Department for the Economy
An Roinn Geilleagair
www.economy-ni.gov.uk

CALL FOR EVIDENCE
DEVELOPING BIOMETHANE PRODUCTION IN NORTHERN IRELAND

MAY 2024

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Introduction

The Economy Minister has outlined four key priorities as part of our new Economic Mission - good jobs, promoting regional balance, raising productivity and reducing carbon emissions. Biomethane, a carbon neutral renewable gas which can be produced locally, could contribute to decarbonising and growing the economy. A purified version of biogas which is produced from the anaerobic digestion of organic matter such as silage, manure and brown bin waste, biomethane could support our pathway to net zero carbon by helping to decarbonise gas networks, providing transportation fuel, and replacing carbon intensive fuels in hard to electrify industries. It could not only provide a locally produced, sustainable source of energy but also enhance our energy security of supply and help to provide a solution to some of the waste management issues which are currently damaging our local environment.

The opportunity offered by biomethane is underlined by recent research which has indicated that there could be sufficient feedstocks, mainly from agricultural sources, to produce enough biomethane to meet a significant percentage of our total gas distribution network demand. If realised, even in part, this could become a key economic driver for growing the rural economy and contributing to regional re-balancing.

The cost of producing biomethane currently means that it is unlikely that widespread, unsupported production of the renewable gas will be achieved by the market alone. While biomethane production is an established process in a number of European countries, it tends to be heavily subsidised. The challenge is to develop an effective policy framework which could unlock the biomethane economy and help the sector to become economically viable without long-term subsidies. This Call for Evidence is seeking information, data and views from key stakeholders which will help to form a comprehensive evidence base for the development of biomethane policy. Your input has a key role to play in the policy process and we encourage as many as possible to contribute.

General Information

Purpose of Document

This Call for Evidence represents a key stage in the development of a policy framework to support the development of the biomethane sector. The Department for the Economy ('the Department' or 'DfE') wishes to engage with key stakeholders in order to gain new insights into how biomethane production might develop locally. We are keen to hear from bodies, groups and individuals within the energy, biogas/biomethane production and agricultural sectors, and also more generally from stakeholders across society, on a range of issues as follows:

Chapter One sets out the strategic context for the development of biomethane policy, examines the potential role for biomethane in the path to net zero, and seeks views on setting an annual biomethane production target.

Chapter Two discusses ways of managing the feedstocks required to produce biomethane and seeks views on the best way of ensuring a sustainable supply.

Chapter Three outlines the financial modelling work completed thus far by DfE to analyse the cost of producing biomethane and seeks further information and views on a range of issues affecting the economic viability of local biomethane production.

Chapter Four addresses the treatment of costs related to connecting biomethane production sites to the gas network and seeks views on options for the optimal treatment of such costs.

Chapter Five seeks views on any other key issues which government departments should consider in developing an effective policy framework for biomethane.

There are multiple questions within each section of the document. **Please respond to as many (or as few) questions as you wish.**

The publication of this Call for Evidence will also be supported by a number of targeted stakeholder engagement events. **If you feel that such an event would benefit you or a group with which you are associated, please contact us (contact details below).**

A Section 75 Equality of Opportunity Screening template for this policy has been completed and published for comment alongside the Call for Evidence. The policy will be re-screened following receipt of responses to this Call for Evidence and later issued for further comment with a draft policy paper. A Regulatory Impact Assessment and Rural Needs Impact Assessment will also issue for comment alongside the planned policy consultation.

Alternative Formats

If you would like the Call for Evidence documents to be provided in an alternative format, please contact DfE's Green Gas team by e-mail: **biomethaneDFE@economy-ni.gov.uk**

Responding to the Call for Evidence

Issued: **17th May 2024**

Respond by: **9th August 2024**

Respond to: We would encourage respondents to respond to this Call for Evidence through the online e-Consultation platform, **Citizen Space** if possible.

However, we will also accept responses submitted by e-mail to: **biomethaneDFE@economy-ni.gov.uk**

Or alternatively by post to:

Green Gas Team
Department for the Economy
Adelaide House
39-49 Adelaide Street
Belfast
BT2 8FD

Please quote the reference 'Biomethane Call for Evidence 2024'.

While DfE is the author of this Call for Evidence, the work involved in drafting this document could not have been completed without much valuable input from the Department of Agriculture, Environment and Rural Affairs ('DAERA'), the Centre for Advanced Sustainable Energy at Queen's University of Belfast ('CASE'), the Northern Ireland Authority for Utility Regulation ('the Utility Regulator'), and local gas network operators and biomethane producers. Their collaboration with the Department is very much appreciated.

Chapter One: Biomethane and the Path to Net Zero

Background

1.1 The Executive's Energy Strategy, *'Path to Net Zero Energy'*[1], which aims to deliver an **affordable, secure,** and **clean** energy system for current and future generations, was published in 2021. It specifically targets net zero carbon and affordable energy as part of the wider action needed to address climate change and deliver a stronger economy.

1.2 Among the key actions which are being taken forward to contribute to delivery of the Strategy's overall aims and objectives, the Department has made a commitment to *"Issue a call for evidence on options for supporting biomethane production".* This Call for Evidence paper is seeking to:

- Consider the role of biomethane in the path to net zero energy by 2050.
- Consider, in collaboration with DAERA, how to optimise management of the feedstocks needed for biomethane production.
- Establish the costs for producing biomethane and potential options for developing the sector, including identification of additional revenue streams.
- Assess, in liaison with the Utility Regulator, how costs related to connecting biomethane production sites to the gas network should be treated.

1.3 This paper presents the analysis that the Department has developed thus far on the costs of producing biomethane and aims to capture views and further information on this topic from interested parties. Our considerations follow on from research DfE jointly commissioned with the Utility Regulator from the Centre for Advanced Sustainable Energy (CASE) at Queen's University of Belfast into the potential for Northern Ireland to better adopt biomethane as part of future energy policy. The CASE study has informed our thinking and understanding of the issues to be addressed. This analysis, together with any further information provided in response to this Call for Evidence, will contribute to the Department's final policy position on biomethane which will align, not only with the Energy Strategy, but also with the key priorities established as part of our Minister's Economic Mission.

