UK Government

RAF044/2223 Life Cycle Assessment for Anaerobic Digestion

Final Report

Department for Energy Security and Net Zero (2026)

Acknowledgements

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Executive Summary

Background

In support of the UK's Net Zero ambitions and the role of biomethane, the Department for Energy Security and Net Zero (DESNZ) commissioned a Lifecycle Assessment (LCA) study of anaerobic digestion (AD) to better understand the greenhouse gas impacts and benefits of biomethane production.

While existing carbon accounting methodologies under schemes such as the Green Gas Support Scheme (GGSS) and Renewable Heat Incentive (RHI) provide a framework for emissions reporting, this work focused on understanding emissions across the full AD lifecycle and the impacts of different reporting approaches. This project sought to develop a more comprehensive and adaptable LCA methodology and tool to assess the lifecycle emissions of biomethane from AD, which could be used to inform future policy development. However, the tool underpinning this report and published alongside it should only be used for modelling purposes and not for the purposes of greenhouse gas reporting under government schemes such as the GGSS. A separate calculator has been published by DESNZ for this purpose[OBJ].

This report summarises the findings of the project, including a review of current LCA methodologies, development of an LCA modelling tool, analysis of the UK AD fleet, and exploration of future growth scenarios.

Methodology Review

A detailed review of existing UK and international LCA methodologies was conducted, drawing particular attention to the RED II approaches used in the GGSS and Renewable Transport Fuel Obligation (RTFO) and international schemes such as the California Low Carbon Fuel Standard.

The review highlighted significant variability in methodological choices and their impact on reported emissions. A key example was the use of credits for CO_2 capture or for avoided upstream emissions when using manure feedstocks, which can drastically reduce the reported carbon intensity of biomethane plant emissions or lead to a net negative emission total. Similarly, the adopted allocation method for co-products such as digestate also had a substantial impact on the carbon intensity of biomethane, depending on how emissions are attributed to the digestate. These findings underscore the need for a flexible and transparent LCA tool to inform policy development.

UK Fleet Analysis

Using the tool, the emissions of the current UK AD fleet were modelled. Key findings include:

- The average carbon intensity of biomethane is 14.8 gCO_2eq/MJ, representing a 78% reduction against UK natural gas (66.1gCO_2eq/MJ) and 81.5% reduction compared to the

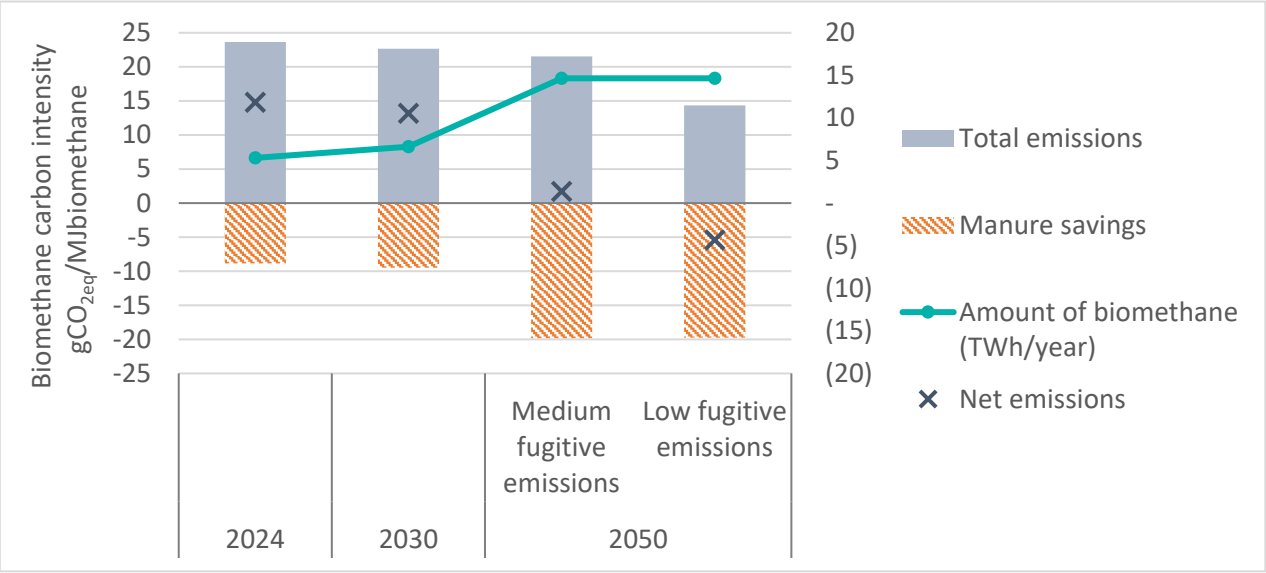
RED II fossil comparator (80 gCO_2eq/MJ). Without manure credit, the carbon intensity of 23.65 gCO_2eq/MJ represents a savings of 64% and 70% respectively.

- Total annual emissions from the fleet in 2024 were estimated at 283 $ktCO_2eq$, based on 5.31 TWh/year of biomethane production.
- Fugitive methane emissions are the most influential variable, with potential to more than double or halve total emissions depending on site performance. These emissions were varied from 1% of total site biomethane production for low-emissions scenarios to 7.8% for high-emissions scenario while the baseline was set at 2.5%.
- Methodological choices such as allocation to digestate and application of manure credits significantly affect results.

Future Scenarios

Future growth scenarios were modelled for 2030 and 2050. Under a highly conservative growth scenario, the modelling suggested that:

- Biomethane production could reach 14.65 TWh/year by 2050.
- Average biomethane carbon intensity could fall to 1.7 gCO_2eq/MJ for a medium fugitive methane scenario, with the potential for net-negative emissions at −5.4 gCO_2eq/MJ at low fugitive emissions scenarios and even lower if CO_2 capture is widely adopted.
- Despite the increase in biomethane production, net emissions (after estimated manure savings are subtracted from total emissions) can drop to 90kt CO_2eq/yr by 2050 for a medium fugitive methane emissions scenario. Robust operations leading to low fugitive methane can reduce that to −285$ktCO_2eq/yr$.
- With 75% of sites capturing CO_2, the sector could achieve over 1 $MtCO_2eq/yr$ in additional carbon savings.



Conclusion

The LCA tool developed through this project provides a robust and flexible framework for assessing the carbon impacts of AD. The findings demonstrate that AD can deliver significant carbon savings, particularly when using manure and waste feedstocks, minimising fugitive emissions, and capturing CO_2. While the conclusions from this report should not be read as government policy intentions, the tool and insights from this study provide evidence that may inform future policy development, including consideration of how to support genuine emissions reductions and good practice across the AD sector.

1. Background

This research was commissioned by the Department for Energy Security & Net Zero (DESNZ) in 2023 on the lifecycle assessment (LCA) of anaerobic digestion (AD).

The carbon accounting methodology for biomethane injection, for plants benefitting from support under the Non-Domestic Renewable Heat Incentive (NDRHI)[1] or Green Gas Support Scheme (GGSS)[2] is clearly set out in national legislation and is aligned with EU legislation[3]; however, this methodology can be somewhat limited (for example, because allocation of emissions between co-products can only be done on an energetic basis, which can be considered inappropriate for co-products not used for their energy content). The aims of this project were therefore focussed on developing a more comprehensive LCA method and tool to enable more accurate determination and reporting of the lifecycle carbon benefits and impacts of UK AD facilities.

As part of this work, a review of existing methods was undertaken, along with a review of methods adopted in our geographies and in other sectors. Based on the findings, and considering the most suitable approach for the UK AD sector, an Excel tool was developed to calculate the lifecycle emissions of biomethane for different types and scales of AD facilities. This report discusses LCA methodologies relevant to AD, as well as the methodologies and assumptions used in the Excel tool, and the sensitivity of the tool to key variables. This report also analyses the GHG emissions of the UK's AD fleet, relying on a series of representative case studies for base data, before extrapolating across the entire fleet. Finally, the report explores how overall carbon savings could be considered when assessing alternative approaches to future policy.

The work has been carried out using a number of methods, including a literature review, stakeholder discussions, tool development and extensive user testing, both internally and externally. The findings from the work are presented here and a parallel User Guide is available to support users of the LCA Tool developed during this engagement.

The work was undertaken during 2024 so uses 2023 as the reference year for the analysis.

[1] OFGEM (2022) 'NDRHI: Sustainability Self-Reporting Guidance (version 2)', available at: https://www.ofgem.gov.uk/sites/default/files/2023-04/SustainabilitySelf-ReportingGuidancePDF Final19April2023.pdf

[2] DESNZ (2024) 'Methods of calculating greenhouse gas emissions: "actual value method" and "default value method"', available at: https://www.gov.uk/government/publications/methods-of-calculating-greenhouse-gas-emissions

[3] REDII, Directive (EU) 2018/2001, available at https://eur-lex.europa.eu/eli/dir/2018/2001/2022-06-07

2. Introduction

Lifecycle assessment (LCA) is a systematic method to determine and calculate environmental impacts associated with all stages of the life cycle of a product or service. Not only can LCA help industry and government to determine and accurately report the carbon impact of their activities, but it can also identify areas for operational improvement, to enhance the performance of systems and to increase profitability. Current methodologies focus on emissions from the feedstock, from cultivation to end use. However, they fail to consider some of the wider system benefits and impacts, such as embodied carbon, counterfactual treatment (i.e. landfill, raw slurry spreading or combustion) and displacement (i.e. synthetic fertiliser).

Recent studies also fail to accurately represent the breadth of organic wastes, residues and products used in AD systems as well as the downstream emissions and impacts associated with digestate management, which can impact and influence carbon abatement, air quality and ammonia emissions, for example. This review therefore considers the full range of parameters relevant to different methodologies and presents, through the Tool, a number of options to inform future policy thinking in this area.

2.1. Introduction to anaerobic digestion and biomethane

Anaerobic digestion (AD) is a biological process that involves breaking down organic feedstock, such as food waste, sewage sludge, manure, crops, and crop waste, in the absence of oxygen. During the process, microorganisms break down the materials in a series of biological reactions, resulting in the production of biogas, which consists of approximately 50–70% methane (CH_4) and 30–50% carbon dioxide (CO_2), as well as some other gases[4] in much smaller amounts. The solid or liquid residue left after the digestion process, called digestate, is typically used as a fertiliser in a similar way to manure, delivering nutrient and organic matter benefits to the soil and subsequent crops.

Biogas and biomethane are versatile sources of renewable energy. The primary applications include electricity generation, heating, and transport fuel (Figure 1. Overview of the production of biogas and biomethane, showing possible production pathways, reflective of a typical UK facility). At present, the biogas produced by AD is generally either combusted in combined heat and power (CHP) units to generate electricity and heat, or upgraded to biomethane in a biogas upgrading unit (BUU) by separating the methane from the CO_2. The resulting electricity and heat can be utilised within the facility or exported as needed, whilst the biomethane can be injected into the gas grid, and/or used for heating, transport, or chemical processing. Typically, biomethane is blended with propane before being injected into the gas grid via a grid entry unit

[4] Other gases are present at a concentration of 0–5%, often under 1%. The concentrations depend on the feedstock used, the amount of air entering the system, and the microbial processes that dominate inside a particular digestor. Anaerobic digestion is carried out by a diverse consortium of microbes, and many side reactions occur. The other gases generated include: hydrogen sulphide (H_2S), hydrogen (H_2), nitrogen (N_2), oxygen (O_2), and carbon monoxide (CO). Water vapour is also present, typically at saturation concentration, which depends on the temperature and pressure of the gas. Trace gases with potential impacts on process include ammonia and siloxanes.

(GEU), to ensure the delivered gas meets grid standards. Direct combustion of biogas in a boiler is also carried out in some instances, typically for on-site use.

The production of biomethane through AD also generates biogenic CO_2 as a by-product from the BUU. In many cases, the CO_2 removed from biogas when upgrading to biomethane is vented to the atmosphere. However, there is increasing interest in capturing this carbon dioxide, because of supply constraints, its increased market value and to improve the sustainability credentials of key users, especially those with consumer interests (e.g., drinks manufacturers, the horticulture industry or in livestock slaughter).

Digesters and their associated equipment typically need both heat and electricity to operate, which can originate from different sources. This energy can be supplied internally by burning biogas, also referred to as the parasitic load, or externally from natural gas and/or grid electricity, or a combination of these sources. Typically, electricity and heat are generated in biogas-fuelled CHP units within the AD process, while occasionally biogas boilers can also be used to generate process heat. In the absence of a CHP, if the electricity is obtained from external sources, process heat can also be supplied sustainably without biogas, for example by heat pumps. Site set up is in most instances bespoke to the type, scale, location and configuration of the facility, and will be influenced by space, grid access and parasitic demand amongst other things.

During the AD process, methane can 'slip' out of various components and at various stages; often referred to as *fugitive methane emissions*. Fugitive methane emissions include accidental spot leakages and diffuse discharges, and these cause an unintentional GHG emission along the biogas and biomethane supply chain. To comply with regulatory requirements, appropriate measures must be in place to monitor and mitigate fugitive emissions during the process.

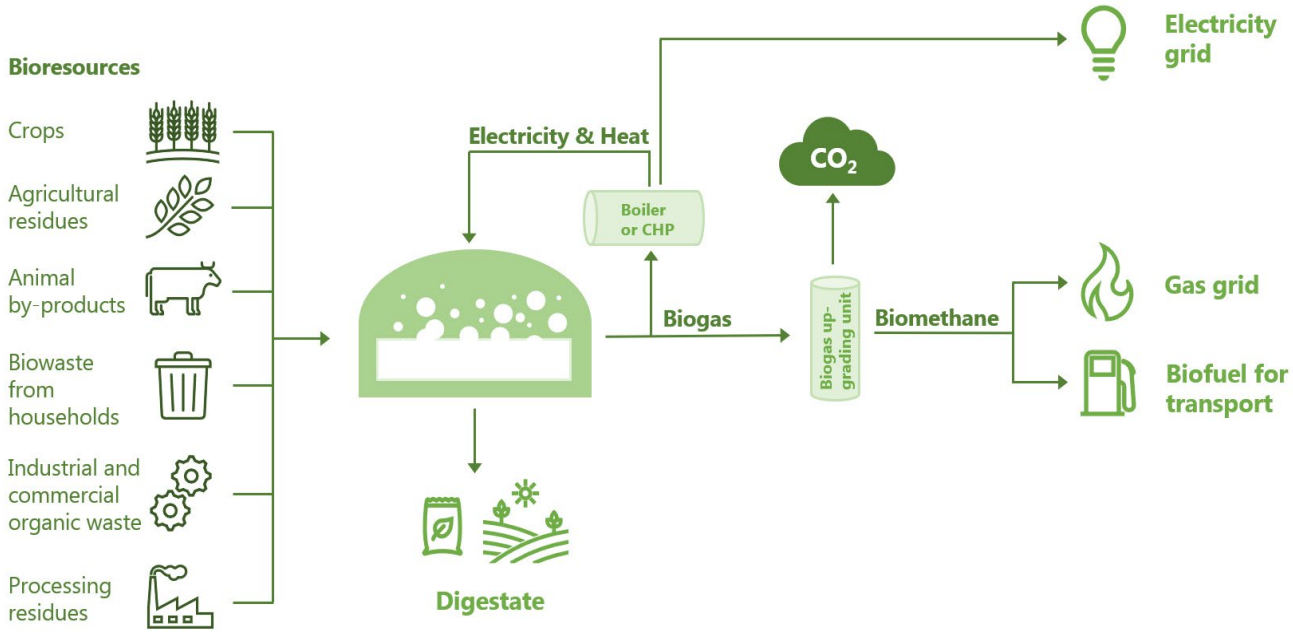


Figure 1. Overview of the production of biogas and biomethane, showing possible production pathways, reflective of a typical UK facility

The UK AD industry is firmly established and continues to expand, delivering a wide range of benefits to the energy, waste and agricultural sectors. Recognising and quantifying such benefits, as well as any impacts, is essential, to ensure appropriate regulation and reward both now and in the future.

2.2. LCA methodology

Approaches to carbon accounting differ depending on the objectives of the analysis, and each can be justified in its own way. Although numerous regulatory requirements, standards and guidelines exist and can define how carbon accounting should be generally carried out, many of these still allow methodological flexibility. Important methodological choices include the scope of the analysis and method for allocation of carbon emissions amongst co-products; however, tools can also be developed to provide multifunctionality, allowing scope and allocation methods to be varied, to test the sensitivity and impacts of different approaches.

Carbon accounting by LCA is an important part of biomethane policy as there are typically GHG criteria that must be met in order for biomethane to be considered sustainable (for the purposes of national statistics and in order to benefit from incentives). This is typically a maximum emissions threshold or a minimum GHG saving (versus a fossil-fuel comparator) that may be associated with the biomethane production, to the point of injection or supply depending on the support being claimed (see Table 1 for more details and examples from the UK). Alternatively, there may be mechanisms by which biomethane producers are rewarded based on the amount of GHG emissions saved – this approach is becoming increasingly common elsewhere in the world, as the pathway to Net Zero becomes more critical (see section 2.3 for more details of some other schemes). In all cases, it is essential that the rules or methods for carbon accounting or LCA are comprehensively considered and clearly laid out.

In this section, methodological options in LCA are discussed and compared to the convention for current emissions reporting under the UK GGSS.

2.2.1. Methodology for GGSS and other UK schemes

In the UK, most AD sites benefit from financial support supplied through various schemes, which are subject to their own carbon-accounting rules and criteria, ensuring that only renewable and sustainable energy is supported. For electricity generation, the relevant schemes include the former Feed-in Tariff (FIT) and the Renewables Obligation (RO), whilst for biomethane plants, the relevant schemes are the former Renewable Heat Incentive (RHI), the ongoing Green Gas Support Scheme (GGSS) and the Renewable Transport Fuel Obligation (RTFO).

The FIT, RO and RHI[5] scheme rules are aligned with the 2009 EU Renewable Energy Directive (RED)[6], whilst GGSS[7] and RTFO[8] are aligned with 2018 recast EU Renewable Energy Directive (REDII)[9], with nuances in application. In particular, RTFO has now deviated from GGSS and REDII in a number of ways. An overview of the methodology of emissions accounting in the two current biomethane support schemes is shown in Table 1. International certification schemes like ISCC EU[10] and REDcert-EU[11] were broadly aligned with GGSS and REDII, although these schemes have recently deviated from GGSS in a small way owing to more recent EU legislation[12] that partly supersedes elements of REDII.

Table 1: Overview of key differences in emissions-calculation methodology, emissions criteria and feedstock criteria in GGSS and RTFO (June 2024).

	GGSS	RTFO (2024)
Scope of emissions accounting	Feedstock cultivation to point of injection	Feedstock cultivation to point of fuel use (well to wheel)
Handling of plants using multiple feedstocks	Gas considered per 3-month period; average emissions reported for the whole quarter.	Gas considered per feedstock; emissions calculated per feedstock.
Counterfactual credit for manure	Yes	No
Emissions limit	24 gCO_2eq/MJ	32.9 gCO_2eq/MJ
Incentive to use waste	50% of gas must be derived from wastes or residues, under specific feedstock restrictions.	Fuel made from specific[13] wastes and residues generate twice as many Renewable Transport Fuel Certificates.

[5] OFGEM (2022) 'NDRHI: Sustainability Self-Reporting Guidance (version 2)', available at: https://www.ofgem.gov.uk/sites/default/files/2023-04/SustainabilitySelf-ReportingGuidancePDF Final19April2023.pdf
[6] Available at http://data.europa.eu/eli/dir/2009/28/2015-10-05
[7] DESNZ (2024) 'Methods of calculating greenhouse gas emissions: "actual value method" and "default value method"', available at: https://www.gov.uk/government/publications/methods-of-calculating-greenhouse-gas-emissions
[8] The latest methodology for GHG emissions accounting under RTFO can be found on the DfT website, https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-compliance-reporting-and-verification
[9] Available at http://data.europa.eu/eli/dir/2018/2001/2024-07-16
[10] More information on ISCC EU can be found on the ISCC website at https://www.iscc-system.org/certification/iscc-certification-schemes/iscc-eu/
[11] More information on REDcert-EU can be found on the REDcert website at https://www.redcert.org/en/redcert-systems/system-documents.html
[12] Including Commission Implementing Regulation (EU) 2022/996, which came into force in 2024.
[13] Current list available at https://www.gov.uk/government/publications/renewable-transport-fuel-obligation-rtfo-feedstock-materials-used-for-creating-renewable-fuels/rtfo-list-of-feedstocks-including-wastes-and-residues

In addition to the calculation rules provided in REDII, further detail and example calculations can be obtained from the associated publication[14] from the EU's Joint Research Centre (JRC) and from the associated GHG tool, BioGrace II[15]. These additional resources can also help understand the methodology for emissions calculations in the UK schemes.

It is also possible to produce biomethane with a certified carbon footprint, for example by using ISCC PLUS or REDcert2 certification, without the conventions of RED or REDII. These schemes were originally designed to certify materials other than energy (e.g. biomethane as feedstock in the chemicals industry); however, if biomethane is being generated for purposes outside of a support scheme (e.g. biomethane that is not claiming GGSS or RTFO), these certification schemes can be used and different methodologies could be applied (e.g. ISCC PLUS permits allocation methods beyond allocation by energy[16], for example by economic value).

A number of key factors relevant to the LCA of biomethane are discussed below, followed by potential areas of divergence when considering a broader approach for the future.

2.2.2. Functional units

Functional units describe the service being delivered by the system studied in the LCA and look to contextualise emissions to a common unit to enable comparison between studies.

In REDII and in all UK reporting for biomethane, biofuels and bioenergy, the functional units are grams of CO_2 equivalent per MJ of useful energy produced. If electricity is the useful output, this is per MJ electricity exported; if heat is the useful output, this is per MJ heat exported; and, if biomethane is the useful output, this is per MJ biomethane injected to grid, for example. If a site has multiple outputs, emissions can be reported both for each output and for all energetic outputs, in $gCO_2eq/MJ_{(output)}$.

As this study is focussed primarily on the carbon intensity of biomethane, GHG impacts along the supply chain are expressed in $gCO_2eq/MJ_{(biomethane)}$ throughout[17]. However, in order to see the wider impacts of the AD sector (i.e. to include those sites that do not upgrade biogas to biomethane), this work also considered gCO_2eq per year and $gCO_2eq/MJ_{(biogas)}$ as alternative functional units for emissions expression.

[14] Giuntoli, J., Agostini, A., Edwards, R. and Marelli, L., Solid and gaseous bioenergy pathways: input values and GHG emissions: Calculated according to methodology set in COM(2016) 767: Version 2, EUR 27215 EN, Publications Office of the European Union, Luxembourg, 2017, doi:10.2790/98297

[15] BioGrace-II GHG calculation tool, version 4d (2016) https://www.biograce.net/biograce2/content/ghgcalculationtool_electricityheatingcooling/overview

[16] Full guidance on ISCC PLUS can be found in the relevant System Document, available at https://www.iscc-system.org/wp-content/uploads/2024/03/ISCC-PLUS_v3.4.2.pdf

[17] It may be more practical to convert emissions per MJ into emission per kWh, as biomethane is typically reported in kWh. This has not been done in this study. To convert emissions per MJ to emissions per kWh, emissions per MJ are simply multiplied by 3.6 MJ/kWh.

2.2.3. System boundary

The system boundary essentially describes the emissions that are considered within the LCA and the emissions that are out of scope. For AD, the system starts at feedstock production and ends at the fuel in use (see also section 2.2.10).

For GGSS and REDII, the system includes emissions from the cultivation (and/or extraction) of the raw materials, emissions from transporting the raw materials, emissions from carbon stock changes caused by land-use change when cultivating these raw materials, emissions from processing the raw materials into biogas and then biomethane, as well as the emissions from transportation, distribution and usage of the fuel.

