount of uncertainty expected, observed (e.g. in literature) or to explore a particular alternative scenario. The sensitivity variables and ranges for the distillery, cement and pulp and paper industries are given in Table 8, these include:

1. **Captured $CO_2$**. The mass carbon captured from the targeted off- and flue-gasses compared to the total available, with a default value of 90% (see Table 1). This variable demonstrates the impact of the effectiveness of the carbon capture process, but also can be used to explore the impact of modulating the amount of carbon captured, which in all scenarios serves to increase/decrease the exported quantity of biomethane (B or F). This variable is especially relevant if the carbon capture process shows a characteristic of diminishing return on cost/energy input when approaching complete carbon capture (which is expected). Future version of this model could incorporate more sophisticated models of carbon capture mass/energy balance to explore this if this variable is shown to be of high impact.
2. **Carbon capture energy consumption**. This variable is simply the total energy expended to convert the off- or flue gases to a $CO_2$ stream. Carbon capture technologies are still developing in technical maturity and therefore there is a broad range of estimates of the energy demand available, and even the source used in this work suggest optimisation may reduce the demand from 3.5 to 2.28 $MJ/tCO_2$ (Chauvy et al. 2020a) therefore a large variation was chosen (+/- 50%) .
3. **Electrolysis energy consumption**. On the other hand, electrolysers are much more mature technology and therefore a narrower range of variation was chosen for this variable (+/- 20%).
4. **Biomethanation energy consumption**. This was the energy consumption by the biomethanation reactor alone i.e. pumping, mixing etc. Due to technical immaturity of the technology the best data found was taken from a pilot plant (Alfaro et al. 2018), and therefore large gains in energy efficiency could be expected with technology development, so a large variation (+/- 50%) was chosen) .
5. **% of biomethane in gas grid.** This variable was chosen to demonstrate the importance of the assumption of natural gas displacement (emission D in Figure 2, as discussed in section

2.4.1). The natural gas grid was modelled by default to contain 0.65% of biomethane, but this variable explored the impact of a future ‘greening’ of the gas grid (up to 20% biomethane).

6. **Grid emission intensity**. Data from Table 5 was used to inform the nominal value (UK wind/solar mix), lower (onshore wind only) and upper (all renewables mix (including biomass, hydro). Despite the range explored 0.0110-0.0632 kgCO$_{2e}$/kWh (for generation) these values are much lower than the average UK grid carbon intensity of 0.253 kgCO$_{2e}$/kWh (Including S2 and S3 emissions to approximate a cradle-to-gate (i.e. generation) system boundary)). Note that this emission intensity was only applied to the additional (renewable) energy requirements of the three main biomethanation components.

The steel industry sensitivity analysis used a different range of **Captured CO$_2$ (40-100%)**, chosen since the **decarbonised** scenario only targets ~70% of the total direct emissions from the analysed steel mill which was the readily available flue gas from the onsite power plant. Other flue- and off-gasses from the mill are from a variety of smaller point sources and therefore could be more costly to capture. In addition, an extra sensitivity variable was explored:

- **Coal substitution with biomethane in BF.** This is an additional integration option for the steel mill, where biomethane can be used to replace a fraction of the coal without overly affecting the adiabatic flame temperature in the BF. According to analysis by Perpiñán et al. (2023) the maximum substation is around 37.7% reduction in coal. The range explored in the sensitivity is 0% (i.e. no coal substitution) to 50%.

*Table 3 Emission intensities and scopes of UK fuel use (WTT – well to tank, Cr-Ga – cradle-to-gate system boundary)*

| **Fuel** | **Scope** | **Emission factor (kgCO$_{2e}$/kWh)** | **Notes/Source** | **Used to calculate** |
|---|---|---|---|---|
| Natural gas (mineral) | 1 | 0.2042 | (GOV.UK 2023c) | NA |
| Natural gas (WTT) (mineral) | 3 | 0.0335 | (GOV.UK 2023c) | F |
| Coal (industrial) (WTT) | 3 | 0.0593 | (GOV.UK 2023c) | F |
| Biomethane (B) | 1 | 0.0004 | (GOV.UK 2023c) | E |
| Biomethane (F) | 1 | 0.2042 | Assumed the same as natural gas (S1) | E |
| Biomethane (WTT) | 3 | 0.0460 | (GOV.UK 2023c) | NA |
| % of green gas in UK grid | NA | 0.65% | (GOV.UK 2023b) | NA |
| UK natural gas grid (Cr-Ga approximation) | Cr-Ga | 0.2378 | Calculated using weighted average of S1 and S3 for natural gas and biomethane | D |

*Table 4 Emission intensities of the UK aggregated and renewable only generation and supply (T&D – transmission and distribution, WTT – well to tank, Cr-Ga – cradle to gate system boundary)*

| **UK electricity category** | **Scope** | **Emission factor ($kgCO_{2e}$/kWh)** | **Source/note** | **Used to calculate** |
|---|---|---|---|---|
| Grid generation (S2) | 2 | 0.2071 | (GOV.UK 2023c) | NA |
| Grid T&D (S3) | 3 | 0.0179 | (GOV.UK 2023c) | NA |
| Grid generation WTT (S3) | 3 | 0.0459 | (GOV.UK 2023c) | NA |
| Grid T&D WTT (S3) | 3 | 0.0040 | (GOV.UK 2023c) | NA |
| Grid generation (Cr-Ga approximation) | Cr-Ga | 0.2530 | Sum of S2 and S3 for generation | F |
| Grid T&D (Cr-Ga approximation) | Cr-Ga | 0.0219 | Sum of S2 and S3 for T&D | F and A |

*Table 5 Emission intensities of renewable generation technologies used to calculate weighted average of emissions from renewable sources (Cr-Ga – cradle to gate system boundary)*

| **Renewable energy generation technology** | **Scope** | **Emission factor ($kgCO_{2e}$/kWh)** | **Source/note** | **Used to calculate** |
|---|---|---|---|---|
| Solar | Cr-Ga | 0.0480 | (Schlömer S. 2014) | NA |
| Onshore wind | Cr-Ga | 0.0110 | (Schlömer S. 2014) | A (sensitivity) |
| Offshore wind | Cr-Ga | 0.0120 | (Schlömer S. 2014) | NA |
| Hydroelectric | Cr-Ga | 0.0240 | (Schlömer S. 2014) | NA |
| Biomass combustion | Cr-Ga | 0.2300 | (Schlömer S. 2014) | NA |
| Natural gas | Cr-Ga | 0.4900 | (Schlömer S. 2014) | NA |
| Aggregated UK renewables generation | Cr-Ga | 0.0632 | Calculated using weighted average based on weightings in Table 6 and Table 7 | A (sensitivity) |
| Aggregated UK renewables generation (Only wind and solar) | Cr-Ga | 0.0169 | Calculated using weighted average based on weightings in Table 6 and Table 7 | A |

*Table 6 Renewables mix in the UK grid (2022 data)*

| **UK renewables mix (2022 data)** | **Generation quantity (TWh)** | **Source/note** |
|---|---|---|
| Wind | 80.2 | (Energy Institute 2022) |
| Solar | 13.9 | (Energy Institute 2022) |
| Other | 35.5 | (Energy Institute 2022) |
| of which Hydro | 7.6 | (GOV.UK 2023a) |
| of which thermal biomass | 27.9 | Calculated as balance of 'Other' |
| Total renewables | 129.6 | Calculated as sum of wind, solar and other |

*Table 7 Wind energy mix in the UK grid*

| Wind energy breakdown | Quantity | Unit | Source/note |
|---|---|---|---|
| Onshore capacity (UK) | 15.0 | GW | (RenewableUK 2023) |
| Offshore capacity (UK) | 14.7 | GW | (RenewableUK 2023) |
| % Onshore capacity | 50.4% | % | Calculated |
| Onshore wind supply | 40.4 | TWh | Calculated based on % and total in Table 6 |
| Offshore wind supply | 39.8 | TWh | Calculated based on % and total in Table 6 |

*Table 8 Sensitivity variables and values used in carbon footprint calculations (Distillery, cement and pulp and paper industries)*

| Sensitivity variable | Unit | Nominal value | Low value | High value |
|---|---|---|---|---|
| Captured CO2 (80-100%) | % | 90 | 80 | 100 |
| Carbon capture energy consumption (+/- 50%) | GJ/t$CO_2$ | 3.5 | 1.75 | 7.0 |
| Electrolysis energy consumption (+/- 20%) | kWh/$m^3_{H2}$ | 4.9 | 3.92 | 5.88 |
| Biomethanation energy consumption (+/-50%) | kWh/$m^3_{CH4}$ | 0.44 | 0.22 | 0.88 |
| % of biomethane in gas grid | % | 0.65 | 0 | 20 |
| Grid emission intensity | kg$CO_{2e}$/kWh | 0.0169 | 0.0110 | 0.0632 |

*Table 9 Sensitivity variables and values used in carbon footprint calculations (steel industry)*

| Sensitivity variable | Unit | Nominal value | Low value | High value |
|---|---|---|---|---|
| Captured CO2 (40-100%) | % | 70 | 40 | 100 |
| Carbon capture energy consumption (+/- 50%) | GJ/t$CO_2$ | 3.5 | 1.75 | 7.0 |
| Electrolysis energy consumption (+/- 20%) | kWh/$m^3_{H2}$ | 4.9 | 3.92 | 5.88 |
| Coke substitution with biomethane in BF | % | 37.7 | 0 | 50 |
| % of biomethane in gas grid | % | 0.65 | 0 | 20 |
| Grid emission intensity | kg$CO_{2e}$/kWh | 0.0169 | 0.0110 | 0.0632 |

## 2.5 Economic calculations

The economic calculations performed as part of this project are intended to give an indication of the expected cost changes, and their relative breakdown by different major process step, in going from the **baseline** to the **decarbonised** processes for each industry. The analysis performed is not a complete bottom-up technoeconomic analysis, hence should be considered indicative only and be used to inform future efforts and progress. Given market variability (especially energy) and data scarcity, any economic predictions made (even with a thorough bottom-up approach) are made with low confidence of the future values, and hence sensitivity analysis is of particular importance to understanding the impact of the uncertain data inputs on the results presented.

Similar to the carbon footprint, only the differences between the **baseline** and **decarbonised** processes are accounted for, and in each additional cost (and revenue or saving) is represented as a fixed unit cost based on a lifecycle approach (i.e. incorporating CAPEX, OPEX, decommissioning etc.) over the life of a project. Values and ranges for the costs and revenues were selected using the best available data in the literature and are shown in Table 10. Upper and lower values, used for a sensitivity analysis, were also populated from literature where this was available, or a method could be devised, but +/- 20% was used where this was not possible.

Carbon capture costs have been varied based on the industry, based (mainly) on the data gathered by Leeson et al. (2017). This cost variation is due to several factors including different capture technologies, available benefits through process integration, initial concentration of $CO_2$ in target off- and flue-gasses and presence of other contaminating gasses.

For revenue from biomethane and savings obtained through reduced fossils fuel use, the long run variable cost of energy supply (LRVC) as per UK government recommendations, and these were based on average, maximum and minimum values over a 10-year average.

The only cost which could not be obtained from literature was for the biomethanation step itself, since this technology is still relatively immature, and a niche interest compared with the other costs required. In this case an estimate of the unit cost of biomethanation was made based on a previous technoeconomic study (Michailos et al. 2020) with calculations outlined in Table 11.

*Table 10 Unit cost values used in economic calculations and sensitivity analysis*

| **Item** | **Nominal cost** | **Lower cost** | **Upper cost** | **Unit** | **Note/source** |
|---|---|---|---|---|---|
| Carbon capture (Iron and Steel) | £74.23 | £20.00 | £120.00 | £/tonne$CO_2$ | Nominal cost and range based on figure 2 in Leeson et al. (2017). |
| Carbon capture (Cement - Calcium looping) | £37.78 | £20.00 | £80.00 | £/tonne$CO_2$ | Nominal cost and range based on figure 2 in Leeson et al. (2017). |
| Carbon capture (Fermentation) | £12.30 | £9.84 | £14.76 | £/tonne$CO_2$ | Nominal cost based on IEA (2013), range is +/- 20%. |
| Carbon capture (Pulp and paper) | £24.73 | £19.78 | £29.68 | £/tonne$CO_2$ | Nominal cost based on Leeson et al. (2017), range is +/- 20%. |
| Carbon capture (General post-combustion) | £74.23 | £20.00 | £120.00 | £/tonne$CO_2$ | Nominal cost and range based on figure 2 in Leeson et al. (2017). |
| Hydrogen | £110.00 | £60.00 | £140.00 | £/MWh (HHV) | Costs chosen from 2020 data in Chart 6.2 in BEIS (2021). Nominal - 'Dedicated offshore', lower - 'Curtailed electricity (25% LF)', upper - 'Grid electricity: Industrial LRVC (Baseload)'. |
| Biomethanation | £7.64 | £6.11 | £9.16 | £/MWh (LHV) | Costs calculated based on values in Michailos et al. (2020), (see Table 11) range is +/- 20%. |
| Natural gas grid injection | £3.92 | £3.13 | £4.70 | £/MWh(LHV) | Nominal is based on Navigant (2019), range is +/-20%. €:£ = 1.2. |
| Biomethane sales revenue | £27.00 | £9.00 | £70.00 | £/MWh (LHV) | Based on LRVC 10-year average for natural gas with upper and lower based central value maximum and minimum over same timescale (GOV UK 2023). |
| Coal substitution (savings) | £10.00 | £7.00 | £13.00 | £/MWh (LHV) | Based on LRVC 10-year average with upper and lower based central value maximum and minimum over same timescale (GOV UK 2023). |

*Table 11 Calculation of unit cost of biomethane as per Michailos et al. (2020)*

| | | |
|---|---:|---|
| Project lifetime | 20 | a |
| Equipment cost | £1,970,000 | £ |
| CAPEX | £4,714,112 | £ |
| OPEX rate (n/n/year of CAPEX) | 0.05 | n/n |
| OPEX | 235,706 | £/a |
| Plant capacity | 5 | MW |
| Plant availability | 8000 | hr/a |
| Discount rate | 0.1 | n/n |
| Annual biomethane output | 40000 | MWh/a |
| Total biomethane output | 800000 | MWh |
| NPC of biomethanation reactor | £6,109,831 | £ |
| Unit production cost of biomethane | £7.64 | £/MWh |

## 2.6 Overall performance metrics

A series of metrics were devised and calculated to compare the decarbonised scenarios (see Table 12) along with explanations of their meaning and/or relevance. Global production of the industrial products were sourced as per Table 13.

*Table 12 Performance metrics of the decarbonised scenarios and their explanation/relevance*

| **Performance metric** | **Unit** | **Explanation/relevance** |
|---|---|---|
| Product decarbonisation | $tCO_{2e,avoided}/t_{product}$ | A measure of the net impact of the biomethanation integration on the carbon emissions of the broader economy based on the unit of production |
| Global decarbonisation potential | $MtCO_{2e,avoided}/a$ | A measure of the total annual decarbonisation potential on a global basis calculated using the product decarbonisation and the global production. |
| Relative cost increase | % increase | A relative measure of cost increase. |
| Specific renewable energy consumption | $MWh/t_{product}$ | The total additional energy consumption (i.e. electrolysis, carbon capture, biomethanation reactor) specific to the unit of production. |
| Decarbonisation intensity | $tCO_{2e,avoided}/MWh$ | Calculated as the decarbonisation ÷ specific renewable energy consumption. This metric can be used to compare the proposed process with a broad range of applications of renewable energy for decarbonisation (e.g. direct electrification of the same industries, domestic usage) |
| Cost of decarbonisation | $£_{increase}/tCO_{2e,avoided}$ | The cost of avoiding GHG emissions via the proposed integration of biomethanation. Can be used to compared different decarbonisation strategies or to estimate requirements of carbon subsidies/taxes. |

*Table 13 Global production statistics*

| Global production | Unit | Value | Source/note<br>Note |
|---|---|---|---|
| Distilled spirits | GL/a | 33.8 | Assume 40% ABV and density 0.73 kg/LA. (Statistica 2023), 2023 data |
| Cement | $Gt_{portland\ cement}/a$ | 3.5 | (Fennell et al. 2021), 2021 data |
| Steel | $Mt_{crude\ steel}/a$ | 1951 | (Worldsteel.org 2022), 2021 data |
| Pulp | $Mt_{virgin\ pulp}/a$ | 182 | (Van Ewijk et al. 2018) |

## 2.7 SWOT analysis of the project approach

Table 14 shows a SWOT (Strengths, Weaknesses, Opportunities, Threats) analysis to appraise the project approach.

*Table 14 SWOT analysis of the project approach*

| **Strengths** | **Weaknesses** |
|---|---|
| Despite uncertainties the data used and approach leads to ‘best available information’ for appraisal of the technology, some evidence is better than none.<br>Sensitivity analysis allows exploration of uncertainty propagation as well as testing of important assumptions or alternative scenarios.<br>Significant contributions are captured without excessive requirements for (minor) technical details.<br>Despite the approach being focused on a single technology (biomethanation) the approach is designed to be independent to highlight pros and cons of this option which can be compared with other decarbonisation options. | Calculations based on a single example of a baseline flowsheet which does not represent the diversity of the studied process industries. Different process variants may have different opportunities for integration of biomethanation. Results/conclusions could be overgeneralized.<br>Multiple non-consistent data sources are required to produce mass/energy balances and system assessments. No single dataset covers all required data. Use of inconsistent data sources can introduce errors.<br>High level of uncertainty in economic input data and additional cost estimation.<br>Technical (engineering, biological) issues surrounding integration of biomethanation, and its feasibility is not (and cannot) be appraised by this approach. Biomethanation process is simplified down to its ability to convert $CO_2$ in any gas mixture with fixed stoichiometry, this oversimplification could lead to unrealistic recommendations.<br>Indirect emissions of the installation of the biomethanation equipment are excluded due to lack of data. |
| **Opportunities** | **Threats** |
| Granularity of results allow focus on the most significant barriers, challenges and opportunities, without getting lost in minor technicalities or details. | Transparent reporting of uncertainties and weaknesses introduced by assumptions may lead to desired audiences discounting the results.<br>Results may be perceived as technology positive/negative rather than technology agnostic (which is the aim).<br>Technicalities not considered (e.g. the effect of purification requirements) could affect the feasibility of the suggested integration scenarios. |

# 3 Results and Discussion

Results are presented on a per industry basis and organised into sections such that for each industrial process the follow are presented:

i. Mass and energy balance of the baseline and decarbonised processes
ii. Carbon footprint description, calculation, and sensitivity analysis
iii. Economic calculations and sensitivity analysis.

The order of presentation of results is rather arbitrary but cement and steel come first, followed by distillery and pulp and paper since the latter two include biogenic emissions in the supply chain which adds another element of complexity to the analysis. Ammonia is presented last since a complete analysis was not done and the work in this area was concluded prior to completing part (i) (see section 3.5).

Summaries of mass and energy balance calculations are shown diagrammatically in the relevant sections but a more detailed presentation of tabulated values, outlining some of the calculation steps is provided in appendix 1.

## 3.1 Cement industry

### 3.1.1 Cement mass and energy balance

Cement is made predominantly from a substance called clinker in variable quantities but in the order of 80% by mass, as well as other additives in limited quantities (e.g. aggregates) which act as a binder and improve the final product characteristics. Clinker is associated with the vast majority of the cradle-to-gate carbon footprint associated with cement, with its production associated with both direct and a large point-source of GHG emissions. Clinker is produced through the calcination of limestone, a chemical reaction which decomposes calcium carbonates, releasing fossil $CO_2$ in the process. The process requires thermal input which is provided by the combustion of (fossil) fuels (Marmier 2023).

The **baseline** process for the cement part of this work was based around a Best Available Technology (BAT) cement plant including a dry kiln process with pre-heater and pre-calciner, producing 3000 tons of clinker per day in Norway as described by Chauvy et al. (2020b). The mass and energy of the **baseline** process is summarized in Figure 3(a).