1.4 In developing the policy framework for biomethane, we are particularly mindful of the need to reduce carbon emissions. This is not only essential for the well-being of future generations, but also a legal obligation. The Climate Change Act (Northern Ireland) 2022[2] sets targets for 2030 which include a 48% reduction in green house gas emissions compared to baseline.

1 *https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf*

2 https://www.legislation.gov.uk/nia/2022/31/contents/enacted

1.5 The concept of the circular economy is also an important backdrop to the development of biomethane policy. The circular approach offers an economic model, pursued by many countries, in which we:

- Rethink and reduce our use of earth's resources.
- Switch to regenerative resources.
- Minimise waste.
- Maintain the value of products and materials for as long as possible.

1.6 The local biomethane sector, if developed effectively, could have much to contribute to the delivery of the Minister's Economic Mission and a thriving circular economy, not only potentially enabling us to replace a fossil fuel with a renewable alternative in our gas network, but also creating jobs in the rural economy, helping us to address waste management issues, and developing new revenue streams from the biomethane supply chain, utilising, for example, digestate and biogenic CO_2.

Biogas and Biomethane

1.7 Biogas is a mixture of methane (typically 45% to 75%), carbon dioxide and small quantities of other gases which, in the UK and Ireland, is primarily produced[3] by the anaerobic digestion (AD) of organic matter in an oxygen-free environment. The precise composition of biogas depends on the type of feedstock and the production pathway. Typical feedstocks include municipal biodegradable waste, livestock slurry, and grass silage. Biogas can be used to produce heat and electricity.

1.8 Biomethane, also known as 'renewable natural gas', is a near-pure source of methane produced by 'upgrading' biogas. The upgrading process removes any carbon dioxide and other contaminants present in the biogas. The resulting biomethane has a number of uses – it can, for example, be used as a vehicle fuel or injected into the gas network to replace natural gas with no changes required to infrastructure or gas appliances.

1.9 Although chemically identical to natural gas (CH_4), burning biogas or biomethane does not add new carbon to the atmosphere. Biogas is obtained from the controlled decomposition of organic matter that is already part of the natural carbon cycle. As it grows, the feedstock used to produce biogas captures CO_2 from the air. When it is transformed into methane and finally burned for energy, the same carbon goes back into the atmosphere in a process known as the short carbon cycle. Biogenic CO_2 can be released and recaptured indefinitely without disrupting the planet's climate in the long term.

3 *Biomethane may also be produced from other methods, e.g. from landfill gas capture, however, for the purposes of this Call for Evidence, DfE is focusing upon biomethane produced by AD from waste due to the local availability of feedstocks and the environmental benefits that this production method can have in terms of dealing with soil nutrient issues.*

1.10 The UK Climate Change Committee's March 2023 Advice Report: '*The Path to a Net Zero Northern Ireland*'[4] recommends that actions taken to increase both land-based and engineered greenhouse gas removals should include the anaerobic digestion of wastes to produce biomethane. We have been independently assessed as having excellent biomethane potential due to our large agricultural sector which can provide feedstocks from livestock slurry, grass/silage, and municipal (brown bin) waste. The CASE study found that the total biomethane potential from organic streams, i.e. manure, 'underutilised'[5] silage, sludge and municipal biodegradable waste (food and green garden waste) in Northern Ireland represents over 100% of the current gas distribution network demand.

1.11 Biomethane produced for injection into the gas network could provide a sustainable decarbonised supply of heat for local communities, using existing infrastructure, with many of the advantages of natural gas (storage, flexibility, high-temperature heat) without the net carbon emissions. Its benefits also include:

- Processing and using methane from the decomposition of organic by-products and waste, a potent greenhouse gas (GHG), that would otherwise be released to the atmosphere[6].
- Contributing to effective waste management and improving overall resource efficiency.
- Displacing imported gas (all natural gas used here is imported via Scotland), thus enhancing security of energy supply.
- Providing non-energy benefits such as recycling of nutrients, creating jobs in the rural economy, and transforming a range of organic wastes into higher-value products.

1.12 Producing and injecting biomethane into the gas network is a proven process that has been implemented in other countries, such as Denmark and Germany, for some time. Denmark first injected biomethane into its gas network in 2013 and is aiming to have 100% biomethane in the network by 2030. Great Britain (GB) also has a growing biomethane sector and issued its own Call for Evidence on a future policy framework for biomethane production in early 2024.

1.13 At present there are 80+ AD plants operating here, most of which receive a subsidy under the Northern Ireland Renewables Obligation (NIRO) scheme to produce biogas for the generation of electricity which is often exported onto the grid. However, there is growing interest in establishing AD plants to produce biomethane.

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4 *Advice report: The Path to a Net Zero Northern Ireland - Climate Change Committee (theccc.org.uk)*

5 *In the CASE study, 'underutilised' silage refers to the difference between volumes of silage currently grown and what could be grown if average grass dry matter per hectare was increased from 6 tonnes.*

6 *Although more short-lived in the atmosphere than CO_2, this methane is 80 times more damaging in heat retention.*

1.14 The Utility Regulator has been working with the natural gas industry and other key stakeholders in recent years to develop the necessary regulatory and technical framework to allow biomethane to be injected into the natural gas network. A key milestone was reached with the first injection of locally produced biomethane into the natural gas network at Dungannon in November 2023. The local natural gas network companies anticipate that up to five further projects could follow by 2025/26 and they have set a target for 1.5 TWh of biomethane to be injected into the gas network annually by 2030 – this is equivalent to around 22% of gas distribution volumes in 2022.

1.15 The costs associated with producing biomethane are currently significantly higher than the price of natural gas. In many jurisdictions, including Denmark and GB, there is a subsidy mechanism, or range of mechanisms, to promote the growth of the sector. In developing a policy framework for local biomethane production, a key consideration is how best to ensure that the production of biomethane is cost-effective and sustainable for the long-term. This is essential to ensure that we are able to realise the potential for biomethane and maximise its benefits for everyone.