When considering biomethane for grid injection (i.e. GGSS), the system essentially ends at the point of grid injection; this can be described as cradle-to-gate. In contrast, when considering biomethane for transport (i.e. RTFO), the system is extended to cover transmission in the gas grid and compression at a filling station, where either compressed biomethane (bio-CNG) or liquified biomethane (bio-LNG) are supplied; this can be described as cradle to grave. In this report, use of biomethane was considered out of scope, so the system boundary is cradle to gate, with emissions after the point of grid injection not considered (see also section 2.2.10 on biogenic CO_2).

The system boundary can be expanded to cover land-use change. Where crops are grown on arable land, no land-use change is considered. Several types of land-use change are either prohibited or restricted in REDII, essentially avoiding the issue of carbon emissions from direct land-use change. However, it is permitted to convert degraded land to arable land for biomethane production, which would typically be associated with carbon capture, or a net carbon benefit. A bonus of 29 g CO_2eq/MJ is applied when crops are grown on severely degraded land, following the REDII methodology.

The system boundary is also expanded to take account of the emissions avoided from conventional manure management, when using manure as an AD feedstock; a credit of 45 gCO_2eq/MJ of manure (rather than of biomethane generated) is applied (see also section 2.2.7). Improvements in soil carbon stock are also treated in a simplified way.

The system boundary can be adjusted according to the rationale of the approach, with consideration of accountability in other sectors, ensuring that emissions savings are not double counted across different activities, sectors and policies. Drawing of an appropriate system boundary can have a significant impact on the outcome of the calculations.

The REDII equation for emissions calculations gives a good overview of what is included within the system boundary. For single feedstocks, it is:

$$E = e_{ec} + e_l + e_p + e_{td} + e_u - e_{sca} - e_{ccs} - e_{ccr}$$

Where:

E = total emissions from the production of the fuel before energy conversion;

e_{ec} = emissions from the extraction or cultivation of raw materials;

e_l = annualised emissions from carbon stock changes caused by land use change;

e_p = emissions from processing;

e_{td} = emissions from transport and distribution;

e_u = emissions from the fuel in use;

e_{sca} = emission savings from soil carbon accumulation via improved agricultural management;

e_{ccs} = emission savings from carbon capture and geological storage; and

e_{ccr} = emission savings from carbon capture and replacement.

Emissions from the manufacture of machinery and equipment (embodied carbon) are not taken into account.

Previous work has suggested that embodied carbon emissions are less than 1% of the total emissions from AD. Recent research conducted on behalf of the Green Gas Certification Scheme (GGCS)[18] reported similar numbers based on current biomethane production facility types, therefore it can be deemed appropriate to discard such emissions from the calculations.

2.2.4. Apportioning

When multiple feedstocks are used to make biomethane, emissions can be apportioned based on the theoretical biomethane yield of these feedstocks. For example, if 50% of the biomethane is derived from maize silage and 50% of the biomethane is derived from manure, then 50% of the emissions associated with AD itself can be apportioned to biomethane from maize silage and 50% of the emissions to biomethane from manure. These would then be added to the emissions associated with each feedstock, for example transport. The emissions associated with the biomethane would then be reported per feedstock. This is the approach used in GGSS and REDII, although the emissions limit under GGSS and REDII GHG criteria, with which sites have to comply, refers to the total emissions where all feedstocks are taken into account.

In this study, only the total emissions considering all feedstocks are reported.

2.2.5. Multifunctionality

In LCA, multifunctionality is used to describe processes with more than one function. The function of AD can be to generate methane, electricity, heat or CO_2, and various combinations thereof, with treatment of co-products and by-products varying on a case by case basis, depending on market, value and impact. Waste processing and digestate production can also be described as a function of AD and are considered accordingly in this study.

[18] Personal communication with the GGCS team.

Multifunctionality adds complexity to any LCA, in determining how or whether any of the emissions burdens should be shared between co-products, or whether any wider benefit or net detrimental impact in the economy delivered as a result of the process should result in a positive or negative value against the primary product.

Multifunctionality can be approached in various ways, and it is important to note that although different approaches give different results, all approaches are valid and permitted under the LCA Guidelines of ISO 14044[19]:

- **System expansion**
    - In AD, a system expansion might not only consider AD, but also other processes being replaced by the co-products of AD. For example, a system expansion might model AD for biomethane production, electricity generation and digestate production, but – in a parallel scenario – would model the natural gas production, grid electricity generation and fertiliser production. Information on environmental impacts would then not be expressed in terms of one functional unit (e.g. per biomethane generated) but would be expressed as impact for X units of methane, Y units of electricity and Z units of fertiliser.
    - The benefit of this approach is that nothing is left out. It is sometimes considered the best way to carry out LCA as ISO 14044 states “Wherever possible, allocation should be avoided by expanding the product system to include the additional functions related to the co-products”. System expansions are more typically adopted in studies examining the impacts of alternative scenarios and are associated with additional LCA work.
    - The limitation of this approach is that – as the results are expressed with multiple functional units – the results are more complex to understand and difficult to compare across other studies.
- **Substitution**
    - Sometimes considered synonymous with system expansion, although here considered separately[20], substitution would also expand the system to cover, for example, natural gas production, electricity generation and fertiliser production, but the environmental impacts of these would be subtracted from the total environmental impact to allow only one functional unit to be used (e.g. impacts per unit biomethane).The benefit of this approach is that all alternatives are considered.

[19] ISO 14044:2006 Environmental management — Life cycle assessment — Requirements and guidelines. As amended in 2020. https://www.iso.org/standard/38498.html

[20] Where this report uses ‘system expansion’ (‘actual system expansion’) and ‘substitution’ as defined in Heijungs R *et al.* (2021) System Expansion and Substitution in LCA: A Lost Opportunity of ISO 14044 Amendment 2. Front. Sustain., Sec. Quantitative Sustainability Assessment, 2 https://doi.org/10.3389/frsus.2021.692055

- The limitation of this approach is that it is very sensitive to the selection of substitute products or processes. In some cases, the co-product has a use that would not exist without the production of that co-product. An example is the use of excess heat from AD to supply greenhouses, where the greenhouses may have been built expressly to utilise the otherwise wasted heat. As a variation of system expansion, substitution is argued as not being appropriate for consumption-based carbon accounting or corporate reporting[21]. One reason for this is that substitutions can give negative emissions for products or corporations, based on emissions that did not happen.

- **Allocation**

  - Sometimes also called partitioning, allocation is the method of dividing the emissions of the process between multiple co-products by means of some form of weighting. A number of allocation weighting methods are possible, such as by weight, by energy content, by economic value and by carbon content.

  - The benefit of this approach is that it only considers impacts directly related to the product or process and does not consider environmental impacts or savings that are out of scope. For example, the reduction of emissions from food waste being diverted away from landfill can be claimed by the landfill industry, where the emissions reduction is happening, rather than by the AD industry, who are providing the alternative processing route for food waste. Allocation is typically used in consumption-based carbon accounting or corporate reporting.

  - The limitation of this approach is that it does not demonstrate the wider benefits of a product or process. Furthermore, different allocation methods have a large impact on the result. While allocation by weight and energy content are practical because they are not subjective, this may place emissions value on co-products that are not widely used. Allocation by economic value more fairly reflects the importance of a co-product, but economic values fluctuate so this is often impractical. Finally, allocation is not well suited to co-products that can go on to be recycled multiple times[22] due to the risk of double-counting and complexity of reporting.

- **Surplus**

[21] Brander M & Wylie C (2011) The use of substitution in attributional life cycle assessment. Greenhouse Gas Measurement and Management, 1(3–4), 161–166. https://doi.org/10.1080/20430779.2011.637670

[22] Azapagic A & Clift R (1999) Allocation of environmental burdens in multiple-function systems, Journal of Cleaner Production, 7, Issue 2, 1999, Pages 101-119, ISSN 0959-6526, https://doi.org/10.1016/S0959-6526(98)00046-8.

- In a surplus system, co-products are ignored and the product of interest (biomethane under GGSS, or heat and/or power when only a CHP is being operated) carries the full emissions burden[23].
- The benefit of this approach is that the full process emissions are considered.
- The limitation of this approach is that it unfairly places the burden on the product of interest and fails to recognise the value of optimising across a range of co-products or outputs for the wider benefit of the economy.

Carbon accounting under REDII specifies use of an allocation approach to multifunctionality (based on energy content), with some use of system expansion and substitution. In this work, various approaches have been considered. These are detailed in the following sections (2.2.6 to 2.2.9).

2.2.6. Allocation of process emissions to digestate as a co-product

Digestate is the undigested feedstock left over at the end of the digestion process. As the generation of biogas only generates carbon dioxide (CO_2) and methane (CH_4) from the feedstock, non-carbon nutrients such as nitrogen (N), phosphorus (P) and potassium (K) are retained from the feedstock through to the digestate. Digestate therefore finds applications as a valuable organic fertiliser. Despite having been through the AD process, digestate still contains undigested organic matter and therefore also finds applications as a soil improver.

In REDII, digestate as a co-product can be handled with allocation by energy content. If the moisture content is above around 88%, the digestate is not considered as having an energy content and digestate as a co-product is essentially treated as surplus[24]. This is also the approach used in emissions accounting under RHI and GGSS. The drawback of using this approach is that digestate is not actually used for energy purposes, so allocation by energy does not accurately reflect its value in the economy. If the energy content of digestate is high (i.e. when the digestate has been heavily dewatered), a lot of emissions are allocated away from the other outputs of AD (i.e. biomethane, heat and/or electricity). Conversely, if the energy content of digestate is zero (because the digestate is watery), no emissions can be allocated to it, despite its use as a co-product. Allocation of emissions to digestate can therefore have a significant impact on the outcomes of the calculations as evidenced by the later sensitivity analysis.

2.2.7. Manure management

Manure is often used as a feedstock for AD processes. It is animal excreta collected from animal housing and farmyards, and can have bedding such as straw mixed into it. The definition of

[23] The term 'product of interest' is used generically here. For example, if a policy supports biomethane generation (such as GGSS), the product of interest would be biomethane, and the functional units are typically a MJ of biomethane. In a 'surplus' approach, any electricity generated as a co-product would be ignored.
[24] This is because the 'wet definition LHV' (lower heating value) is used, where the energy derived from combustion of digestate is weighed up against the energy needed to evaporate the water away. See also page 5 of European Commission (2017) Note on the conducting and verifying actual calculations of GHG emissions savings Version 2.0, available at https://energy.ec.europa.eu/document/download/8906ee2a-1974-4659-aa31-273247cae005_en

manure can vary; sometimes it is understood to mean solid manures only, excluding liquid manure (slurry) and manure with significant amounts of bedding (litter). In terms of collectable manures, the largest volumes of manure (solid and liquid) collected are from cattle, but all housed livestock generate manures, with significant volumes also coming from pigs, poultry and other farmed animals.

Manure contains undigested organic matter, which – without additional management measures – will naturally decompose and release methane. Methane is a powerful greenhouse gas, with a global warming potential of 23–28 times that of carbon dioxide. Therefore, when stored in open lagoons or piled at the edge of the field, as is relatively common practice for farms, there is a significant loss of methane to the atmosphere as a result of this decomposition of manure.

When manure is instead used for biomethane production, the methane that would have otherwise been emitted to the atmosphere is captured and utilised. Therefore, as well as the production of green gas, the use of manure as a feedstock in AD presents an additional benefit in terms of sustainability and GHG emissions.

LCA methodologies can differ in that this additional benefit is either captured or not captured in the calculations of GHG emissions. For example, REDI and REDII account for it differently.

In REDI, there is no way to account for the benefit of using manure as a feedstock. In REDII, however, the additional benefit of using manure as a feedstock is captured and accounted for by applying a 'manure credit' of −45 gCO_2eq/MJ manure[25]. This is the substitution approach to multifunctionality.

This manure credit, when applied, can have drastic impacts on the resulting emissions associated with the biomethane. In REDII, there is a table with disaggregated default values for the GHG emissions of biomethane production. The default manure credit in a solely wet-manure-fed system, with closed digestate storage, equates to −111.9 gCO_2eq/MJ of biomethane. Even when actual values are used and manure is co-digested with other feedstocks, the manure credit can result in significant savings.

However, using this method of applying a specified carbon credit to systems that use manure as a feedstock is a simplification and can therefore be inconsistent with the actual environmental benefit. The calculations behind the manure credit in REDII are based on wet cattle manure (slurry), but the manure credit is not restricted in its manure type. It is likely that the GHG emissions from different manures are not the same as the emissions from liquid cattle manure (slurry), therefore the assumed GHG savings across all types of manure may be unreliable.

Although there is clearly a significant emissions reduction when using manure for AD, it can also be argued that claiming this saving in the fuel and energy sector (i.e. on the biomethane) is not fair, and this saving instead belongs to the agriculture sector, where the saving occurs. In the UK, this would reflect whether the emissions saving is claimed under DESNZ or Defra policy.

[25] REDII states *'The values for biogas production from manure include negative emissions, for emissions saved from raw manure management. The value considered is equal to – 45 gCO_2eq/MJ manure used in anaerobic digestion'*.

However, there is no clear mechanism through which agriculture could claim this saving, in contrast to the incentives in renewable energy (i.e. GGSS and RTFO), so currently the emissions saving is captured under the energy schemes.

Furthermore, the implication of biomethane with a negative carbon intensity is that burning more biogas or biomethane derived from manure is actively removing greenhouse gas from the atmosphere.

As the manure credit and how it is applied can have a significant impact on the outcome of the calculations, the approach is considered optional in the subsequent analysis.

2.2.8. Waste management

Organic waste going to AD is also likely to be associated with an emissions saving, if the waste is being diverted away from landfill. It is also possible to use a substitution approach to multifunctionality here, where waste management is added as a service; in practice, this would be a waste carbon credit.

A credit for waste use is not part of REDII, presumably because there are other avenues for the disposal of organic waste, such as composting, which challenges the pillar of additionality needed for carbon credits. There may also be questions of double counting (i.e. whether emissions savings from improved waste management are counted under waste-management or energy policy).

An estimate of emissions savings from diverting food waste from landfill to AD was suggested by DESNZ for this study, based on emissions values for landfill and AD given in the UK emission factors data set for 2024[26]. This value is −691.38 gCO_2eq/kg of food waste. However, it is not the case that in all systems food waste going to AD is being diverted away from landfill. According to the same UK emission factors data set, diverting organic waste away from composting to AD is associated with no change in carbon impact, and diverting organic waste from incineration to AD is associated with a negligible increase in emissions.

Further work is needed to agree a baseline scenario for landfilling of waste, for example using a baseline scenario made up of a specific proportion of waste going to landfill, incineration and composting, according to data from a specific year. Data is not readily available on the proportion of food waste or organic waste sent to landfill, but it is clear that the choice of baseline year would have an impact; the volume of biodegradable waste sent to landfill in the UK has almost halved from 2010 to 2021[27] (the most recent period for which data is available).

In this study, a carbon credit for waste was only considered in the sensitivity analysis, not in the main analysis, owing to a lack of robust figure. As 23%[28] of all waste in the UK goes to landfill,

[26] Using 2024 GHG conversion factors from DESNZ, available at https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting
[27] DEFRA (2023) Official Statistics, UK statistics on waste, Updated 28 June 2023, available at https://www.gov.uk/government/statistics/uk-waste-data/uk-statistics-on-waste
[28] DEFRA (2023) Official Statistics, UK statistics on waste, Updated 28 June 2023, available at https://www.gov.uk/government/statistics/uk-waste-data/uk-statistics-on-waste

the waste credit was taken as 23% of −691.38 gCO_2eq/kg of food waste; equating to −159.02 gCO_2eq/kg.

No credit was considered for process residues, as many of these have markets outside of AD (e.g. brewery residues for animal feed).

2.2.9. Allocation of process emissions to CO_2 as a co-product

As any CO_2 captured from a process has no energy value, allocation by energy is not possible. Upstream emissions cannot be allocated to CO_2, so it is seen as arising with zero emissions.

However, a carbon credit (i.e. the substitution approach to multifunctionality) can be awarded if the CO_2 is captured and stored in a recognised manner (CCS) or if the CO_2 is used in a product that is shown to have displaced fossil CO_2 in the market (CCR or CCU). In order to prevent double counting of any credit, an AD site cannot apply a carbon credit for CO_2 used in CCS or CCR if the receiving party is also making a claim on it; for example, if a carbon credit for the CCS is then sold on through a carbon market. Credits awarded for CCU/CCR can be controversial, as the carbon is not necessarily permanently sequestered (for 100 years minimum) and there is not necessarily evidence available that the previous source of fossil CO_2 is now also not being released into the atmosphere.

As allocation of emissions to CO_2 can have a significant impact on the outcomes of the calculations, provision has been made in the Tool to include or exclude this step, and the impact of this as an option is discussed in the subsequent analysis.

2.2.10. Biogenic CO_2

Emissions of CO_2 from the combustion of biomethane are 'biogenic CO_2', meaning the carbon has come from biomass (including sludge and waste); this is in contrast to 'non-biogenic CO_2' or 'fossil CO_2' released from burning natural gas and other fossil fuels[29].

Biogenic CO_2 emissions are considered to be zero in GGSS and REDII (because biogenic CO_2 uptake during biomass cultivation is also considered to be zero, sometimes termed the '0/0 approach' to model biogenic carbon).

In this work, a 0/0 approach to biogenic CO_2 was used (i.e. CO_2 uptake from the cultivation of biomass and CO_2 emissions from the combustion of biomethane are not counted). The release of biogenic CO_2 at the point of combustion is not very relevant in this study as the system boundary was the point of injection (see section 2.2.3).

[29] Biogenic CO_2 is defined in Annex I (Glossary) of the most recent IPCC report, AR6, available at https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_Annex-I.pdf
IPCC, 2022: Annex I: Glossary [van Diemen et al)]. In IPCC, 2022: Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [P.R. Shukla *et al.*] doi: 10.1017/9781009157926.020

2.2.11. Environmental impact and global warming potential

Global warming potential (GWP) of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) can be measured over different timeframes. It is conventional for fuel reporting, company reporting and national reporting to use GWP100, considering the impact over a 100-year period; therefore, this convention has been adopted in this study. The terms GHG emissions and carbon footprint refer to a GWP timeframe of 100 years and are all stated as CO_2 equivalents, adjusted accordingly for ease of comparison.

Global warming potential over 20 years could also be relevant as methane emissions have a very potent greenhouse effect in the short term, so this would inflate figures for GWP of AD processes involving significant loss of methane. Conversely, it has also been argued that methane is incorrectly accounted for in both the GWP100 and GWP20 methods, as methane is broken down in the atmosphere over around 12 years, while CO_2 survives in the atmosphere for hundreds of years, and so the impacts on global warming are very different, with methane emissions representing strong but short-lived greenhouse effects[30,31]. The impacts of these nuances were not built into the tool.

The GWPs for methane and nitrous oxide used in this work are 25 gCO_2eq/g and 298 gCO_2eq/g, respectively, in line with GGSS reporting and REDII. However, EU Implementing Regulation 2022/996, which came into effect in EU member states in early 2024, increased the GWP of methane to 28 gCO_2eq/g and decreased the GWP of nitrous oxide to 265 gCO_2eq/g. Although the tool uses the REDII GWPs, the values can be changed in the tool if desired.

Biomethane sites reporting emissions under GGSS and RTFO in 2024 are using a methane GWP of 25, but those reporting under ISCC-EU are likely to be using a methane GWP of 28. Using the higher GWP for methane would give higher emissions results. The implication of this is discussed in the report.

2.2.12. Fugitive methane emissions

Although not a methodological difference, the amount of fugitive methane emissions can vary hugely from site to site, and they can have a very large impact on the total process emissions. Site monitoring is being implemented more widely across the UK industry, primarily as a result of commercial interests, to identify where losses are occurring. However, monitoring and measurement could be important from an emissions reporting perspective, as opposed to relying on conservative default values as is currently permitted.

In this study, estimated methane emissions were used, as real data was not available. The sensitivity of results to different estimates was also considered.

[30] See this 'explainer' article from the CLEAR centre at UC Davis for an overview of the debate https://clear.ucdavis.edu/explainers/gwp-star-better-way-measuring-methane-and-how-it-impacts-global-temperatures

[31] See also this analysis from the NFU on how this impacts UK farming https://www.nfuonline.com/updates-and-information/everything-you-need-to-know-about-gwp-methane-accounting/

2.3. LCA methods from other policies and incentives

Government support mechanisms for biomethane and biofuels exist in other areas and other countries, and these mechanisms and their treatment of LCA have been reviewed.

In the UK, the Low Carbon Hydrogen Standard[32] defines what constitutes 'low carbon hydrogen' at the point of production (for use alongside the UK Hydrogen Strategy[33] and Energy Security Strategy[34]). The production of hydrogen from biomass can share some similarities with the production of biomethane from biomass, so many commonalities arise.

In the USA, the California Low Carbon Fuel Standard is a trading mechanism to reduce the carbon intensity (CI) of California's fuel mix. Its associated rules for carbon accounting can be applied to biomethane production.

Beyond biomethane support schemes, other carbon accounting standards from government mechanisms may be relevant to this work. In addition to their carbon accounting rules for fuels and energy, the EU have categories of rules for carbon accounting for products, termed the Product Environmental Footprint (PEF). In their carbon tax systems, both the UK and the EU have a cap-and-trade approach, which permits the trading of emissions. These emissions are traded under the rules of the Emissions Trading Scheme (ETS).

On a more global scale, LCA is defined in ISO 14040-14044. Furthermore, the UK LCA standard PAS 2050 and the global Greenhouse Gas Protocol, which was heavily influenced by PAS 2050, guide carbon accounting across a wide range of sectors. Further detail on some of the key policies and their relevance to LCA are discussed below.

2.3.1. UK Low Carbon Hydrogen Standard

The Low Carbon Hydrogen Standard (LCHS) defines what constitutes 'low carbon hydrogen' at the point of production, and sets a maximum threshold (20 gCO_2eq /MJ) for the amount of greenhouse gas emissions allowed in the production process. In addition to meeting the emissions intensity up to the point of production, producers must also prepare a mitigation plan for fugitive hydrogen emissions. In addition, when certain biogenic feedstock is used, additional requirements need to be met; the additional criteria include land, forest and soil carbon criteria, and the exact criteria which a given consignment of hydrogen must meet depend on the feedstock from which it is made.

It is worth noting that the additional feedstock criteria are very similar to those used in GGSS, RTFO and REDII. The UK Government provides a free hydrogen emissions calculator[35], and training for its correct utilisation. Additionally, to demonstrate compliance with the sustainability criteria, the Standard advises the usage of a recognised voluntary scheme (e.g. ISCC).

[32] Low Carbon Hydrogen Standard. Available from: https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria
[33] UK Hydrogen Strategy (2021). Available from: https://www.gov.uk/government/publications/uk-hydrogen-strategy
[34] Energy Security Strategy (2022). Available from: https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy
[35] Hydrogen Emissions Calculator. Available from: https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria

2.3.2. California Low Carbon Fuel Standard

Under the Californian Low Carbon Fuel Standard (LCFS), the GHG calculation for the fuel mix placed on the market is linked to buying or selling carbon credits generated by renewable fuels and the impacts of standard emission factors for fossil fuels. The LCFS is technology agnostic, setting a declining annual GHG limit (gCO_2eq/MJ energy provided) for the transport fuel pool. Fuels below the limit generate credits, those above carbon debts. So, as long as a reduction in emissions can be evidenced against the threshold, credits will be issued, regardless of the technology used.