The common stack of the pre-calciner and kiln produces a flue-gas with around 20% $CO_2$ by volume , of which 38% is estimated to originate from the fuel inputs with the remaining 62% from the decomposition/calcination of limestone (Marmier 2023).

Fuels commonly used in the clinker production includes coal, Profuel (shredded municipal waste), Cemfuel (solvent waste), MBM (meat and bone meal, an animal byproduct) and Kerosene (used for preheating the kiln at start-up), Petcoke and Natural Gas. An assumption is made that biomethane can substitute these in the process without major modification, whereas Direct use of $H_2$ would be more complex as it would lead to higher water pressure in the system - with changes to clinker properties and potential corrosion due to greater formation of acids.

The **decarbonised** PFD along with a summary of the relevant mass and energy balance quantities is shown in Figure 3(b). The integration design considered the capture of the single stack flue-gas and drop in replacement of the input fuel with biomethane (F), 29% of total production, on an energy equivalent basis. The 69% excess biomethane (F) is exported (e.g. via the gas grid) for downstream use.

The mass and energy balance of the biomethanation subsystems is shown in Figure 4 noting that the required install electrolyser is 929 MW to service the needs of the cement plant with the electrolyser, carbon capture and biomethanation reactor consuming 87%, 11% and 2% respectively of the renewable electricity supplied to the decarbonised process.

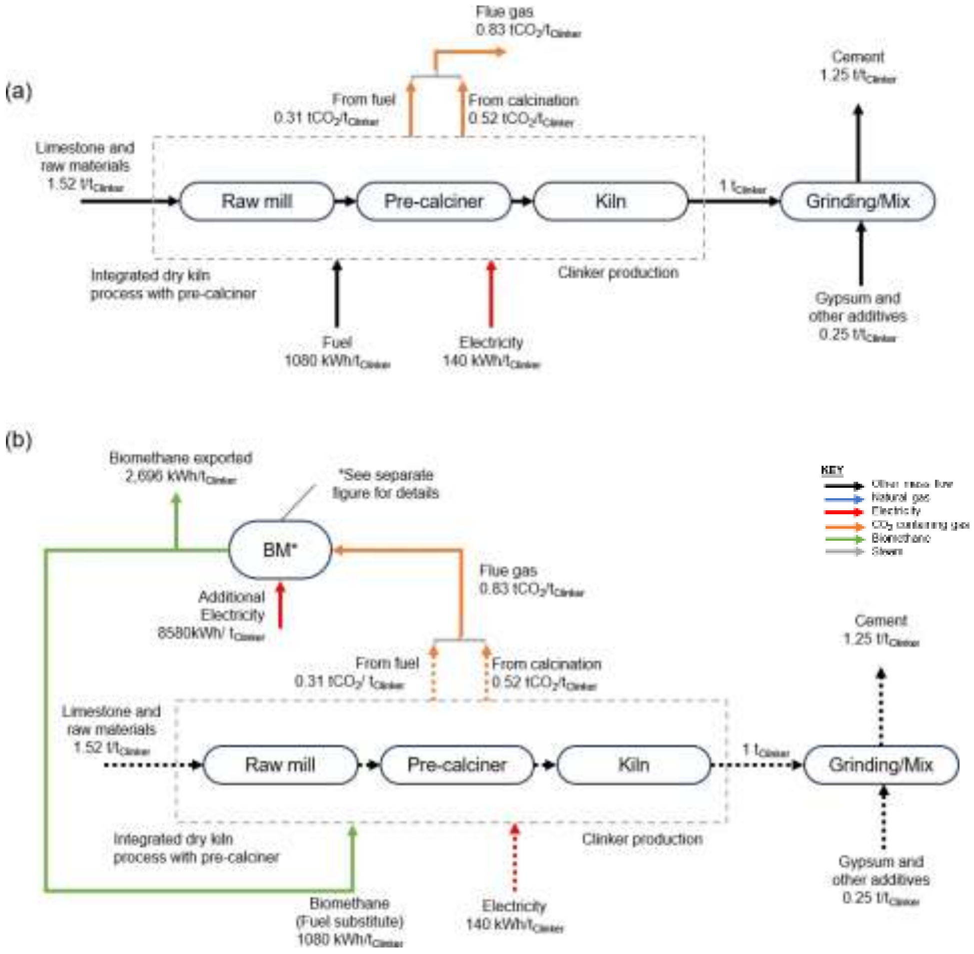


*Figure 3 Relevant mass and energy balance values for cement production process showing (a) baseline and (b) biomethanation integrated/decarbonised scenarios. Dashed arrows represent unchanged flows from baseline process.*

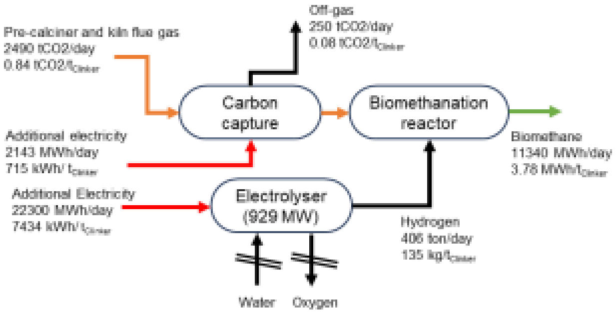


*Figure 4 Mass and energy balance of the biomethanation process for the cement decarbonised scenario*

### 3.1.2 Cement carbon footprint

Figure 5 is a visual summary of the **baseline** and **decarbonised** carbon footprint scenarios for the chosen cement production facility. The carbon footprint obtain from literature (Hanein et al. 2018) has a cradle-to-gate system boundary and a value of 870 $kgCO_{2e}/t_{Clinker}$. The carbon footprint of the **decarbonised** process differs little from the generalized schematic presented in the methodology, except to note that no change to the electricity supply (ES) of the **baseline** process through the integration steps. All emissions are of fossil origin since the incoming carbon is either in the form of limestone or (assumed) fossil fuel.

Results of the **decarbonised** carbon footprint calculation are summarized in Figure 6. The **baseline** carbon footprint is reduced to 166 $kgCO_{2e}/t_{Clinker}$ with by far the largest contributing factor coming from the carbon capture itself and eventual substitution of the natural gas downstream use which is due to the large fraction of biomethane (F) being exported from the production plant (69%). Of the additional emissions the largest contribution comes from the electrolysis which is expected due to its domination of the additional electricity consumption through integration. This set of results illustrates the importance of the assumptions made surrounding natural gas substitution and the inclusion of the downstream usage within the analyzed system boundary.

The sensitivity analysis (Figure 7) illustrates well the relative significance of the explored sensitivity variables. The carbon intensity of the (renewable) energy supply is by far the most influential factor that can make or break the carbon savings achieved though the biomethanation integration. The range explored is limited to the current best option (onshore wind, 0.011 $kgCO_{2e}/kWh$) to an aggregated value for all renewables in the UK (0.0632 $kgCO_{2e}/kWh$) and even this small increase is enough to offset much of the other carbon savings (results in a final carbon footprint of 578 $kgCO_{2e}/t_{Clinker}$). If average grid electricity were used for this process, then the resulting carbon footprint was estimated as 2300 $kgCO_{2e}/t_{Clinker,}$ a 164% increase.

Captured $CO_2$, % of biomethane in the grid and electrolysis efficiency (in order of impact) all had a moderate effect on the resulting carbon footprint. Captured $CO_2$ in important since it determine the amount of carbon savings (direct) and avoided downstream and so feeds directly into the largest reductions in carbon footprint. Increasing % of biomethane in the grid reduces the carbon effectiveness of the substitution since the carbon intensity of the material gas grid is smaller. Changes in electrolyser efficiency drive carbon savings due to the large fraction of electricity being consumed by this component.

Amongst the other sensitivity variable explored, the impact of the energy consumption of the carbon capture and biomethanation processes were both relatively small.

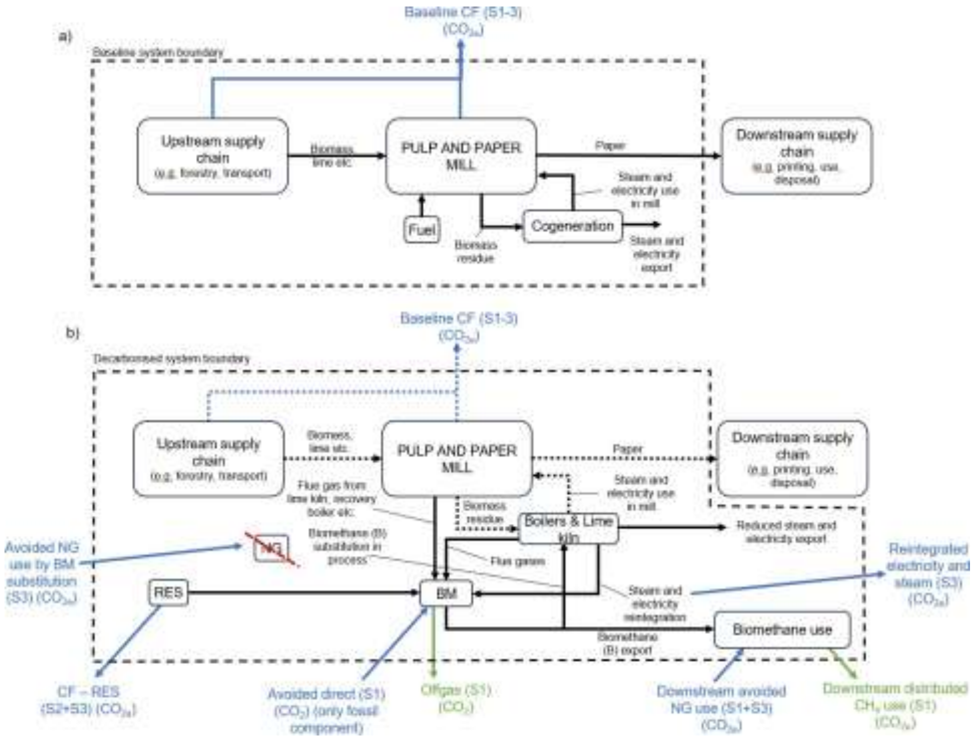


*Figure 5 Clinker production baseline (a) and decarbonised (b) carbon footprints showing summary of calculation of additional produced and avoided emissions. (CF – carbon footprint, NG – natural gas, ES – electricity supply, RES – Renewable electricity supply, BM – biomethanation, F - fossil). Black arrows are material/energy flows, blue arrows are fossil GHG emissions. Dashed arrows represent unchanged flows from the baseline process*

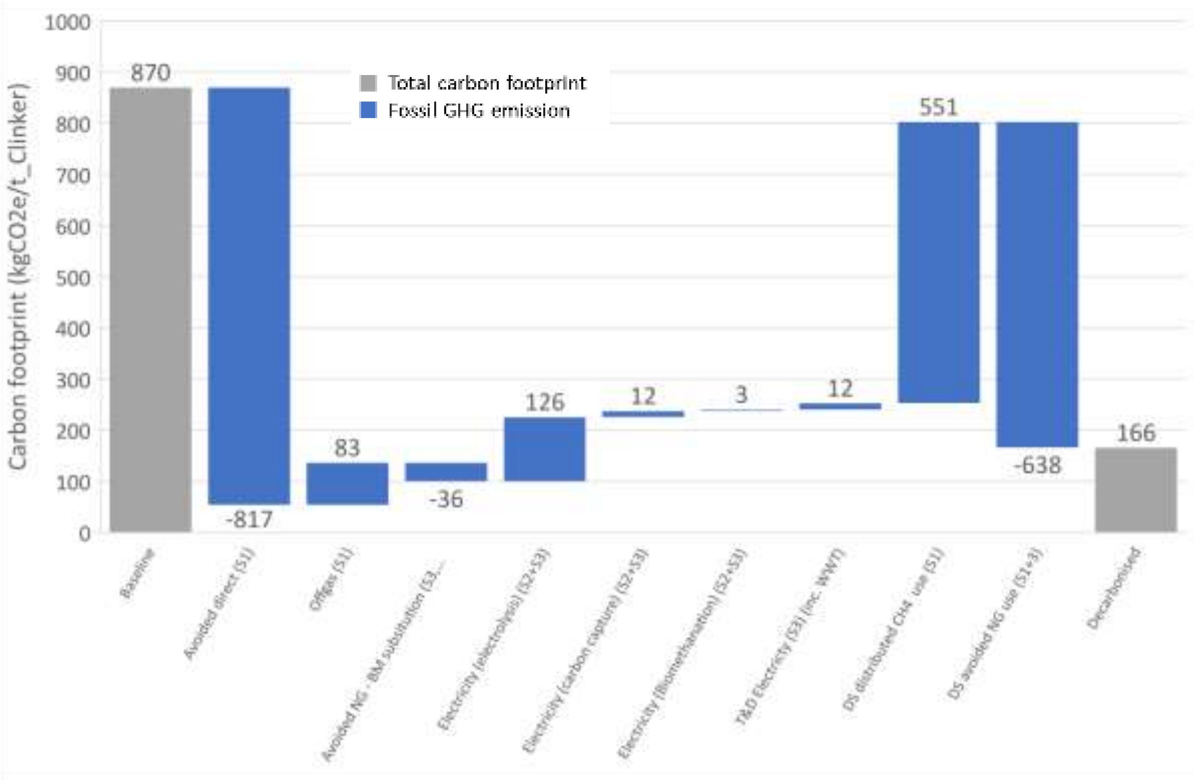


*Figure 6 Cement carbon calculation showing baseline and decarbonised scenario carbon footprint (NG – natural gas, T&D – transmission and distribution, BM – biomethanation, DS - downstream)*

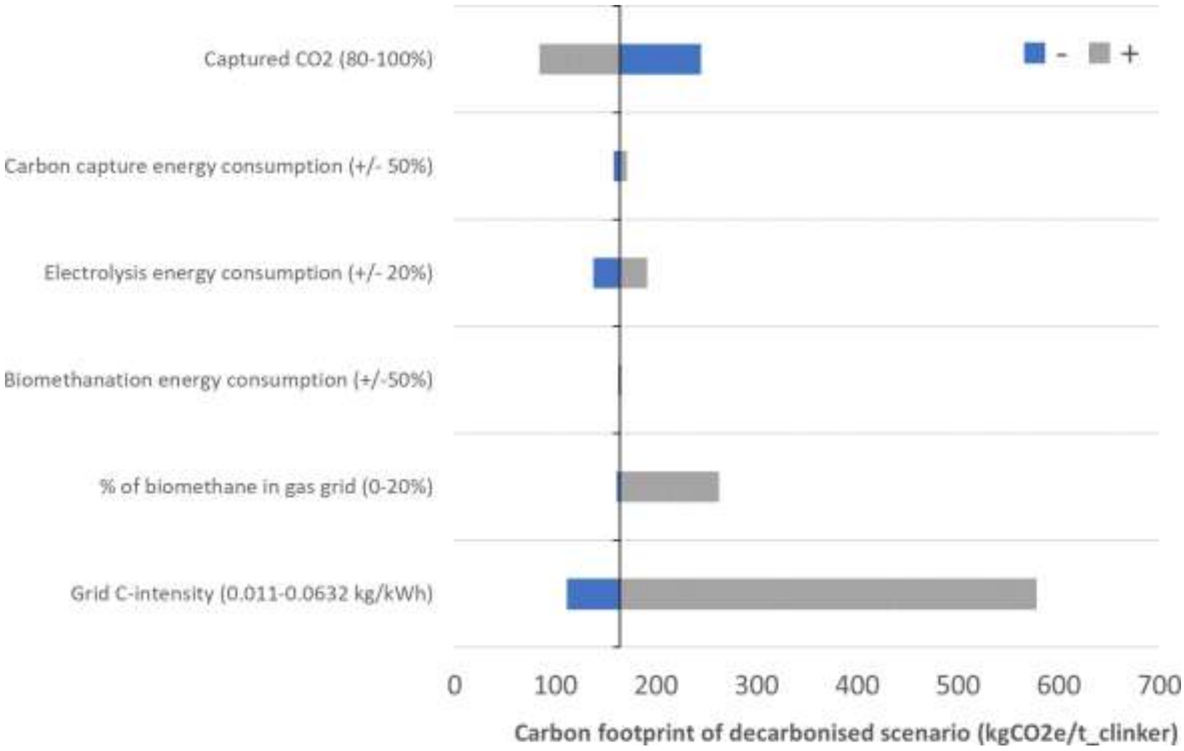


*Figure 7 Sensitivity analysis of the calculated carbon footprint for the decarbonised cement scenario*

### 3.1.3 Cement economics

Baseline production cost of clinker production were estimated as €53/$t_{cement,}$ (CEMBUREAU 2021) which is approximately equivalent to £55 /$t_{clinker}$ (0.8 tclinker/tcement (Marmier 2023), £1:€1.2).On this basis the additional costs were calculated, and a summary of the economic analysis is shown in Figure 8. Decarbonised production costs were calculated as £644 /$t_{clinker}$, a large increase by a factor of ~11. The best- and worst-case estimates are also shown, which represent the cumulative limits of the upper and lower sensitivity variables (i.e. best case = lowest costs – highest revenue and savings and vice versa) to illustrate the large uncertainties associated with these calculations (£237-842 /$t_{clinker}$), corresponding to 331-1431% increase.

Additional costs are dominated by the cost of hydrogen which incorporates both the energy costs (major component of OPEX) as well as the high capital costs of current electrolyser technologies. Revenue from biomethane (F) sales are rather small, and targeting higher value products may be the able to offset such large cost increases.

The sensitivity analysis (Figure 9) reveals hydrogen production costs and biomethane sales to be the most influential variables, which is expected as these are the largest contributors to the variation in production costs, however even with the lowest predicted hydrogen generation cost, or highest revenue generated from biomethane (F) the production cost (375, 528 /$t_{clinker}$) remains much higher than the baseline (£55 /$t_{clinker}$). To maintain production costs as per the baseline, all else being equal, hydrogen would need to be produced at almost zero cost (£0.46/MWh), or alternatively a sales price of £245 /MWh for the biomethane (F), or its higher value equivalent would be needed.