1.16 One action which the Department could consider as part of a policy framework is setting an annual target for local biomethane production, potentially as part of an overall UK biomethane target. A volume-based production target could, for example, be set in stages up to 2050 and include sub-targets for biomethane from specific feedstocks. Establishing a production target would indicate government's interest in developing the sector and could help to stimulate interest from producers and investors.

1.17 It is also important that we consider how we might best utilise locally produced biomethane for maximum effect. While this Call for Evidence has a particular focus on producing biomethane for injection into the gas network, the Department recognises that there are a range of alternative uses for biomethane which could also support delivery of the Energy Strategy's objectives, including:

- compressed biomethane for transport;
- biomethane in power production; and
- direct use of biomethane by industry.

We must also consider how we might use CO_2 captured in the biogas to biomethane cleaning process to produce synthetic eFuels with green hydrogen, e.g. SAF (sustainable aviation fuel), eKerosene and eDiesel.

The optimal use of biomethane may, of course, change over time as we progress towards 2050.

Question 1: What are your views on the primary role that biomethane might play in supporting our path to net zero, e.g:

- decarbonising the gas network?
- sustainable transport fuel?
- for direct use by industry?
- other uses?

Question 2: What are your views on how the optimal use of biomethane might evolve over time, i.e:

- in the short-term (up to 2028);
- in the medium-term (up to 2035); and
- in the long-term (up to 2050 and beyond)

Question 3: Do you think we should set an annual production target for biomethane? If so, on what should the target be based?

Chapter Two: Management of Feedstocks

2.1 This Call for Evidence is interested in views on managing the feedstocks required to produce biomethane and, in particular, on how feedstocks might best be managed to both ensure a sustainable supply of feedstocks for AD biomethane plants and optimise the opportunity to address environmental issues associated with excess nutrients from agricultural slurry.

2.2 A significant proportion of municipal waste from households and industry in Northern Ireland that is suitable for AD is already diverted from landfill to suitably licensed AD plants. DAERA has been exploring options to divert further biodegradable waste from landfill and identified that as much as 106kt could be diverted from landfill and processed via AD. In 2022, 272kt of biodegradable waste (excluding livestock manures) were processed in local AD plants, including 125kt from the Republic of Ireland.

Question 4: **How would you propose to increase the proportion of domestic and commercial biodegradable food waste diverted from landfill to AD plants?**

2.3 Sewage sludge is not currently used in AD plants in Northern Ireland although it is common in GB and Europe. However, sewage sludge is estimated to form only 2% of our potential feedstock volume compared with the greater volumes available of slurry solids. It is noted that the technology to produce energy from the liquid fraction in biogas production is evolving.

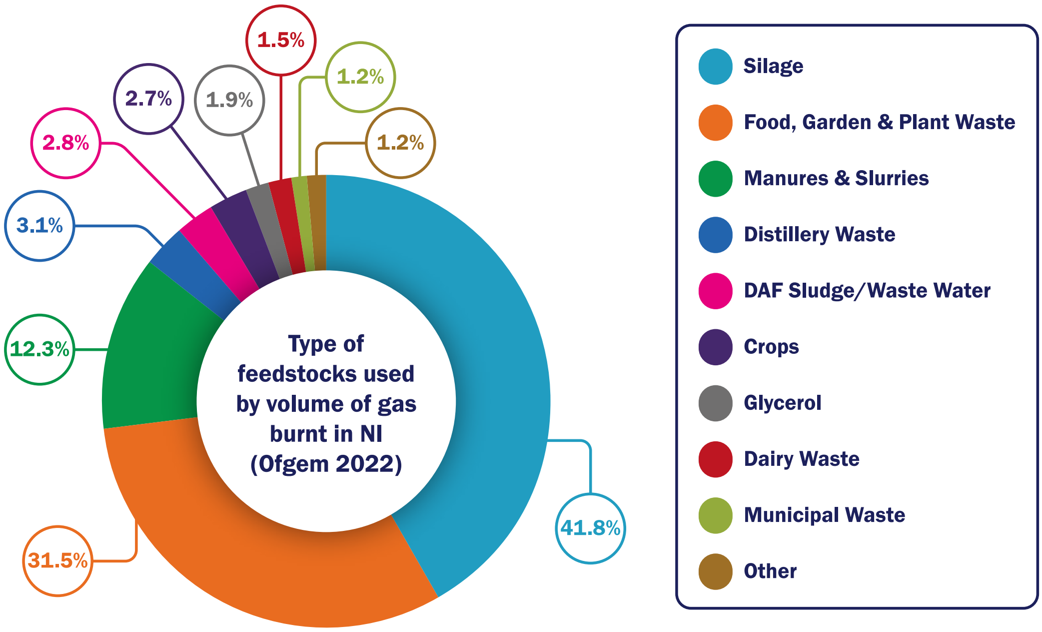
2.4 The primary focus of this section, however, is on exploring feedstocks which have the most potential to be made available for biomethane production in high volumes – namely slurry solids and grass silage.

Existing and potential feedstocks

2.5 The research study commissioned by DfE in liaison with the Utility Regulator from the Centre for Advanced Sustainable Energy (CASE), based at Queen's University Belfast, included specific research into existing and potential feedstocks for local biomethane production. Much of the following section is based on that report.

2.6 The CASE study identified that a range of feedstocks are currently used to produce 525.19million m^3 or 213 GWh of biogas per annum in Northern Ireland. Figure 1 illustrates the types of feedstock utilised in percentage terms. This shows that grass silage is by far the main feedstock currently used in anaerobic digestion here. Given our ability to grow grass, it also has the greatest potential, alongside the availability of manure/slurry, for providing additional feedstock for biomethane production using the same land base.

Figure 1: Type of feedstocks used by volume of gas burnt in NI (Ofgem 2022)



Grass silage potential

2.7 The CASE study highlights that, in this region, the growth of grass currently averages about 6 tonnes of dry matter per hectare and satisfies varying proportions of livestock dry matter diet requirements. When grass growth conditions are favourable, there is a national surplus in the annual production of silage. Through optimal nutrient management, there is the potential to increase the amount of dry matter produced per hectare of grass yield. The DAERA Soil Nutrient Health Scheme is attempting to address the knowledge gap that farmers may have in understanding the optimum nutrient levels in their soil for grass and crop growth. This will enable landowners to sustainably increase the yield and quality of grass their land can produce while maximising the efficient use of nutrients.