To calculate the emissions associated with a biofuel, the LCFS takes into account all of the steps of producing, transporting, and consuming a fuel. The LCFS makes use of two models to calculate direct effects of fuel production: CA-GREET (which is based on the Well-to-Wheel), and OPGEE. Additionally, the LCFS uses the GTAP and AEZ-EF models for the calculation of indirect effects associated with the production of the fuel. Interestingly, under the LCFS framework, the type of fuel produced determines the methodology used for the calculations. For example, the emissions calculation is predetermined for the simplest pathways (e.g., gasoline and diesel). Most common low-carbon fuels fall within the category of Tier 1 for which a simplified GHG calculator is available. Tier 1 includes, for example, the production of biomethane from the anaerobic digestion of dairy and swine manure, or from organic waste. Tier 2 is reserved for innovative, next-generation pathways, which may use unique feedstocks or include advanced technologies (e.g., CCS). Additionally, the LCFS methodology only accounts for the emissions of residues and wastes after the collection point.

In terms of land-use change, the GHG calculations under LCFS include both the direct effects of producing and using the fuel, and the indirect effects that are associated with crop-based biofuels. The aim of including indirect land use change (ILUC) within the LCA framework is that the high GHG emissions associated with ILUC discourage their use. LCFS does not prohibit the use of any type of feedstock, even those that could lead to higher emissions (e.g., food-crops), but it does include an ILUC factor for use in calculations when using affected feedstocks. In the EU, under REDII, ILUC factors are accounted for separately as part of the mandatory land criteria which includes limitations on the use of high carbon stock areas, and voluntary environmental and socio-economic criteria. Whilst the LCFS does not stipulate any other sustainability criteria in terms of socio-economic aspects.

The main difference between mechanisms is that whilst REDII sets an emission saving threshold against a fossil comparator, the LCFS places the focus on GHG emissions reduction, and installations that deliver higher emissions reductions generate higher rewards. The strengths of policies based on GHG savings is that technologies delivering greater benefit are promoted. Additionally, LCFS policies are technology neutral and encourage producers to continue to work to reduce the emissions associated with their fuels, potentially delivering greater benefits at an accelerated pace. Conversely, under a biofuel blending mandate, such as REDII, producers are not encouraged to improve the CI of the biofuel beyond the minimum threshold. Table 2 summarises the main differences between policies in regard to GHG calculations.

Table 2: Comparison of methodologies for calculating biomethane GHG emissions.

Policy	Policy type	GHG Calculation methodology		Other criteria
		Calculations	**ILUC**	

REDII	Blending mandate	Support received if GHG reduction threshold is met	Accounts for emissions associated with all steps of producing, transporting, and consuming a fuel. System boundaries defined by the well to wheel (WtW) approach; default calculations provided for some pathways. Users are encouraged to present actual values.	Considered under the mandatory land criteria but not included in the calculations.	Mandatory land criteria and voluntary environmental and socio-economic criteria.
LCFS	GHG reduction	Level of support increases with increasing GHG reductions	Accounts for emissions associated with all steps of producing, transporting, and consuming a fuel. External models used for GHG calculations, aligned with consistent methodology.	Included in calculations; high GHG values expected to discourage fuels with high ILUC.	No environmental or socio-economic criteria included.

2.3.3. UK Emissions Trading Scheme & Common Biomass Sustainability Framework

The UK Emissions Trading Scheme (UK ETS) currently covers the heavy industry, power, aviation and domestic maritime sectors – approximately 25% of UK territorial emissions. By setting a cap on emissions from these sectors, and creating a carbon price, the scheme incentivises investment in decarbonisation in line with climate targets across the UK.

Under the current UK ETS, sustainability criteria apply only to bioliquids used for energy generation. Solid and gaseous biomass are generally treated as zero-rated and do not currently need to demonstrate compliance with UK ETS sustainability criteria. For bioliquids, operators seeking to apply a zero-emission factor must demonstrate compliance with sustainability criteria, including land-use criteria and greenhouse gas emission saving criteria.

The UK and EU are currently in negotiations to link the UK ETS and the EU ETS, and will update stakeholder as appropriate on the outcome of any linking agreement.

In December 2025, the Government launched a consultation on developing and implementing a cross-sectoral common sustainability framework to enable consistency between biomass sectors and strengthen criteria in line with latest evidence. The common framework proposals cover the sustainable sourcing of the biomass (land criteria), limiting the supply chain emissions (GHG criteria) and how compliance with the sustainability criteria is monitored and verified. The Government is currently considering responses to the common biomass sustainability framework consultation and plans to publish a government response in due course.

3. UK AD fleet

According to Alder BioInsights' (NNFCC's) AD Deployment in the UK Database[36] in early 2024, the UK AD fleet consists of over 600 operational sites. Data contained within this database is sourced from publicly available information (e.g. local and national planning documents, official statistics, press releases, etc) and is updated on a monthly basis[37]. This dataset has been used to analyse the composition of the existing fleet, to understand the emissions associated with current activities, and to extrapolate the findings to the potential future fleet, with results reported below.

Since the growth of the AD sector has been stimulated by a range of financial support mechanisms, there has been an evolution of the type, size and feedstock mix used by facilities over time. Originally, the feed-in-tariff (FIT) and the renewable heat incentive (RHI) encouraged on-site biogas combustion, producing heat and power for on-site or local use, or for export via the national power grid. Latterly, the RHI and more recently the GGSS and RTFO have encouraged more biomethane production, decarbonising the gas grid and transport sector respectively. Each scheme has fixed sustainability criteria and feedstock restrictions that apply to new and legacy capacity, and this has also influenced the type, scale and nature of developments over the years. As a result, the fleet has been categorised according to the type, scale and nature of inputs and outputs combined.

3.1. Categorisation by use of biogas, size and feedstock

The following criteria were used to categorise the UK AD fleet based on the information contained within the database:

- **Use of biogas.** The two main uses of biogas in UK AD plants are combustion in a CHP (to generate electricity and heat) and upgrading to biomethane (typically for injection into the grid), referred to in this work as BtG. Many BtG sites also combust some gas in a CHP and may also export electricity. Combustion in a boiler is also possible. *Within the dataset, the uses are classed as CHP (N.B. these may also operate a boiler, but do not carry out any biogas upgrading), BtG (N.B. these sites may also operate a CHP and/or boiler) and heat only.*

- **Size.** The size of site is typically defined by the installed capacity and expressed in terms of output. In this analysis, the following classifications have been used (see also annex, Table 13):

    - Micro: CHP capacity of 149 kWe or less (***no** BtG at this scale*)

[36] A limited version of this database can be accessed under https://www.biogas-info.co.uk/resources/biogas-map/
[37] The limitation of this data set is that the public data sources (from which it derives) typically do not contain information about decommissioning of sites, the installation of sites that fall under planning exemptions, or the installation of sites that do not receive subsidy. For example, several sewage-processing AD plants are missing from the database, as are many micro-scale AD plants.

  - Small: CHP capacity of 499 kWe or less (***no** BtG at this scale*)
  - Medium: CHP capacity of 2.99 MWe or BtG capacity of 749 scm/h or less
  - Large: CHP capacity of 5.49 MWe or BtG capacity of 1,299 scm/h or less
  - Very large: CHP capacity of 5.5 MWe or more, or BtG capacity of 1,300 scm/h or more.

- **Feedstock.** Based on type, source and classification, feedstocks have been categorised into manure, crops, food waste, residues, and various combinations thereof. *The Alder BioInsights AD database contains only 9 sewage AD plants that are producing biomethane for grid injection, although there are considerably more operating CHP-only facilities in the UK, so these were left out of the fleet analysis.*

See the annex for more detail on what each category includes.

3.1.1. Comparing biogas use

At the time of writing this report (2023), in terms of plant numbers, there were more AD sites with CHP only, with around 477 CHP-only sites and 120 BtG sites operational. However, in terms of installed capacity, the BtG sites represent the larger share. It should be noted that actual output from UK AD plants is not reported, but given many operate below their installed capacity due to technical or feedstock constraints, actual production is likely to be lower than the theoretical potential (see also section 5.1.3).

3.1.2. Comparing sizes and feedstocks

Figure 2 shows the number and capacity of BtG and CHP sites, by size and by feedstock. A full breakdown of sites can be found in the Annex.

For BtG sites, the figures show that medium-sized AD plants represent the largest category, both in number and installed capacity. In terms of feedstock, the agricultural BtG plants represent the largest contingent, with manure mix and crop only sites together making up just under two thirds of the installed BtG capacity. There are no small or micro BtG plants, as cost and technical barriers currently prevent biogas upgrading at this scale.

The greatest electrical capacity is also from medium-sized AD plants, together representing around half of the installed capacity, although small AD plants are the greater in number. In terms of feedstock, CHP sites are approximately half agricultural and half waste (predominantly food waste) or residue fed. Almost 20% of CHP plants are small or micro sized, and these are almost all agricultural.

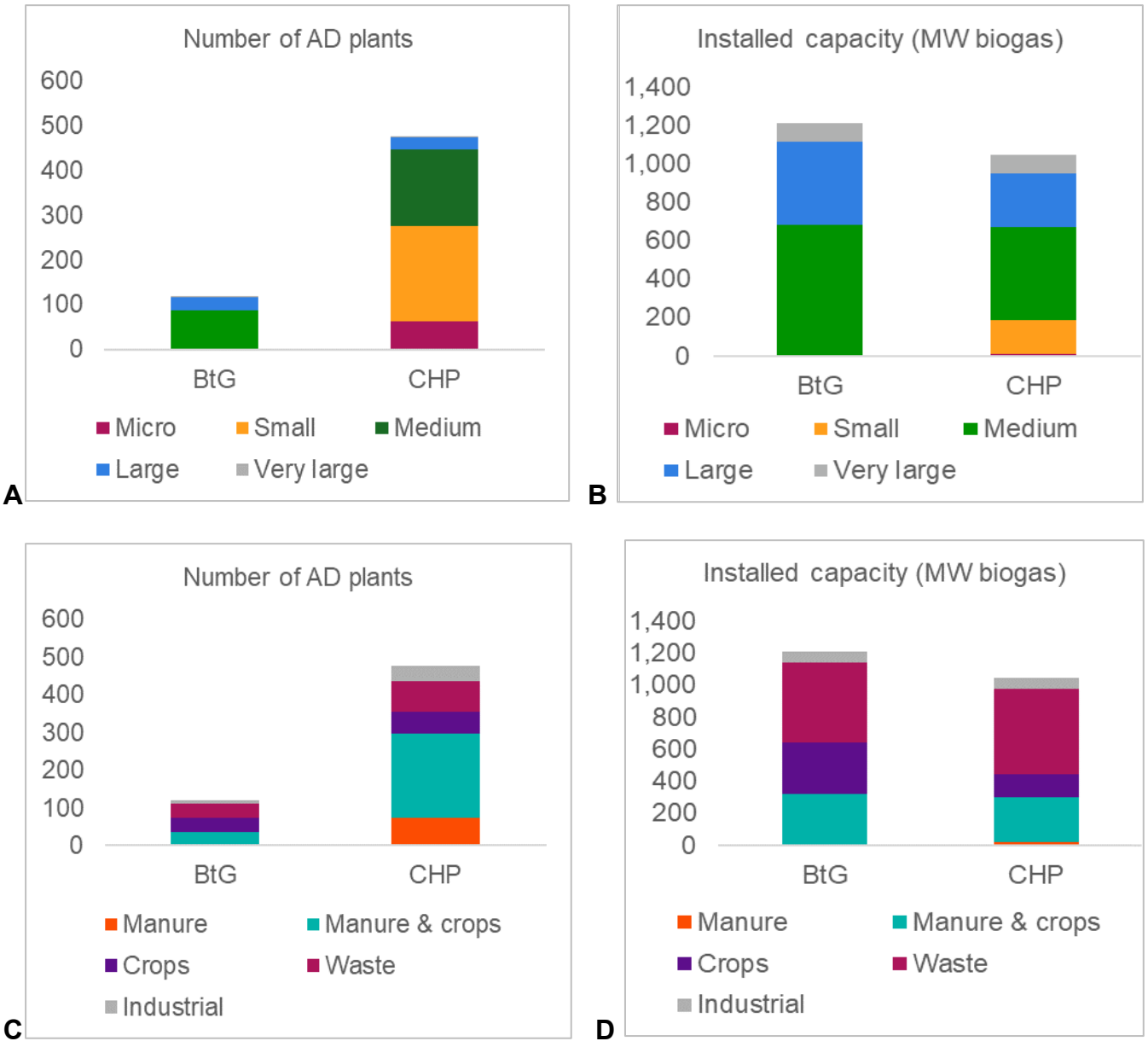


Figure 2: AD plants by size (A and B) and feedstock (C and D), shown as number of plants (A and C) and size of plant (in installed biogas capacity, B and D).

3.1.3. Exclusions

The following AD sites were excluded from further analysis:

- Sites using biogas only for heat. This is because insufficient evidence was available, and they represent less than 1% of installed AD capacity. Only 7 sites were listed in the database as using their biogas only for heat (in a boiler). Most were fed with manure only, or manure and dairy residues, with 4 being micro and 2 being small. One medium-sized AD site also fell into the heat-only category, and this was attached to a brewery or distillery.
- Sites using mixed waste (i.e. 'black bag waste') where the organic fraction has been separated out in a dedicated facility. This is because insufficient evidence was available

on them. The database contained only three such sites, although they were large or very large.

- It should also be noted that in terms of the main feedstock groups, sewage sludge is a significantly large feedstock for AD but has been excluded here. Biogas from sewage sludge AD in the UK can be used for both CHP and BtG. However, sewage treatment facilities are inherently a different business and operating model to agricultural and waste-processing AD, with the production of electricity or biomethane not being the main driver, therefore, it is likely that site-set up and operation will vary significantly. Hence this study focuses on only AD sites processing food and processing wastes, processing and agricultural residues and agricultural products.

3.1.4. Fleet Summary

The fleet has been segregated into the categories discussed above, by type, scale and feedstock to allow such groupings to be modelled in the LCA Tool, using data gathered from the case studies (as discussed below).

Using this data, it was possible to identify a representative selection of sites to survey, to obtain actual data to validate the model and to calculate their emissions.

Table 3: Numbers of operational CHP only sites, by scale and feedstock

	Manure only	Manure and crop/other	Crop, crop-residue only	Industry-associated	Waste	Total
Micro	48	14	0	0	0	62
Small	27	132	30	14	11	214
Medium	0	76	24	25	46	171
Large	0	0	3	1	23	27
Very large	0	0	0	0	3	3
Total	78	222	57	41	83	477

Table 4: Numbers of operational BtG sites, by scale and feedstock

	Manure only	Manure and crop/other	Crop only	Industry-associated	Waste	Total
Medium	0	31	29	5	23	88
Large	0	6	7	3	13	29
Very large	0	0	0	0	3	3
Total	0	37	36	8	37	120

4. Case studies, model and LCA tool

4.1. Case studies

In order to estimate the emissions associated with the UK AD fleet, representative AD plants were selected from Alder BioInsights' AD database based on type, scale and feedstock mix, and surveyed for design and operational data. Data was gathered (in 2023) from 22 sites in total, of which 12 were mainly upgrading biogas to biomethane for grid injection (biomethane to grid, BtG) and 10 were mainly using biogas in a combined heat and power (CHP) unit (Figure 3).

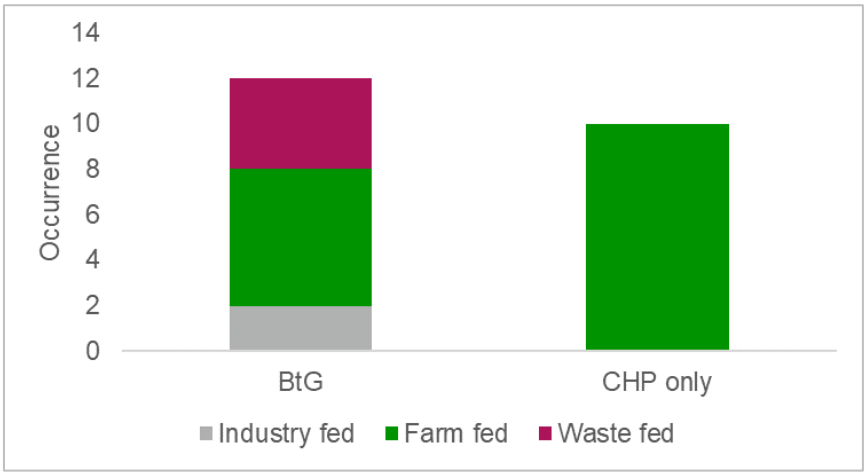


Figure 3: Overview of the 22 case studies by biogas use (biomethane to grid, BtG, and combined heat and power, CHP) and feedstock.

Sites were asked to provide data as annual, quarterly, or any other convenient period[38], but with the request that the chosen period was typical for them. Most sites provided quarterly data (corresponding to the data they gather for RHI or FIT reporting to Ofgem), which was then multiplied by 4 to give an estimate of annual data. Three sites (the micro-AD sites) did not have reporting obligations (to Ofgem) so did not routinely record operational data. These sites gave indicative monthly data, which was multiplied by 12 to give an estimate of annual data.

Not all sites were able to provide all data. The majority of sites were only able to provide the data that they routinely gather for Ofgem reporting.

It should be noted that none of the sites were able to share actual data on fugitive methane emissions, so these were estimated. Few sites were able to share details about gas flaring and no sites provided crop cultivation data, so estimates were again used for these.

[38] Months and quarters were deemed as suitable estimates for a whole year. There was no concern around seasonality of feedstocks, as crops are typically harvested once but stored all year round as silage (although quality of silage can decrease as it ages as is used up, exposing parts of it to air), and food/processing waste is highly variable regardless of season. There may be higher energy requirements in the winter (i.e. to heat the digesters) but the difference was not deemed significant.

Emissions data from each of the case studies can be seen in the Annex.

4.2. Model and LCA tool

The operational data provided in the case studies was used to generate a tool which can be used to model AD plants. The tool allows a number of design parameters to be adjusted, such as size and product output, as well as feedstock types and source of energy used (e.g. mostly biogas). Performance parameters could also be adjusted, including availability, electricity needs and efficiency. The tool also allows the adjustment of fugitive methane emissions from a range of sources: design (including the biogas upgrading unit and any CHPs or boilers), digestate storage and operation (from the digester and associated pipework). Detail on the parameters used in the tool can be found in the tool itself, as well as in the Annex of this report.

The model was incorporated into an LCA tool, informed by the review of existing and alternative LCA methods, and following a period of stakeholder consultation. This bespoke tool was developed to calculate the lifecycle emissions of biomethane and to examine the GHG impacts of parameters beyond the scope of GGSS and REDII, to better inform future policy and industry thinking on the potential of the AD sector[39]. However, the tool developed was only used for modelling purposes and should not be used for the purposes of greenhouse gas reporting under government schemes such as the GGSS.

4.3. Factors affecting emissions

Using the model to generate individual examples shows how various parameters have an effect of GHG intensity of biomethane generated.

4.3.1. Fugitive methane emissions

Fugitive methane emissions have a very large effect on the overall GHG emissions of biomethane production. Fugitive methane emissions in AD arise from a number of sources. Some are fixed in the system by the design of the equipment; equipment that converts biogas (e.g. CHPs, boiler, flares and biogas-upgrading units) typically has a certain amount of methane slip, and it may be possible to reduce this at the design phase by purchasing equipment with particularly low methane slip. The handling of digestate (e.g. whether it is stored in a gas-tight system, whether it is treated, etc) is also known to have a large effect on fugitive methane emissions from AD, although the extent of this is not known and research and industry results vary greatly. There are also operational parameters that influence fugitive methane emissions, such as the extent to which valves and ports are opened, and whether these are correctly sealed after opening.

[39] In addition to the model, the tool allows actual data from AD sites to be used. A user can toggle between the two modes using the Welcome worksheet and populating the Actuals worksheet. However, actual mode should be used with caution, as it is possible to generate unrealistic situations from hypothetical scenarios.

The model includes several different scenarios for fugitive methane emissions (detailed in the Annex). Figure 4 shows the GHG emissions associated with biomethane from a medium-sized plant using waste as a feedstock, applying nine different scenarios for fugitive methane.

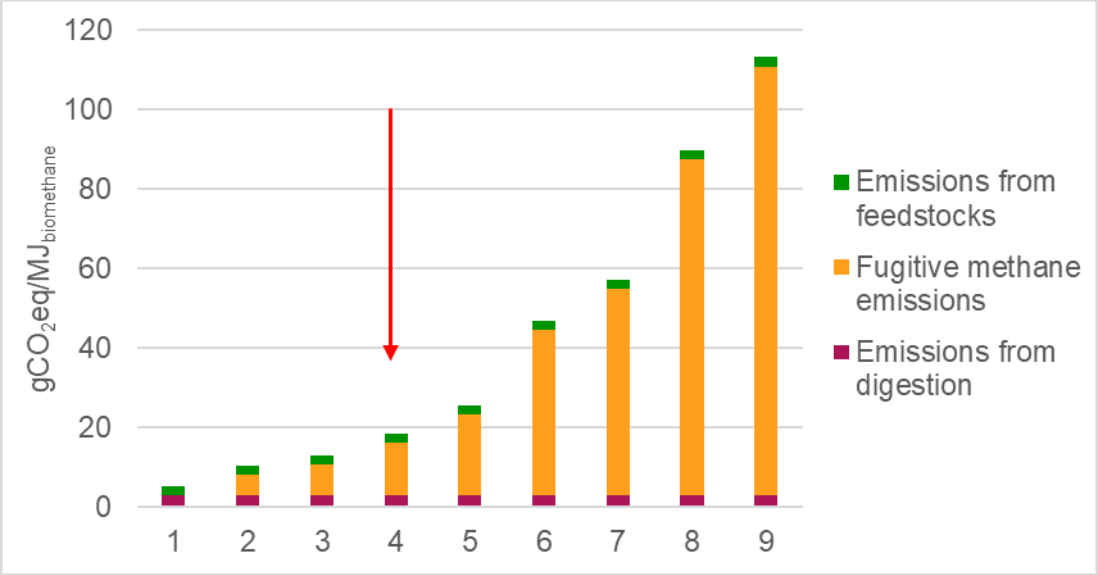


Figure 4: Emissions associated with biomethane from a medium-sized plant using waste as a feedstock, applying nine scenarios with increasing fugitive methane emissions (as detailed in Table 5). The arrow indicates the fugitive methane scenario (4), equivalent to 2.5% fugitive emissions, used as the baseline in the subsequent sections of this work.

A breakdown of those scenarios is found in Table 5 (and Annex 9.9)[40]. An arrow on the figure indicates the fugitive methane emissions used in the baseline scenario for this work: scenario 4. This baseline waste-processing medium-sized AD plant is also used in sections 4.3.2, 4.3.3, 4.3.4 and 4.3.5, where the same data (scenario 4) is referred to as α. Low-emissions and high-emissions scenarios used in this work refer to scenario 2 and 6, respectively.

It should be noted that GWP for methane was set in this work as 25 gCO_2eq/g, in line with GGSS reporting and REDII. However, EU Implementing Regulation 2022/996, which came into effect in EU member states in early 2024, increased the GWP of methane to 28 gCO_2eq/g. Biomethane sites reporting emissions under GGSS are using a methane GWP of 25, but those reporting under ISCC-EU since 2024 are likely to be using a methane GWP of 28. Using the higher GWP for methane would give higher emissions results (shown in Table 5).

Fugitive methane emissions are not routinely measured and the true state of fugitive methane emissions from AD is not fully understood. DESNZ has explored the issue in the Methane

[40] A number of literature resource and stakeholder testimonies were used to generate the numbers for fugitive methane emissions. In particular, Bakkaloglu *et al.* (2021) Quantification of methane emissions from UK biogas plants (https://doi.org/10.1016/j.wasman.2021.01.011), which gave total emissions from 0.02% to 8.1%. Data for individual pieces of equipment was heavily inspired by Wechselberger *et al.* (2023) Methane losses from different biogas plant technologies (https://doi.org/10.1016/j.wasman.2022.12.012), and total fugitive emissions were validated against the recent German-language study EvEmBi, the report of which was published in 2022 (https://www.fnr.de/ftp/pdf/berichte/22407917.pdf). The EvEmBi project reported mean total fugitive emissions of 2.7% or 3.3%, depending on whether certain sites were excluded from the study. A study from Denmark by Scheutz & Fredenslund (2019) (https://doi.org/10.1016/j.wasman.2019.07.029) gave emissions as between 0.4% and 14.9%, with the mean for agricultural AD plants at 2.4% (and for wastewater plants at 7.5%).