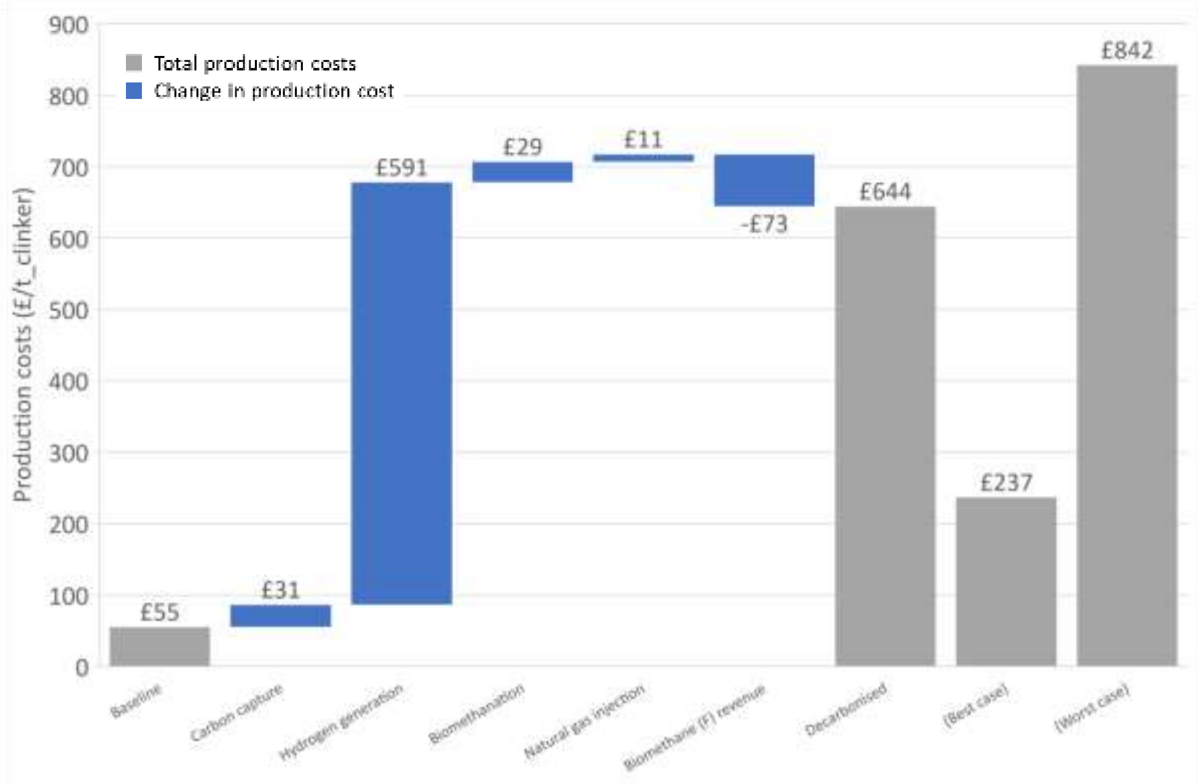


*Figure 8 Cement production economics showing baseline and decarbonised scenario production costs*

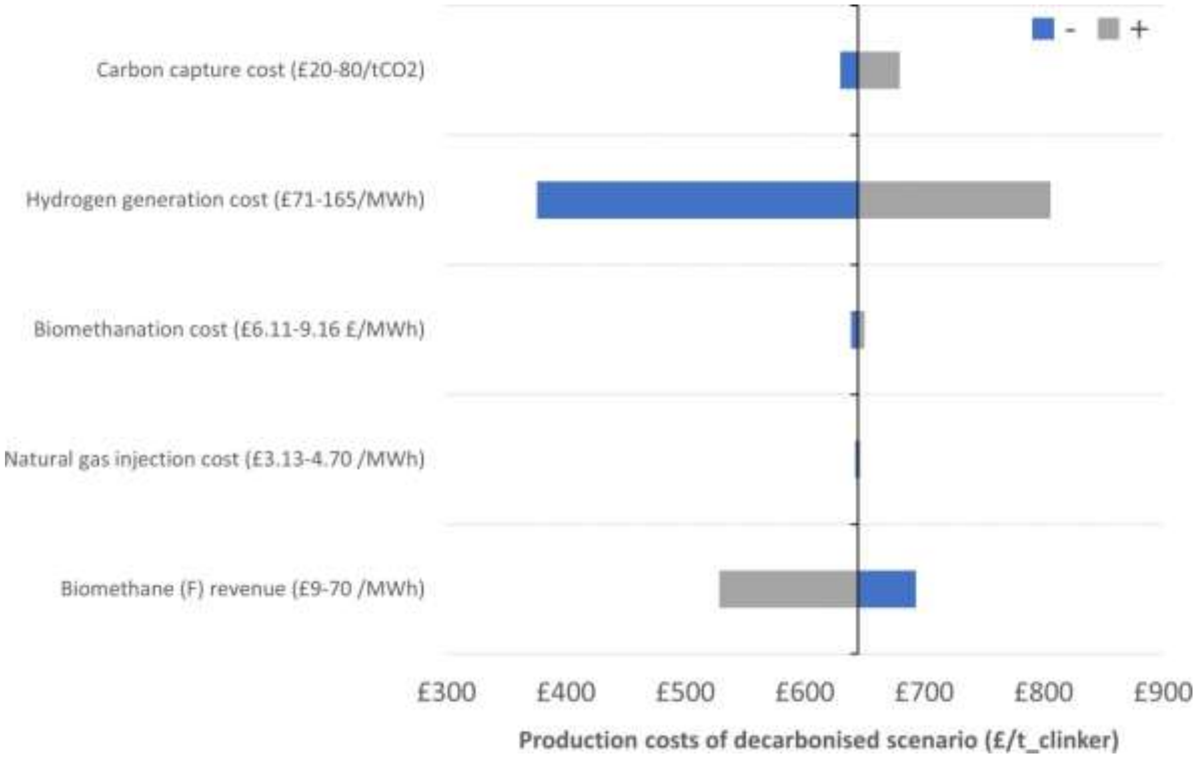


*Figure 9 Sensitivity analysis of the calculated production costs for the decarbonised cement scenario*

## 3.2 Steel industry

### 3.2.1 Steel mass and energy balance

Steel is produced through one of four main methods; Blast furnace and basic oxygen furnace (BF-BOF), smelting reduction, direct reduction and electric arc furnace (EAF), and scrap melting in EAF, shown in Figure 10. In 2006, across the EU-27 BF-BOF was the most common method (60%) with followed by the EAF route (40%) (Remus 2013).

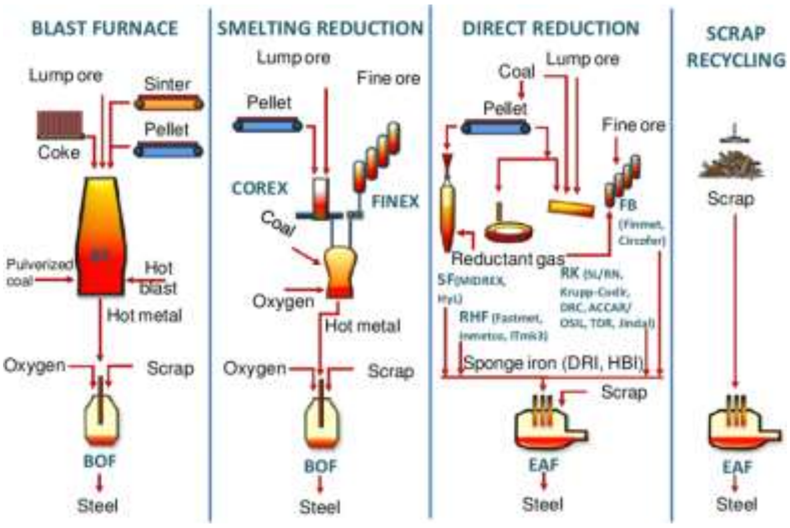


*Figure 10 Routes of Steel production Source (Zulhan 2013)*

In this work, a BF-BOF flowsheet was developed to represent the **baseline** process considered for biomethanation integration (Figure 12(a) check). The six main processing elements of the BF-BOF process; the coking oven (CO), sinter (SP) and pellet plants (PP), the BF, the BOF and the hot strip mill (HSM) were considered, and the fuel inputs and off-gas outputs were modelled using predominantly data from Remus (2013) supplemented by data from Rosenfeld et al. (2020).

Steel plants are already highly integrated through the recycling of process-gasses, namely the coke oven gas (COG), blast furnace gas (BFG) and basic oxygen furnace gas (BOFG) which are produced in large quantities and then used as inputs, supplemented with coal and natural gas to each of the main processing elements such as sintering, coking, and blast furnace. The flow rate and the composition of the process gases and the ratio of their recycling into the steel mill were obtained from Remus (2013) together with their composition. Excess off-gases, not re-used as inputs into the processes, are sometime sold due to their fuel/chemical value, but often are fed to a local power plant for electricity generation. The **baseline** process assumes the latter, as also in the study of Rosenfeld et al. (2020) and Duwahir (2016). From the composition of the excess process gases, the reduced forms of carbon are assumed to be oxidized stoichiometrically to $CO_2$ before being emitted directly at the power plant, with all locally produced electricity is used by the steel mill itself. These direct emissions from combustion account for around 70% of the total direct emissions from a BF-BOF plant, based on the estimate of total direct emissions of 1200 $kgCO_{2e}/tLS$ (ton of liquid steel) (IEA 2020). Other direct emissions come from smaller distributed sources such as hot stoves, hot strip mill and secondary steel making, sinter plant and eventual flares (Duwahir 2016).

The **decarbonised** steel scenario (Figure 12(b)) adds post-combustion carbon capture to the power plant flue gas which is then converted to biomethane (F). All natural gas inputs to the SP, PP, BF, BOF and HSM were replaced with biomethane (F) (6% of production) along with a fraction of the coal input (37.7% of coal replaced with biomethane, 16% of biomethane production) to the BF, as suggested by Perpiñán et al. (2023). Excess biomethane (F) (78% of biomethane production) is exported for downstream use. The mass and energy balance of the biomethanation subsystems is shown in Figure 12 noting that the required install electrolyser is 4650 MW to service the needs of the steel mill with the electrolyser, carbon capture and biomethanation reactor consuming 89%, 9% and 2% respectively of the renewable electricity supplied to the decarbonised process.

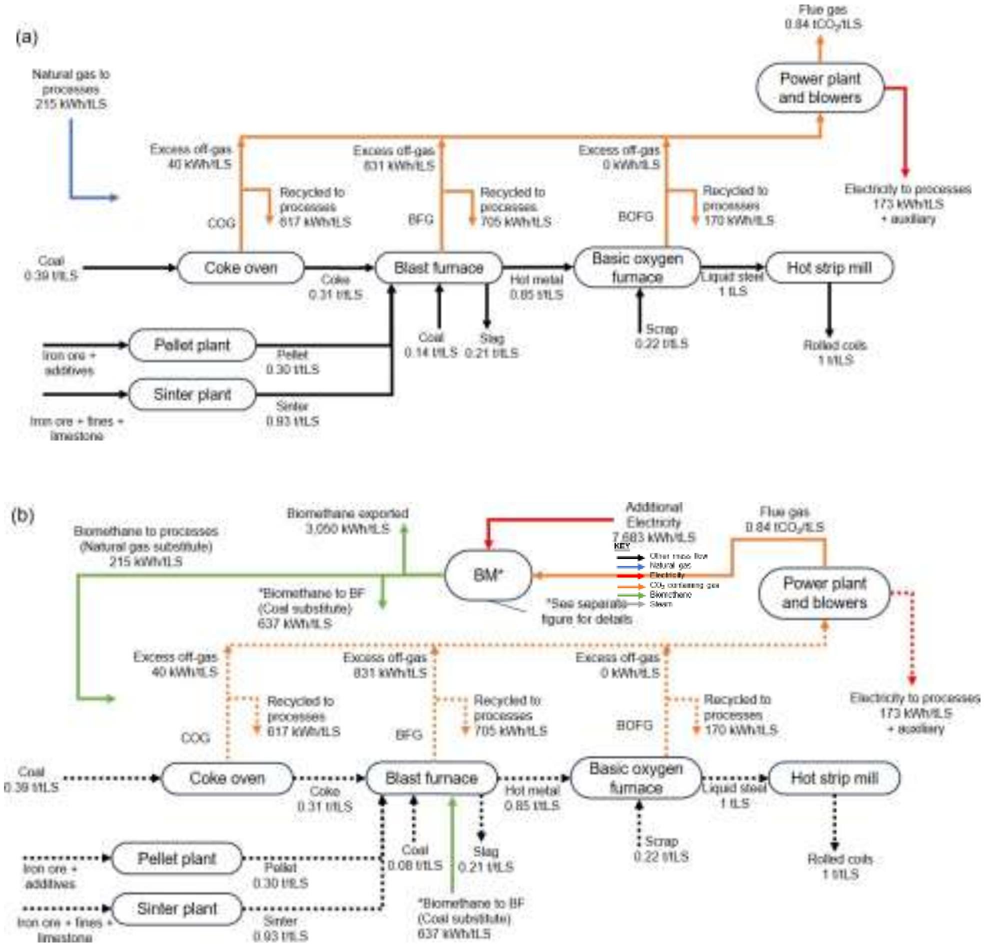


*Figure 11 Relevant mass and energy balance values for a steel mill showing (a) baseline and (b) biomethanation integrated/decarbonised scenarios. Dashed arrows represent unchanged flows from baseline process. (tLS – tonne liquid Steel)*

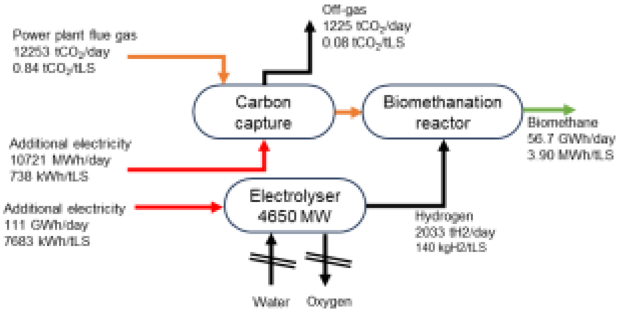


*Figure 12 Mass and energy balance of the biomethanation process for the steel decarbonised scenario*

### 3.2.2 Steel carbon footprint

Note that much of the results and discussion for steel production is similar to that made about the cement production process, so only distinctive points will be made rather than repeating. Figure 13 is a visual summary of the baseline and decarbonised carbon footprint scenarios for the chosen BF-BOF steel mill. The **baseline** carbon footprint obtained from literature (IEA 2020) has a cradle-to-gate system boundary and a value of 2200 kg$CO_{2e}$/tLS. Similar to the cement process there is a change to the energy inputs during the integration of biomethanation, namely complete replacement of natural gas, and partial replacement of coal. All emissions are fossil based and originate in the coal and other inputs to the plant (e.g. limestone).

Results of the **decarbonised** carbon footprint calculation are summarized in Figure 14. The baseline carbon footprint is reduced to 1455 kg$CO_{2e}$/tLS with a similar profile of relative contribution of the different GHG sources. A distinction is that the degree of decarbonisation is relatively less i.e. only 34% reduction compared to the **baseline** footprint (c.f. 81% for cement). This is due to two main factors; a) that 90% of the $CO_2$ produced during clinker production is converted to biomethane, compared to only 70% in the steel mill, meaning missed opportunities for downstream substitution of natural gas, and b) that for steel, a greater fraction of the carbon footprint is presumed to be attributable to the upstream supply chain, indeed direct emissions at the steel mill only account for around 54% (i.e. 1200/2200) of the overall carbon footprint which limits the impact that biomethanation can be used for decarbonisation.

The sensitivity analysis (F) shows similar trends to the cement analysis with the most influential factor influencing the degree of decarbonisation being the emissions intensity of the renewable energy supply. Using an aggregated renewable electricity source (0.0632 kg$CO_{2e}$/kWh) rather than just wind and solar increases the **decarbonised** carbon footprint to 1887 kgCO2e/tLS. If average grid electricity were used for this process, then the resulting carbon footprint was estimated as 3519 kg$CO_{2e}$/tLS (a 60% increase c.f. **baseline**).

Fraction of captured $CO_2$ is explored to a larger range (30-100%) than for cement (c.f. 80-100%) and so its impact on the decarbonised carbon footprint is relatively more pronounced. As with cement, % of biomethane in the grid and electrolysis efficiency both had a moderate effect on the resulting carbon footprint. Coal substitution has a minor effect on the carbon footprint since only S3 emissions are being avoided (i.e. WTT emissions) as the avoided direct emissions are already being accounted for in S1 emissions. The impact of the energy consumption of the carbon capture processes was relatively small.

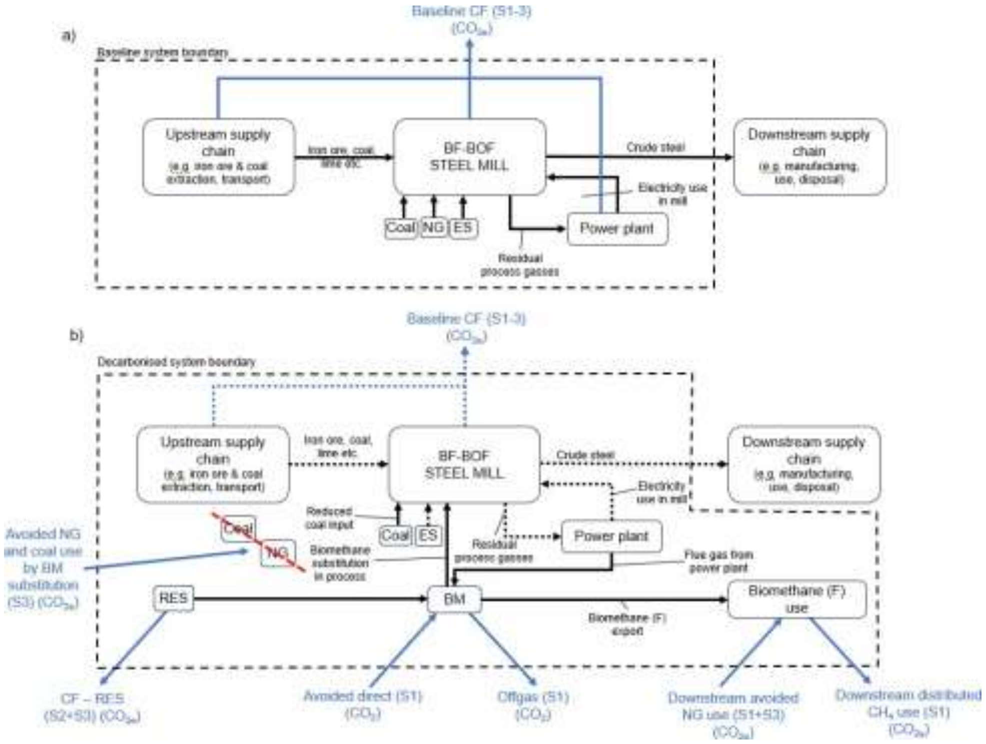


*Figure 13 Integrated steel mill (BF-BOF) baseline (a) and decarbonised (b) carbon footprints showing summary of calculation of additional produced and avoided emissions. (BF = blast furnace, BOF – basic oxygen furnace, CF – carbon footprint, NG – natural gas, RES – renewable electricity supply, BM – biomethanation, F - fossil). Black arrows are material/energy flows, blue arrows are fossil GHG emissions. Dashed arrows represent unchanged flows from the baseline process*

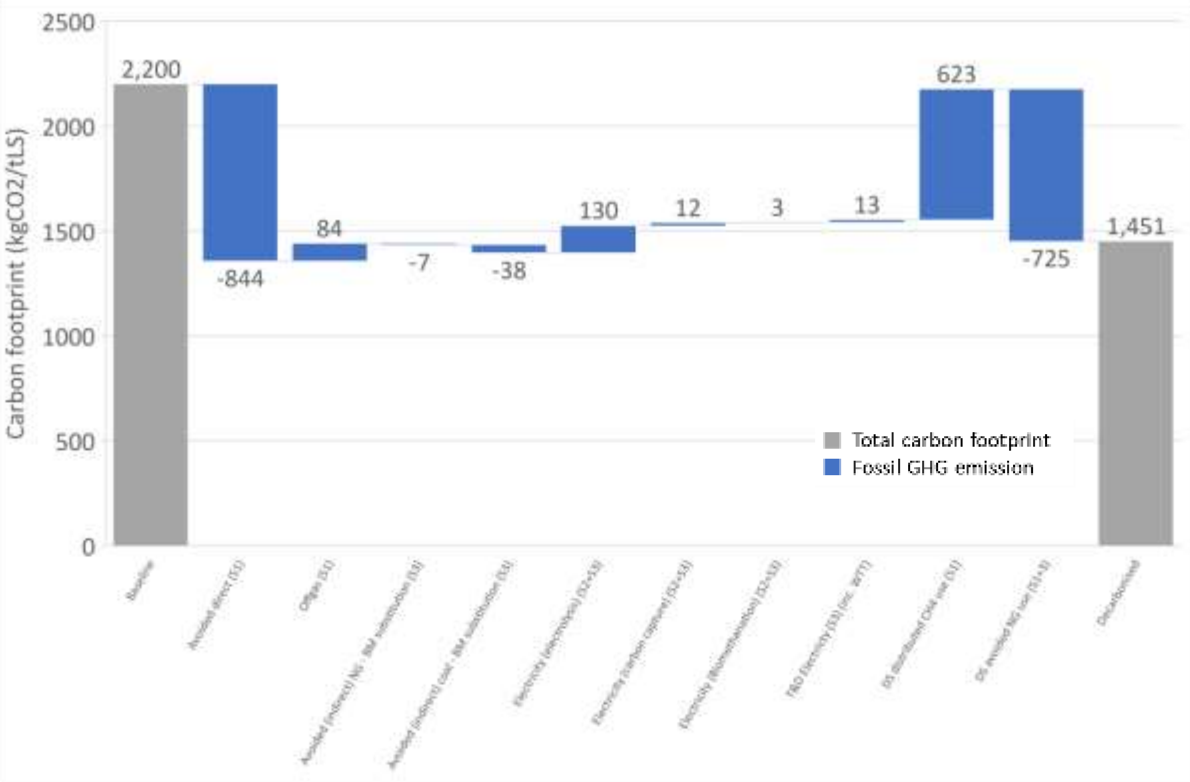


*Figure 14 Steel production carbon calculation showing baseline and decarbonised scenario carbon footprint (NG – natural gas, T&D – transmission and distribution, BM – biomethanation, LS – liquid steel, DS - downstream)*