2.8 The CASE study suggests that there is significant potential to produce excess silage above currently observed yield levels. It estimates that the total fresh weight of 'underutilised' silage here in 2020 was 4,693kt, which equates to 1,374kt of silage dry matter and a biomethane potential of 500million Nm^3. This represents around 68% of the annual gas distribution network demand in 2020-2021. It should be noted that, in calculating these figures, the CASE study does not consider the changes in agronomic practice which might be required to bridge the gap between current average utilisable yield and the theoretical levels it uses in its assumptions.

2.9 DAERA agrees with the CASE study assertion that it is important that the additional use of imported chemical mineral fertilisers to increase grass yields is avoided, and that the use of nutrients in slurry and digestate is maximised. Imported chemical mineral fertilisers are not only energy and greenhouse gas intensive to produce, but they also contribute to additional nutrients (particularly phosphorus) which we already have in excess on an annual basis.

Question 5: **Do you believe farmers should be encouraged to produce grass silage for AD plants to produce biomethane and, if so, how?**

Manure and slurry

2.10 The CASE study estimated volumes of manure/slurry from housed livestock using livestock numbers sourced from the NISRA Agricultural Census (June 2020)[7] to provide cattle, pig, and poultry numbers at a farm scale. On each farm, the quantity of livestock in each category was converted to an associated volume of manure produced over a one-year period. As the minimum slurry storage capacity on holdings in Northern Ireland is 22 weeks, the housing period was set at 22 weeks for all cattle categories. For pig and poultry livestock, the housing period was a whole year. Manure characteristic variables for the conversion to biomethane are summarised in **Table 1** below and results relating to the full biomethane potential from both manure and underutilised silage is summarised in **Table 2**[8].

Table 1: Breakdown of NI manure variables

Livestock group	Cattle	Pig	Poultry
Total material produced (million m^3 or t/year)	6.9	1.3	1
Total solids (%)	8.5[a]	5.5[b]	50.5
Volatile solids (%)	80.0[a]	80[b]	80[a]
Biomethane yield (m^3/tVS)	215.5[c]	328.00[c]	330[c]
Total biomethane (million m^3)	101.00	19	132

[a]*Scarlat et al, 2018,* [b]*Curry et al, 2018,* [c]*Average of Scarlet et al. and Melikoglu and Menekse*

Table 2: NI Agricultural feedstocks and associated biomethane potential

Feedstock	Description	Volume of material (kt)	Associated volume of biomethane (million Nm^3)
Manure from housed livestock	Cattle, pig, and poultry manure collected (22 weeks housing for cattle)	9,218	253 **Minus 38.8 (already produced) = 214*

2.11 CASE estimated that the total biomethane potential from all housed manure here at 253million Nm^3, with around 64.6million Nm^3 of biogas already being produced from manure and slurry material[9]. Assuming methane is 60% of total biogas volume, this feedstock is associated with 38.8million Nm^3 of biomethane, around 15% of the total potential. Removing manure's current contribution to biogas from the calculation leaves 214million Nm^3 of biomethane, which has an energy potential of around 29% of the annual natural gas distribution demand (calorific value 10.88 kWh/m^3).

7 *NISRA Agricultural Census in Northern Ireland (June 2020)*
8 *More details in Mehta et al., 2022*
9 *Ofgem, 2022*

2.12 The increased supply and movement of manure material to AD plants does not require any increase in livestock farming intensity but instead brings with it added potential for nutrient redistribution which could reduce the risk of nutrient overloading in some areas. On-farm slurry separation is an important process to incorporate into new strategies of slurry movement as the solid fraction of slurry is more practical and cost-effective to move. To ensure the sustainability of livestock and anaerobic digestion, it is imperative, however, that excess nutrients (particularly phosphorus) are extracted from both slurry and digestate and exported outside Northern Ireland. There is currently an estimated annual excess of 6,000 tonnes of phosphorus from livestock slurry[10].

Question 6: Should farmers be encouraged to participate in the widescale separation of slurry to produce feedstock for AD? If so, how can farmers be encouraged to separate their slurry?

CASE summary of all feedstocks

2.13 The CASE study concluded that, if organic feedstock material available (sewage sludge, organic waste and manure) was routed through AD facilities to produce biomethane, around 280million Nm^3 of biomethane could be produced in total from a total material volume of 9.5million tonnes. Note that underutilised grass silage figures have been excluded due to the uncertainty around achievability in the local agricultural context.

Table 3: Biomethane potential for various organic feedstocks available in NI

Feedstock	Mass (kilo tonnes)	Associated volume of biomethane (million Nm^3)
Sewage sludge	161	10.36
Municipal biodegradable waste (Food + green garden)	174[11]	17.9
Manure from housed livestock	9,218	253
TOTAL	**9,552**	**281**

10 https://www.afbini.gov.uk/publications/rephokus-report-oct-2020

11 *The CASE figure of 174kt refers to food and garden waste which is currently composted in Northern Ireland (and presumably subject to contractual arrangements between the local authorities and the companies receiving the waste for composting). A recent estimate for 2021/22 indicates that a further 285 kt of biodegradable municipal waste is sent to landfill here.*

2.14 DAERA is particularly keen that manure and separated slurry are used as a feedstock for biogas and biomethane production and is supportive of a shift away from natural gas and diesel towards biomethane to decarbonise the gas network, heavy transport, and energy intensive industry and, potentially, future carbon capture as recommended by the UK Climate Change Committee. In August 2021, the then DAERA Minister established a Slurry Task and Finish Group to produce a report on the future management of slurry. The main recommendation in the group's report was that DAERA, in conjunction with DfE, should introduce a Small Business Research Initiative (SBRI) focused on creating a circular economy for bioenergy and nutrients where inputs, including nutrient separated slurry, could be used to produce biogas and biomethane via AD. In this way, local agriculture could become less reliant on imported high phosphorus fertiliser and feed and could reverse the decline in the ecological status of waterways and habitats. Further and potentially greater opportunities for circular economy benefits may entail the export of biofertilisers/nutrients/fibres/materials.