Emissions from AD (MEAD) study[41], undertaken by NPL and is due to publish additional research under a follow-on study. However, it is clear they have a critical impact on the sustainability of biomethane.

[41] Methane Emissions from Anaerobic Digestion (MEAD) - GOV.UK

Table 5: Parameters set in the model in order to generate the nine fugitive-methane scenarios in Figure 4 and associated biomethane carbon intensity based on GWP of methane set as 25 and 28. Additional information is found in the Annex, section 9.9. Scenario 4 was used in the subsequent work in this study.

Scenarios:	1	2	3	4	5	6	7	8	9
Biogas CHP (as % methane to CHP)	0%	0%	0.50%	0.50%	1%	1%	2%	2%	4%
Biogas upgrading unit (as % methane to BUU)	0%	0%	0.50%	0.50%	2%	2%	4%	4%	8%
Fugitive methane, operation (as % of all methane in biogas)	0%	0.50%	0.50%	1%	1%	3%	3%	6%	6%
Fugitive methane, digestate (as % of all methane in biogas)	0%	0.50%	0.50%	1%	1%	3%	3%	6%	6%
Total fugitive emissions (as % of biomethane generated)	**0%**	**1%**	**1.50%**	**2.50%**	**3.80%**	**7.80%**	**9.91%**	**15.61%**	**19.25%**
$gCO_{2eq}/MJ_{biomethane}$ (GWP 25)	5.2	10.4	13.0	18.3	25.4	46.7	57.2	89.7	113.1
$gCO_{2eq}/MJ_{biomethane}$ (GWP 28)	5.5	11.8	15.0	21.3	29.9	55.5	68.1	107.1	135.2

4.3.2. Feedstocks

Feedstocks have an influence on the emissions associated with biomethane production. Figure 5 shows how transport distance, the use of crops (instead of waste) and the poor use of fertiliser[42] in the cultivation of those crops can increase overall emissions.

In Figure 5, fugitive methane emissions and emissions from digestion go down slightly with the inclusion of crop-derived biomethane owing to the difference in dry matter of crops (vs waste) and its implications on allocation to digestate (see more in section 4.3.4).

[42] As with methane, it should be noted that the GWP of N_2O – an important greenhouse gas emitted when fertiliser is applied in the field – is aligned with REDII at 298 gCO_2eq rather than the newer 265 gCO_2eq.

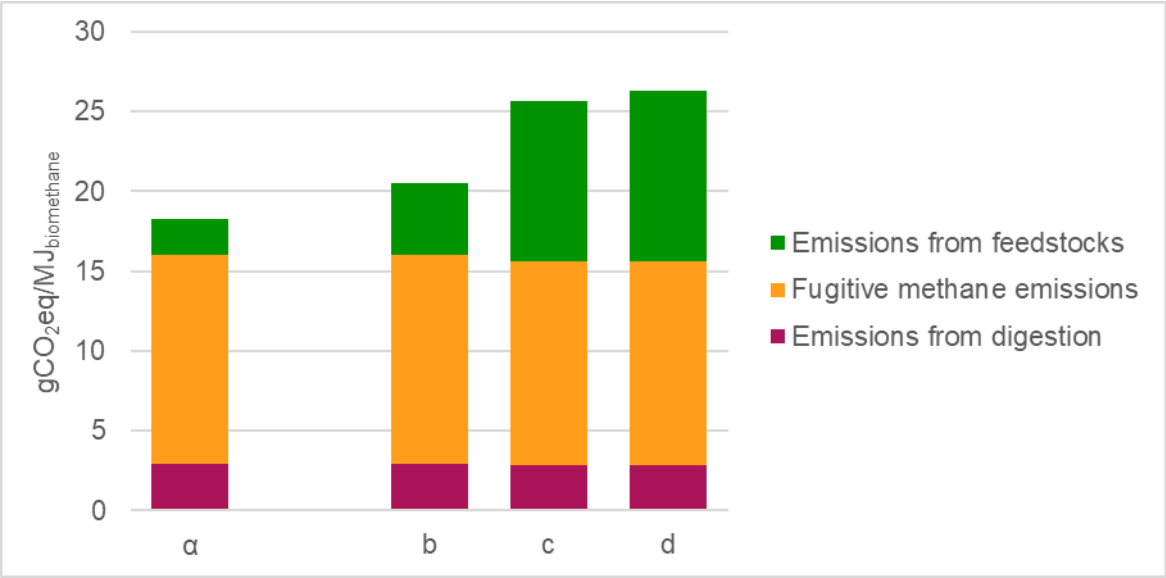


Figure 5: Emissions from 4 feedstock scenarios. Scenario (α) is a baseline waste-only AD plant. In scenario (b), transport distance is doubled (from 150 km to 300 km, assuming a diesel truck). In scenario (c), 50% of biomethane now comes from crops. In scenario (d), fertiliser use for that crop is increased 50% (without a corresponding increase in crop yield).

4.3.3. Operations

Some operational parameters have an impact on GHG emissions. Figure 6 shows the impact of several operational parameters on overall emissions.

Sites with a low digestion efficiency (scenario B) require more feedstock to obtain the same biomethane yield, so emissions from feedstocks have increased.in this case, fugitive emissions have gone *down* as the increased amount of digestate vs biomethane has impacted allocation. See more on the implications of allocation to digestate in section 4.3.4.

Sites with a higher electricity demand (scenario C) show an increase in emissions associated with digestion. It should be noted that, in the model, this additional electricity is supplied by the grid, rather than a larger biogas CHP. A larger CHP would also have an impact on emissions, diverting biogas away from biomethane and therefore reducing output. This is not modelled in the tool.

Sites operating significantly below their installed capacity (scenario D) but with the same energy demand also show higher emissions than the baseline.

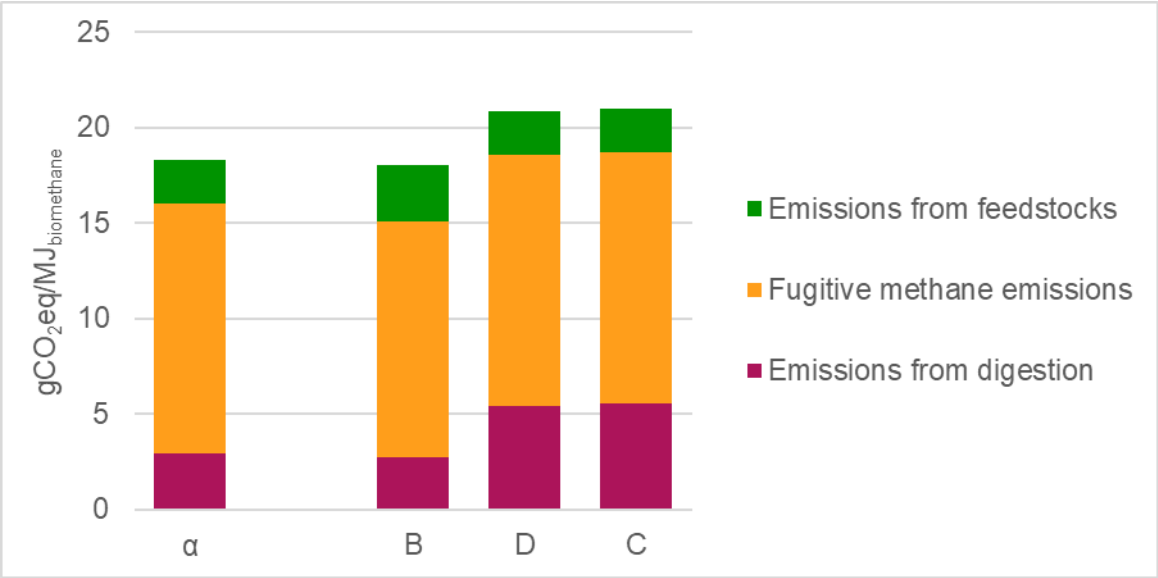


Figure 6: Emissions associated with biomethane from 4 operational scenarios. Scenario α is a baseline with medium efficiency, electricity needs and outputs performance. Scenario B has a low digestion efficiency (a 27% reduction in biogas yield from the feedstock, as compared to A, leading to a higher feedstock demand to achieve the same biomethane yield). Scenario C has a high electricity demand (a 35% increase in electricity demand, as compared to A). Scenario D represents a site operating significantly below its installed capacity (a 27% lower biomethane output compared to scenario α, owing to less feedstock being used).

4.3.4. LCA methodology: allocation

In addition to real-life differences between AD sites (e.g. operations and feedstocks), LCA methodologies have an impact on emissions calculations. In particular, two elements of REDII methodology – also used in the baseline of this study – can have a large and complex impact: allocation and substitution (carbon) credits.

Allocation of emissions to co-products is based on their energy content, as many co-products are energetic (e.g. heat and electricity). However, non-energy co-products, such as digestate (a fertiliser), are also handled with allocation by energy content. As mentioned in section 2.2.6, allocation to digestate is only possible with this methodology if the moisture content is below 88% (i.e. the DM is above 12%). The DM of digestate varies with feedstock and site set-up, but the vast majority of unprocessed digestates fall below 12% DM. However, some sites carry out solid–liquid separation of digestate, generating a solid fraction with a DM above 12%, typically around 25%.

Figure 7 shows the baseline assumptions used in this study for a waste-processing AD plant as compared to two scenarios with different digestate treatments and, therefore, different allocations. All feedstock and operational parameters between the 3 scenarios are the same. However, in the baseline scenario the digestate undergoes some solid–liquid separation: 25% of the digestate is concentrated into a 25% DM fraction (thick enough for handling as a solid) and the remaining 75% ends up as a 5% DM fraction (watery enough for convenient liquid-handling). This allows some emissions (in this case, 10.3%) to be allocated to digestate, away from biomethane. In a comparator scenario (x), the digestate is not separated and – as its DM

is below 12% – no emissions can be allocated to it, and emissions for biomethane are higher than the baseline. In another comparator scenario (y), a more powerful piece of equipment is used for concentrating the digestate, and 30% of the digestate is concentrated into a 30% DM fraction (with the remaining 70% ending up in a 1% DM fraction). This allows more emissions (in this case, 16.0%) to be allocated to digestate, away from biomethane. This means that the emissions are lower than the baseline.

This is an effect of the LCA methodology whereby multifunctionality (i.e. generation biomethane and another co-product) is addressed using allocation by energy content. The emissions associated with AD are the same in all 3 scenarios, as all feedstock and operational parameters are the same. The only reason the emissions associated with biomethane are different in all 3 scenarios is that the different energy contents in the digestates allow different allocations – regardless of the fact that the digestate is not used for energy.

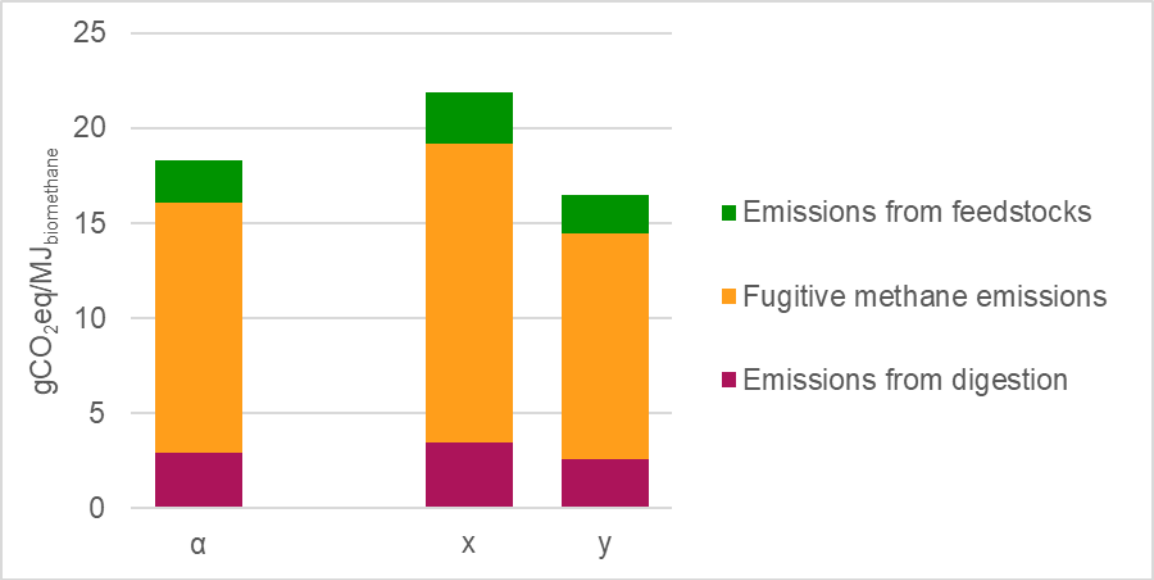


Figure 7: Emissions associated with biomethane from a medium-sized waste-processing plant under 3 different digestate-processing scenarios. In the baseline scenario, α, digestate is separated into a solid fraction at 25% DM and a liquid fraction at 5% DM, with 25% and 75% of the digestate (DM) going to each fraction, respectively. In scenario x, digestate is unprocessed; its DM is 10%. In scenario y, the solid–liquid separation of digestate is more effective: the solid fraction is more concentrated (30% DM), while the liquid fraction is more dilute (1%), and a larger fraction of the digestate has been recovered in the solid fraction (30%) than the liquid fraction (70%).

Solid–liquid separation of digestate is not the only parameter to impact allocation away from biomethane. If, for any reason, there is a larger amount of digestate given the amount of biomethane generated (e.g. because the feedstock has a low biomethane yield or because the process is using a short residence time and not getting the full biomethane potential out of the feedstock), this also leads to emissions being allocated away from biomethane.

4.3.5. Substitution or carbon credits

Some feedstocks can be associated with a substitution or carbon credit, which gives the benefit of an avoided emission (i.e. from improved feedstock handling) to the product (biomethane) and any co-products.

In the baseline scenario used in this study, a manure credit – as in REDII – was used for sites using manure as a feedstock. Figure 8 shows how the use of manure (as compared to waste and crop) impacts overall emissions.

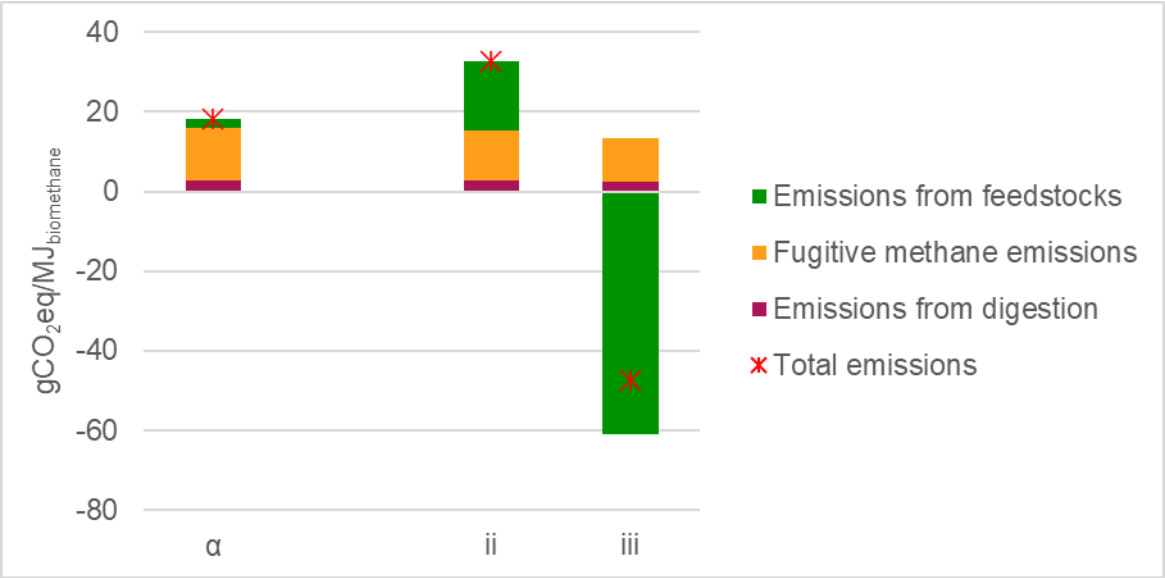


Figure 8: Emissions associated with biomethane from 3 feedstock scenarios. Biomethane is derived entirely from waste in scenario (α), from crops in scenario (ii), and from manure in scenario (iii). Total emissions are shown in a cross symbol, taking into account both the positive and negative emissions.

In the baseline scenarios in this report, no carbon credit was awarded for the use of other wastes as feedstocks. This is in line with REDII. The impact of a waste carbon credit is shown in Figure 9, and the impact of removing the manure credit is shown in Figure 10.

It is clear that the use of carbon credits for certain feedstocks has a large impact on sites using those feedstocks, and typically generates negative emissions factors (compared to the counterfactual fate of that feedstock) in sites using only those feedstocks. The impact of including or excluding carbon credits for certain feedstocks is much larger – for sites using only these feedstocks – than the impact of any changes in operations (e.g. increasing or decreasing transport distance, etc).

The value of the carbon credit is also not trivial, as larger carbon credits will have a larger impact in reducing emissions and will generate larger negative emissions intensities.

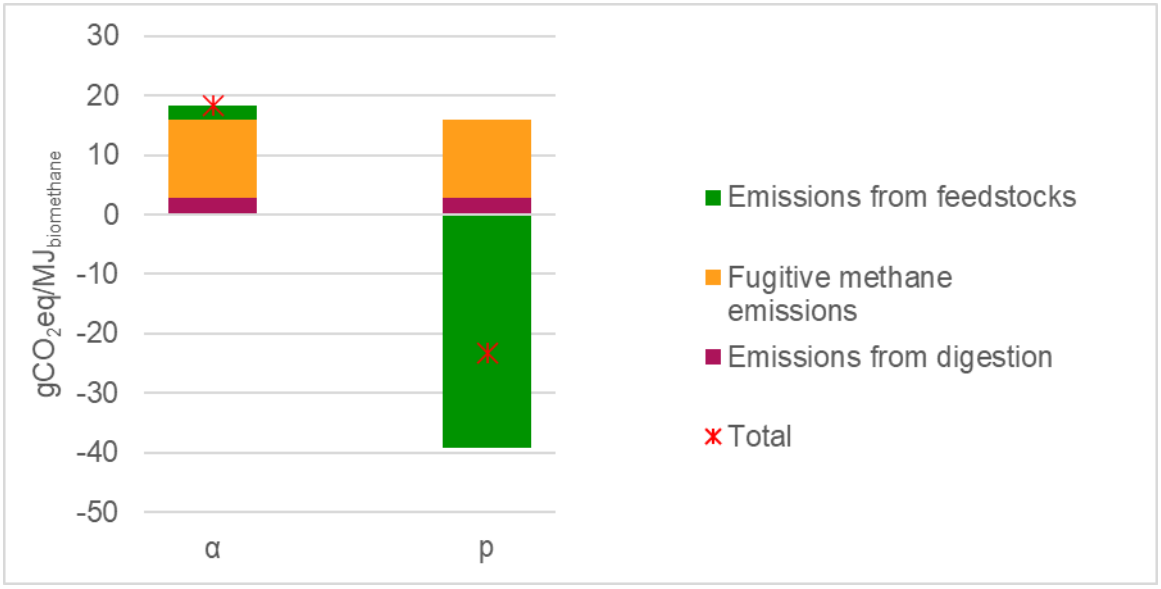


Figure 9: Emissions from a medium-sized waste-processing biomethane AD plant without considering a carbon credit for the use of wastes as a feedstock (α) and the same plant, applying a carbon credit (p). For details of the credit used, see section 2.2.8.

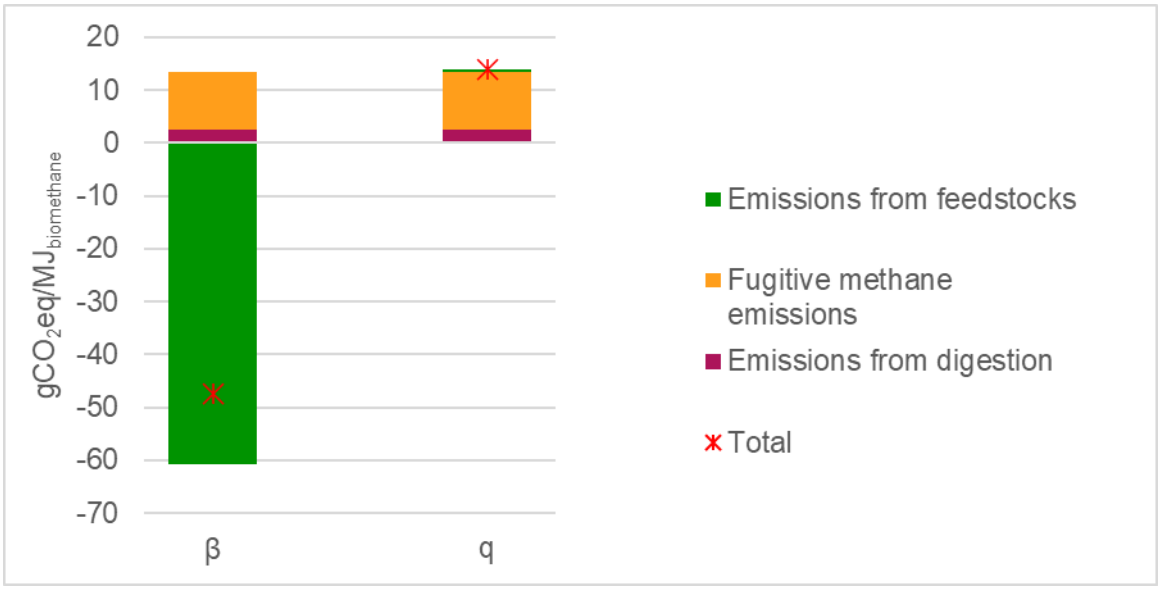


Figure 10: Emissions from a medium-sized manure-processing biomethane AD plant with carbon credit for the use of manure as a feedstock (β) and the same plant, removing the carbon credit (q). For details of the credit used, see section 2.2.7.

4.3.6. Interaction between negative emissions and other factors

Several factors that typically increase emissions, like those discussed in section 4.3, can make emissions more negative when a feedstock with negative emissions is used. For example, low digestion efficiency (i.e. not getting all the biomethane potential out of a feedstock) would generate a lower emission (greater negative emission), as shown in Figure 11.

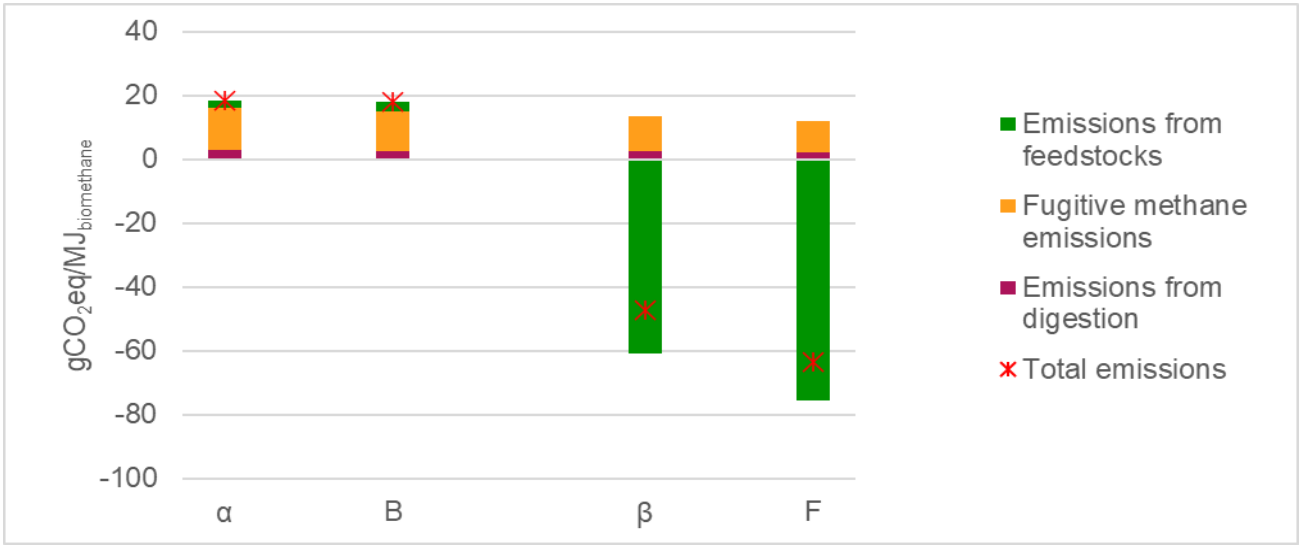


Figure 11: Emissions from a waste-processing (α) and a manure-processing (β) biomethane AD plant with medium digestion efficiency, compared to low-digestion efficiency (B and F).