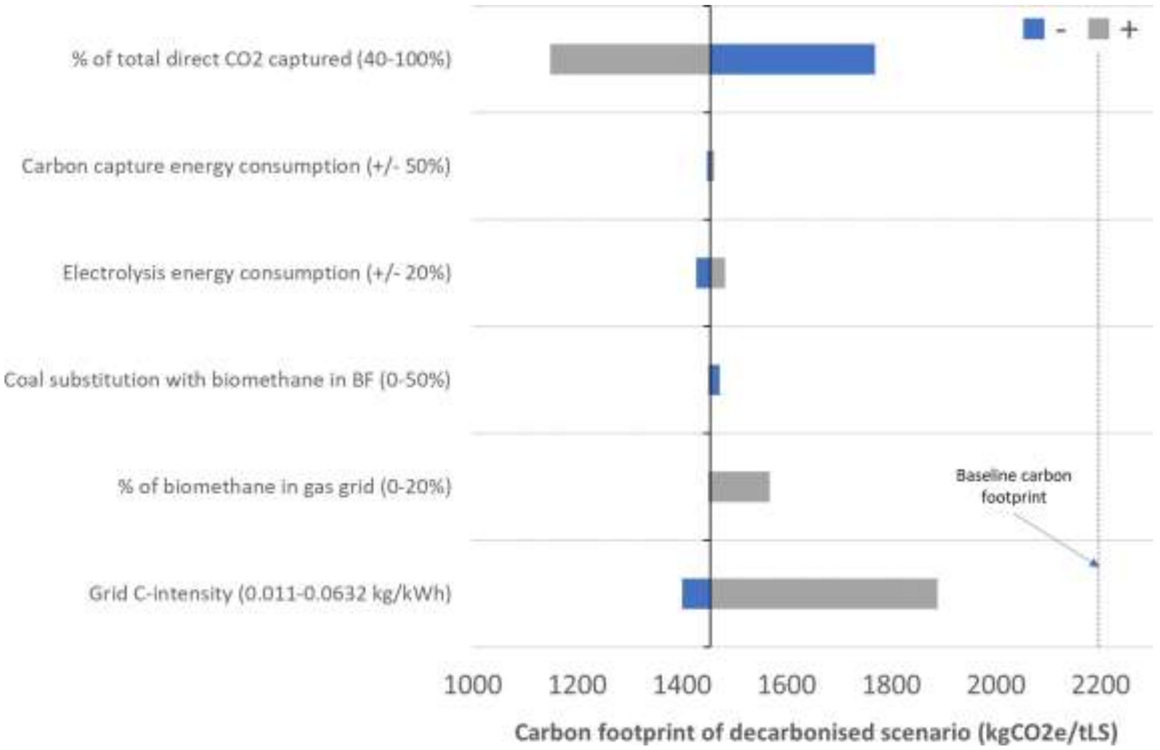


*Figure 15 Sensitivity analysis of the calculated carbon footprint for the decarbonised steel scenario (LS – liquid steel)*

### 3.2.3 Steel economics

Baseline production cost of crude steel production were estimated as €458/tHM (Hot metal) (Navigant 2019) which is approximately equivalent to £325 /tLS (1.17 tLS/tHM (Perpiñán et al. 2023), £1:€1.2). On this basis the additional costs were calculated, and a summary of the economic analysis is shown in (Figure 16). Decarbonised production costs were calculated as £919 /tLS, an increase of 182%. The best- and worst-case estimates are also shown, which represent the cumulative limits of the upper and lower sensitivity variables (i.e. best case = lowest costs – highest revenue and savings and visa versa) to illustrate the large uncertainties associated with these calculations (£469-1180/tLS) corresponding to a range of 43-262% cost increase.

Additional costs for the **decarbonised** scenario are dominated by the cost of hydrogen which incorporates both the energy costs (major component of OPEX) as well as the high capital costs of current electrolyser technologies. Revenue from biomethane (F) sales are rather small relative to other costs, and targeting higher value products may be an option to offset such large cost increases.

The sensitivity analysis (Figure 17) reveals hydrogen production costs and biomethane sales to be the most influential sensitivity variables on production costs, which is expected as these are the largest contributors to the increase in production costs, however even with the lowest predicted hydrogen generation cost, or highest revenue generated from biomethane (F), the production cost (656, 787/tLS), corresponding to 101% and 141% cost increase, remains much higher than the **baseline** (£325/tLS). To maintain production costs as per the baseline, all else being equal, hydrogen would need to be produced at a negative cost (-£3/MWh), or alternatively a sales price of £221/MWh for the biomethane (F), or its higher value equivalent would be needed.

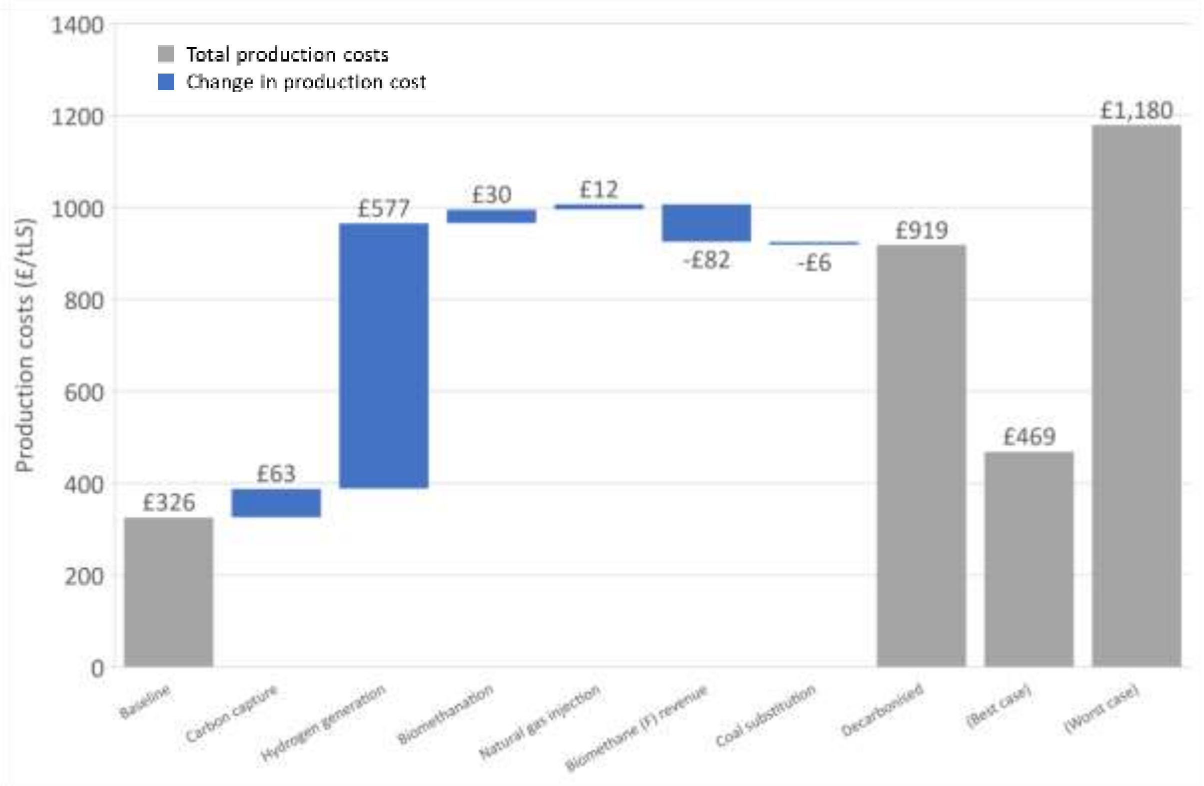


*Figure 16 Steel production economics showing baseline and decarbonised scenario production costs (LS – liquid steel)*

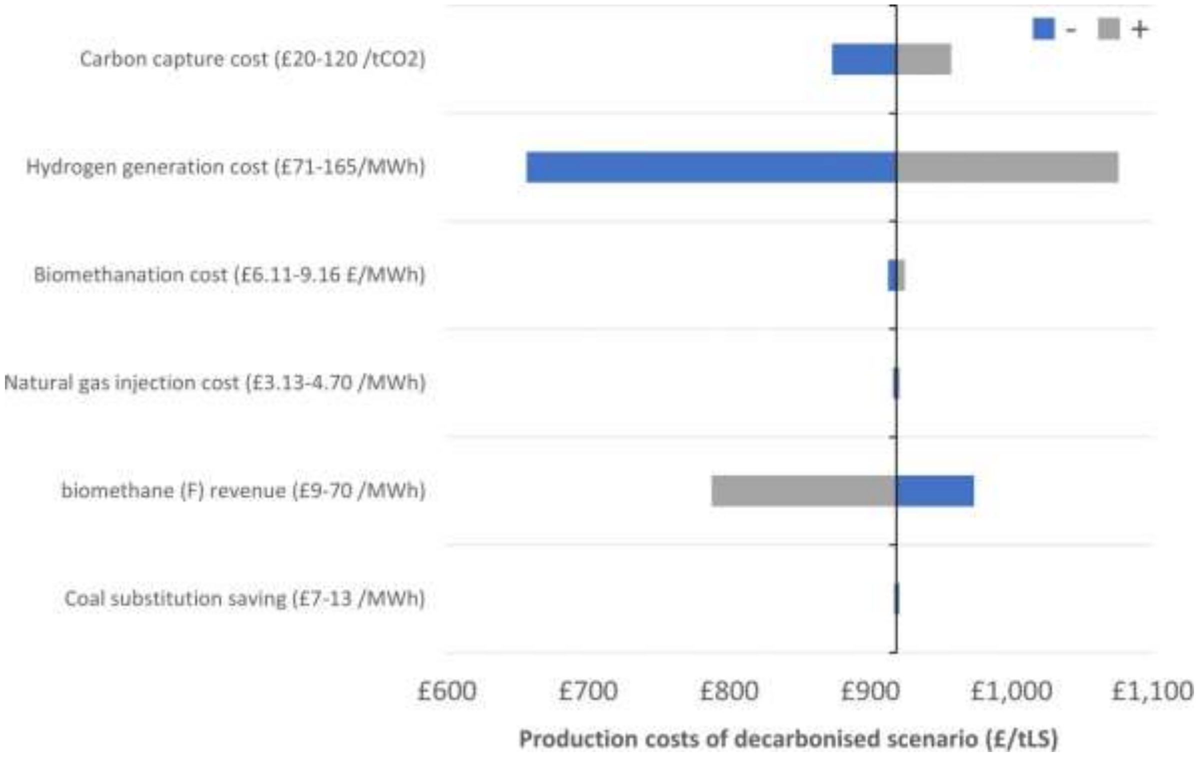


*Figure 17 Sensitivity analysis of the calculated production costs for the decarbonised steel scenario (LS – liquid steel)*

## 3.3 Distillery industry

### 3.3.1 Distillery mass and energy balance

Ethanol production industries can be characterized by their production of non-potable (e.g. biofuels) or potable (e.g. beer, wine, spirits) final products, and represent a diverse range of processes, all using a fermentation process to convert sugars to ethanol. Potable ethanol industries can be further categorized by the feedstock biomass used as the sugar source (grains, grapes, honey, sugarcane) and the alcohol by volume (ABV) of the final product which determines whether a further concentration step (i.e. distillation) is used. Despite these categories there is still considerable diversity between process, and their energy usage profiles, for example beer and wine production share (broadly speaking) common fermentation process but the pretreatment of grains to produce beer involves a large thermal load for the kilning, mashing and kiln boiling stages, whereas pretreatment of grapes for winemaking is a relatively mild set of processes with much lower energy inputs. Distillation, used in the production of spirits and fortified wines, clearly adds a large additional thermal load since it involves the vapourisation of the ethanol contained in the original fermentation product (e.g. the ‘wash’ in whisky production)

As well as flue-gases produced through the combustion of fossil fuels (or sometime biogas) to serve the thermal demand of the process through direct heating or steam generation, the fermentation process also produces a relatively pure stream of biogenic $CO_2$ which could be targeted for biomethanation since it requires little (or no) pretreatment, i.e. no carbon capture process.

In the context of this work, the diversity of the potable ethanol industries results in a variation of the opportunities available through biomethanation integration. A more in-depth study could attempt to further characterise these opportunities, but for the purpose of this work, and a single process was chosen, on the basis of a sufficiently detailed consistent dataset available in academic literature. A distillery was targeted due to the high thermal demands of the distillation process itself, which is often satisfied by natural gas or biogas (often via steam), and so it appears a good fit for biomethanation integration. The chosen data comes from the work of O'Shea et al. (2020) which quantitatively describes an Irish distillery (largest in the Republic of Ireland) that produces 61 million litres of original alcohol (MOLA) per year as distilled spirits. The mass and energy balance of relevance, developed as the **baseline** scenario, is shown in Figure 18(a).

The study itself (O'Shea et al. 2020) aims to assess the impact of biogas integration with the distillery from a GHG emissions perspective, with the main outcome being that the scope 1 emissions of the distillery were reduced by 54% by the introduction of AD, but it is interesting to note that once S3 and other external emissions are accounted for, including the increased demand of animal feeds from the broader economy (that are no longer produced by the distillery), that this reduction is was calculated as only 1%. In this work we do not specify whether the **baseline** process includes AD integration since this does not significantly affect the assessments performed, but in reality, as mentioned in the introduction, there may be opportunities for beneficial process integration between AD and biomethanation, which are beyond the present scope.

The **baseline** process includes the electrical (14%) and natural gas (86%) inputs to the plant, which are split predominantly between the distillery and feeds recovery operations on the site. Development of the **decarbonised** process (Figure 18(b)) involved the capture of carbon from all flue-gas from onsite steam generation, which was combined with the fermentation off-gas (assumed not to require significant pre-treatment) and fed to the biomethanation process. Fermentation was considered with the following reaction stoichiometry in order to calculate the quantity of $CO_2$ based on the ethanol production.

$$C_6H_{12}O_6 \rightarrow 2C_2H_5OH + 2CO_2$$

The two fluxes of carbon dioxide are of similar orders of magnitude, 52% from combustion and 48% from fermentation. Biomethane was used to replace all use of natural gas on the site (55% of total), with the balance being exported (45%), a consequence of which is that all produced biomethane under regular operation (i.e. ignoring start-up requirements) is biogenic in origin, with the carbon originating in the biomass feedstock to the distillery. The mass and energy balance of the biomethanation subsystems is shown in Figure 19 noting that the required install electrolyser is 105 MW to service the needs of the distillery with the electrolyser, carbon capture and biomethanation reactor consuming 92%, 5% and 2% respectively of the renewable electricity supplied to the decarbonised process.

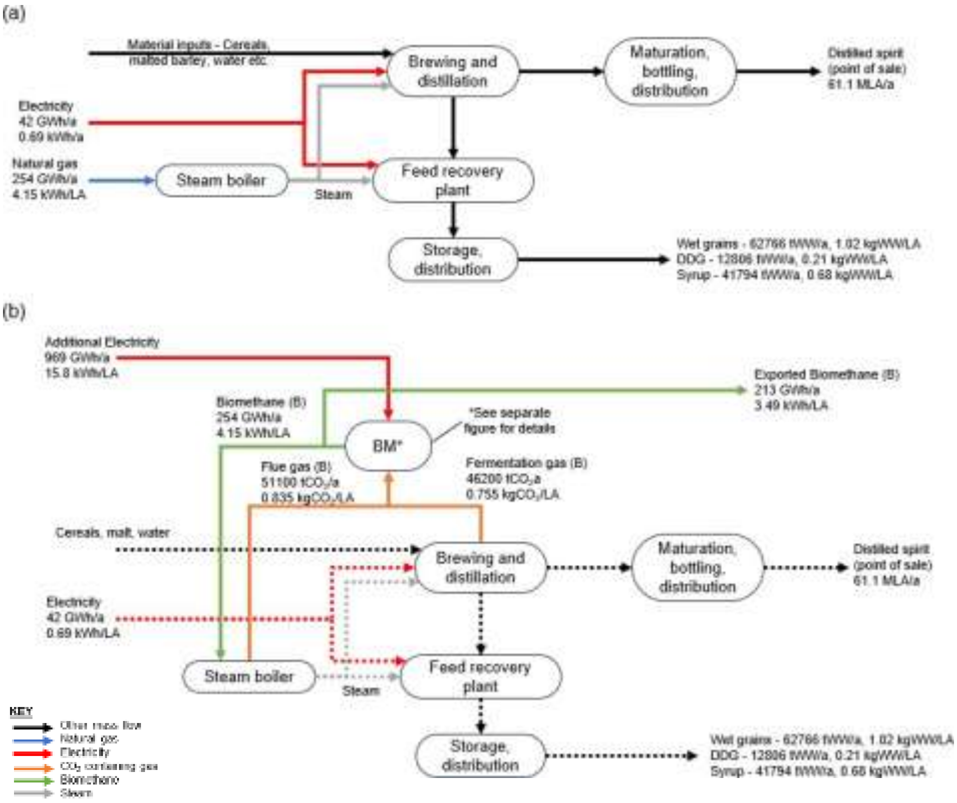


*Figure 18 Relevant mass and energy balance values for distillery process showing (a) baseline and (b) biomethanation integrated/decarbonised scenarios. Dashed arrows represent unchanged flows from baseline process. Figures are quoted as annual mass/energy (/a) per litre of alcohol (/LA) production. (WW – Wet weight, B – Biogenic GHG flows).*

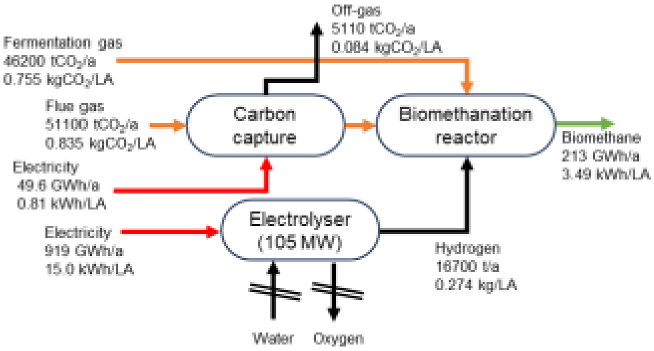


*Figure 19 Mass and energy balance of the biomethanation process for the distillery decarbonised scenario*

### 3.3.2 Distillery carbon footprint

The S1-S3 (i.e. an approximation of cradle-to-grave system boundary) **baseline** carbon footprint is estimated in O'Shea et al. (2020) as 2.03 kgCO2e/LA (Litre of alcohol). Other carbon footprint estimates are broad ranging, so it was decided to continue with a consistent dataset. Figure 20 shows the considered GHG emissions in the **baseline** and **decarbonised** carbon footprint calculations. As mentioned, a consequence of the process integration is that all direct emissions as well as the downstream emissions from the use of the biomethane (B) were biogenic, and therefore direct CO2 emissions were offset by the original biomass growth through photosynthesis. Note that the avoided direct (S1) only includes the fraction of the original direct emissions that were fossil in origin (i.e. from natural gas combustion) rather than all of the direct GHG emissions. This is appropriate since the original footprint does not include biogenic CO2 emissions (noting that other biogenic GHG emissions are included (e.g. methane)) and therefore we avoid double counting. Downstream non-CO2 emissions from biomethane (B) combustion are included in the calculation.