2.15 In January 2023, as part of the Small Business Research Initiative, DAERA launched the Phase 1 (feasibility) stage of a funding competition for projects looking at the sustainable utilisation of livestock slurry to reduce phosphorus within the local agriculture system and ensure efficient recycling of organic nutrients. Six local companies were awarded a total of £600,000 to develop practical and environmentally friendly solutions for livestock slurry. Each proposed the mobile separation of livestock slurry to produce a high dry matter, 'compost' like material to use as a feedstock for AD plants to produce biogas and biomethane. Practical trials during the project demonstrated that the biomethane yield from separated slurry was 70-80% of that from grass silage. Project proposals also suggested the further separation of AD digestate to produce a range of exportable products such as biofertiliser and peat free compost. It is intended that this project will progress to a larger scale demonstrator Phase 2 stage in 2024.

Question 7: **How do you believe digestate from AD should be managed to assist in dealing with the excess nutrient issue in Northern Ireland?**

2.16 DAERA view biomethane produced via AD as a vector, not only to decarbonise heat and transport, but also, if managed correctly, to act as a vehicle to encourage the centralised processing and nutrient separation of slurry to provide feedstock for biogas and biomethane. However, this process must be managed carefully, with collaboration across Government, Arm's Length Bodies, academia and industry. This includes ensuring that any increase in the production of biogas and biomethane is done sustainably, using slurry as an input and incorporating nutrient separation/stripping and the production of biofertiliser for use both locally and for export to offset the need for imported artificial fertiliser.

2.17 Although AD provides an opportunity to decarbonise the gas network, heavy transport and energy intensive industry, as well as future carbon capture, it must not come at a cost to water and air quality. Nor should any increase in the volume of grass/silage dry matter, produced per hectare on existing grassland specifically for AD, be driven by additional imported artificial fertiliser which is high in greenhouse gases. This would undermine the climate change and environmental benefits of a shift to using biomethane in the gas network and for transport.

Chapter Three: Economics of Producing Biomethane

3.1 To shape an effective policy framework to support the development of a sustainable and affordable biomethane sector here, we need to fully understand the economics of producing biomethane, including:

- How much does it cost to produce biomethane from each of the key feedstocks available and how does the calorific value (energy content) of that biomethane vary?
- What subsidies are or might be available to support biomethane production?
- What revenue streams might be developed to support a sustainable biomethane business model?
- What is an acceptable buying/selling price for biomethane?
- What impacts might biomethane production have on consumers' bills?

3.2 Drawing on information provided by biomethane producers, the Department has developed a model for analysing production costs. It has been challenging to obtain a range of realistic figures for the various elements associated with local biomethane production. Many costs are specific to each AD biomethane plant and can vary widely based, for example, on geographical location and type of feedstock.

3.3 The main purpose of the modelling was to develop an accurate picture of the costs and revenues associated with an AD biomethane plant and provide an estimated figure for the overall cost per kWh of producing biomethane from each of the main feedstocks to enable comparisons to be made.

3.4 The costs considered and assumptions made for the purposes of financial modelling are detailed in the next section.

Modelling the Costs of Producing Biomethane

Feedstocks

3.5 Modelling has been completed for three main types of feedstock:

- Chicken litter
- Municipal biodegradable waste
- Silage/livestock slurry mix (approximately 70%/30%)

3.6 These feedstocks were chosen for modelling as they appear to be the most abundant in Northern Ireland. A mixture of 70% to 30% of silage vs slurry was adopted as an efficient blend of the feedstocks. We have not modelled a higher percentage of slurry as this feedstock produces biogas with a lower energy content than other feedstocks, leading to inefficiencies if utilised in larger proportions in the biomethane production process. Nor have we considered any form of energy crops, such as maize, beets etc, as these are not currently in widespread use here.

Question 8: **Are there any other feedstocks/feedstock blends which we should model and analyse? If so, please provide any available data which might assist with modelling of the costs and revenues for biomethane production from these feedstocks.**

3.7 In considering feedstocks, our modelling included the cost of the feedstock, transport costs and the income from any gate fees (for municipal biodegradable waste).

Capital expenditure

3.8 We have examined the capital expenditure (capex) involved in developing and building an AD biomethane plant, including cost of construction and purchasing the required equipment, and assumed that these costs will be recovered over a 15-year period[12] (AD plants would, however, be expected to be operational over a longer period).

3.9 For the purposes of modelling, DfE has used a reference plant of a scale that takes in approximately 100,000 tonnes of feedstock per year. We are aware that no biogas/ biomethane plants of such scale are currently found here. However, experience in other countries, such as Denmark, would indicate that, due to economies of scale, proximity to gas network connections and other efficiencies, the biomethane sector might develop with greatest efficiency on the basis of large scale, centralised plants. Large scale plants would also help to reduce the impact of biomethane plants on local communities, with fewer plants needed to inject the same volume of gas into the network than a large number of smaller plants.

3.10 We have noted that co-operatives are models that have been highly successful in a number of areas, such as the dairy sector. The establishment of biomethane co-operatives might be one way in which smaller scale operations would be able to share costs and contribute towards producing biomethane to meet our gas distribution needs. This might involve:

- Smaller scale operations supplying feedstocks to a central AD biomethane plant for processing and subsequent injection into the gas network.
- Establishment of a central injection hub which could be used by multiple producers.

Question 9: **Do you think the development of the local biomethane sector should be based on large-scale, centralised AD plants and why/why not?**

Question 10: **In your view, might adoption of a co-operative model contribute towards growing the biomethane sector and, if so, what are your views on the optimal model?**

12 *Costs included in modelling are based on information provided in early 2023.*

3.11 In considering ongoing operating expenditure (opex), our modelling was again based on a large scale AD biomethane plant with a feedstock capacity of 100,000 tonnes per annum and included electricity costs, water charges, insurance, labour, chemicals, digestate processing costs, and maintenance.