Negative emissions, arising from feedstocks associated with carbon credits, are also affected by allocation to digestate as a co-product. Figure 12 shows the same two digestate scenarios as Figure 7, but in addition to waste, scenarios with manure as the feedstock are also shown. Here, rather than leading to lower emissions, improved solid–liquid separation (scenario z) leads to higher (less negative) emissions than in the baseline manure scenario (β). In contrast, if the digestate is not separated, the emissions are lower (more negative). Again, this is only due to the LCA methodology of allocation, rather than any impacts on real emissions from these AD sites.

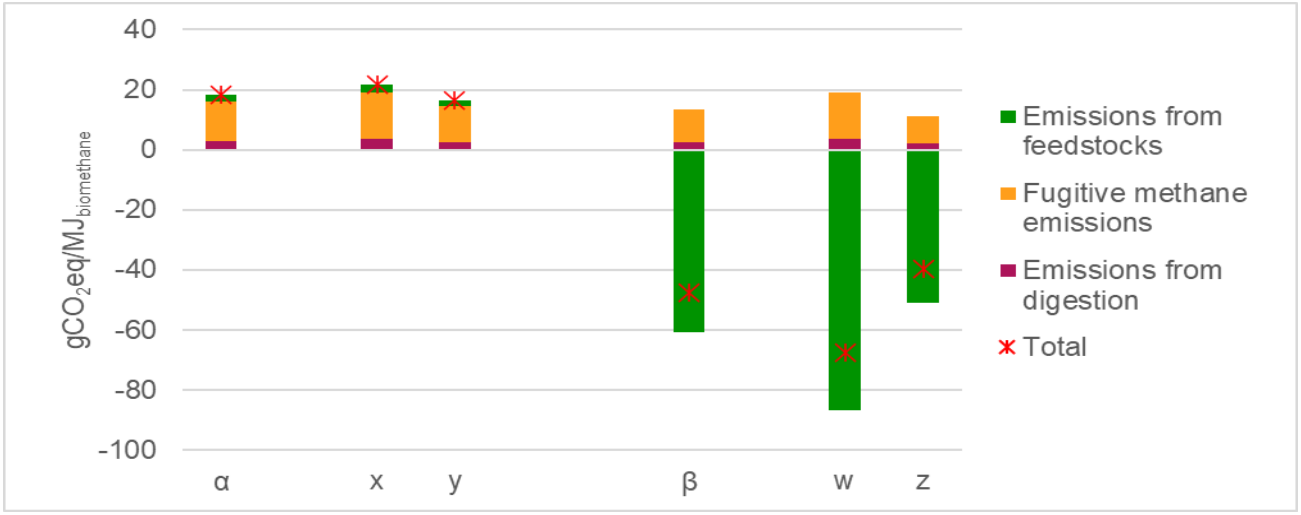


Figure 12: Emissions associated with biomethane from a medium-sized manure-processing plant under 3 different digestate-processing scenarios. In the baseline scenario, β, digestate is separated into a solid fraction at 25% DM and a liquid fraction at 5% DM, with 25% and 75% of the digestate (DM) going to each fraction, respectively. In scenario w, digestate is unprocessed; its DM is 10%. In scenario z, the solid–liquid separation of digestate is more effective: the solid fraction is more concentrated (30% DM), while the liquid fraction is more dilute (1%), and a larger fraction of the digestate has been recovered in the solid fraction (30%) than the liquid fraction (70%).

4.3.7. Impact of these factors on policy

In particular where biomethane support mechanisms offer greater support for greater carbon savings, it is important to understand the impacts that LCA approaches may have on total carbon emissions.

A site using only manure as a feedstock would, in theory, also be able to generate a larger negative emission by using large amounts of manure but getting little energy out. This would be an unintended consequence of the policy, and would not be the most efficient use of the resource (which would be to get the maximum amount of biomethane out). Furthermore, incomplete digestion of the manure may have an impact on fugitive methane emissions from digestate storage and spreading.

For example, a site using only manure as a feedstock would generate a lower (i.e. more negative) emissions value if they did not carry out solid–liquid separation of digestate versus if they did carry out solid–liquid separation.This would be an unintended consequence of the policy, and it is unclear the effect that less solid–liquid separation of digestate would have on emissions from digestate storage and in-field emissions from fertiliser application.

However, it should be noted that the Non-Domestic Renewable Heat Incentive and Green Gas Support Scheme both pay participating AD operators according to the amount of biomethane injected into the grid, rather than by emission levels, meaning that current government policy is not likely to incentivise this unintended consequence.

5. UK Fleet GHG Analysis

5.1. Modelling the UK fleet

Using this tool, it is also possible to analyse the fleet and to perform a sensitivity analysis looking at various operational parameters. An alternative approach to analysing the UK fleet – direct extrapolation from the case studies – can be found in the Annex.

As a baseline, the fleet was modelled using average feedstocks and associated data (from the model), average operational data (energy requirements, volumes of biomethane achieved, efficiency of digestion, etc), as well as low fugitive methane emissions from installed equipment (i.e. biogas upgrading unit, CHP and boiler), medium fugitive methane emissions from operation and medium fugitive methane emissions from digestate.

5.1.1. Conventional functional units

Typically, emissions from biomethane production are given on the basis of a MJ of biomethane produced.

In order to look at the whole fleet, a weighted average of the GHG emissions associated with each category of site in the fleet was calculated. The weighting was based on the occurrence of each site type. The results for each type of AD plant are shown in Table 6. The weighted average emission – taking into account the different volumes of methane generated at each type of AD plant – is 14.8 $gCO_2eq/MJ_{biomethane}$.

Table 6: Type of AD plant along with their occurrence in the UK fleet and the GHG emissions of biomethane from the model.

Type of AD plant	Occurrence	Emissions in $gCO_2eq/MJ_{biomethane}$
BtG, medium, manure & crop	31	−9.8
BtG, medium, crop	29	32.6
BtG, medium, industry	5	17.9
BtG, medium, waste	23	18.3
BtG, large, manure & crop	6	−8.5
BtG, large, crop	7	33.1
BtG, large, industry	3	18.6
BtG, large, waste	13	19.1
BtG, very large, waste	3	18.1
Weighted average (by occurrence)		14.8

5.1.2. Comparison with fossil fuel

To bring the value of 14.8 $gCO_2eq/MJ_{biomethane}$ into context, it is necessary to consider what is being replaced in the market (Figure 13). In the context of GGSS, the emissions limit is 24 $gCO_2eq/MJ_{biomethane}$, which represents a 70% emissions savings against a fossil-fuel comparator of 80 gCO_2eq/MJ. Using the same comparator, emissions of 14.8 $gCO_2eq/MJ_{biomethane}$ represent a saving of 81.5%, using the LCA method and assumptions in this study. This comparator is higher than natural gas, which can be justified owing to the potential uses of biomethane not only in displacing natural gas in domestic boilers, but also in displacing natural gas, oil and coal in industrial heat applications.

Using a more conservative comparator, the carbon intensity of natural gas on the UK grid (in 2024) is 66.075 gCO_2eq/MJ[43]. Making a direct comparison, the emissions saving from the biomethane currently being produced is 77.6%, using the LCA method and assumptions in this study.

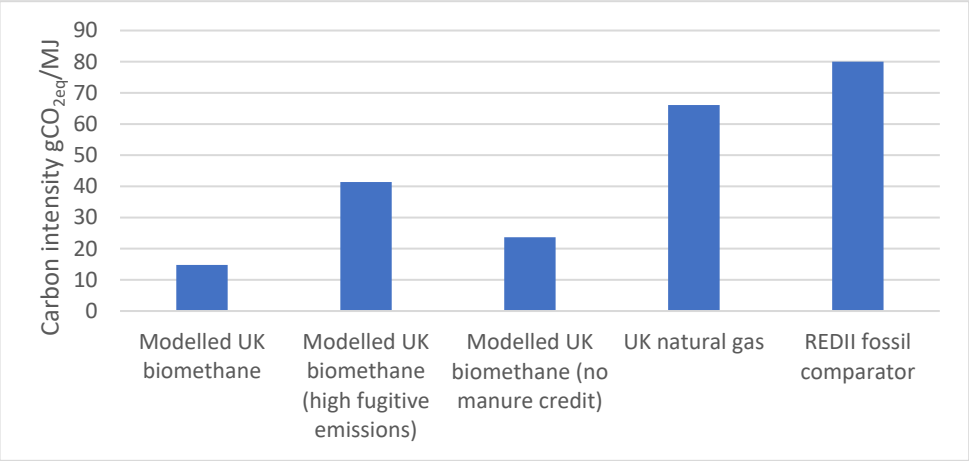


Figure 13: Emissions from modelled UK biomethane as compared to two different fossil fuel comparators.

Table 7: Emissions from modelled UK biomethane as compared to two different fossil fuel comparators (as in Figure 13). High fugitive methane scenario is taken from Table 9.

	Emissions intensity (gCO_2eq/MJ)	Emissions saving vs UK natural gas %	Emissions saving vs RED II comparator
Comparator (gCO_{2eq}/MJ)		*UK Natural gas - 66.1*	*RED II fossil comparator - 80*
Modelled UK biomethane (base case)	14.8	77.61%	81.50%
Modelled UK biomethane (high fugitive emissions)	41.4	37.37%	48.25%

[43] Using 2024 conversion factors from DESNZ, including Scope 1 and 3 emissions for natural gas (100% mineral blend), available at https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

Modelled UK biomethane (no manure credit)	23.67	64.19%	70.41%

5.1.3. Annual emissions

It is clear that the value of 14.8 $gCO_2eq/MJ_{biomethane}$ only gives limited information, as it does not relate to the amount of biomethane generated. However, the total volume of biomethane production in the UK is not publicly declared, and official estimates (e.g. DUKES[44]) are regarded within industry to be overstated[45] as they are based primarily on estimates of installed capacity. They do not take into account the amount of biomethane actually produced.

The case studies showed that while CHP-only AD plants were commonly operating at an average of 91% of their installed capacity, biomethane injecting plants were operating further below their installed capacity. This may be because sites have over-sized their AD capacity or grid injection equipment (upon which capacity is typically based) in anticipation of future expansion, or to deliver economies of scale necessary to make projects financially viable, and subsequently struggled to secure sufficient feedstock. Farm-fed AD plants in the case studies reached an average injection rate of 86% of installed capacity, while some of the waste-fed plants in the case studies reached only 50% of their installed capacity. This difference may be attributable to the expectation that waste-fed AD plants will be able to expand in the future and lower than expected volumes of waste are available today, given delays introducing separate food waste collections, considering many waste-fed plants are set to target newly collected waste when it becomes available. This could also be attributable to operational parameters such as the comparative ease of running an AD site on consistent agricultural feedstocks from a small number of sources (as opposed to variable waste feedstocks from various sources).

Table 8 shows the annual emissions associated with generating biomethane, which are 282,808 tCO_2eq/year, associated with a biomethane volume of 19,113 TJ/year or 5.31 TWh (around 80.1 % of installed capacity). On an annual level, 5.31 TWh of biomethane is around 0.7% of the UK's natural gas demand (787 TWh/year[46]).

[44] Digest of UK Energy Statistics (DUKES), available for every year at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
[45] Personal communications.
[46] Using 2022 data from DUKES Table 4.1 Natural gas commodity balance

Table 8: Type of AD plant along with their occurrence in the UK fleet and the GHG emissions of biomethane from the model.

Type of AD plant	Occurrence	Annual emissions from biomethane in tCO_2eq/year
BtG, medium, manure & crop	31	−36,836
BtG, medium, crop	29	115,254
BtG, medium, industry	5	10,930
BtG, medium, waste	23	51,276
BtG, large, manure & crop	6	−12,353
BtG, large, crop	7	56,370
BtG, large, industry	3	13,616
BtG, large, waste	13	60,534
BtG, very large, waste	3	24,019
Total as extrapolated to fleet*		282,808

* Based on a volume of 19,113 TJ (5.05 TWh) per year (around 80.1 % of installed capacity).

5.1.4. Sensitivity to operational parameters

The sensitivity of the modelled fleet to various adjustable parameters was considered with parameters adjusted and results shown in Table 9. Against the baseline scenario of 282,808 tCO_2eq/year, changing each parameter either increased or decreased the emissions (Figure 14).

Increasing the fugitive methane emissions had the largest impact on overall emissions, with emissions increasing by 508,599 tCO_2eq/year (+180%) to 791,407 tCO_2eq/year in the high-fugitive-emissions scenario and decreasing by 141,432 tCO_2eq/year (–50%) to 141,376 tCO_2eq/year in the low-fugitive-emissions scenario.

As mentioned previously, most biomethane-injecting AD plants were not operating at their installed capacity. Increasing the volume of biomethane injected (by getting closer to the installed capacity) increased the annual emissions by 41,555 tCO_2eq/year to 324,363 tCO_2eq , but it also increased the volume of biomethane generated (from 19,113 TJ/year to 24,503 TJ/year or 5.05 TWh/year to 6.81 TWh). On a per MJ biomethane level, it *decreased* the average carbon intensity from 14.8 to 13.2 $gCO_2eq/MJ_{biomethane}$ (Figure 15).

Table 9: Parameters and results for sensitivity analysis in Figure 14 and Figure 15.

	Low	Baseline	High
Fugitive methane	**1% overall** 0% of CHP 0% of BUU 0.5% from operations 0.5% from digestate	**2.5% overall** 0.5% of CHP 0.5% of BUU 1% from operations 1% from digestate	**7.8% overall** 1% of CHP 2% of BUU 3% from operations 3% from digestate
Annual emissions in tCO_2eq	141,376	282,808	791,407
Annual emissions % of baseline scenario	50%	100%	280%
Emissions in $gCO_2eq/MJ_{biomethane}$	7.4	14.8	41.4
Digestion efficiency	**82%**	**113% (see Annex 9.8.7)**	**143% (see Annex 9.8.7)**
Annual emissions in tCO_2eq	260,500	282,808	297,407
Annual emissions % of baseline scenario	105%	100%	92%
Emissions in $gCO_2eq/MJ_{biomethane}$	13.6	14.8	15.6
Capacity reached (of installed BtG)	**57%**	**78%**	**100%**
Annual emissions in tCO_2eq	243,146	282,808	324,363
Annual emissions % of baseline scenario	86%	100%	115%
Emissions in $gCO_2eq/MJ_{biomethane}$	17.4	14.8	13.2
Transport of feedstock	**All 0 km**	**Waste/residue: 150 km** **Crops/manure: 20 km**	**Waste/residue: 300 km** **Crops/manure: 40 km**
Annual emissions in tCO_2eq	260,505	282,808	305,445
Annual emissions % of baseline scenario	92%	100%	108%
Emissions in $gCO_2eq/MJ_{biomethane}$	13.6	14.8	16.0

Increasing digestion efficiency led to a small improvement in emissions, although it should be noted that the potential link between digestion efficiency and fugitive methane emissions from digestate was not modelled, which would likely have a larger effect on overall emissions.

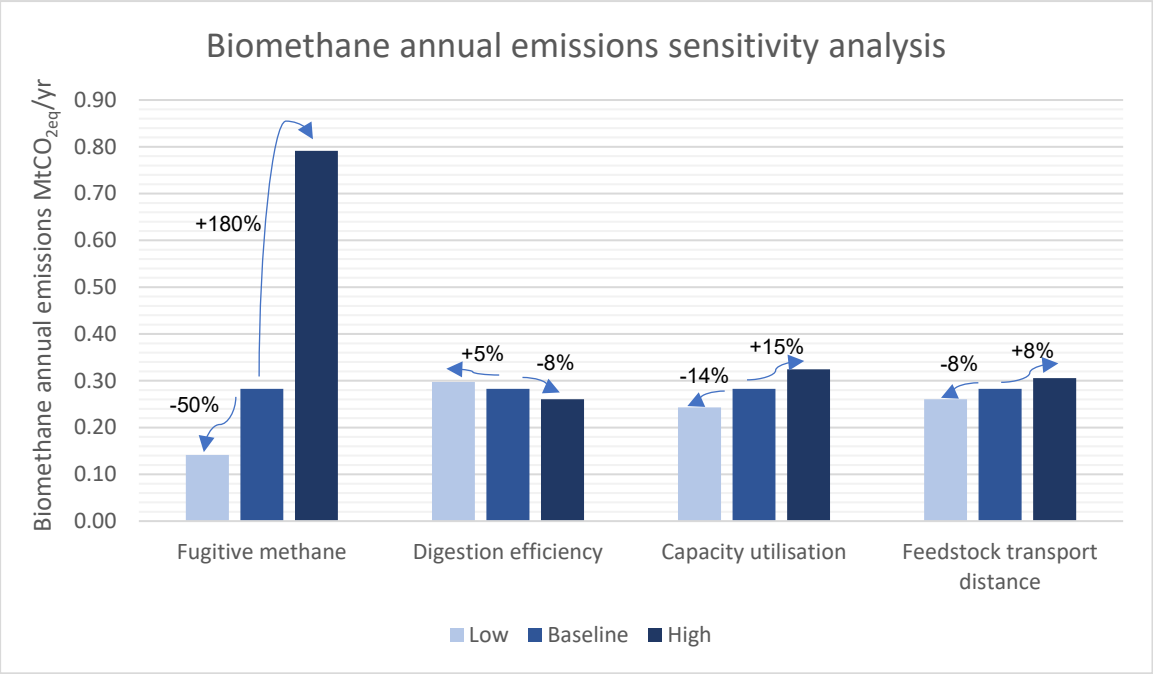


Figure 14: Sensitivity analysis showing annual emissions (in million tonnes of CO_2) when several parameters (feedstock transport, capacity achieved, digestion efficiency and fugitive methane emissions) are increased or decreased.
Increasing the capacity reached also increased the amount of biomethane generated (from 19,113 TJ/year to 24,503 TJ/year or 5.31 TWh/year to 6.81 TWh). The overall effect is that the carbon intensity per MJ of biomethane was decreased, see next figure.

Alternative modes of feedstock transport were not built into the model, but by doubling the transport distance or by reducing it to zero, it was possible to see the impact of transport on emissions. Reducing feedstock transport to zero (or switching to a zero-emissions vehicle) reduced annual emissions by 22,303 tCO_2eq (8%), while doubling transport increased emissions by the same amount. On a per MJ basis, cutting feedstock transport emissions reduced emissions from 14.8 to 13.6 gCO_2eq/MJ and doubling transport distance increased emissions from 14.8 to 16.0 gCO_2eq/MJ.

To illustrate the impact of the sensitivity analysis on the carbon intensity, Figure 15 depicts how this changes as fugitive methane, digestion efficiency, BtG capacity reached and transport distance vary.

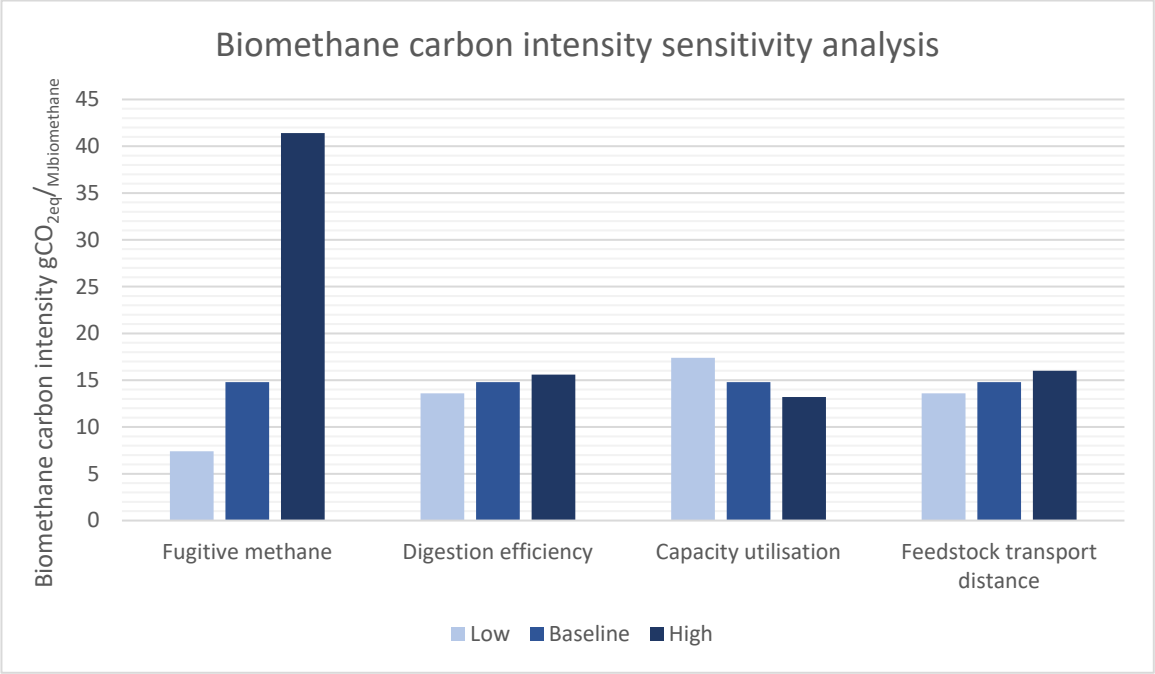


Figure 15: Sensitivity analysis of carbon intensity (in $gCO_{2eq}/MJ_{biomethane}$) based on values provided in Table 9.

5.1.5. Sensitivity to LCA methods

The sensitivity of the modelled fleet to various LCA methodological choices was considered. Against the baseline scenario of 282,808 tCO_2eq/year, changing methodological approach either increased or decreased the emissions (Figure 16). Not applying a manure credit increased annual emissions by 60%, while not allocating emissions to digestate increased emissions by 22%. Combining these two (neither applying a manure credit nor allocating emissions to digestate) doubled emissions.

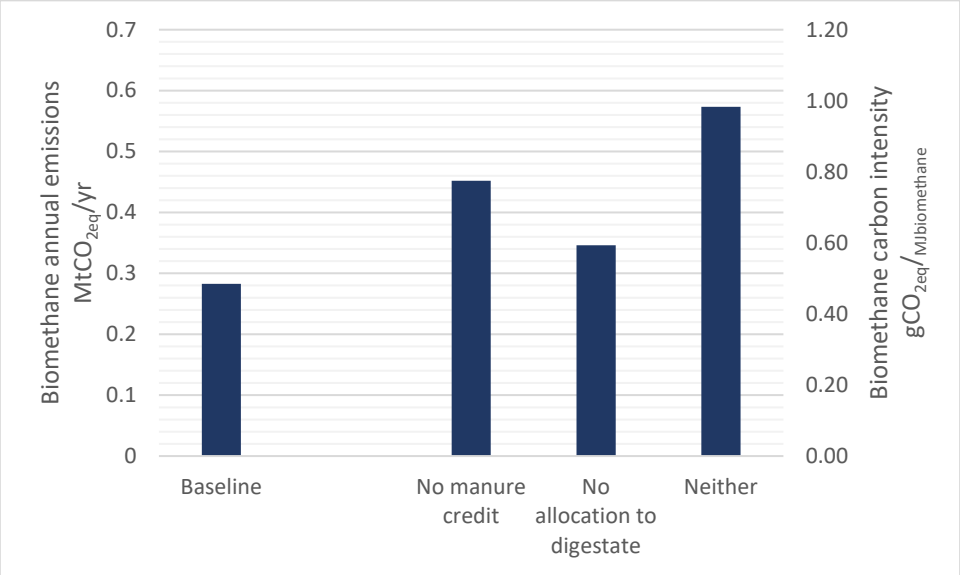


Figure 16: Emissions from the current biomethane fleet, showing the impact of changing LCA methodology.