We present two versions of the carbon footprint calculation of the **decarbonised** scenario, firstly without and then with, the biogenic CO2 emission sources and sinks included. Figure 21 shows the calculation following the same methodology as for cement and steel i.e. to only include fossil (and in this case non-CO2 biogenic emissions). While this is the 'most correct' method and in alignment (presumed) scope and methodology of the **baseline** carbon footprint calculation, it could appear that we are double counting the avoided emissions both as direct emissions and as downstream emissions. As for the other industrial processes studies, emissions reductions are dominated by these two avoided emission categories, with appreciable additional emissions coming from the renewable electricity consumed by the electrolysis process. The final carbon footprint of the decarbonised scenario was calculated as 0.5 kgCO2e/LA, a 75% reduction. For comparison, the S3 proportion of the **baseline** carbon footprint is also given (1.52 kgCO2e/LA), illustrating that the carbon reductions are going beyond the decarbonisation of the direct/electricity consumption of the distillery, to partially offset emissions from the up/downstream supply chain.

Figure 22 shows the same carbon footprint calculation, but including the biogenic emissions, and in order to illustrate their offset, an estimate of the upstream carbon sink of the photosynthesis process is included. Due to inconsistent dataset use, the result is not exactly the same as for the 'fossil only' calculation (0.54, c.f. 0.50 kgCO2e/LA). This figure illustrates that no double counting has taken place in the previous calculation, since downstream direct emissions from biomethane (B) combustion are approximately offset against upstream photosynthesis, while in alignment with the assumptions made in the methodology, we still avoid the use of natural gas from the grid. This is also an illustration that greater decarbonisation is possible by targeting biogenic carbon sources for biomethanation.

Carbon footprint sensitivity follows a similar relative pattern to both previously investigated industrial processes, with the carbon intensity of the electricity grid and the % biomethane (B) in the natural gas grid being by far the most influential sensitivity variables considered.

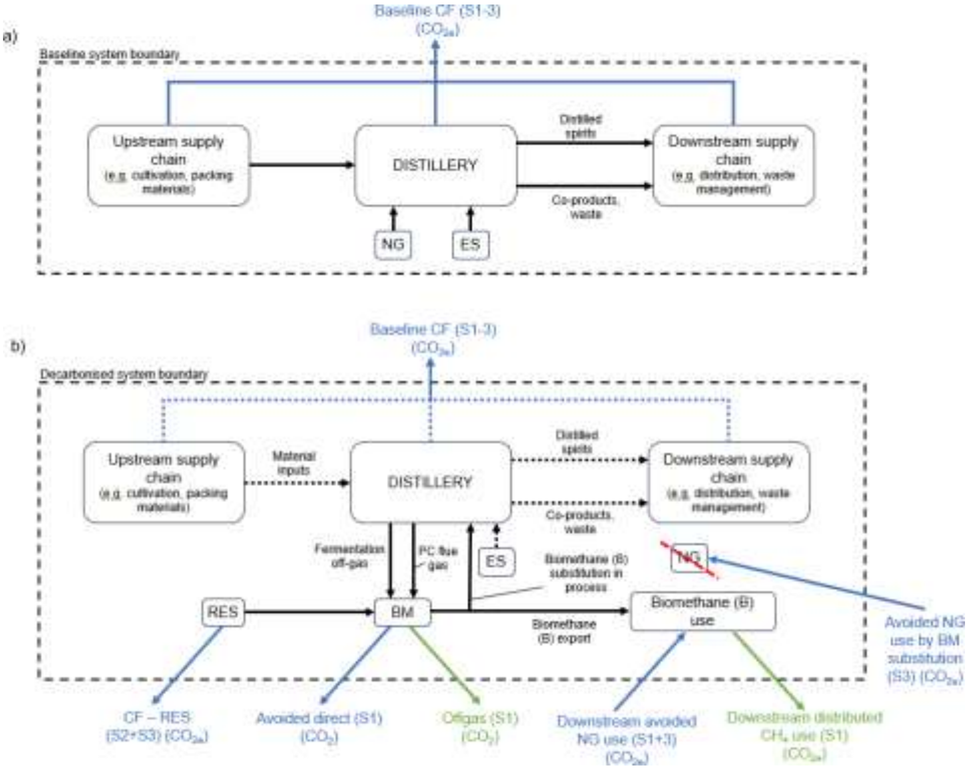


*Figure 20 Distillery baseline (a) and decarbonised (b) carbon footprints showing summary of calculation of additional produced and avoided emissions. (CF – carbon footprint, NG – natural gas, ES – electricity supply, RES – Renewable electricity supply, BM – biomethanation, PC – post-combustion, B – biogenic, F - fossil). Black arrows are material/energy flows, blue arrows are fossil GHG emissions, green arrows are biogenic GHG emissions. Dashed arrows represent unchanged flows from the baseline process*

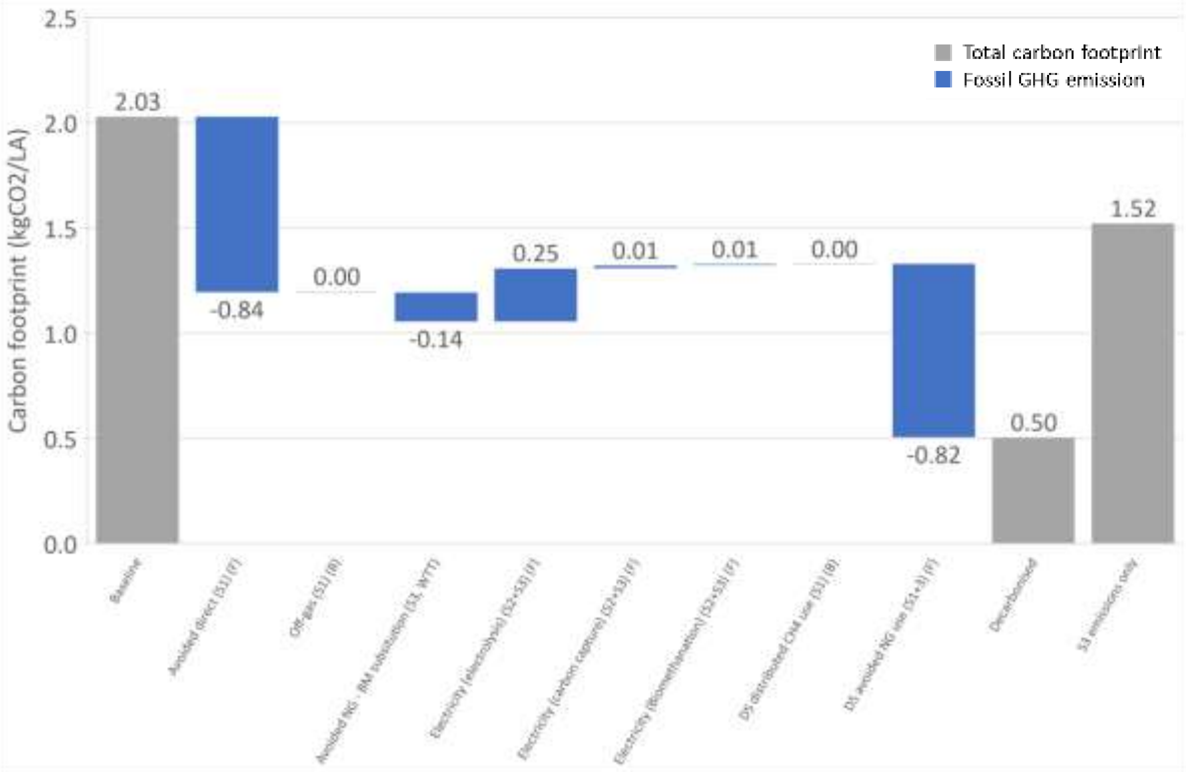


*Figure 21 Distillery carbon calculation showing baseline and decarbonised scenario carbon footprint including only fossil and non-$CO_2$ biogenic emissions (LA – litre of alcohol, NG – natural gas, T&D – transmission and distribution, BM – biomethanation, DS - downstream)*

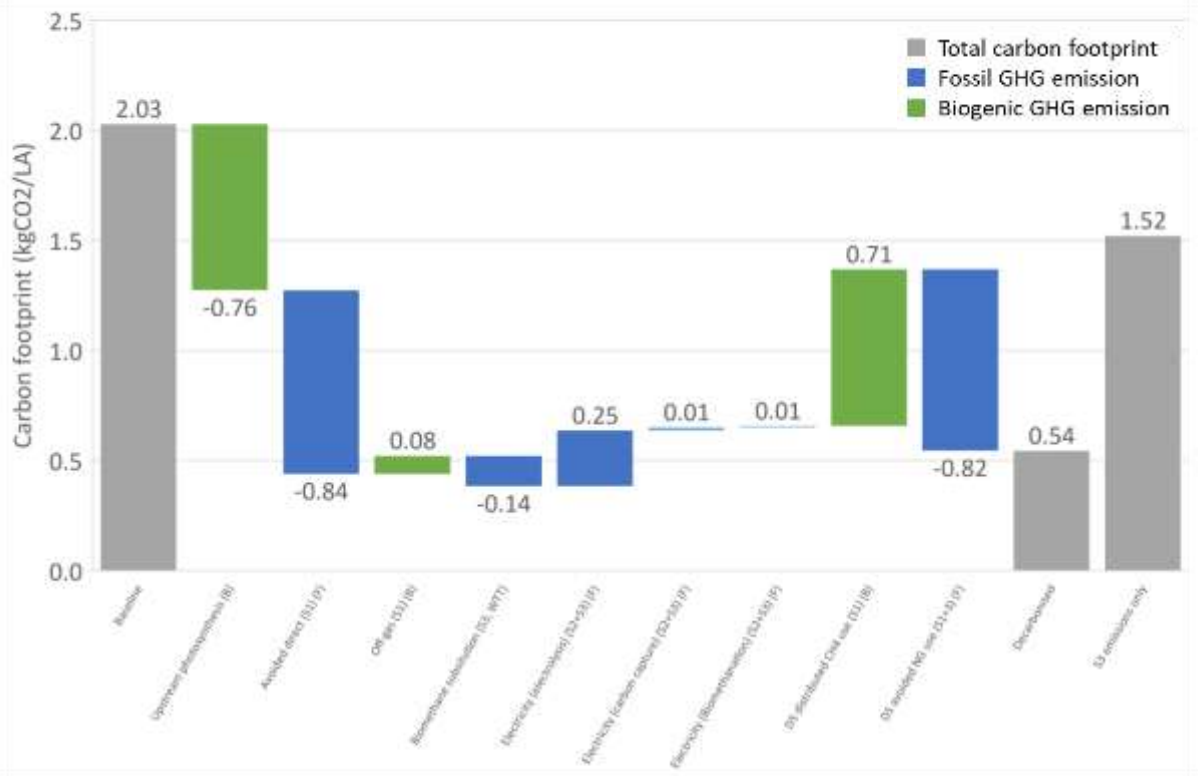


*Figure 22 Distillery carbon calculation showing baseline and decarbonised scenario carbon footprint showing fossil and biogenic emissions (including upstream photosynthesis) (LA – litre of alcohol, NG – natural gas, T&D – transmission and distribution, BM – biomethanation, DS - downstream)*

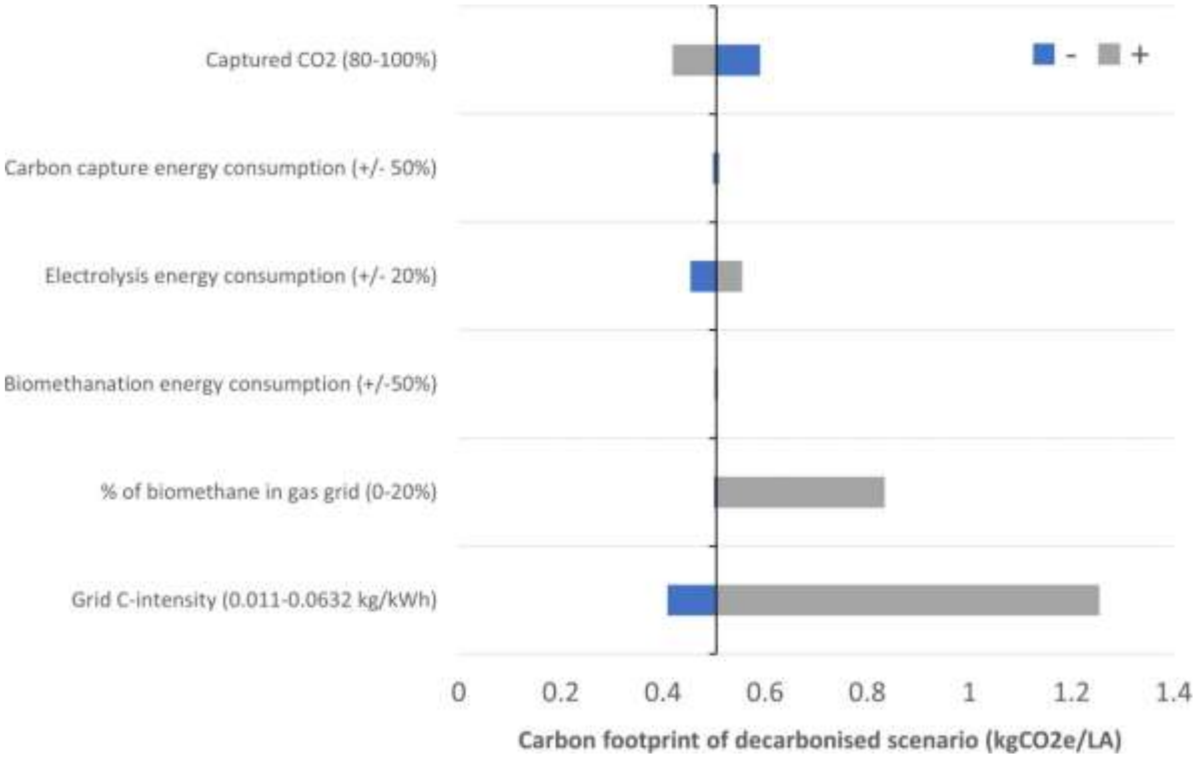


*Figure 23 Sensitivity analysis of the calculated carbon footprint for the decarbonised distillery scenario (LA – litre of alcohol)*

### 3.3.3 Distillery economics

Additional costs (Figure 24) are modest compared with cement and steel, with the production cost of the decarbonised process calculated at £4.69/LA, a modest 36% increase. This is mainly a consequence of higher relative baseline production costs per unit production, which in turn contributes to a much higher market price. For direct comparison, £3.44 is £4.35/kg, compared with £0.055/kg for cement. Best- and worst-case scenarios put production costs as £3.93-£4.69/LA. As for all other process, additional costs are dominated by the cost of hydrogen, 90% of the additional cost and, as before, the sensitivity analysis (Figure 25) show the hydrogen cost and biomethane revenue to be the most influential sensitivity variables explored.

For this scenario, since the biomethane is biogenic it would be justified to assume it could command a higher sale price compared with its fossil equivalent. However, robust data on the sale price of biomethane relative to natural gas is difficult to obtain and is distorted by economic subsidies and policy support around the world. Rather than avoiding this issue, an indicative analysis has been performed exploring the scenario where this biomethane (B) was grid injected as part of the UK Green Gas Support Scheme (GGSC), and while the described facility may not be eligible for support through the scheme (which is focused on AD based biomethane), the produced biomethane (B) does meet the sustainability criteria set out by the government (<24 $gCO_{2e}$/MJ) which can be calculated as 18.3 $gCO_{2e}$/MJ despite that this calculation includes the carbon footprint of the distilled spirits production as well. The GGSC has a three-tier tariff as follows (last publication 1/10/23):

- Tier 1: Up to 60,000 MWh per year – 6.09p/kWh
- Tier 2: the next 40,000 MWh per year – 3.90p/kWh
- Tier 3: above 100,000 MWh up to 250,000 MWh per year – 3.45p/kWh

Above this threshold there is no support, so for this calculation it is assumed that gas above the tariff limit is sold in party with the value of natural gas (271,000 at 2.7 p/kWh).

Based on these assumptions the calculated revenue from the biomethane (B) produced increases from £0.09/LA to £0.27/LA which adjusts the estimated production cost as £4.51, an increase of 31% (c.f. 35% for the **decarbonised** scenario).

To avoid production cost increase through biomethane integration the cost of hydrogen would need to be reduced to -£5.43/MWh (i.e. produced at negative cost) or alternatively a sales price of £383/MWh for the biomethane (B), or its higher value equivalent would be needed.

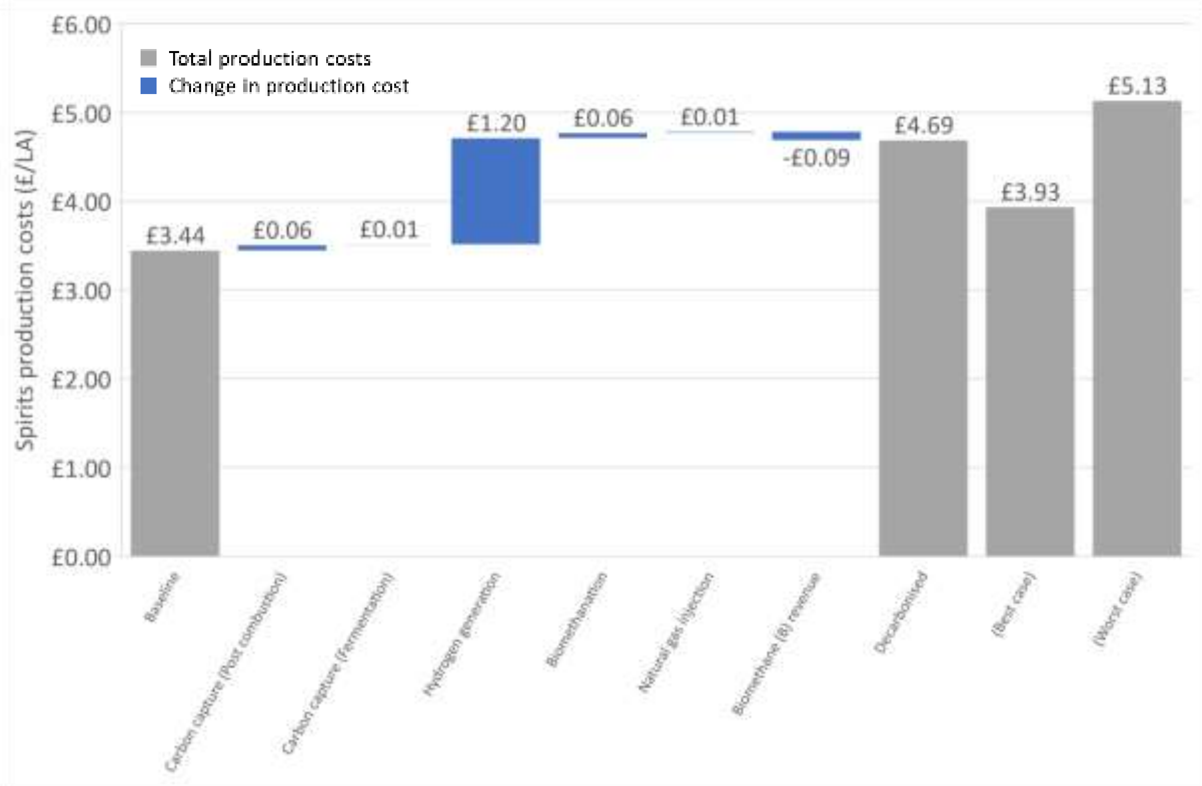


*Figure 24 Distillery economic showing baseline and decarbonised scenario production costs (LA – litre of alcohol)*