Level of subsidy

3.12 In most other jurisdictions analysed by DfE, some form of government support exists to support the development of the biomethane industry. The table below outlines an approximate value of the subsidy per kWh in a sample number of jurisdictions.

Table 4: Biomethane Subsidies in Other Jurisdictions

Country[13]	Tariff Rate (per kWh)	Other Support
Great Britain	1.56p – 5.51p *(different tariff rates apply for different levels of production*	
Czech Republic	5.5c	
Denmark	3.5c – 5.5c	
Finland	6.0c *(transport)*	
France	5.0c – 14.0c	
Germany	>8.0c – 10.0c	Interest free loans
Italy	6.5c *(transport)* 8.0c – 10.0c *(electricity)*	
Norway	7.0c	Investment support 40% of cost
Sweden	4.0c	Investment support 40% of cost

Source: Centre for Advanced Sustainable Energy at Queen's University of Belfast

3.13 For the purposes of modelling an AD biomethane plant in Northern Ireland, the Department has assumed that a baseline subsidy level of 6.5p per kWh is available (this is based on the estimated value of the Renewable Transport Fuel Obligation scheme to biomethane producers, as assessed in 2023. For further information see paragraphs 3.28-3.33 below).

Wholesale cost of natural gas

3.14 In order to compare the cost of biomethane with natural gas, the Department has assumed a wholesale gas price of 2.5p/kWh[14].

13 *The Republic of Ireland is to introduce a Renewable Heat Obligation (RHO) to support biomethane production which will incentivise suppliers of fossil fuels used for heat to ensure a proportion of the energy they supply is renewable. Details on design of the RHO are due to be published in 2024.*

14 *Wholesale gas prices can be volatile - 2.5p represents the approximate price at mid-December 2023.*

Costs not included in modelling

3.15 The calorific value (CV) of biomethane is lower than that of natural gas which means that it has a lower energy content. This difference varies according to the type of feedstock used to produce biomethane. At present, in order to increase the CV of biomethane to match the energy content of the existing natural gas in the local gas network, propane is added before biomethane is injected. Over the longer-term, as the volume of biomethane injected into the network increases and/or alternative arrangements are implemented to account for gas of differing CV's in the system, the volume of propane required should decrease or no longer be required. It may also be possible to implement technical solutions, such as direct injection into the transmission network, to negate the need for propanisation. We have therefore assumed that propane will not be injected and its cost is not included in our modelling.

3.16 At this stage, we have also not attributed any costs or benefits in respect of the development of carbon dioxide (biogenic CO_2), digestate or other by-products of the biomethane production process as revenue streams. Our engagement with biomethane producers and the wider biomethane sector would indicate that, while these by-products offer future potential, they are not revenue streams at present. Indeed, some producers have indicated they incur costs to transport digestate offsite from their plants, although such costs would presumably be borne by the purchaser in the event of digestate being successfully monetised.

Summary of key baseline assumptions

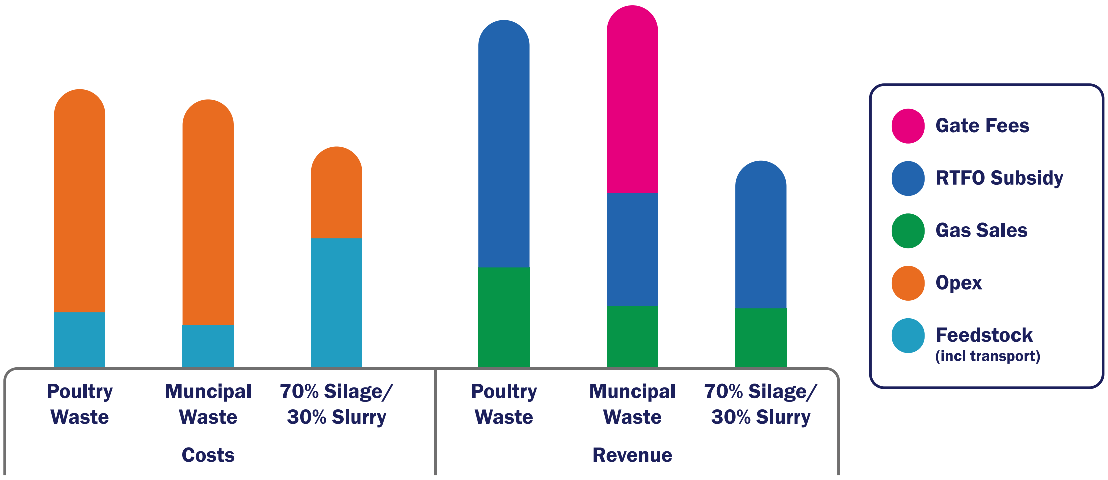
3.17 In summary, the Department's baseline assumptions for modelling and analysing the costs associated with producing biomethane are as follows:

- Plant size of 100,000 tonnes (feedstock capacity per annum)
- Natural gas price of 2.5p/kWh
- Baseline subsidy level of 6.5p/kWh
- No added propane
- No revenue from by-products

DfE Findings

3.18 The bar chart below illustrates the outcome of our financial modelling of the relative costs and revenues for each of the reference plants (excluding capex)[15]:

Figure 2: Costs and Revenue for 100,000 Tonne AD Biomethane Plant



3.19 There are a number of observations that can be taken from the above:

- For a silage/slurry plant, the feedstock represents a much higher percentage of total costs in comparison with biomethane plants using other feedstocks.
- For chicken litter and municipal waste plants, opex represents the key cost.
- For a municipal waste plant, gate fees, i.e. fees charged to dispose of waste, make up a high percentage of the overall revenue of such a site.
- For a silage/slurry-based plant, a subsidy level of 6.5p per kWh and the income from gas sales are still less than the costs incurred.

3.20 It is important to note that the feedstocks considered produce very differing yields of biogas/biomethane. For example, the yield per tonne from chicken litter can be 25% more than that of silage and nine times more than that of cattle slurry.