5.2. Carbon savings not quantified

5.2.1. CO_2 capture and liquefaction

This study did not look at emissions savings from CO_2 capture in the current fleet, as no CO_2-capturing sites were considered in the case studies. Around 13[47] AD sites currently have CO_2 capture and liquefaction equipment installed, with more planned.

Assuming these 13 sites are all medium-sized, this represents around 52,709 tCO_2/year saved, bringing the fleet emissions down to 230,100 tCO_2eq/year (from 282,808 tCO_2eq/year). This figure takes into account the additional electricity[48] needed for CO_2 compression, which reduces the emissions savings from CO_2 capture by 3%. See Annex section 9.10 for details of this calculation.

Although this is not currently sent to permanent sequestration, this CO_2 displaces – within the market – fossil CO_2 currently used for other purposes (such as beverage carbonation, dry ice production and livestock sedation). It should be noted that the carbon credit for displaced fossil

[47] Personal communication, Q1 2024
[48] It was assumed that additional electricity consumption game from the electricity grid. This means that the number will come down as the UK electricity grid becomes greener.

CO_2 is debated because – while it is clear that fossil CO_2 is displaced in the *market* – it is not clear whether fossil CO_2 generation is reduced in the *world*, or whether it is still generated but no longer captured and liquified.

5.2.2. Carbon savings from increased soil carbon stock

No data was available in the case studies on increases in soil carbon stock from improved agricultural management, such as the impact on soil carbon of the application of digestate or alternative cropping techniques. For this reason, no default values have been included in the tool; however, a placeholder is available to allow values to be included should data become available as it is envisaged that accounting for soil carbon accumulation can have a significant positive impact on overall emissions. The challenge in including such savings lies in the measurement, monitoring, allocation and evidencing of such benefits. Further work is required to establish a method and guidance for such, to allow this to be more accurately included in the future.

5.3. Not included in this study

This work focussed on emissions from biomethane production. This means that emissions allocated to exported electricity, exported heat, or digestate as co-products are not reported.

This work focussed on the biomethane fleet, so the CHP-only AD fleet was not included.

6. Future growth scenarios

The UK has developed a strong AD industry over the last 25 years with a heightened recent focus on biomethane for grid injection, with the current injection, as of 2024, being around 7.9 TWh[49]. Growth has been driven by a range of support schemes, focussed on increasing production of renewable energy from a range of technologies, including AD. Although growth has slowed in recent years, mainly due to the closure of some of the support schemes, interest in the development of new projects remains high given the breadth of benefit and scale of opportunity the sector presents. Legacy support from these schemes, in addition to the current GGSS, is expected to deliver a peak of around 8 TWh of biomethane injection per year by 2030 based on current projections. Also, looking beyond current biomethane capacity, approximately 10.6 TWh per year of additional biogas production capacity exists in CHP-only AD plants.

The Biomass Strategy 2023[50] outlined that around 30–40 TWh of biomethane production in 2050 would help the UK achieve net zero cost-effectively, based on best utilising feedstocks such as animal slurries, food waste and maize, sewage sludge and the upgrade of landfill gas. This could come from both legacy capacity, some of which could be converted from biogas-CHP to biomethane, and newly installed capacity which would need to increase significantly from current levels.

NESO are considering the role of biomethane in the energy system and included 64 TWh in their Holistic Transition pathway in FES 2025. Recent industry analysis[51] concluded that looking broader than the current feedstock mix, considering the wider benefits of AD and biomethane, and considering feedstock availability, it is possible to deliver up to 120 TWh of biomethane per year in the UK by 2050.

Growth in the sector is expected to come from a range of types and scales of AD. As a result, and to evaluate the future fleet impact, the following growth scenarios are considered in this analysis (Table 10), basing 2030 projections on GGSS market intelligence (at the time of writing this report in 2024) and ambition, and an almost trebling of capacity by 2050.

[49] DUKES (2025), Chapter 6.4. Available from: https://www.gov.uk/government/statistics/renewable-sources-of-energy-chapter-6-digest-of-united-kingdom-energy-statistics-dukes
[50] Biomass Strategy (2023). Available from: https://www.gov.uk/government/publications/biomass-strategy
[51] Green Gas Taskforce report. Available from: https://greengastaskforce.co.uk/wp-content/uploads/2025/09/GGT-Unlocking-the-Potential-of-Biomethane.pdf

Table 10: Conservative future forecast for fleet composition.

Year	2024		2030		2050	
Type of AD plant	Number	Inst. Cap. (scm/h)	Number	Inst. Cap. (scm/h)	Number	Inst. Cap. (scm/h)
BtG, medium, manure only			3	1,547	43	22,180
BtG, medium, manure & crop	31	5,990	34	17,538	77	39,717
BtG, medium, crop	29	13,910	29	13,910	40	19,187
BtG, medium, industry	5	2,028	7	2,839	10	4,056
BtG, medium, waste	23	10,985	26	12,418	30	14,328
BtG, large, manure only			1	832	16	13,307
BtG, large, manure & crop	6	4,990	7	5,822	24	19,960
BtG, large, crop	7	4,295	7	4,295	17	10,431
BtG, large, industry	3	1,568	8	4,181	20	10,453
BtG, large, waste	13	10,490	18	14,525	25	20,173
BtG, very large, waste	3	5,625	4	7,500	8	15,000
TOTAL	120	69,882	141	83,859	267	166,613

6.1. Future fleet impact

Using the model along with the type and frequency of biomethane plants shown in Table 10, with all the same assumptions as in the basic fleet model (Table 6 and Table 8), the emissions from biomethane generation in 2030 are 313,875 tCO_2eq/year (13.2 $gCO_2eq/MJ_{biomethane}$) and in 2050 are 90,186 tCO_2eq/year (1,7 $gCO_2eq/MJ_{biomethane}$). This is using the baseline assumptions on fugitive methane emissions and including manure credit.

It is expected that as the industry continues to grow, awareness improves and better technology becomes available, fugitive methane emissions will be significantly lower. Using a lower emissions scenario brings emissions down to 138,644 tCO_2eq/year (4.91 $gCO_2eq/MJ_{biomethane}$) in 2030, and −284,809 tCO_2eq/year (−5.4 $gCO_2eq/MJ_{biomethane}$) in 2050. These numbers reflect production volumes of 6.62 TWh in 2030 and 14.65 TWh in 2050, assuming 78% of installed capacity is achieved (rising to 8.35 TWh in 2030 and 18.79 TWh in 2050 if 100% of installed capacity is reached). Figure 17 shows the predicted emissions per year in 2024, 2030 and 2050, based on the baseline fugitive methane emissions scenarios for 2024 and 2030, and on a low-fugitive-methane-emissions scenario for 2050.

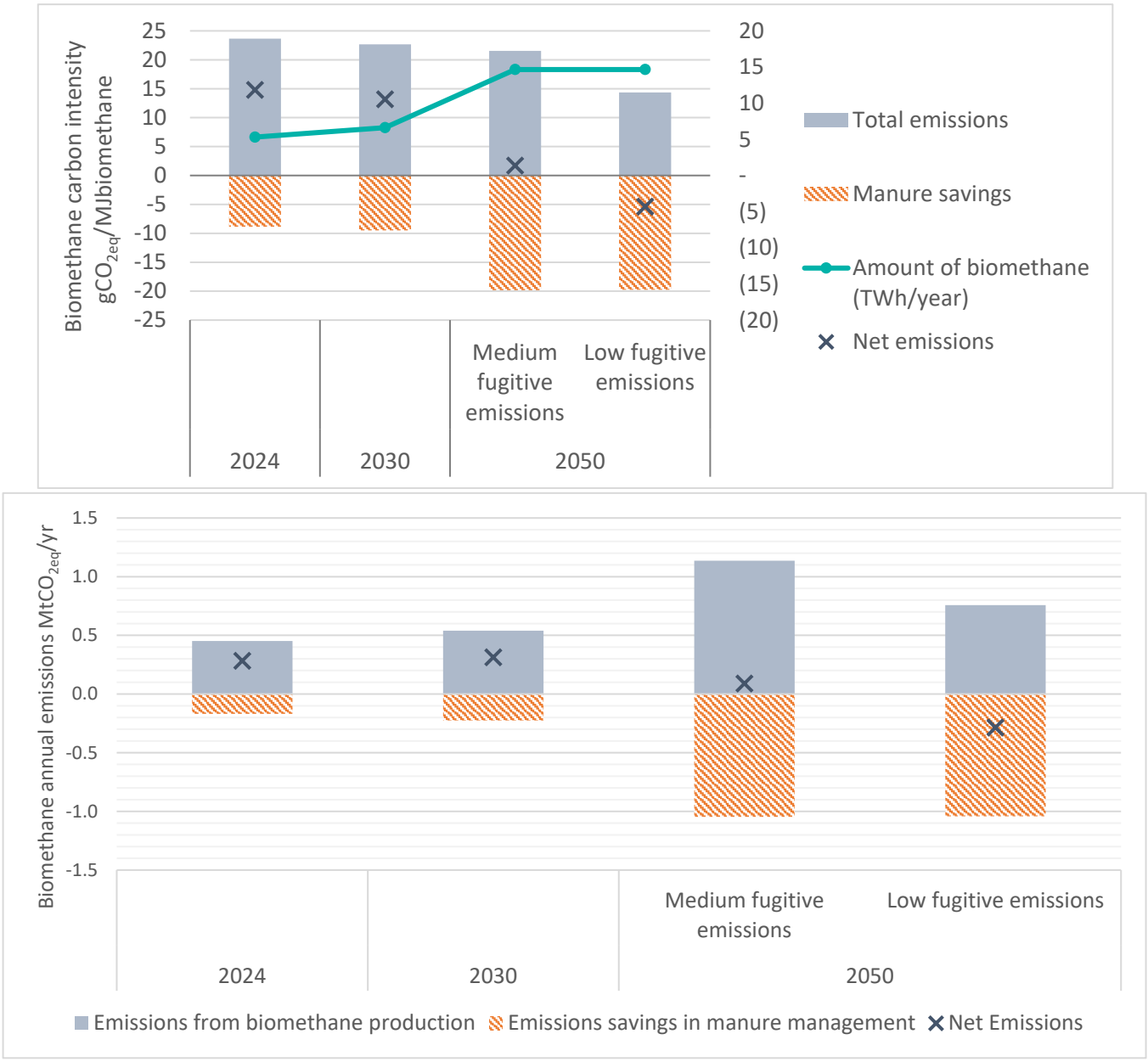


Figure 17: Carbon intensity of biomethane production as modelled in 2024, 2030 and 2050 on a per megajoule basis, along with the amount of biomethane generated in each year (top). Annual emissions from the combination of those two factors are also shown (bottom). A low fugitive-emissions scenario is assumed for 2050, as standards are likely to improve across the industry. CO_2 capture (for CCS or CCU) is not considered here.

Table 11: Numbers for Figure 17.

	2024	2030	2050
Annual emissions (tCO_2eq/year)	282,808	313,875	90,186
Biomethane emissions (gCO_2eq/MJ)	14.8	13.2	1.7
Amount of biomethane (TWh/year)	5.31	6.62	14.65

Assuming by 2030 half of the 24 new installations have CO_2 capture installed, as well as the 13 currently carrying out CO_2 capture, this could be further reduced by 123,662 tCO_2eq/year (from 313,875 tCO_2eq/year to 190,213 tCO_2eq/year in a medium-fugitive-emissions scenario and from 138,644 to 14,981 tCO_2eq/year in a low-fugitive-emissions scenario). There is a significant interest in greenhouse gas removals, both in government and in the private sector, to achieve net zero in hard-to-abate sectors. Assuming this drives CO_2 capture at both new and existing AD sites, and that three quarters of the fleet has CO_2 capture by 2050, there would be an additional carbon saving of 1,316,977 tCO_2eq/year (reducing emissions from 90,186 to −1,226,790 tCO_2eq/year in the medium-emissions scenario and from −284,809 to −1,601,786 tCO_2eq/year in the low-emissions scenario.

It is unclear whether this future carbon saving from CO_2 capture at AD sites can be claimed against biomethane production, or whether it will be used more widely to meet national or industry-level net-zero targets (e.g. traded on a carbon market). It is also unclear whether the manure credit will be permitted by 2050, or whether the agriculture sector will look to claim the emissions savings.

Arguably, a fairer way to describe the fleet is to give all the emissions associated with biomethane production, alongside all the carbon savings unlocked with the production of this biomethane. This is shown in Figure 18, where a low-fugitive-methane scenario is used for 2050 (owing to the expected improvements in equipment and best available techniques, as well as tightening of regulations) but not for 2030 (as significant large-scale change is unlikely in the next 5 years). The figure separates out all emissions savings from all credits (including the credits permitted under GGSS – for manure and CO_2 capture – and credits not currently considered – for waste).

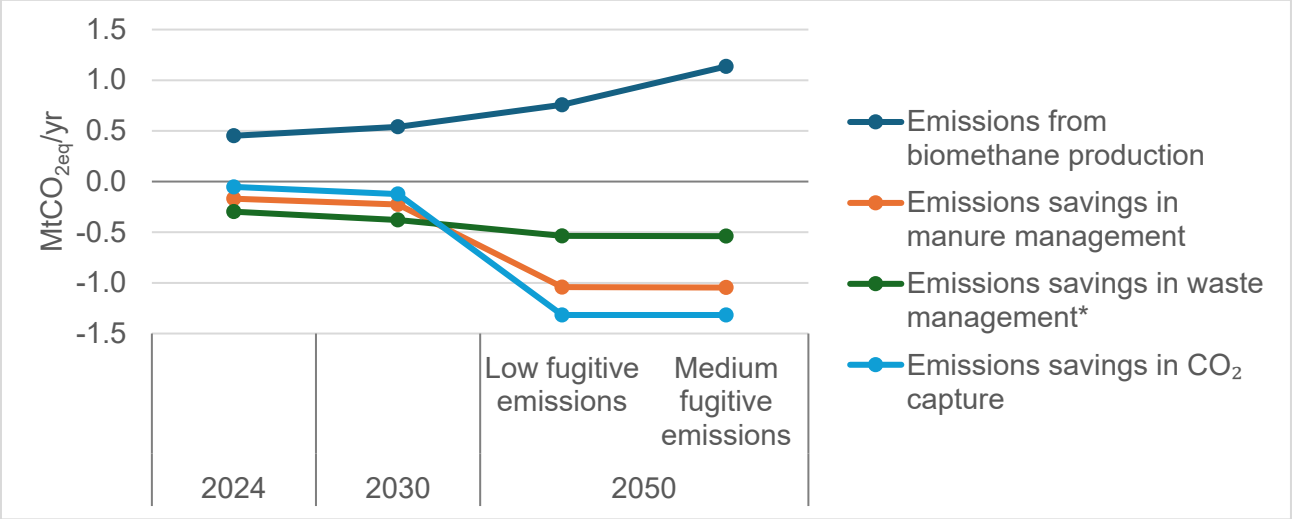


Figure 18: Emissions from biomethane production as modelled in 2024, 2030 and 2050, with carbon savings considered separately. Negative emissions for manure and waste management are against counterfactual use of those feedstocks and should not be considered equivalent to negative emissions from CO_2 capture. *The carbon credit for waste management is not robust, see section 2.2.8. N.B. Emissions savings from soil carbon accumulation have not been considered here, but would likely also add another line in the negative emissions side, with a downward trend over time.

Table 12: Emissions from biomethane production as modelled in 2024, 2030 and 2050, with carbon savings considered separately, as in Figure 18. 2024 and 2030 assume medium fugitive emissions.

	2024	2030	2050	
			Low fugitive emissions	Medium fugitive emissions
Emissions from biomethane production (tCO_2eq/year)	452,030	539,765	757,065	1,136,282
Emissions savings in manure management (tCO_2eq/year)	−169,222	−225,890	−1,041,874	−1,046,096
Emissions savings in waste management* (tCO_2eq/year)	−297,467	−379,593	−536,665	−536,665
Emissions savings in CO_2 capture (tCO_2eq/year)	−52,709	−123,662	−1,316,977	−1,316,977

As the demand for captured CO_2 and the support mechanisms associated with it evolve, LCA methodologies may change in that emissions from biomethane generation may also be allocated to CO_2 capture. This cannot be done by energy content, only by mass, carbon content or economic allocation. In Figure 18, allocation to digestate based on energy content is still used. However, if LCA methodology conventions for fuel reporting are opened up to allow other types of allocation, allocation to digestate by energy content may be replaced.

The increase in capacity modelled here is very conservative (14.65 TWh by 2050), and falls short of the 30–40 TWh of biomethane production set out in the Biomass Strategy as helping to achieve net zero cost effectively. Furthermore, industry estimates have shown that it would be possible to increase biomethane production around 10-fold, if working outside of the restriction of 50% crop use in AD plants, adopting alternative crop production regimes. Making use of sustainable agriculture and CO_2 capture, industry reports have suggested that it would be possible to achieve these volumes and deliver net negative CO_2 emissions.

6.2. Future work and research needs

Future work is still needed to address areas missing in this work.

It is clear that fugitive methane emissions have a huge impact on emissions, but the real state of affairs is not known. Recently published and ongoing DESNZ research is addressing some of these gaps. It is also important to understand how to reduce fugitive methane emissions, both through the use of low-emissions equipment (including CHPs and biogas upgrading units) and best practice in regular leak detection and prevention, to ensure the biomethane produced in the future is truly sustainable.

While different LCA approaches to multifunctionality (e.g. biomethane and digestate as co-products) were discussed in sections 2.2.5 to 2.2.9, only allocation by energy content or no

allocation (co-products as surplus) were considered. Further work developing alternatives, such as a robust figure for allocation to digestate and/or CO_2 by economic value, would be valuable.

As discussed in section 2.2.8, more work is required to generate a robust waste management credit value. It is clear that waste management is an important service provided by AD, but the value of the service requires further elaboration in order to allow that benefit to be reflected in any carbon credits.

Emissions savings from soil carbon accumulation from low-carbon crop cultivation methods and the application of solids from digestate spreading were not considered, owing to a lack of good data in the case studies. However, this could represent significant emissions savings for biomethane plants using crops as feedstocks, and is predicted by many in the industry as one of the main drivers of biomethane growth in the future, aligning with regenerative agriculture principles being prioritised in Defra policy at present. Other than a handful of voluntary schemes, there are few incentives for farmers to carry out carbon-negative farming practices outside of biomethane or biofuel feedstock production, so this represents a major opportunity to reduce emissions from agriculture with a readily established solution.

Biomethane from the treatment of wastewater and waste-activated sludge (WAS) was also not considered in this work. This is partly owing to a lack of good case studies, and partly because the arguments in favour of AD of wastewater and WAS include the provision of process heat and electricity within the wastewater treatment sector, which is different from the arguments in favour of biomethane generation in general. Therefore, it can be argued that it is not fair to look at wastewater and WAS sludge in the same way as other AD feedstocks; instead, it is important to look at the whole picture within a wastewater treatment plant, and the role that biogas plays.

7. Conclusions

Carbon accounting by LCA is an important part of biomethane policy as there are typically GHG criteria that must be met in order for biomethane to be considered a renewable energy source, and in order to benefit from incentives. This is typically a maximum emissions threshold or a minimum GHG saving against a fossil-comparator that may be associated with the biomethane production, to the point of injection or supply depending on the support being claimed. Alternatively, there may be mechanisms by which biomethane producers are rewarded based on the amount of GHG emissions saved – this approach is becoming increasingly common elsewhere in the world, as the pathway to Net Zero becomes more critical. In all cases, it is essential that the rules or methods for carbon accounting or LCA are comprehensively considered and clearly laid out. It is also important that the risk of unfairness or unintended consequences associated with the methodology are known.

Informed by the review of existing and alternative LCA methods, and following a period of stakeholder consultation, the bespoke LCA tool was developed to calculate the lifecycle emissions of biomethane and to examine the GHG impacts of parameters beyond the current scope, to better inform future policy and industry thinking on the potential of the AD sector.

The tool serves to demonstrate the impact of various LCA methodology choices on the calculated carbon intensity of biomethane. Furthermore, it serves to run various scenarios that can be used to shape future policy using actual or modelled data.

Running actual data from the current biomethane fleet showed that the carbon intensity of biomethane generated in existing systems ranges from carbon negative (using large quantities of manures and applying a carbon credit) to higher than the current GGSS targets (using certain LCA methodologies). Actual data on fugitive methane emissions was not available from any of the surveyed plants, and plants used optimistic default values for their own carbon accounting (e.g. for RHI).

As evidenced by the analysis, the outcomes of the LCA are highly sensitive to the quality of data used and the selected method, and a broad range of results are apparent. However, while AD plants are incentivised to deliver lower carbon biomethane through the use of GHG thresholds, tighter thresholds or scaling financial support with emissions could encourage AD operators to pursue further emissions reductions.

The first step in reducing emissions and delivering lower-carbon biomethane is awareness of the key contributors, which are evident from this study. The main sensitivities have been identified as fugitive methane emissions, availability, performance and transport, as well as certain idiosyncrasies associated with the LCA methodology conventionally used for biomethane and biofuels reporting.

Furthermore, following significant advances in system design, operation and technology in the past decade, new AD capacity is already expected to deliver lower carbon biomethane as a result of more sustainable feedstock production, procurement and use; improved efficiency;

automated leakage detection systems; and, equipment available to monitor, reduce and capture fugitive methane emissions at various stages of the process, from feedstock storage and processing through to digestate storage, distribution and spreading.

As the focus of policies and the sector has broadened beyond just delivering renewable energy, a whole systems view leads to AD being considered a critical component for meeting the 2050 net zero target. As now adopted in other sectors and elsewhere around the world, incentivising lower carbon energy on the basis of emissions reductions, rather than setting a threshold for all production to meet as is currently the case with GGSS, could accelerate decarbonisation efforts within the biomethane sector. Furthermore, taking a broader LCA view as opposed to well-to-wheel accounting, allows the wider system benefits to be considered and accounted for, in turn delivering greater value to the producer through improvements to the environment and the economy. Broadening the scope of the approach also allows the wider system benefits, such as increased digestate use and more sustainable crop production, to be recognised in parallel sectors, in turn supporting decarbonisation efforts elsewhere.

8. Glossary

AD – anaerobic digestion, a biological process that breaks down organic matter in the absence of oxygen and generates a biogas consisting largely of methane and CO_2.

Biogas – the unprocessed gas generated from AD, consisting of methane, CO_2 and other gases such as water vapour, nitrogen, ammonia and hydrogen sulphide.

BtG – biomethane to grid, describing AD sites that upgrade biogas to biomethane and inject it into the gas grid.

CCU – carbon capture and use, sometimes called carbon capture and replacement (CCR). In AD, an example would be the capture of CO_2 from the biogas upgrading unit and its use in the manufacture of carbonated beverages.

CCR – carbon capture and replacement, see CCS.

CCS – carbon capture and storage. In AD, an example would be the capture of CO_2 from the biogas upgrading unit and its permanent storage (e.g. in a geological CO_2 storage site).