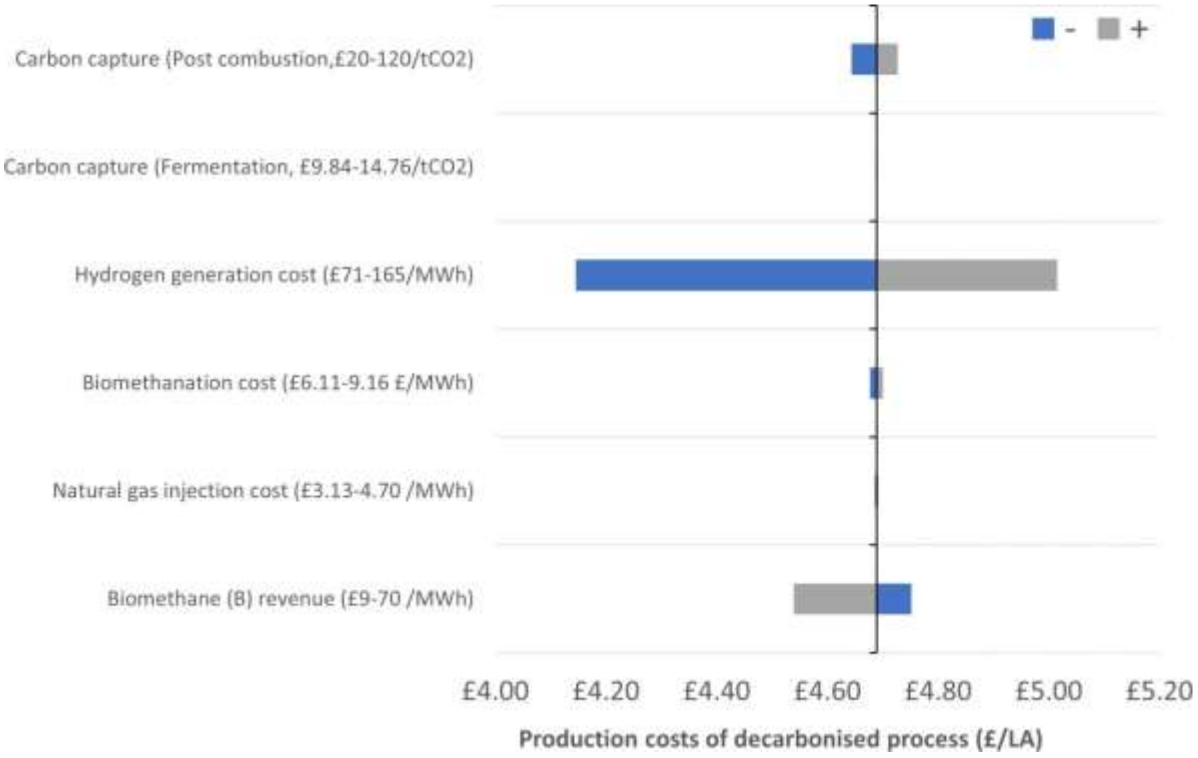
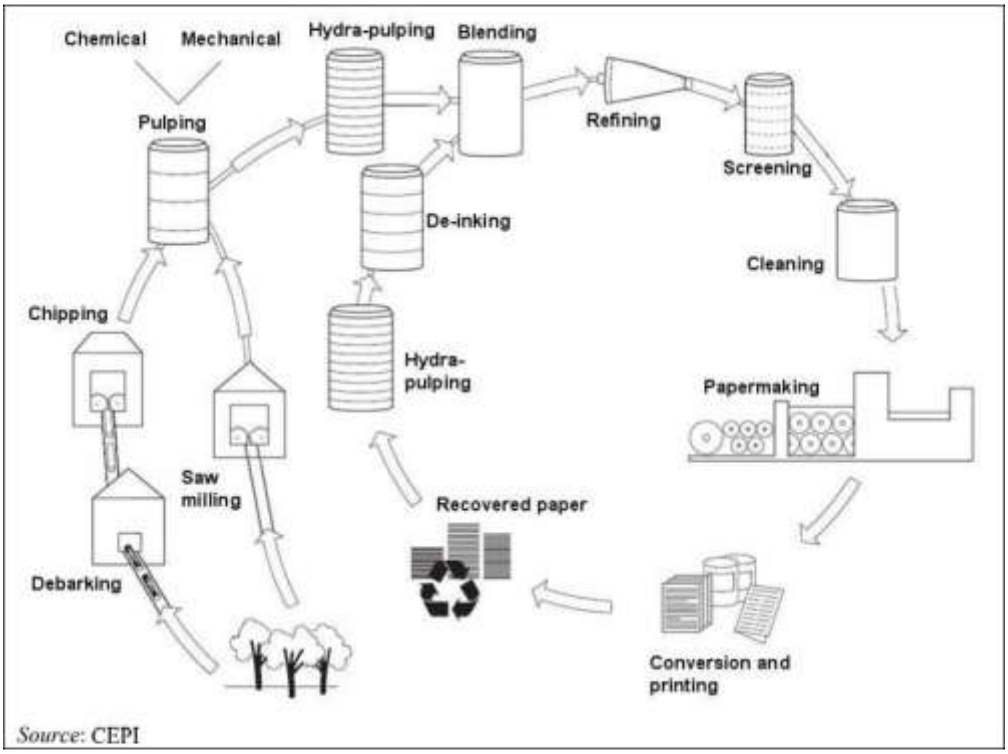


*Figure 25 Sensitivity analysis of the calculated production costs for the decarbonised distillery scenario (LA – litre of alcohol)*

## 3.4 Pulp and paper industry

### 3.4.1 Pulp and paper mass and energy balance

The pulp and paper industry involves the conversion of virgin wood, through a series of steps, to produce pulp which is then used to produce paper. Recycle paper and card are also a large source of pulp commonly used, either alone or blended with virgin pulp. A summary of the type of operations involved in paper production is shown in Figure 26. Papermills can be integrated or non-integrated depending on whether the final product is finished paper, or pulp for further processing, and there are several main types of pulp mill including mechanical, semi-chemical, fully chemical (sulphite and sulphate). According to 2008 data European paper production is dominated by the sulphate process (known as the Kraft process) with 27 out of 42 Mt of pulp production through this route (Suhr 2015).



Source: CEPI

*Figure 26 The papermaking process (Suhr 2015)*

Data for the relevant mass and energy flows for the **baseline** scenario for pulp and paper production was based on the work of Kuparinen et al. (2019) which describes a modern Nordic softwood Kraft integrated pulp and paper mill 4000 ADt/d (Air Dried ton) with mass balance values obtained from the MillFlow software. While the mass and energy data is a simplified version of the complete flowsheet for the mill, the relevant values are present, such as fluxes of $CO_2$ containing gasses from the lime kiln, recovery boiler and biomass boiler, fuel and energy requirements including electricity and natural gas inputs (only to the lime kiln) and exported electricity quantities.

Alongside natural gas, the energy demands of the integrated mill are satisfied through onsite cogeneration which supplies steam and electricity, fueled by biomass residues of the process steps. Since the mill is energy self-sufficient (except for natural gas input to the lime kiln), the majority of direct emissions are biogenic (100% from biomass and recovery boiler, and 64% from the lime kiln). It was assumed that excess steam from the process was exported for use elsewhere, but this was not specified in the data source.

Development of the **decarbonised** process (Figure 28) involved diversion of all three flue-gasses to carbon capture and biomethanation. Biomethane (B) was used to replace natural gas used in the lime kiln (3% of total), with the balance being exported (97%), a consequence of which is that all produced biomethane under regular operation (i.e. ignoring start-up requirements) was biogenic in origin, with the source-carbon originating in the wood feedstock. Excess steam and electricity, rather than being exported, were used to satisfy part of the demand of the carbon capture process (19% and 5% respectively), with the balance being met by externally sourced renewable energy. The mass and energy balance of the biomethanation subsystems is shown in Figure 29 noting that the required install electrolyser is 4930 MW to service the needs of the distillery with the electrolyser, carbon capture and biomethanation reactor consuming 91%, 7% and 2% respectively of the renewable electricity supplied to the decarbonised process.

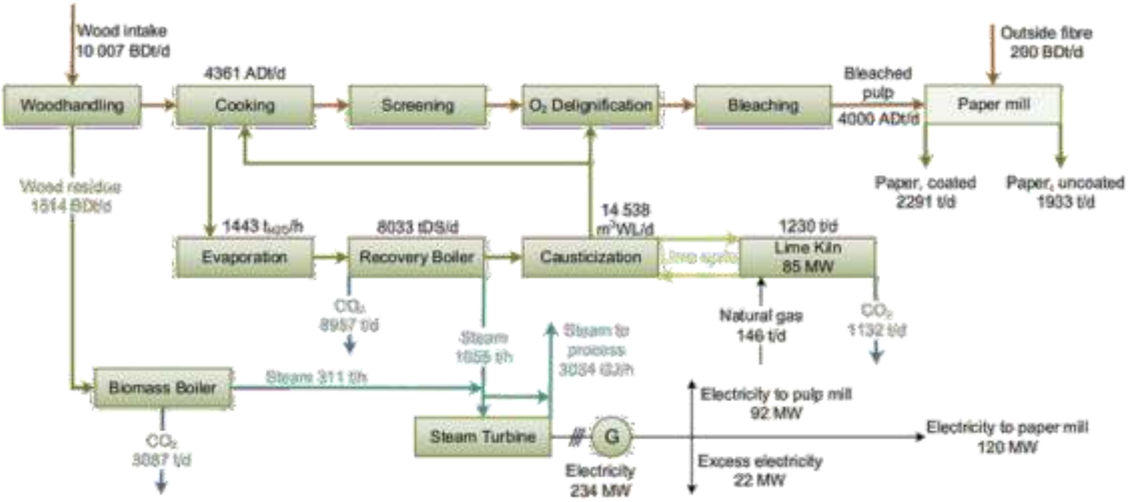


*Figure 27 Simplified process flow diagram of an integrated softwood kraft pulp mill located in Northern Europe. The values are given on hourly (h) or daily (d) basis. (ADt - air-dried ton, BDt - bone-dry ton, DS - dry solids, and WL - white liquor) (Kuparinen et al. 2019)*

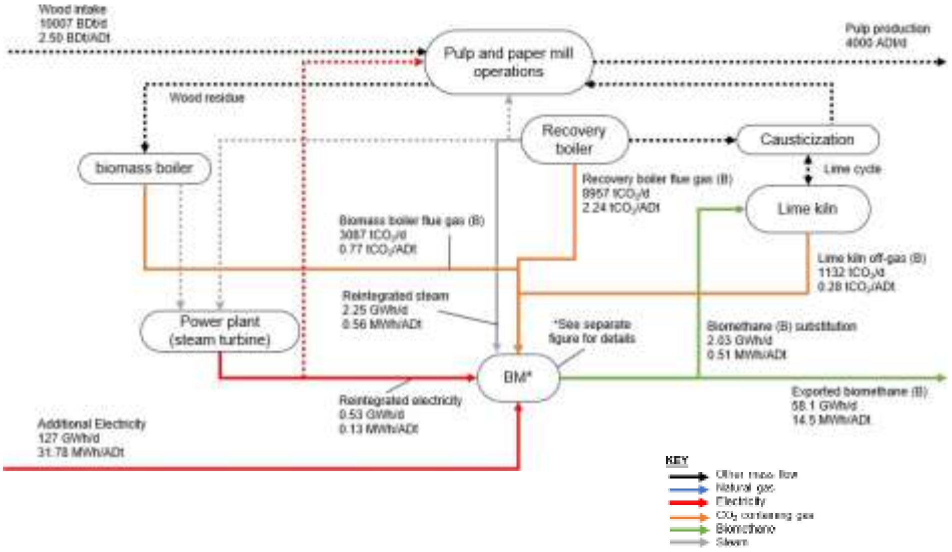


*Figure 28 Relevant mass and energy balance values for pulp and paper production process showing biomethanation integrated/decarbonised scenario. Dashed arrows represent unchanged flows from the baseline process. Values are quoted as daily mass/energy (/d and per Air-dried ton (/ADt) production. (B – Biogenic GHG flows)*

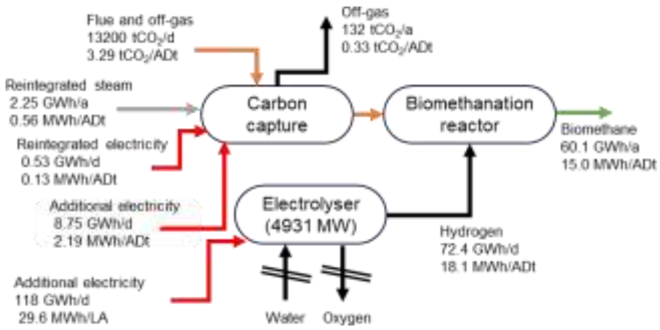


*Figure 29 Mass and energy balance of the biomethanation process for the pulp and paper decarbonised scenario*

### 3.4.2 Pulp and paper carbon footprint

The carbon footprint of the **baseline** and **decarbonised** processes are shown in Figure 30 and the cradle-to-gate carbon footprint was chosen as 950 $kgCO_{2e}/ADt$ (Sun et al. 2018). The discussion surrounding biogenic biomethane (B) for the **decarbonised** distillery scheme, as well as discussion of which emissions should be included in the calculation (only fossil and non-$CO_2$ biogenic) is equally relevant here since all of the direct and downstream emissions become biogenic through displacement of natural gas with biomethane (B).

As per the distillery assessment, two version of the carbon footprint calculation are presented firstly without (Figure 31) and then with (Figure 32) the biogenic CO2 emission source and sinks included. Emissions reductions are dominated by the downstream substitution for natural gas, appreciable additional emissions coming from the renewable electricity consumed by the electrolysis process. The final carbon footprint of the **decarbonised** scenario was calculated as -1915 $kgCO_{2e}/ADt$. As mentioned in section 2.4.2 this negative value does not represent an absolute (net) carbon removal from atmosphere, since all carbon taken from atmosphere by photosynthesis is eventually emitted and none is subject to long term storage. The negative value should instead be interpreted as the total carbon emission avoided in the broader economy (through the substitution of natural gas downstream) per ton of production.

Figure 32 shows the carbon footprint calculation including biogenic emissions including an estimate of the upstream carbon sink of the photosynthesis. Similar to the distillery scenario, inconsistent data was used for the 'fossil only' and 'fossil + biogenic' calculations meaning there is a discrepancy in the eventual carbon footprint (-1815, c.f. -1915 $kgCO_{2e}/ADt$). Carbon footprint sensitivity follows a similar relative pattern to both previously investigated industrial process, with the carbon intensity of the electricity grid and the % biomethane (B) in the natural gas grid being by far the most influential sensitivity variables considered. However, the % of carbon captured (80-100%) becomes more significant due to the quantity of $CO_2$ emitted (biogenic) relative to the **baseline** carbon footprint.

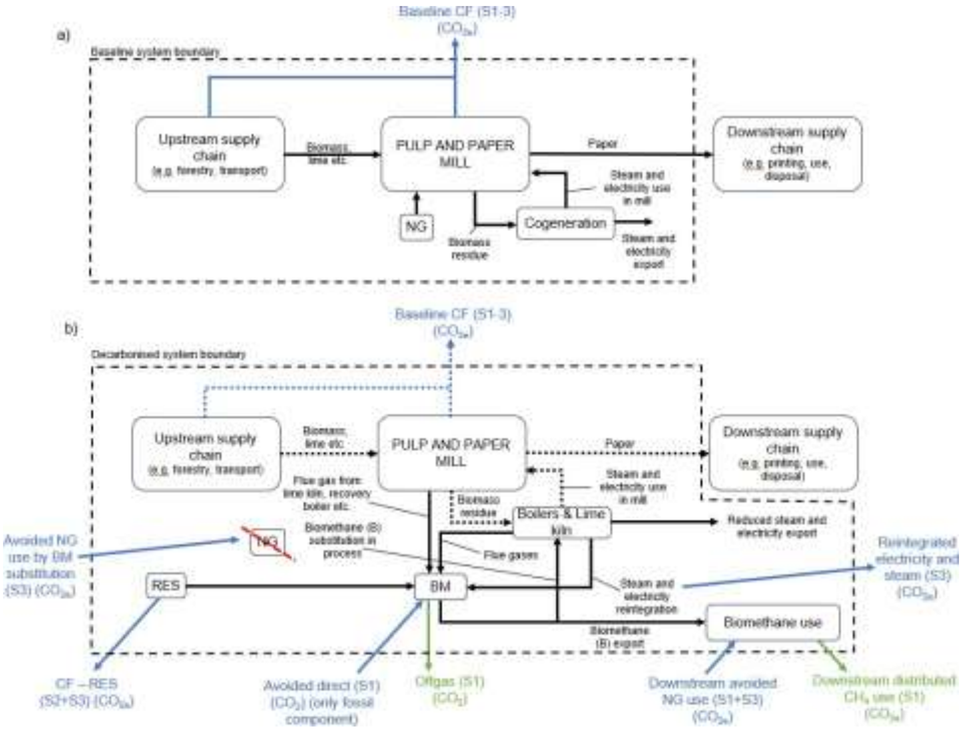


*Figure 30 Pulp and paper production baseline (a) and decarbonised (b) carbon footprints showing summary of calculation of additional produced and avoided emissions. (CF – carbon footprint, NG – natural gas, RES – Renewable electricity supply, BM – biomethanation, B – biogenic, F - fossil). Black arrows are material/energy flows, blue arrows are fossil GHG emissions, green arrows are biogenic GHG emissions. Dashed arrows represent unchanged flows from the baseline process*

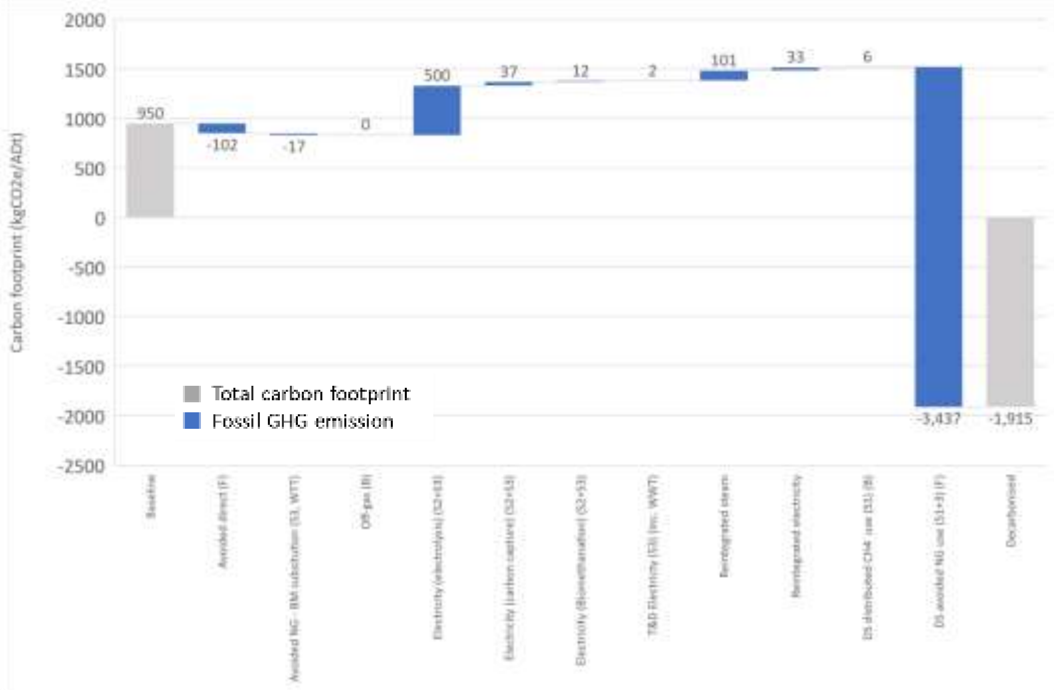


*Figure 31 Pulp and paper carbon calculation showing baseline and decarbonised scenario carbon footprint including only fossil and non-$CO_2$ biogenic emissions (NG – natural gas, T&D – transmission and distribution, BM – biomethanation, ADt – air-dried ton, DS - downstream)*