3.21 We should also note that the majority of chicken litter and municipal waste feedstocks are already being used by existing biogas/biomethane plants. It is therefore likely that future biomethane plants will have to use agricultural feedstocks which are still relatively abundant.

15 *This chart illustrates relative costs and revenues only as actual costs and revenues are commercially sensitive.*

3.22 Overall, DfE's analysis has shown the following estimates for costs per kWh for producing biomethane from the three listed feedstocks:

Table 5: Costs by Feedstock Type

Feedstock	Production Costs (p/kWh)	Levelised Cost of Energy (LCOE)[16] (p/kWh)
Chicken Litter	7.3[17]	14
Municipal Waste	12	21
Silage/Slurry Mix	9.8	15

3.23 This indicates that biomethane produced here would have to be sold for around 7 to 12 pence per kWh to cover the production costs of each biomethane plant. This is three or more times the assumed wholesale price of natural gas. The Department does not anticipate that biomethane production costs in current structures will reduce significantly in the foreseeable future. This indicates that a basic subsidy level of 6.5p/kWh may not necessarily be enough to cover the production costs of a biomethane plant.

3.24 In terms of recovering the initial investment in construction as well as production costs over the life of the biomethane plant, the LCOE column in the above table estimates that biomethane would need to be sold at a price of at least 14p/kWh.

3.25 Based on these figures, DfE has estimated that the return on investment for an AD biomethane plant is in the region of 7% at best. However, for some of the more energy inefficient feedstocks, biomethane production would appear to be unprofitable.

Question 11: **Do you agree with the above findings on costs and revenues for an AD biomethane plant? Do you have any data which would indicate different outcomes and, if so, could this be shared with DfE?**

Question 12: **Are there other costs or revenues that DfE should consider in its financial modelling and, if so, what are they?**

Question 13: **What are your views on the level of return on investment (in percentage terms) necessary for an AD biomethane plant to appear attractive to a producer or investor?**

16 *LCOE is the average net present cost of energy production over the lifetime of the AD plant. It is the average revenue per kWh that would be needed to cover the plant's capital and operational costs over its life.*

17 *The higher energy content of biogas produced from chicken litter produces efficiencies which mean that, when refined into biomethane, a lower price p/kWh is required to cover opex compared with silage/slurry.*

Development of Revenue Streams

3.26 If the biomethane sector is to show that it can be commercially viable without long-term subsidies, it will be necessary to monetise outputs in new ways as far as possible. The Department would suggest three key potential revenue streams (there are likely more) which producers might access in addition to the sale of biomethane to reduce the required subsidy:

(i) **Sale of processed digestate:** digestate is the nutrient-rich residual material left after the anaerobic digestion process which, if properly processed, may be applied to agricultural land as a bio-fertiliser and/or soil amendment to improve soil health. For example, digestate might be separated at AD plants (to remove phosphorus before land spreading) and sent to a centralised location (for free or for a very low charge) for further nutrient separation/processing to produce a bespoke tailored artificial fertiliser replacement. If digestate could be monetised and managed, it might become a major income stream for biomethane producers.

(ii) **Sale of separated biogenic CO_2:** biogenic CO_2 is a by-product of the process by which biogas is upgraded to biomethane. It represents CO_2 in a relatively concentrated form which might be used for industrial or agricultural purposes or combined with hydrogen to yield an additional stream of synthetic fuel (such as eMethanol or sustainable aviation fuel). There may also be an opportunity for future carbon removal certificates as a revenue stream subject to suitable routes being identified for CO_2 sequestration.

(iii) **Sale of green gas certificates:** such as Renewable Transport Fuel Certificates (for further information see paragraphs 3.28-3.33 below).

3.27 The Department is keen to explore whether it may be feasible to develop digestate, biogenic CO_2 and/or other by-products, such as biochar, as viable income streams to support the economics of biomethane production. We are also interested in exploring any innovative approaches which could support the cost of biomethane production, or ways in which the wider environmental benefits of biomethane might be quantified and/or monetised.

Question 14: **In your view, could digestate and/or biogenic CO_2 be developed as viable income streams to support the economics of biomethane production? Can you provide any data on potential costs and revenues?**

Question 15: **What other income streams or future revenue streams might be considered? Can you provide data on potential costs and revenues from any other revenue streams?**

Certification Schemes

3.28 As indicated above, the sale of green gas certificates represents a further way in which biomethane producers can recover some of their production costs. Most local AD biomethane projects are currently utilising, or intend to utilise, the UK's Renewable Transport Fuel Obligation (RTFO) scheme.

Renewable Transport Fuel Obligation

3.29 In 2008, with the aim of reducing greenhouse gas emissions from vehicles, the Department for Transport placed an obligation on suppliers of transport fuels in the UK to demonstrate that a proportion of the fuel they supply comes from renewable sources. The required percentage (total obligation) currently stands at 14.942% in 2024 and is due to rise to 21.066% by 2032. Producers of fuels meeting the sustainability criteria can apply for Renewable Transport Fuel Certificates (RTFCs), which can then be traded on an open market and sold to transport fuel suppliers to help them meet this obligation. It is important to note that, as well as showing their fuels meet strict eligibility criteria in terms of sustainability, renewable fuel producers must also prove that they are not receiving any state support/incentives towards the production of the fuel to ensure that multiple subsidies are not being claimed for the same product.

3.30 RTFCs are issued per kilogram or litre of fuel and, if renewable fuels are produced from certain feedstocks and meet strict criteria, multiple RTFCs can be claimed per kilogram or litre of fuel. Biomethane, for example, has a multiplier of 1.9 applied per kilogram, whereas hydrogen has a multiplier of 4.58. In addition, some feedstocks are eligible to be double counted. If biomethane is produced from manure, for example, it is eligible for 3.8 RTFCs per kilogram of fuel produced[18].

3.31 It is anticipated that there will be high demand from fuel suppliers in GB for RTFCs generated here from biomethane production, and potentially also significant demand from local fuel suppliers once compressed natural gas (CNG) refuelling infrastructure increases here. In broad terms, the RTFO scheme could provide a stable income stream for local biomethane producers for at least the next ten years at a negligible cost to our gas consumers. DfE's analysis has concluded that the RTFO scheme would provide a level of support of around 6.5p per kWh. Note that this income may reduce over time as less fossil fuels are used in transport across the UK.