CHP – combined heat and power, used to describe a unit process at an AD site that uses gas (e.g. biogas or natural gas) to generate a combination of heat and power at a typical thermal efficiency of 38–45% and electrical efficiency of 35–41%.

CI – carbon intensity [of a fuel, product or service], which is the greenhouse gas emissions associated with a fuel, product or service, expressed as their global warming potential in terms of equivalent weight of carbon.

FIT – UK Feed-in Tariffs scheme, a government scheme to support renewable electricity generation that was open to applicants from 2010 to 2022.

GCV – gross calorific value, also referred to as HHV; see HHV.

GGSS – Green Gas Support Scheme

GHG – greenhouse gas, a gas that contributes to global warming via the greenhouse effect.

GWP – global warming potential, a method of comparing greenhouse gases by their impact.

HHV – higher heating value, also referred to as GCV; the energy content of a fuel, described as ‘higher’ because it does not consider the fact that some heat is lost when condensing the water vapour generated during combustion of the fuel. See also LHV.

kWh – kilo Watt-hours, equivalent to

Nm^3 – cubic meters of gas under normal conditions

LCA – lifecycle assessment

LCFS – [California] Low Carbon Fuel Standard

LHV – lower heating value, also referred to as NCV; the energy content of a fuel, described as 'lower' because it considers the fact that some heat is lost when condensing the water vapour generated during combustion of the fuel. See also HHV.

MJ – megajoules, equivalent to 3.6 kWh

NCV – net calorific value, also referred to as LHV; see LHV.

RED – Renewable Energy Directive (2009)

REDII – The 2018 recast Renewable Energy Directive

RHI – UK Renewable Heat Incentive, a government scheme to support renewable heat generation (including biomethane) that was open to applicants from 2011 to 2022.

scm – cubic meters of gas under standard conditions

TJ – terajoules, equivalent to 1,000,000 MJ

upgrading – the process of removing contaminating gases from biomethane, mainly water vapour, CO_2 and hydrogen sulphide.

9. Annex

9.1. AD Fleet analysis: site sizing

There are several conventions for AD plant sizing. Typically, sites with biomethane upgrading are described by the installed capacity of the biomethane-to-grid injection equipment, given in scm/h, regardless of whether they also operate a biogas CHP. Where sites mainly operate a biogas CHP (i.e. do not generate biomethane), sizing is typically described by the installed electrical capacity of the CHP, either in kW (if under 1000 kW) or MW (if over 1 MW). This convention was also used throughout this work. The following sizing was used in this work:

Table 13: Sizing used in this work.

	CHP only	Biomethane to grid
Micro	Up to 149 kW	(not available in this size) Under 40 scm/h
Small	Up to 499 kW	(not available in this size) Under 149 scm/h
Medium	Up to 2.999 MW	Up to 749 scm/h
Large	Up to 5.499 MW	Up to 1,299 scm/h
Very large	Over 5.5 MW	Over 1,300 scm/h

This sizing convention does not easily allow a comparison between CHP and biomethane-to-grid plants. To do this, an estimate of installed capacity in terms of useable biogas was made. The results are shown in Figure 2. Electrical capacity was converted to biogas capacity using standard efficiencies and conversion factors[52].

9.2. Fleet breakdown

A breakdown of the UK fleet can be found in Table 14.

As stated in the main body of the text, this data is based on the NNFCC database (2024). Some caveats with this database are that it may exclude some micro-scale AD plants (that are outside

[52] This takes into account into account: the conversion from scm – the units preferred in the UK gas grid – into Nm^3 – the units preferred in the engineering and biogas sector – which is 0.95 Nm^3/scm, and the lower heating value of methane, which is 35.8 MJ/Nm^3 or 9.94 kWh/Nm^3, all sourced from https://www.engineeringtoolbox.com/

of planning permission and subsidy) and some sewage-processing or wastewater-processing AD plants (that are outside of subsidy). Closures of AD plants may also not be fully captured.

Furthermore, the data in the NNFCC database was further edited to exclude all sewage-processing AD plants, as well as any AD plants using food waste obtained from mixed municipal solid waste (i.e. 'black bag' waste processed in a material recovery facility to remove non-organic content).

Table 14: Breakdown of UK AD fleet as used in this report.

Size	Feedstock	Biogas use	Occurrence	Capacity, BtG (scm/h)	Capacity, electric (kW)	Equivalent biogas capacity (MW)
MICRO	Manure	CHP	48		2,898	7.6
	Manure and crops	CHP	14		867	2.3
SMALL	Manure	CHP	27		5,487	14.4
	Manure and crops	CHP	132		44,467	117.0
	Crops	CHP	30		9,576	25.2
	Food waste	CHP	11		3,962	10.4
	Residues	CHP	14		4,479	11.8
MEDIUM	Manure and crops	CHP	76		60,757	159.9
	Crops	CHP	24		34,330	90.3
	Food waste	CHP	46		69,621	183.2
	Other waste	CHP	25		17,976	47.3
LARGE	Crops	CHP	3		10,543	27.7
	Food waste	CHP	23		91,640	241.2
	Other waste	CHP	1		4,800	12.6
V LARGE	Mixed waste	CHP	3		37,200	97.9
MEDIUM	Manure and crops	BtG	31	15,990	30,273	252.8
	Crops	BtG	29	13,910	17,802	197.4
	Food waste	BtG	23	10,985	29,005	195.2
	Other waste	BtG	5	2,028	6,415	38.8
LARGE	Manure and crops	BtG	6	4,990	6,297	70.6
	Crops	BtG	7	4,295	29,536	124.2
	Food waste	BtG	13	10,490	35,555	207.1
	Other waste	BtG	3	1,568	5,500	31.4
V LARGE	Mixed feedstocks	BtG	3	5,625	12,450	93.7
Total			597	69,882	571,434	2,260.2

Equivalent biogas capacity is calculated as the BtG capacity times 10.5 kWh/scm, divided by 97% efficiency, plus the CHP electrical capacity divided by 38% efficiency, all divided by 1000 kW/MW.

9.3. Data collected and assumptions used in case studies

Table 15: Data and key assumptions.

Key data and assumptions	
Feedstock volumes	Actual
Feedstock characteristics	Mostly actual, some default from RHI/FIT reporting.
Feedstock transport distances	Actual
Transport vehicles	Assumed as 40t diesel trucks, for solid feedstocks, and the equivalent for liquid feedstocks.
Crop yields and agricultural inputs	Defaults from RHI/FIT tool
Losses from silage making	Assumed at 10% (in line with RHI/FIT/REDII)
Electricity imported from grid	Actual
Fuel (diesel & natural gas) used	Actual
Biomethane injected	Actual
Electricity generated & exported	Actual
Heat generated & exported	Actual
Fugitive methane emissions from digestion	Assumed at 1%
Fugitive methane emissions from biogas upgrading	Assumed at 1%
Other fugitive methane emissions (e.g. from CHP, boiler, flare, digestate storage)	None in the base method

9.4. UK AD fleet

9.4.1. The survey

A survey was prepared and emailed out to a large number of AD site owners, operators and technology providers, of varying size and technology type, representing all categories.

The survey was formatted as a MS Word document accompanied by an MS Excel spreadsheet. The Word document contained two main questions; the first asking about site set-up, and the second asking about site operation. Prompts for each question were given as bullet points to help guide the responder and encourage a detailed answer.

To aid with the answering of the second question on site operation, a spreadsheet was also sent out which had tables for the collection of meter readings, as well as feedstock and digestate tonnages. The respondent could choose whether to answer that question by sharing numbers in the table, provide more of a narrative in the Word document, or both.

A follow-up call was also requested as part of the survey. This was set-up to help answer any questions that arose from the survey, or to identify and fill in any data gaps. It was also an opportunity to encourage an open discussion on more complex topics that perhaps an AD operator would find difficult to answer simply in a survey, such as fugitive methane or digestate management.

9.4.2. Reponses

Twenty-three AD sites responded to the survey. In terms of biogas use, these were:

- 11 CHP-only sites
- 12 BtG sites

In terms of feedstocks, these were as follows:

- 4 sites using manure only
- 13 sites using a mixture of manure and crop or other
- 1 site using only crop or crop residue
- 2 sites using industrial residues
- 3 sites using wastes

A full breakdown, by type, scale and feedstock mix is presented in the table below, with individual case studies denoted by letters and corresponding descriptions provided below the tables.

CHP only

	Manure only	Manure and crop/other	Crop, crop-residue only	Industry-associated	Waste
Micro	48 ***I, J, K, M***	14 ***R***			
Small	27	132 ***T, V, W, U***	30	15	11
Medium	*2*	76 ***C, S***	24	25	46
Large	*1*		*3*	1	*23*
Very large					*3*

Biomethane injection

	Manure only	Manure and crop/other	Crop only	Industry-associated	Waste
Medium		31 ***B, F***	29 ***N, O***	5 ***P***	23 **A, D, E**
Large		*6* ***G, H,***	*7* ***L***	3 ***Q***	13
Very large					*1*

9.5. Emissions analysis of the case studies

The base method used in this section aligned with REDII in that the (a) system boundary was from feedstock generation to point of biomethane grid injection or point of electricity grid feed-in, (b) allocation was by energy content, and (c) a manure credit was applied. However, the baseline assumptions on fugitive methane were taken from the UK B2C2 tool, where it is assumed that there is 1% fugitive methane from AD and 1% from biogas upgrading (unless evidenced that it is lower). In the base method, no other fugitive methane emissions were considered. An overview of key data sources and assumptions can be found in the Annex section 9.2.

9.5.1. All sites – emissions on the basis of biogas produced

Emissions in AD – for example for sustainability reporting under the subsidy schemes, RHI/GGSS and FIT/RO – are typically given on the basis of useful output (i.e. for BtG sites, per MJ of biomethane, and for CHP sites, per MJ of exported electricity). However, owing to the efficiencies of conversion (i.e. around 95−99% for BtG and 36−40% for CHP), it is difficult to compare the two types of site when using these different units. For this reason, Figure 19 shows the emissions from both the BtG and CHP sites, but on the basis of emissions per MJ of biogas generated. There is no notable difference between the BtG and CHP plants, with BtG sites having emissions between −14 and 25 gCO_2eq/MJ_{biogas} and CHP sites having emissions between −13 and 19 gCO_2eq/MJ_{biogas}. Data on differences in fugitive methane emissions were not measured and therefore not taken into account.

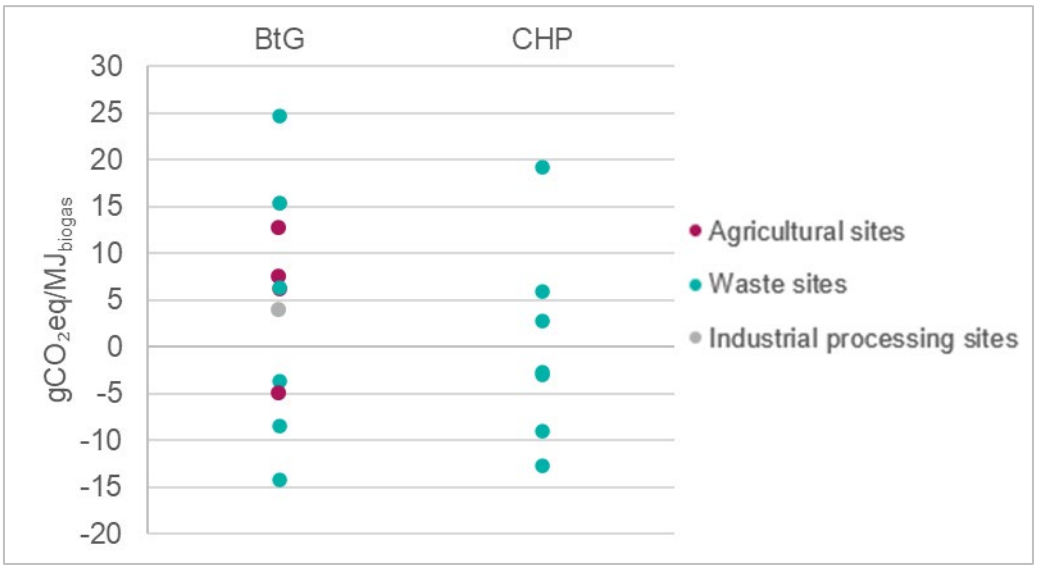


Figure 19: Emissions on the basis of biogas produced, for sites where biogas is used for biomethane to grid (BtG) and for combined heat and power (CHP). Teal symbols represent farm-fed AD plants, pink symbols represent waste-fed AD plants and grey symbols represent those fed by industrial residues (in this case, brewery/distillery).

9.5.2. Biomethane (BtG) sites

Figure 20 plots the emissions from the 12 BtG sites. Overall, emissions range from −19 to 28 $gCO_2eq/MJ_{biomethane}$. All sites meet the RHI GHG threshold of 34.8 $gCO_2eq/MJ_{biomethane}$ but two do not meet the GGSS threshold of 24 $gCO_2eq/MJ_{biomethane}$. There is no clear trend between agricultural and waste-processing AD sites, with agricultural AD plants appearing at the bottom of the chart (using high amounts of manure) and at the top of the chart (using no manure). Sites taking large volumes of industrial residues are also widely distributed.

Sites with negative emissions were characterised by their use of large volumes of manure (23%–58%, by biomethane yield). The sites with the highest emissions were characterised by the use of a high fraction of crops (100% in the two agricultural sites and 47% in the site using mainly industrial residues) with no manure.

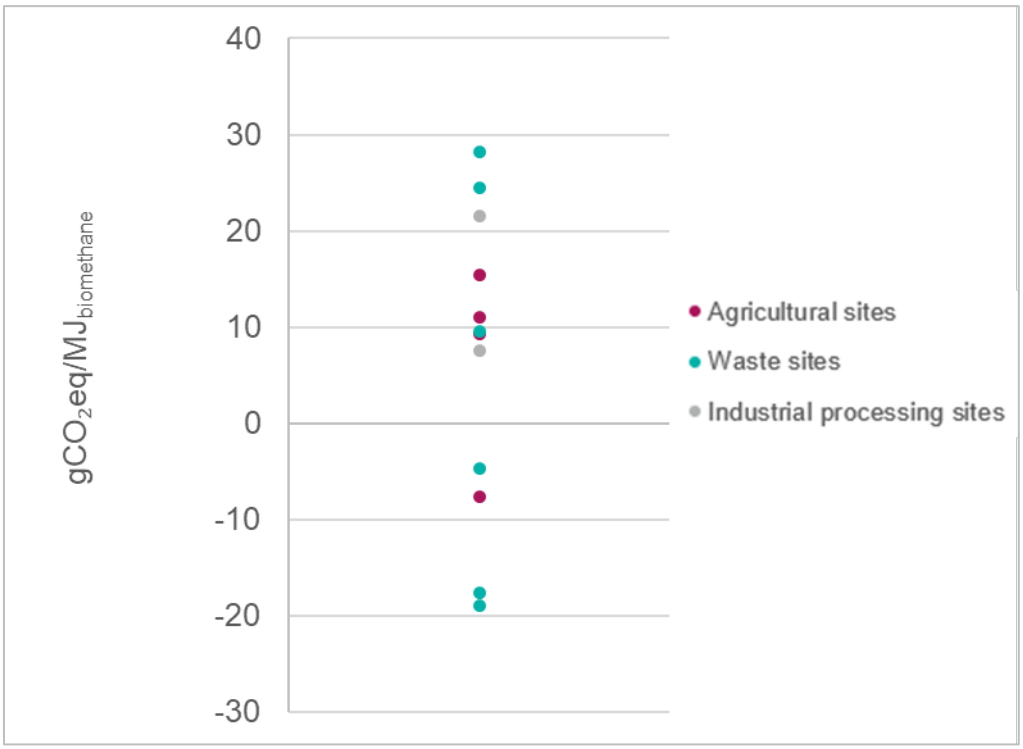


Figure 20: Emissions associated with BtG sites surveyed. Teal symbols represent agricultural AD sites, pink symbols represent waste AD sites and grey symbols represent plant processing industrial residues.

9.5.3. CHP sites

Figure 21 plots the emissions from the 10 CHP-only sites, where the emissions are given on the basis of electricity generated. These include three micro-AD sites using only manure.

All CHP-only sites from the survey are farm-fed. Electricity from the three micro-AD sites that use only cattle slurry had exceptionally low GHG emissions (below −3,000 $gCO_2eq/MJ_{electricity}$). Another site which used large volumes of manure had emissions of below −500 $gCO_2eq/MJ_{electricity}$. Removing these outliers, the remaining sites are shown in Figure 22, with emissions ranging from −37 to 74 $gCO_2eq/MJ_{electricity}$. The high-emissions site was a micro-AD plant using predominantly crops with just 9% manure.

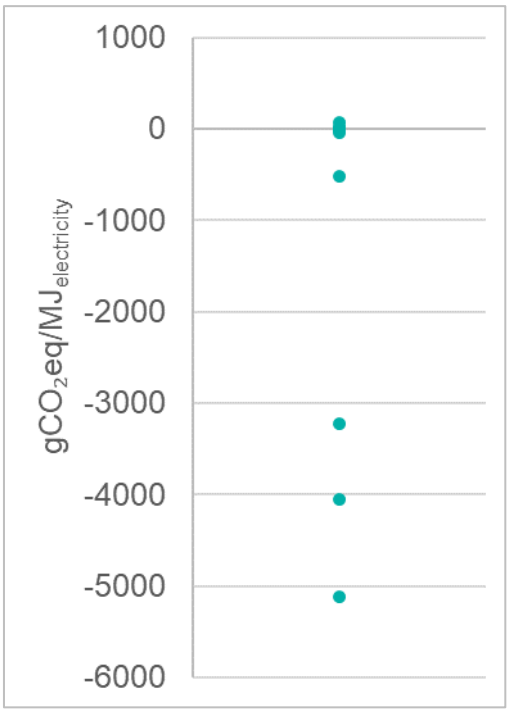


Figure 21: Emissions associated with all CHP sites surveyed

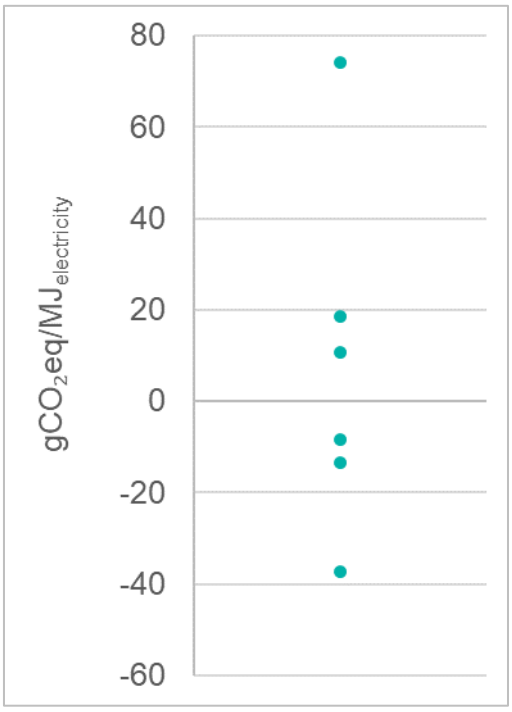


Figure 22: Emissions associated with CHP sites surveyed (excl. outliers)

9.6. Sensitivity to methodology choices

9.6.1. Manure credit

The manure credit aims to reflect the significant environmental benefit of digesting manure as a feedstock. When manure and slurry are stored conventionally, they are associated with large methane emissions; however, when properly handled and processed via AD, this conventional emission does not take place.

Agricultural sites using manure often also use crops as feedstocks to improve the methane yield and to justify the economies of scale required to make the system viable. Digesting only crop feedstocks often does not achieve the carbon savings necessary for the generated methane to be considered sustainable under the definition stipulated in the GGSS, where crop production emissions are particularly high (see Figure 23, where two agri-fed biomethane sites are over the GGSS GHG limit of 24 $gCO_2eq/MJ_{biomethane}$). However, by co-digesting crops and manure, and averaging emissions across consignments as per the current GGSS Guidance, the credit for the avoided manure emissions makes it possible for the crop feedstocks to be deemed sustainable.

Using the BtG case studies, it is possible to compare emissions when including the manure credit and excluding the manure credit in the calculations. With the manure credit, two sites exceed the GGSS emissions limit of 24 $gCO_2eq/MJ_{biomethane}$, but without the manure credit only one additional plant is pushed over the limit. This suggests that agricultural BtG sites digesting a combination of manure and crops may not need the manure bonus in order to stay under the GHG limit, depending on other methodology choices (see below). Nonetheless, emissions do increase for sites using manure when the manure credit is not applied.

9.6.2. Allocation (by energy) of emissions to digestate

Furthermore, removing allocation to digestate (on top of removing the manure credit) pushes a further two agricultural AD sites over the GGSS emissions limit, and takes the three sites already over the limit to even higher levels (Figure 23). Without a manure credit or allocation to digestate by energy, only one of the 6 agricultural AD sites is below the GHG threshold.

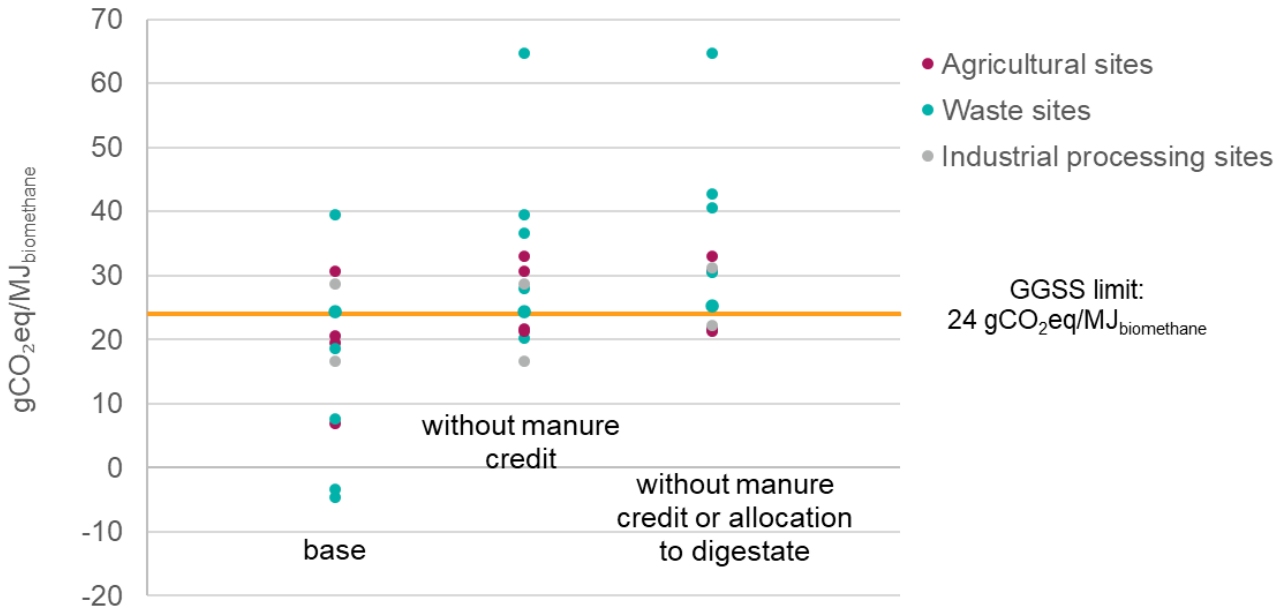


Figure 23: Emissions associated with biomethane produced at the 12 case study sites. Teal symbols represent agricultural AD sites, pink symbols represent waste AD sites and grey symbols represent plant processing industrial residues. Orange line at 24 gCO_2eq/MJ represents the GHG emissions limit of the GGSS scheme. ***Figure compares the emissions associated with biomethane when calculated with the base LCA methodology used in this study (base method), when calculated without the manure credit, and when calculated without the manure credit and without allocation of emissions to digestate.***

9.6.3. Fugitive methane emissions from digestate storage

In the base LCA method, fugitive methane emissions were as assumed in the UK B2C2 tool, which is the basis of current GHG reporting under FIT and RHI (1% for BUU slip and 1% from the digester). However, in the calculations associated with REDII[53], more attention has been paid to site set-ups, in particular how digestate is stored. Where digestate storage is open, it is assumed in REDII that sites fed with crops leak 2.2% of the biomethane generated, sites fed with waste leak 2.5% and sites fed with manures leak 10% of the biomethane generated.