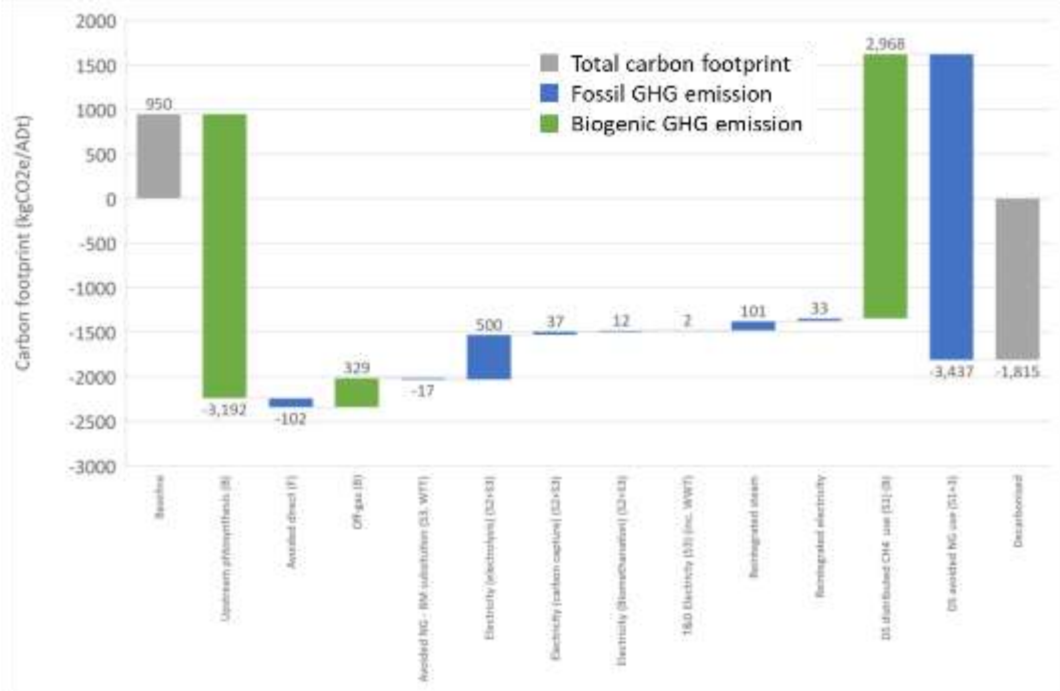


*Figure 32 Pulp and paper carbon calculation showing baseline and decarbonised scenario carbon footprint showing fossil and biogenic emissions (including upstream photosynthesis) (ADt – air-dried ton, NG – natural gas, T&D – transmission and distribution, BM – biomethanation, DS - downstream)*

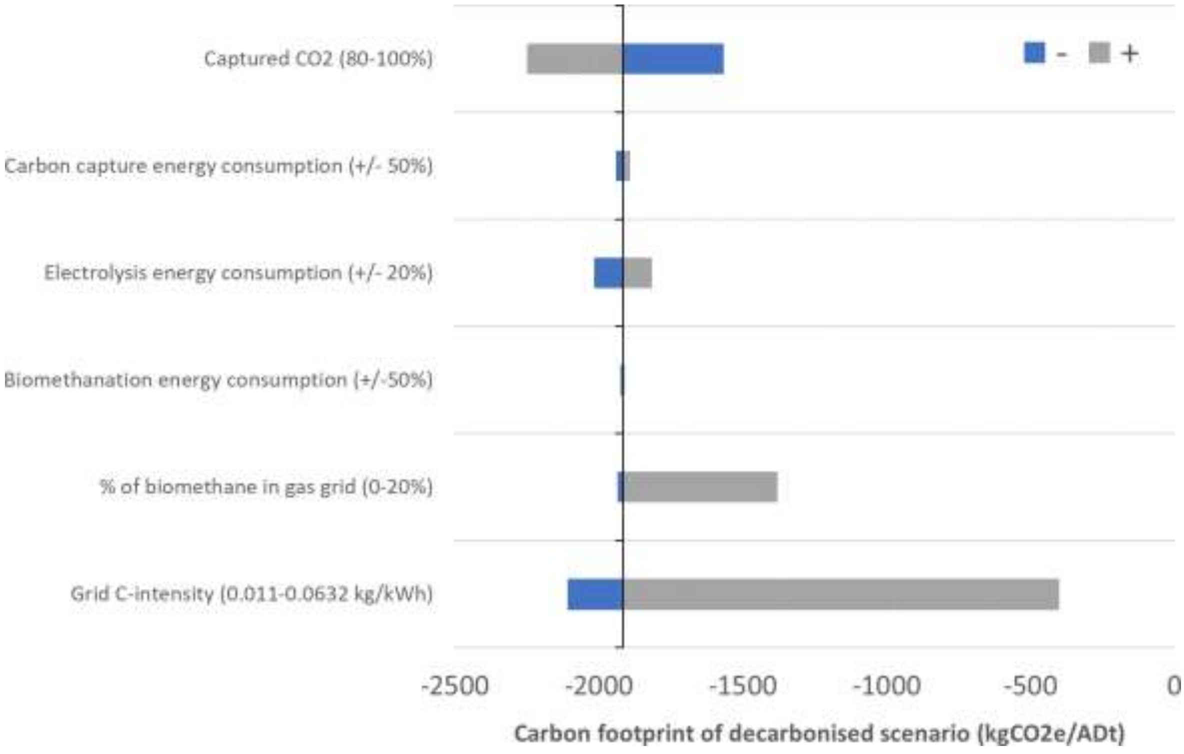


*Figure 33 Sensitivity analysis of the calculated carbon footprint for the decarbonised pulp and paper scenario (ADt – air-dried ton)*

### 3.4.3 Pulp and paper economics

Baseline production cost of paper production were estimated as €500.3/$t_{paper}$ (CEPI 2018), approximately equivalent to £395/ADt (1.06 $t_{paper}$/ADt (Kuparinen et al. 2019), £1:€1.2). On this basis the additional costs were calculated, and a summary of the economic analysis is shown in Figure 34. Decarbonised production costs were calculated as £2609 /ADt, an increase of 561%. The best- and worst-case estimates were £863-3563/ADt corresponding to a range of 118-802% cost increase. As per other scenarios, additional costs for the decarbonised scenario are dominated by the cost of electrolysis.

In the distillery economic calculations, the effect of a premium price for biomethane (B) was explored due to its biogenic carbon source. Applying the same analysis to the pulp and paper scenario would make little difference since the total biomethane production is 22 million MWh/a whereas the GGSC only allows support up to 250,000 MWh/a so this was not thought appropriate. As per previous industries considered, the sensitivity analysis (Figure 35) reveals hydrogen production costs and biomethane sales to be the most influential variables, which is expected as this are the largest contributors the variation in production costs.

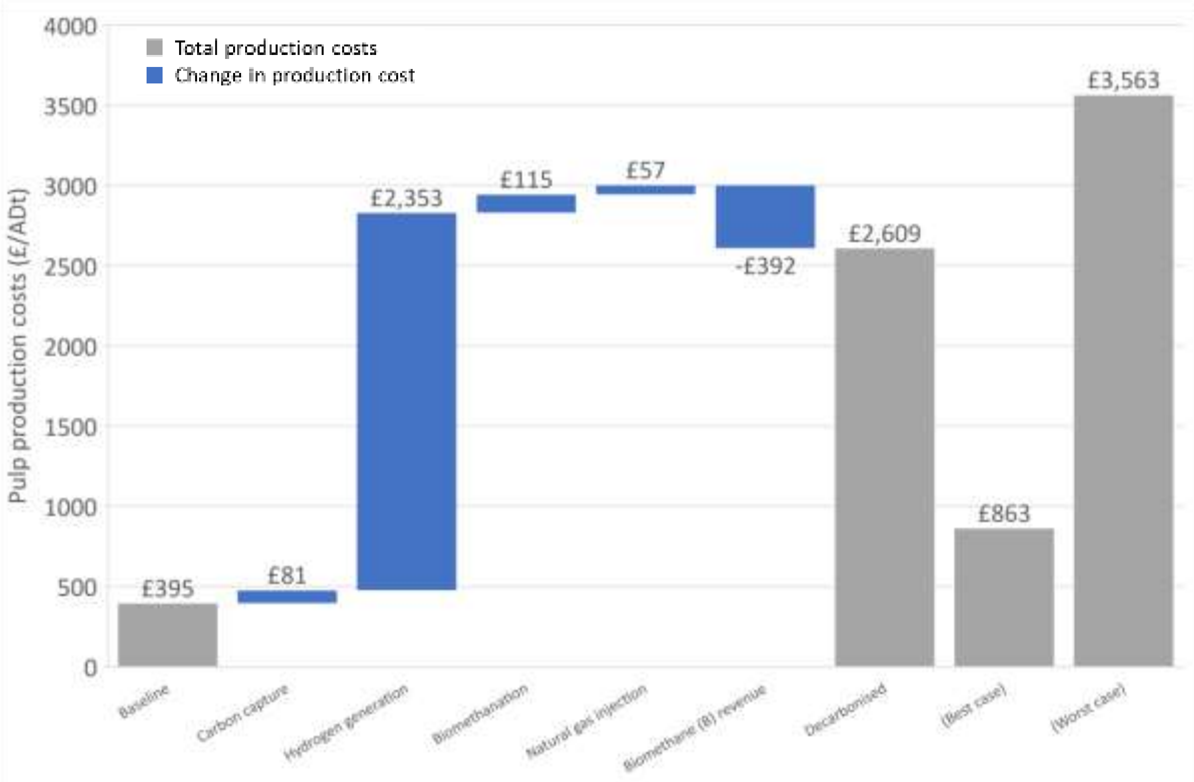


*Figure 34 Pulp production economics showing baseline and decarbonised scenario production costs (ADt – air-dried ton)*

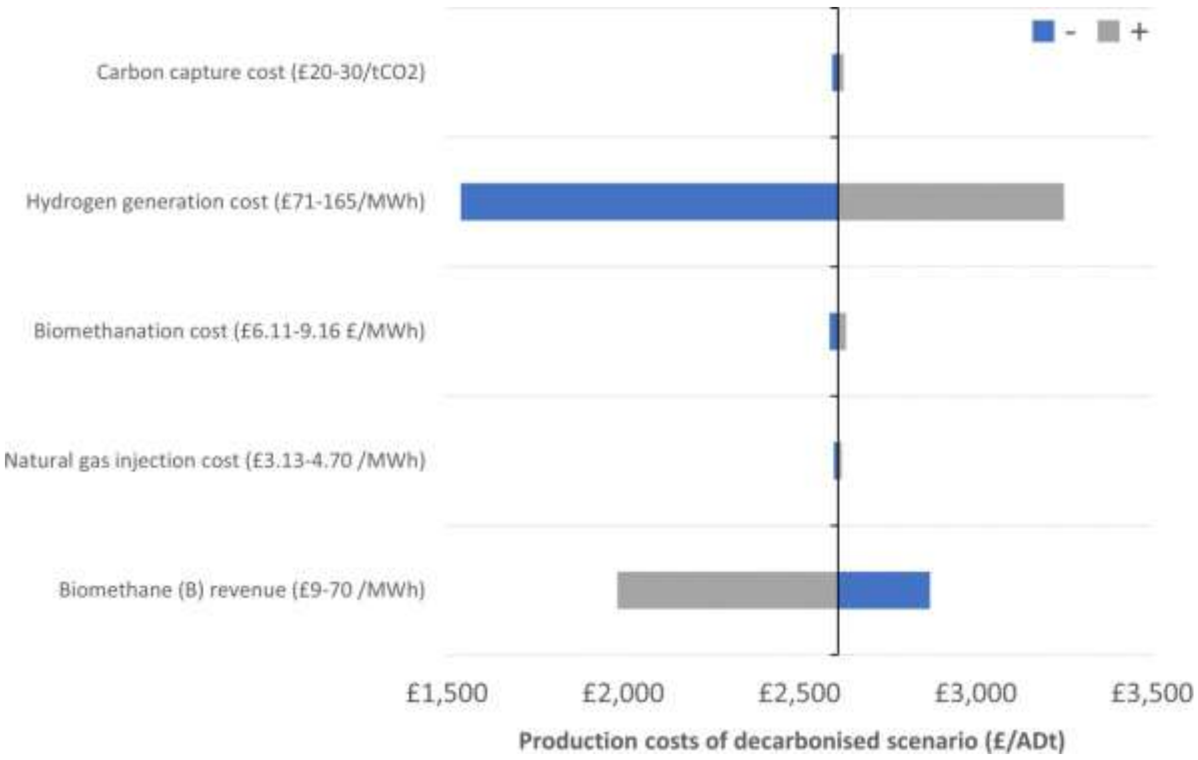


*Figure 35 Sensitivity analysis of the calculated production costs for the decarbonised pulp and paper scenario (ADt – air-dried ton)*

## 3.5 Ammonia production

Ammonia is the chemical building block for all mineral nitrogen fertilizers, including urea. 70% of global production is used for fertilisers alongside other industrial applications. Around 70% of ammonia is produced from natural gas with the balance coming from coal gasification (IEA 2021). A simplified process schematic of a typical methane-fed ammonia production process is shown in Figure 36(a) and while several successful commercial variants of the process exist, the underlying reactions are the same.

Despite the ammonia production process being identified as a potential candidate for decarbonisation through biomethanation integration, hydrogen is the desired feedstock to the Haber-Bosch process, which would require the continued operation of steam methane reforming (SMR), water gas shift (WGS) and pressure swing absorption (PSA) parts of the process to produce these from biomethane rather than natural gas as shown in Figure 36(b). However, a much simpler scheme would be to directly feed hydrogen (produced from the same electrolysis process) to the Haber-Bosch system, avoiding the requirements for SMR, WGS, PSA and reducing the required installed size of the electrolyser as an added bonus (Figure 36(c)). The direct integration of electrolysis with the Haber-Bosch reactor would not incur inherent losses in the biomethanation reaction (83% of LHV contained in the original $H_2$ is present in the $CH_4$) as well as efficiency losses at every stage due to parasitic energy demands, thermal losses etc.

On this basis it was decided not to continue this investigation into ammonia decarbonisation and therefore no carbon footprint or economic analysis were performed.

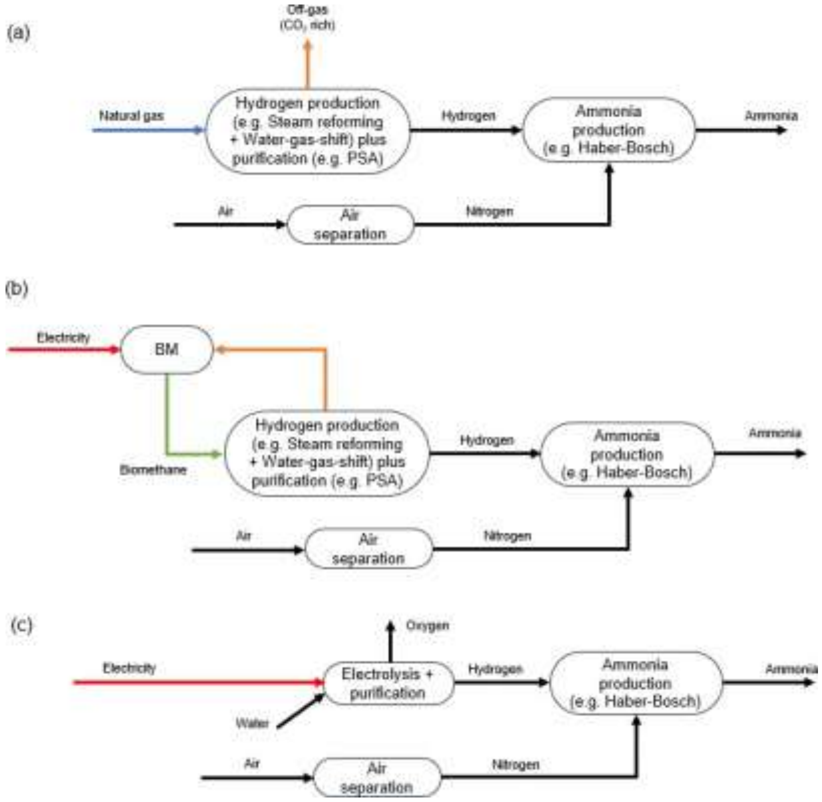


*Figure 36 (a) An example of a simplified ammonia production process, (b) integrated with biomethanation, and (c) with the hydrogen generation process replaced with electrolysis. ((b) will always consume more electricity per unit ammonia than (c) due to energy lost in BM process and efficiency losses across multiple processing steps).*

## 3.6 Summary of results and comparison of decarbonised scenarios

*Table 15 Summary of results for all industries considered (B – Biogenic, F – Fossil, LS – liquid steel, LA – litre alcohol, ADt – Air dried ton)*

| Industry | **Baseline or Decarbonised** | **Carbon footprint** | **Fossil (F) or Biogenic (B) direct emissions (F:B)** | **Biomethane export** | **Additional (renewable) electricity requirement** | **Production cost Nominal case (best case)** |
|---|---|---|---|---|---|---|
| Cement | Baseline | 870 kgCO$_{2e}$/t$_{Clinker}$ | Fossil | - | - | £55/ t$_{clinker}$ |
|  | Decarbonised | 166 kgCO$_{2e}$/t$_{Clinker}$ | Fossil | 69% | 1070 MW for 125 t$_{clinker}$/hr | £644/ t$_{clinker}$ (£237/ t$_{clinker}$) |
| Steel | Baseline | 2200 kgCO$_{2e}$/tLS | Fossil | - | - | £326/tLS |
|  | Decarbonised | 1455 kgCO$_{2e}$/tLS | Fossil | 78% | 5200 MW for 5.3 MtLS/a | £919/tLS (£469/tLS) |
| Distillery | Baseline | 2.03 kgCO$_{2e}$/LA | Mixed (52:48) | - | - | £3.44/LA |
|  | Decarbonised | 0.50 kgCO$_{2e}$/LA | Biogenic | 45% | 113 MW for 61 MLA/a | £4.69/LA (£3.93/LA) |
| Pulp and paper | Baseline | 950 kgCO$_{2e}$/ADt | Mixed (3:97) | - | - | £395/ADt |
|  | Decarbonised | -1915 kgCO$_{2e}$/ADt | Biogenic | 97% | 5410 MW for 4000 ADt/d | £2609/ADt (£863/ADt) |

A selection of results from the four different industries considered are shown in Table 15.

Focusing on the decarbonisation results, two main factors appear to strongly influence the degree of decarbonisation that is possible using biomethanation. Firstly, processes where a large fraction of the baseline carbon footprint is from direct emission of $CO_2$ containing gases (Cement, pulp and paper) are more deeply decarbonised since the majority of the carbon reductions come from capture of these gases and downstream displacement of natural gas. For steel and distillery industries, a much larger fraction of the emissions are indirect (supply chain) or non-point sources, which could limit the decarbonising effect of biomethanation integration. Secondly, targeting biogenic carbon sources offers a greater degree of decarbonisation since there is a direct replacement of a fossil fuel with a biofuel downstream. In both cases studies (distillery, pulp and paper), the input of biogenic carbon allows all direct fossil emissions to be replaced with biogenic emissions.

As described in section 2.6, a series of performance metrics were proposed to allow internal and external (e.g. with different decarbonisation options for specific industries) comparison of the decarbonisation scenarios.

- **Product decarbonisation** is strongly influenced by the direct avoidable emissions and further enhanced by the produced biomethane being biogenic and substituting for fossil natural gas.
- **Global decarbonisation potential** is driven by the disparity of the global production quantities of the industries considered, with cement and steel providing the greatest opportunity due to being produced in larger quantities.

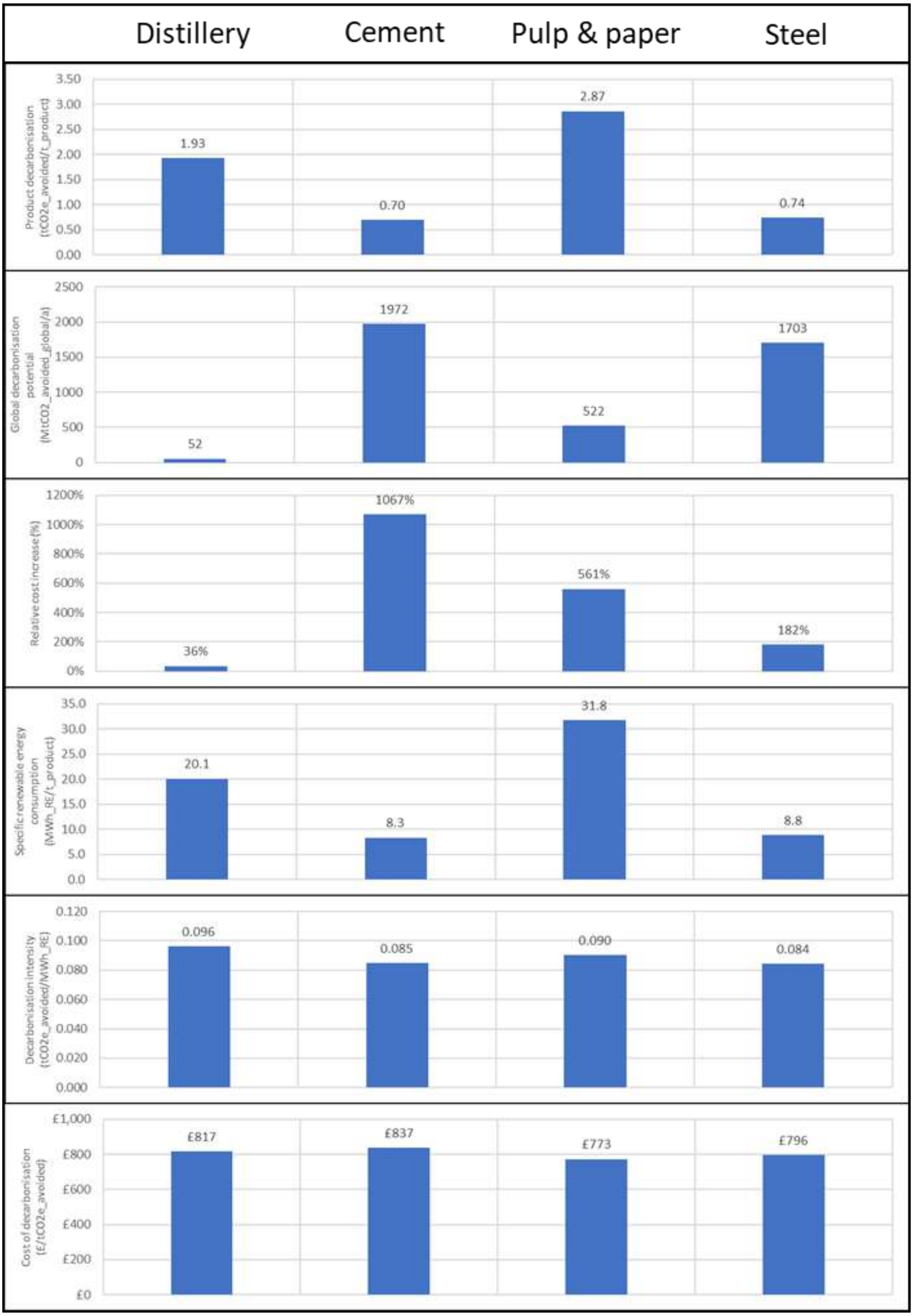


*Figure 37 Overall performance metrics of the integrated scenarios for the four industries considered*

- **Relative cost increase (%)** varies considerably (36-1067%) between the studied industries, mainly due to the different baseline production relative to the direct emissions. Additional costs were mainly influenced by hydrogen production costs, which were proportional to the $CO_2$ emitted directly from the **baseline** process, but the $CO_2$ emitted per unit production cost was highly variable between the scenarios.
- **Specific renewable energy consumption** was strongly driven by the quantity of $CO_2$ directly emitted in the baseline scenario since renewable energy was used to satisfy the energy demand of the carbon capture, electrolysis and biomethanation reactor, which all operated (approximately) in proportion to the available $CO_2$.

The final two performance metrics, **decarbonisation intensity** and **cost of decarbonisation**, allow the considered scenarios to be put in a broader context. Both metrics vary little between the considered scenarios since the carbon reduction through biomethanation depend mainly on the direct $CO_2$ emissions available for conversion, and costs associated with the technologies were considered using fixed unit costs for all system elements. A biogenic carbon source results in a higher decarbonisation intensity (0.090-0.096 $t_{CO2e(avoided)}$/MWh) compared to a fossil carbon one (0.084-0.085 $t_{CO2e(avoided)}$/MWh).

Calculated values of **decarbonisation intensity** could be compared with other uses of renewable electricity for decarbonization, for example, direct electrification of the considered industries or even direct usage. If the latter is considered, currently the substitution of 1 MWh of renewable electricity, provided by onshore wind (0.011 $gCO_{2e}$/kWh) for the same energy provided by the UK electricity grid (aggregated, 0.253 $gCO_{2e}$/kWh ) results in a **decarbonisation intensity** of 0.242 $t_{CO2e(avoided)}$/MWh (0.2530 - 0.0110). If correct this would indicate that it would be more beneficial, purely from a decarbonisation perspective, to prioritise direct use of renewable energy compared to technologies such as biomethanation. Indeed, this agrees with the generalised analysis done by SAPEA (2018) which recommends that decarbonisation using CCU e.g. via electrofuels should only be done after near-complete decarbonisation of the electricity system since it will inherently be less efficient than direct use of renewable energy, for which they suggest 2050 is a realistic timescale.

**Cost of decarbonisation** was calculated as £773-837/$tCO_{2e}$ across the scenarios explored. This metric can be used to compare decarbonisation options, but also can be related to carbon markets or more generally the value assigned to decarbonisation by society. For example, UK government guidance suggests that in 2024, a carbon value of £269/$tCO_{2e}$ (range 134-403) (GOV UK 2023) be used for valuation of greenhouse gas emissions. It is clear from these figures that a huge challenge of biomethanation will be its associated costs. However, one obvious solution to this would be to target a higher value product than methane that can be produced from hydrogen and carbon dioxide which will be of particular interest to the Carbon Recycling Network.

# 4 Conclusions

The study explored the options for integration of biomethanation with carbon intensive process industries for decarbonisation. Initially five industries were considered: Cement, steel, distillery, pulp and paper and ammonia. After initial flowsheet development, ammonia was excluded from the analysis on the basis that direct integration of the Haber-Bosch process with hydrogen generation through electrolysis would make more sense than converting hydrogen to methane, and then back to hydrogen again.

For the other four industries considered further, it was found that biomethanation can result in substantial decarbonisation, ranging from 0.70-2.87 $tCO_{2e}/t_{product}$. The **baseline** and **decarbonised** carbon footprints of the four industries were 870 $kgCO_{2e}/t_{Clinker}$ and 166 $kgCO_{2e}/t_{Clinker}$, 2200 $kgCO_{2e}$/tLS and 1455 $kgCO_{2e}$/tLS, 2.03 $kgCO_{2e}$/LA and 0.50 $kgCO_{2e}$/LA, 950 $kgCO_{2e}$/ADt and -1915 $kgCO_{2e}$/ADt for cement, steel, distillery and pulp and paper respectively.

The largest contribution to the decarbonisation effect of these integrated scenarios was that biomethane was used both internally and by downstream users, replacing the demand for natural gas (predominantly fossil) in the process and broader market. For industries where the carbon source was biogenic this effect was more pronounced such that decarbonisation via biomethanation could be more effective than direct electrification (i.e. removal of direct fossil GHG emissions).

Sensitivity analysis in all cases showed that the decarbonisation potential relied heavily on the use of the lowest carbon electricity available from renewable sources (e.g. wind) to provide the large quantities of energy required by electrolysis and carbon capture processes, and also that capturing the largest fraction of the available carbon resulted in a greater degree of decarbonisation. In comparison, the energy efficiency of the major biomethanation system components has a relatively small effect. Despite promising results in terms of predicted decarbonisation, net-zero emissions cannot be approached by these industries by biomethanation alone, as when viewed from the point of view of absolute emissions (i.e. excluding substitutions) the downstream combustion of biomethane results in the final emission of the carbon that was captured as part of the biomethanation process.

Based on nominal values for increased costs and additional revenue streams, the economic assessment predicted large cost increases decarbonisation of cement (1070%), pulp and paper (561%) and steel (182%) although these were much more modest for the distillery scenario (37%). Best case analysis of the cost increases were 330%, 118%, 43%, 14% respectively. These additional costs were dominated by the production costs of hydrogen which are predicted to remain high into the future even where curtailed electricity is targeted. A promising way to reduce the net-cost increase would be to target a higher-value products than methane to generate additional revenue. It is important to note that any attempt of predictive economic analysis will be subject to a large degree of uncertainty, especially given energy market volatility. Values should be taken as indicative.

The four processes were compared based on several performance metrics derived from the results of the study. Two of these were of particular importance: **decarbonisation intensity** represents the degree of decarbonisation relative to the use of renewable energy and can be used to compare different application of this electricity for decarbonisation. For the processes considered this was 0.084-0.096 $tCO_{2e,avoided}$/MWh with the industries with biogenic carbon sources being slightly higher. **Cost of decarbonisation** represents the cost per unit of avoided $CO_{2e}$ and can be used to compare decarbonisation options as well as compare with other valuations placed on GHG emissions. For the processes considered this was £773-837/$tCO_{2e}$.

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# 6 Appendices

## 6.1 Appendix 1 – Mass and balance data summary tables

*Table A1 Mass and energy balance summary for cement distillery process*

| **Quantity** | Value | Unit |
|---|---:|---|
| Clinker production | 3000 | t/d |
| off-gas flow rate | 2.47E+05 | m3/h (1.2 bar,40C) |
| off-gas flow rate (STP) | 258,244.56 | m3/h |
| **Composition of off-gas** | | |
| N2 | 64.7% | % |
| CO2 | 20.4% | % |
| O2 | 8.6% | % |
| H2O | 6.2% | % |
| CO | 1330 | ppm |
| SO2 | 111 | ppm |
| NO | 474 | ppm |
| NO2 | 2 | ppm |
| CO2 flow rate | 5.27E+04 | m3/h |
| CO2 flow rate | 2,483.57 | t/d |
| Specific CO2 flow rate | 0.83 | tCO2/tClinker |
| **Carbon Capture** | | |
| CO2 captured | 2,235.22 | t/d |
| CO2 in off-gas | 248.36 | t/d |
| **Biomethanation** | | |
| Stoichiometry H2:CO2 | 4 | |
| H2 input | 1.90E+05 | m3/h |
| Specific H2 input | 135 | kg/tClinker |
| Efficiency Biomethanation | 99% | % |
| CH4 output | 46,940 | m3/h |
| CO2 output | 474 | m3/h |
| H2 output | 1,897 | m3/h |
| sum Biomethane output | 49,310 | m3/h |
| %CH4 in output | 95% | %vol |
| %CO2 in output | 1% | %vol |
| %H2 in output | 4% | %vol |
| Biomethane average LHV | 34.5 | MJ/m3 |
| Biomethane Energy output | 11,339 | MWh/d |
| **Biomethane use/export** | | |
| Required Energy input for Clinker production | 3,250.00 | MWh/day |
| Exported biomethane | 8,089.46 | MWh/day |

*Table A2 Mass and energy balance summary for steel production process*

| Quantity | Value | Unit |
|---|---|---|
| Steel production | 5.30E+06 | tLS/year |
| **(Calculated) LHV of off-gases** | | |
| COG | 18.3 | MJ/Nm3 |
| BFG | 3.0 | MJ/Nm3 |
| BOFG | 7.8 | MJ/Nm3 |
| *Natural Gas* | 36.0 | MJ/Nm3 |
| **Volumetric Flow of excess off-gases** | | |
| COG | 8.0 | Nm3/tLS |
| BFG | 989.0 | Nm3/tLS |
| BOFG | -11.3 | Nm3/tLS |
| *Natural Gas* | *21.6* | *Nm3/tLS* |
| **CO2 flows from excess off-gases** | | |
| COG | 3.3 | Nm3/tLS |
| BFG | 441.1 | Nm3/tLS |
| BOFG | -8.8 | Nm3/tLS |
| *Natural Gas* | 21.6 | Nm3/tLS |
| Total CO2 from excess off-gases | 435.6 | Nm3/tLS |
| **Carbon Capture** | | |
| CO2 captured | 392.0 | Nm3/tLS |
| CO2 off-gas | 43.6 | Nm3/tLS |
| **Biomethanation** | | |
| Stoichiometry H2:CO2 | 4 | n/n |
| H2 input | 1,568.0 | Nm3/tLS |
| Efficiency H2AD | 99% | % |
| CH4 output | 388.1 | Nm3/tLS |
| CO2 output | 3.9 | Nm3/tLS |
| H2 output | 15.7 | Nm3/tLS |
| sum Biomethane output | 407.7 | Nm3/tLS |
| CH4 Concentration | 95% | %vol. |
| CO2 Concentration | 1% | %vol. |
| H2 Concentration | 4% | %vol. |
| Biomethane average LHV | 34.5 | MJ/Nm3 |
| Biomethane Energy output | 14,054 | MJ/tLS |
| **Coal substitution at Blast Furnace** | | |
| Coal Substitution in BF | 61 | kg coal/tHM |
| Total coal Use in BF | 162 | kg coal/tHM |
| % substitution of coal with Natural gas | 38% | |
| Substitution ratio | 1.14 | kg coal/kg NG |
| tLS: Ton HM | 1.17 | t LS/ tHM |
| Calculated NG used in BF | 53.5 | kg SNG/tHM |
| **Biomethane use/export** | | |
| Natural Gas use in Steel Plant | 776 | MJ/tLS |
| Biomethane reused (NG + Coal substitution) | 3071 | MJ/tLS |
| Biomethane Exported | 10982 | MJ/tLS |

*Table A3 Mass and energy balance summary for distillery process. Source: (O'Shea et al. 2020)*

| Quantity | Value | Unit |
|---|---|---|
| **Distillery outputs** | | |
| Alcohol production | 61.126 | MOLA/a |
| Draff | 47 | ktWW/a |
| Thin stillage | 278 | ktWW/a |
| Thick stillage | 323 | ktWW/a |
| **Feed processing plant outputs** | | |
| Wet grain | 62766 | tWW/a |
| DDG | 12806 | tWW/a |
| Syrup | 41794 | tWW/a |
| **Inputs** | | |
| Natural gas | 254 | GWh/a |
| Of which natural gas to feed processing | 8.7 | GWh/a |
| Electricity | 42 | GWh/a |
| Flu gas CO2 flux | 51054 | t/a |
| **Fermentation CO2 flux calculation** | | |
| STD density of ethanol | 0.78945 | g/cm3 |
| ethanol mass flux | 4.83E+07 | kg/a |
| CO2/ethanol (fermentation) | 0.957 | kgCO2/kg_ethanol |
| Fermentation CO2 flux | 46158 | tCO2/a |
| **Carbon Capture** | | |
| CO2 captured (fossil) | 45949 | tonne/a |
| Offgas | 5105 | tonne/a |
| **Biomethanation calculations** | | |
| Stoichiometry H2:CO2 | 4 | |
| mass H2:CO2 | 0.182 | kgH2/kgCO2 |
| mass H2:CH4 | 0.500 | kgH2/kgCH4 |
| mass H2:H2O | 0.222 | kgH2/kgH20 |
| Total CO2 input | 92106 | t/a |
| %CO2 biogenic | 50.1 | % |
| H2 input | 16747 | t/a |
| Efficiency biomethanation | 99% | % |
| CH4 output | 33158 | t/a |
| CO2 output | 921 | t/a |
| H2 output | 167 | t/a |
| sum Biomethane output | 34246 | t/a |
| Molar volume | 22.4 | m3/kmol |
| CH4 output | 4.64E+07 | m3/a |
| CO2 output | 4.69E+05 | m3/a |
| H2 output | 1.88E+06 | m3/a |
| Total | 4.88E+07 | m3/a |
| % CH4 in output | 95.1 | % |
| % CO2 in output | 1.0 | % |
| % H2 in output | 3.9 | % |
| CH4 LHV | 35.8 | MJ/m3 |

| | | |
|---|---|---|
| H2 LHV | 10.8 | MJ/m3 |
| Biomethane average LHV | 34.5 | MJ/m3 |
| Biomethane Energy output | 1.68E+09 | MJ/a |
| **Biomethane used/exported** | | |
| Required Energy input to boilers | 9.14E+08 | MJ/a |
| Biomethane to boilers | 2.65E+07 | m3/a |
| Exported biomethane | 7.68E+08 | MJ/a |
| Biomethane exported | 2.23E+07 | m3/a |
| of which, methane exported | 2.12E+07 | m3/a |

*Table A4 Mass and energy balance summary for pulp and paper process. Source: (Kuparinen et al. 2019)*

| Quantity | Value | Unit |
|---|---|---|
| **Production** | | |
| Operating hours | 8400 | h/a |
| Pulp production | 4000 | ADt/d |
| Paper production | 4224 | t/d |
| **Wood handling** | | |
| Wood income | 10007 | BDt/d |
| Residue | 1541 | BDt/d |
| Wood moisture | 0.54 | |
| **Recovery boiler** | | |
| Biomass fuel use | 8033 | tDS/d |
| Net steam flow | 1055 | t/h |
| CO2 production | 8957 | t/d |
| **Biomass boiler** | | |
| Biomass fuel use | 1514 | BDt/d |
| Net stream flow | 311 | t/h |
| CO2 production | 3087 | t/d |
| **Lime kiln** | | |
| Lime production | 1230 | t/d |
| Make-up limestone | 60 | t/d |
| Heat requirement | 85 | MW |
| Fuel consumption (natural gas) | 146 | t/d |
| CO2 production | 1132 | t/d |
| Share of Biogenic CO2 | 64 | % |
| **Energy** | | |
| Power generation | 1406 | kWh/ADt |
| Power consumption, pulp mill | 552 | kWh/ADt |
| Power consumption, paper mill. | 681 | kWh/ADt |
| Power produced in the mill | 234 | MW |
| Power consumed in the pulp mill | 92 | MW |
| Power consumed in the paper mill | 120 | MW |
| Excess power generated | 22 | MW |
| Total Steam flow in the mill | 1366 | t/h |
| Steam use, pulp mill | 813 | t/h |
| Steam use, paper mill | 401 | t/h |

|  |  |  |
|---|---:|---|
| Unused steam | 152 | t/h |
| Energy equivalent of the steam used | 3034 | GJ/h |
| **Flue gas** |  |  |
| Total CO2 production | 13176 | t/d |
| **Steam energy calculation** |  |  |
| Energy content of the steam (Enthalpy) | 2.22 | MJ/kg |
| Steam energy used in the pulp mill | 1.81E+06 | MJ/h |
| Steam energy used in the paper mill | 8.91E+05 | MJ/h |
| Unused steam | 3.38E+05 | MJ/h |
| Total steam energy used in the integrated mill | 2.70E+06 | MJ/h |
| Biomethane equivalent | 8903 | m3/h |
| Total energy required in the pulp mill | 2.44E+06 | MJ/h |
| Total energy required for the paper mill | 1.32E+06 | MJ/h |
| **Carbon capture** |  |  |
| CO2 captured | 11858 | t/d |
| CO2 captured (Fossil) | 408 | t/d |
| **Biomethanation** |  |  |
| Stoichiometry H2:CO2 | 4 | n/n |
| Efficiency AD | 99% | % |
| CH4 Output | 2.49E+05 | m3/h |
| CO2 output | 5.03E+03 | m3/h |
| H2 output | 1.01E+04 | m3/h |
| Biomethane output | 2.64E+05 | m3/h |
| %CH4 in output | 94% | % |
| %CO2 in output | 2% | % |
| %H2 in output | 4% | % |
| CH4 LHV | 35.8 | MJ/m3 |
| H2 LHV | 10.8 | MJ/m3 |
| Hydrogen energy flux | 1.09E+07 | MJ/h |
| Biomethane energy output | 9.03E+06 | MJ/h |
| Avg. LHV of Biomethane | 34.2 | MJ/m3 |
| **Biomethane used/exported** |  |  |
| Biomethane exported | 8.72E+06 | MJ/h |
| Biomethane reused in Lime Kiln | 3.04E+05 | MJ/h |
| % of biomethane reused | 3% | % |