In the baseline scenario, fugitive emissions were as follows:

0.5% of methane to biogas CHP or boiler, 0.25% of methane to natural gas CHP or boiler

1% from digester

0.9% from BUU

0.05% from flare

2.5% from digestate storage where waste or crops used as feedstocks, 10% from digestate storage where manure was used, and apportioned accordingly based on ratio of gas generated

[53] Giuntoli, J., Agostini, A., Edwards, R. and Marelli, L., Solid and gaseous bioenergy pathways: input values and GHG emissions: Calculated according to methodology set in COM(2016) 767: Version 2, doi:10.2790/98297

from manure and other feedstocks. If sites had covered digestate storage, this was reduced to zero, if site had partially covered digestate storage, this was halved.

Based on the site description from the interviewed sites, as well as satellite images around their location, the case studies were categorised into those with open, closed and partially closed digestate storage (Table 16).

Table 16: Digestate storage in the biomethane-injecting AD sites from the survey.

	Open	Partially closed	Closed
Number	2	7	3

Where digestate storage was closed, no fugitive methane emissions from digestate storage were included (as in the base scenario). Where digestate storage was open, the emissions from digestate were calculated based on the feedstock mix. Where digestate storage was partially closed, the emissions were calculated based on the feedstock mix and then halved.

Considering emissions from digestate storage pushed up the emissions for several AD sites (Figure 24). While in the base scenario only two sites were over the GGSS emissions limit of 24 $gCO_2eq/MJ_{biomethane}$, including emissions from digestate storage pushed another two over the limit. Additionally removing the manure credit pushed an additional 4 sites over the GGSS emissions limit, meaning that only 4 of the 12 sites were below the emissions limit considering emissions from digestate storage. Removing the ability to allocate emissions to digestate did increase emissions further for some sites but did not push any more sites over the GGSS limit.

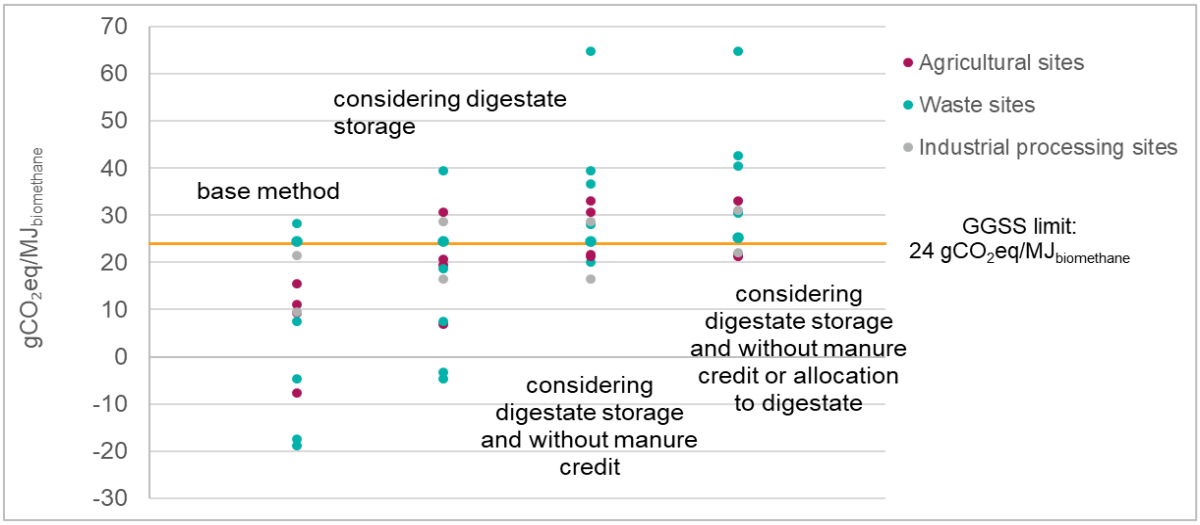


Figure 24: Emissions associated with biomethane produced at the 12 case study sites. Teal symbols represent agricultural AD sites, pink symbols represent waste AD sites and grey symbols represent plant processing industrial residues. Orange line at 24 gCO_2eq/MJ represents the GHG emissions limit of the GGSS scheme. Figure compares the emissions associated with biomethane when calculated with the base LCA methodology used in this study (base method), when considering the digestate storage, when calculated without the manure credit while considering digestate storage, and when calculated without the manure credit while considering digestate storage and disregarding allocation to digestate.

9.7. Extrapolating case study data to fleet

There are 120 BtG AD plants in our fleet analysis. In order to determine the emissions from this fleet, the 12 case studies were divided into types of AD plant and an average emissions value for each type of AD plant was calculated. As there were no case studies for large and very large waste-processing BtG AD plants, average emissions for medium waste-processing BtG plants were used for their large and very large counterparts in order to generate a weighted average across the entire fleet.

9.7.1. Conventional functional units

Typically, emissions from biomethane production are given on the basis of a MJ of biomethane produced.

Table 17 shows the nine types of biomethane plant identified in the fleet analysis, along with their occurrence and the GHG emissions associated with the biomethane produced from the case study sites in each category.

In order to look at the whole fleet, a weighted average of the GHG emissions associated with biomethane production in the case studies was calculated. The weighting was based on the occurrence of each site type. As no case studies were available for large or very large waste-processing plants, the values for medium waste-processing plants were extrapolated. This approach gave an average GHG intensity of 17.4 $gCO_2eq/MJ_{biomethane}$.

Table 17: Type of AD plant along with their occurrence in the UK fleet and the GHG emissions of biomethane from the relevant case studies.

Type of AD plant	Occurrence in fleet	Occurrence in case studies	Results of case study, emissions in $gCO_2eq/MJ_{biomethane}$			
			Average	Based on individuals		
BtG, medium, manure & crop	31	2	7.0	−4.7	18.6	
BtG, medium, crop	29	2	16.0	24.4	7.6	
BtG, medium, industry	5	1	28.7	28.7		
BtG, medium, waste	23	3	23.6	30.7	19.5	20.6
BtG, large, manure & crop	6	2	1.8	7.0	−3.3	
BtG, large, crop	7	1	39.5	39.5		
BtG, large, industry	3	1	16.6	16.6		
BtG, large, waste	13	0	(23.6)			
BtG, very large, waste	3	0	(23.6)			
Total	120	12				
Weighted average (by occurrence)			17.4			

9.7.2. Annual emissions

It is clear that the value of 17.4 $gCO_2eq/MJ_{biomethane}$ only gives limited information, as it does not relate to the amount of biomethane generated. However, the total volume of biomethane production in the UK is not publicly declared, and official estimates (e.g. DUKES[54]) are regarded within industry to be overstated[55] as they are based primarily on estimates of installed capacity. They do not take into account the amount of biomethane actually produced.

Annual emissions from biomethane generation per year were estimated by multiplying the emissions from each site by the amount of biomethane produced by each site, and the occurrence of each type of site. The results are shown in Table 18. This method gave 353,019 tCO_2eq/year, associated with a biomethane volume of 17,653 TJ/year or 4.90 TWh/year (around 74% of the installed capacity[56]).

Table 18: Type of AD plant along with their occurrence in the UK fleet and the GHG emissions of biomethane from the relevant case studies.

Type of AD plant	Occurrence in fleet	Occurrence in case studies	Annual emissions from biomethane in tCO_2eq/year (biomethane out in TJ/year)			
			Average	Based on individuals		
BtG, medium, manure & crop	31	2	129 (60)	−400 (85)	657 (35)	
BtG, medium, crop	29	2	2,811 (172)	4,365 (179)	1,257 (166)	
BtG, medium, industry	5	1	5,871 (204)	5,871 (204)		
BtG, medium, waste	23	3	2,697 (109)	4,425 (144)	1,340 (69)	2,326 (113)
BtG, large, manure & crop	6	2	33 (163)	781 (112)	−715 (214)	
BtG, large, crop	7	1	9,254 (235)	9,254 (235)		
BtG, large, industry	3	1	2,886 (174)	2,886 (174)		
BtG, large, waste	13	0	[2,697] (217*)			

[54] Digest of UK Energy Statistics (DUKES), available for every year at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
[55] Personal communications.
[56] Installed capacity was measured here as 6.63 TWh/year, slightly smaller than the annual estimate in NNFCC's annual AD Deployment Report owing to the exclusion in this study of a few biomethane plants associated with sewage sludge.

BtG, very large, waste	3	0	[2,697] (434*)
Total	120	12	
	Total as extrapolated to fleet		353,019 (17,653)

**Biomethane production values for large and very large waste-fed plants are estimated by multiplying the value from a medium-sized waste-fed plant by 2 (for large) and 4 (for very large)*

9.7.3. Comparison with fossil fuel

To bring the values of 17.4 $gCO_2eq/MJ_{biomethane}$ and 353,019 tCO_2eq/year into context, it is necessary to consider what is being replaced in the market. In the context of GGSS, the emissions limit is 24 $gCO_2eq/MJ_{biomethane}$, which represents a 70% emissions savings against a fossil-fuel comparator of 80 gCO_2eq/MJ. Using the same comparator, emissions of 17.4 $gCO_2eq/MJ_{biomethane}$ represent a saving of 78%, using the LCA method and assumptions in this study. This comparator is higher than natural gas, which can be justified owing to the potential uses of biomethane not only in displacing natural gas in domestic boilers, but also in displacing natural gas, oil and coal in industrial heat applications.

A more conservative comparator can also be used. The carbon intensity of natural gas on the UK grid is 66.075 gCO_2eq/MJ[57]. Making a direct comparison, the emissions saving from the biomethane currently being produced is 69%, using the LCA method and assumptions in this study. On an annual level, 4.90 TWh/year of biomethane produced is around 0.6% of the UK's natural gas demand (787 TWh/year[58]).

9.8. Model scenarios

Various parameters can be varied in the model using drop-down menus.

- Feedstock mix used by AD site
- Useful products generated by site (excluding digestate, which is generated by all sites)
- Size of AD plant
- Energy supply
- Fugitive methane emissions, as dictated by the site design
- Gross calorific value (GCV) of gas entering grid

[57] Using 2024 conversion factors from DESNZ, including Scope 1 and 3 emissions for natural gas (100% mineral blend), available at https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

[58] Using 2022 data from DUKES Table 4.1 Natural gas commodity balance

- Outputs performance
- Digestion efficiency
- Fugitive methane emissions, as a result of operating the site

9.8.1. Feedstock mix used by AD site

Crops

Various purpose-grown crops are used for AD, such as maize silage, grass silage, whole crop rye, and energy beet. Some co-products are also used in AD, with the main one being pressed sugar beet pulp.

The average crop mix used in the surveyed sites was 53% maize silage, 20% rye silage, 6% grass silage and 21% other. This is on the basis of biomethane generated, not tonnage used. The model uses a 'model crop', consisting of maize, rye and grass, extrapolated from the average mix to 67% maize silage, 26% rye silage and 8% grass silage. In terms of input weight, this equates to 59% maize silage, 34% rye silage and 7% grass silage.

The cultivation values (crop yield, fertiliser amount, etc) for Model Crop were calculated as the weighted average of the 3 input crops (by tonnage). Their cultivation data was taken from defaults in the B2C2 tool (2014); DM, VS and BMP for Model Crop were also calculated as the weighted average of the 3 input crops. Transport distances were taken as 20km – this was an indicative value from the case studies

Residues

A range of residues are used in AD, with some of the largest categories being residues from breweries/distilleries and residues from dairies. Some agricultural residues are also used, such as straw. In this work, the model scenario uses only brewers' spent grain / draff, which is a common and high-yielding residue. For industry-associated sites (e.g. AD plants attached to distilleries), transport distances were short. However, for other sites using residues, 150 km was a typical value, so this was used in the model.

Wastes

A wide range of wastes can be used, including household food waste from kerbside collections, restaurant/catering waste, food waste from markets and auctions, food-processing waste from factories, and packaged food waste (e.g. from retail), for example.

In this work, the model scenario uses commercial food waste (from retail and factories) as an indicative feedstock that was in line with the average biomethane potential of feedstocks used at waste-processing AD plants. Transport distance was selected as 150 km, which was a typical value in the case studies.

Manures

Several manures were used in the case studies, including chicken manure, cattle slurry, cattle solid manure, and pig slurry. On average, the mix was 67% chicken manure, 20% cattle slurry, and 6.5% each of cattle solid manure and pig slurry. A Model Manure was used in the model, focussing on the 2 main manures from the case studies and extrapolating to 100% (77% chicken manure and 23% cattle slurry, on the basis on methane yield). On a weight basis, this is 56% chicken manure and 44% cattle slurry (owing to the high biogas yield of chicken manure). This is the mixture that was used to generate Model Manure. Distances were taken as 20 km, a typical value from the case studies.

Feedstock mixes used

Several feedstock scenarios can be selected in the model.

‘Crop only’ is a theoretical scenario. Around a quarter of existing biomethane sites use only crops, according to the NNFCC database. However, it should be noted that a number of these are likely to use some non-crops. Three crop-only biomethane-injecting AD sites were reached in the survey, and while 2 used only crops, the third used almost 20% cereal husks. It should also be noted that even crop-only AD plants may occasionally use manures, for example because they provide a good source of microorganisms, which are particularly useful when there has been a site shut-down and digestion needs to be ramped up. Finally, crop-only AD is not permitted under GGSS, where at least 50% of the biogas generated must derive from residues or waste (including manures).

The ‘Residues only’ setting was used to model industry-associated AD plants in the fleet. ‘Residues only’ is a theoretical scenario. Such sites are mainly associated with an industrial facility, such as a brewery or dairy. It should be noted that these sites may use other feedstocks when residue availability is insufficient to reach full capacity. Two biomethane-injecting AD sites surveyed were industry associated. While one was fed only from the industrial residue, the other was supplemented with around 45% crop.

‘Waste only’ is a theoretical scenario. The waste AD sites surveyed in this work used a very wide range of wastes, and sometimes residues.

‘Manure only’ is a theoretical scenario. No biomethane-injecting AD sites using only manure were reached through the survey, and none are in the current fleet database. However, with manure remaining an abundantly available feedstock for AD (though a low-yielding one), it is highly likely that such sites will exist in the future.

‘Crop and manure’ is a theoretical scenario. As GGSS requires a minimum of 50% of the biogas generated to derive from waste or residues (including manures), 50% manure was chosen in this scenario. Of the sites surveyed, three were injecting biomethane and using a mixture of manure and crops. On average, they used 40% manure. Although all were subject to the feedstock criteria, they made up the 50% using farm wastes or residues. Including the CHP only AD sites that use manure and crops, the fraction of manure used dropped even lower to an average of 25%. This is because the sites surveyed were not bound by the feedstock criteria.

9.8.2. Useful products

All AD plants generate biogas and digestate, but the useful products are different. In terms of energy, the following outputs were considered:

- Electricity (from biogas)
- Heat (from biogas)
- Biomethane

Additional products considered were:

- Digestate
- CO_2 (from biogas upgrading)

9.8.3. Size

The size of AD plants has an effect on their sustainability, as there are typically carbon benefits associated with the efficiency of scale.

There is no standard sizing of AD plants in the industry. It is common to refer to sites by their installed biomethane or CHP capacity, although they can also be described by the amount of feedstock or biogas they were designed to handle.

In this work, AD plants were divided into the following sizes: micro, small, medium, large, very large. See Table 13: Sizing used in this work. Where sites only operated a biogas CHP (i.e. did not generate biomethane), sizing was defined by the CHP electrical capacity. Where sites upgraded biogas to biomethane, the capacity of grid injection was used to define the size, regardless of whether they also generated electricity.

9.8.4. Energy supply

Electricity requirements

Electricity requirements were from the following areas:

- Digestion
    - Previous industry rules of thumb have indicated that around 15−20% of a CHP-only site's electricity generated is used for digestion requirements.
    - By plotting the electricity demand of CHP-only AD plants from our case studies against their capacity, 20% was confirmed. The kWh represented by 20% CHP electricity was calculated for each size in the model and applied to the AD site of that size (regardless of whether they operated a CHP).
- Biogas upgrading

  - For sites carrying out biogas upgrading, electricity demand was considered as 0.28 kWh per Nm³ of biomethane upgraded. This was determined empirically from the case studies.

- CO_2 compression

  - No sites using CO_2 compression were reached with the surveys, so typically electricity use was sourced from an industry expert as 0.1 kWh per Nm³ of CO_2 compressed.

9.8.5. Gross calorific value (GCV) of gas entering grid

Where sites inject into the gas distribution network (i.e. the lower pressure regional gas grid, as opposed to the higher-pressure national transmission system), the grid operators set a target GCV that AD sites must meet, otherwise their gas will be rejected from grid injection[59]. A higher target GCV means that biomethane must be blended with more propane.

Values chosen for GCV in this work are: none (for sites injecting directly into the national transmission grid, currently very rare), low at 38.8 MJ/Nm³, medium at 39.2 MJ/Nm³ and high at 40.0 MJ/Nm³. These values are indicative values sourced from an expert stakeholder, but sites interviewed reported occasionally having target GCV outside this range (both lower and higher).

9.8.6. Outputs performance

Output performance represents the extent to which AD sites reach their installed capacity. The medium position was shaped by the average (mean) output from the case studies (78% for biomethane and 91% for CHP), while the low and high scenarios were one standard deviation away (57%–100% for biomethane, 85%–97% for CHP).

9.8.7. Digestion efficiency

Digestion efficiency was empirically derived from case studies as medium (mean) 113% (with low and high being 1 standard deviation away at 82% and 143%). While it seems unlikely that digestion efficiency is over 100%, this presumably reflects that feedstocks – particularly mixed wastes – are variable.

9.8.8. Fugitive methane emissions

Fugitive methane emissions in the model are divided into 3 areas:

- Fugitive methane emissions by design.
  - These emissions depend on the design of equipment purchased when the plant was built.
  - These emissions are incorporated into the model as fixed values for fugitive methane emissions from boilers, CHPs, and bigas upgrading units.

[59] This relates to the Gas Safety (Management) Regulations 1996.

  - For boilers and CHP units using biogas, low emissions are set at 0.5%, medium emissions at 1%, high emissions at 2% and very high emissions at 4% of methane going to these units.
  - For boilers and CHP units using natural gas, evidence suggests that fugitive emissions are significantly lower. Low emissions are set at 0.25%, medium emissions at 0.5%, high emissions at 1% and very high emissions at 4% of methane going to these units
  - For biogas upgrading units, low emissions are set at 0.5%, medium emissions at 1%, high emissions at 2% and very high emissions at 4% of methane going to these units.

- Fugitive methane emissions in operation
  - These emissions are generated when the AD plant operator carries out certain activities. Good practice (such as minimising the time that valves and ports are open, ensuring they are correctly closed after use, and regularly maintaining them) would be expected to lower these fugitive methane emissions.
  - These emissions are incorporated into the model as a single fixed value for emissions from digestion.
  - Low emissions are 0.5%, medium emissions are 1%, high emissions are 3% and very high emissions are 6% of methane generated by AD.
- Fugitive methane emissions from digestion
  - Fugitive methane emissions from digestion have been considered separately here as there are operational and design factors at play.
  - These emissions are incorporated into the model as a single fixed value for emissions from digestate.
  - Low emissions are 0.5%, medium emissions are 1%, high emissions are 3% and very high emissions are 6% of methane generated by AD.

9.9. Fugitive-methane scenarios

The fugitive-methane scenarios shown in Figure 4 are based on specific selections in model-mode of the GHG tool used in this project. These are shown in Table 19.

Table 19: Scenarios used in model-mode of the GHG tool for the scenarios in Figure 4.

a	1	2	3	4	5	6	7	8	9
Fugitive methane: design	None	None	Low	Low	Med.	Med.	High	High	V. high
Outputs performance	Medium	Med.	Med.	Med.	Med.	Med.	Med.	Med.	Med.
Electricity needs	Medium	Med.	Med.	Med.	Med.	Med.	Med.	Med.	Med.
Digestion efficiency	Medium	Med.	Med.	Med.	Med.	Med.	Med.	Med.	Med.
Flared gas	Medium	Med.	Med.	Med.	Med.	Med.	Med.	Med.	Med.
Fugitive methane: operation	None	Low	Low	Med.	Med.	High	High	V. high	V. high
Fugitive methane: digestate	None	Low	Low	Med.	Med.	High	High	V. high	V. high

9.10. Calculating CO_2 captured in UK AD plants

The amount of CO_2 captured from medium-sized AD plants was assumed to be the volume of biogas going into the biogas upgrading unit minus the volume of methane (i.e. other gases are assumed to be negligible). Throughout the model, the methane in biogas was assumed to be 55% (55% being a very typical value, with real values ranging from 50% to 60%, and up to 70% being possible based on the Buswell equation, though rarely seen in practice). Thus, CO_2 was assumed to be 45% of biogas. A CO_2 recovery efficiency of 80%[60] was assumed.

The volume of biogas used for upgrading in a medium-sized biomethane plant was back-calculated from the biomethane generated for injection. Biomethane for injection was calculated from capacity and output efficiency, taking into account propane blending. Capacity for biomethane generation for injection was set in the model for medium-sized BtG plants as 550 scm/h. This number is multiplied by the number of hours in a year (8760) to obtain the annual injection capacity of 4,818,000 scm.

Based on the results from the case study that BtG plants are currently only achieving an average of 78% of their installed capacity, this number is reduced to 3,758,040 scm/year, which is 3,570,138 Nm³/year (using 0.95 Nm³/scm[61]). This equates to 139,949,410 MJ/year (HHV) based

[60] Confirmed by two manufacturers of biogas upgrading units with CO_2 capture and liquefaction.
[61] https://data.nationalgas.com/technical-guidance

on a GCV (i.e. HHV) of 39.2 MJ/Nm³, a typical value in the UK. This equates to 125,954,469 MJ/year (LHV) based on a conversion factor of 0.9 (LHV/HHV).

In this study, it was estimated that 3.29% propane is blended (based on a target GCV of 39.2 MJ/Nm³ and an actual GCV in the upgraded biogas of 36.0 MJ/Nm³, which is a typical value in UK AD plants). This means that only 121,807,393 MJ/year (LHV) come from the upgraded biogas. Assuming a low fugitive methane loss of 0.5% in the biogas upgrader, the amount of methane entering the biogas upgrader is 122,419,490 MJ/year (LHV), equating to a methane volume of 3,417,630 Nm³/year (35.82 MJ/Nm³) in the biogas going to the upgrader. The CO_2 in the biogas is obtained by multiplying this volume by 45%/55%, which yields 2,796,242 Nm³/year, or 2,236,994 Nm³/year once the 20% loss has been taken into account. This is 4,183 t CO_2 /year (0.00187 t/Nm³ CO_2 density).

As there are currently 13 AD plants capturing CO_2, this is 54,381 tCO_2/year for the fleet.

Additional electricity use for CO_2 compression generates additional emissions. Industry estimates from equipment manufacturers put this at around 0.1 kWh per Nm³ of biogas upgraded. For the medium-sized model plant, this is 621,387 kWh/year. Using a carbon intensity for the UK electricity grid of 207 gCO_2eq/kWh[62], this represents 129 tCO_2eq/year. Extrapolated to the 13 AD plants with CO_2 capture, this brings the CO_2 savings from CO_2 capture down to 52,709 tCO_2eq/year.

[62] DESNZ Greenhouse gas reporting: conversion factors 2023, https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

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