18 *Source: RTFO Compliance Guidance 2023 (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1137149/RTFO_Compliance_Guidance_2023_Final.pdf)*

3.32 One drawback to the RTFO scheme, however, is that energy suppliers/users cannot purchase the RTFCs, only fuel suppliers. This means that the green credentials of biomethane produced here could be separated from the physical gas being injected into the gas network. That is, if producers sell the RTFCs associated with their biomethane to fuel suppliers in GB, they can only sell the biomethane itself as ‘fossil gas’ to gas suppliers in Northern Ireland. Fuel suppliers in GB may actually use natural gas as vehicle fuel, but they would be able to designate it as ‘renewable fuel’ as they have claimed the corresponding RTFCs, while local gas suppliers or large energy users who wish to purchase the biomethane can only purchase it as a ‘fossil fuel’. The Department recognises that this presents a difficulty, particularly for industrial energy users who may be under pressure from their supply chains to decarbonise operations here. Industrial energy users could perhaps consider contracting directly with biomethane producers to buy biomethane, but they would need to cover the value of the RTFO in order to avoid the fuel’s green credentials being sold for RTFCs. This would obviously impact significantly on the price of biomethane.

3.33 The Department would be keen to hear views on the suitability of the RTFO scheme to support the growth of the local biomethane sector and on any alternative options.

Question 16: Is 6.5p per kWh a reasonable assessment of the level of financial support offered by the RTFO scheme?

Question 17: In your view, can the RTFO scheme make a useful contribution towards the development of local biomethane production and why/why not?

Question 18: Are you aware of alternative certification schemes or other options which might better fit with local needs and, if so, what are they?

Other Support Mechanisms

3.34 In considering any other potential support mechanisms for local biomethane production, the Department recognises that the value of any such support would have to at least match that of the RTFO. And, most importantly, the impact on consumers of funding any support mechanism would have to be given very careful consideration.

3.35 One of the key themes underpinning the Energy Strategy is consumer protection, namely: ***Placing you at the heart of our energy future: We will make energy as simple as possible for everyone in society and develop policies that enable and protect consumers through the energy transition. Affordability and fairness will be key considerations in all our policy decisions.*** Protection of consumers, particularly domestic energy users is a fundamental consideration for every policy undertaken by the Department.

Green Gas Support Scheme

3.36 Great Britain has a bespoke scheme which provides financial incentives for new AD biomethane plants with the aim of increasing the proportion of green gas in the gas network. Not applicable in Northern Ireland, the Green Gas Support Scheme (GGSS) provides support to registered biomethane producers based on the volume of eligible biomethane produced from AD that they inject into the gas network. Once registered on the Scheme, participants receive quarterly payments for a period of 15 years. The GGSS is funded through a Green Gas Levy (GGL) which places an obligation on GB gas suppliers, excluding those who supply at least 95% certified green gas, to pay a quarterly levy based on the number of meter points they serve. Renewable Gas Guarantees of Origin issued by the Green Gas Certification Scheme are an approved way of evidencing green gas supply within the GGL. The cost of the GGL is passed on to consumers and is estimated to add between 59p and £2.10 to an annual household gas bill in Great Britain.

3.37 If we were to look at a bespoke scheme for local biomethane production along the lines of GB's GGSS, we would first have to consider how such a support mechanism might be funded and any subsequent impact on gas bills.

3.38 Funding a subsidy scheme by adding a levy onto energy bills is a widely used mechanism that is found in many other jurisdictions with a biomethane industry. To estimate the potential impact of this type of levy on consumers, we need to assess the volume of biomethane that may be injected into the gas network. Predicting this figure in the short to medium term is difficult. However, based on the percentage of natural gas in the network that might be replaced by biomethane, and applying a subsidy level of around 6.5p per kWh (equivalent to the estimated value of RTFCs to biomethane producers), we can get a rough indication of likely impact of a levy on domestic gas bills. The table below assumes a volumetric calculation will be applied to energy use, i.e. the levy is not charged at a flat rate to gas consumers.

Table 6: Potential Impact of a Green Gas Levy on NI Domestic Gas Bills (per annum)

Domestic Gas Usage	Percentage Biomethane in Gas Network			
	5%	10%	15%	20%
Lower Usage (9,000 kWh)	£29	£59	£88	£117
Avg Usage (12,000 kWh)	£39	£78	£117	£156
Higher Usage (15,000 kWh)	£49	£98	£146	£195

3.39 To provide a subsidy in the region of 6.5p per kWh (as it would have to at least match the value of the RTFO to receive uptake) and assuming some 20 AD biomethane plants are operational by 2030, it would cost the Executive approximately £76.5m per year. If a levy were added on to gas bills to cover this, due to our relatively small customer base, it would increase domestic gas bills by up to £195 per annum. For a small to medium-sized business (2.2m kWh), bills would increase by approximately £20k per year.

3.40 These calculations highlight the potentially significant cost to consumers of a bespoke mechanism to support the development of local biomethane production and indicate that a green gas support scheme funded in this way would be expensive and likely unaffordable. There is also a risk that, if costs for consumers increase, either as a consequence of a levy or another support mechanism, new connections to the gas network may decrease and existing consumers may switch to alternative fuels leaving an even smaller consumer base to bear network costs.

3.41 Furthermore, the cost of such a levy does not include making biomethane available to consumers. Biomethane is more expensive than natural gas for suppliers to purchase and any extra cost to purchase biomethane would have to be passed on to those customers who specifically request it.

Question 19: **What are your views on the above illustration of the potential impact of a green gas levy on consumers' gas bills and other possible unintended consequences? Do you think (i) domestic gas customers; (ii) small to medium-sized businesses; or (iii) large energy users would be willing to pay a levy to support the development of the biomethane sector? If so, how much would each be willing to pay?**

Question 20: **In your view, would (i) domestic customers; (ii) small to medium-sized businesses; or (iii) large energy users be willing to pay a premium to purchase biomethane, i.e. per kWh, and if so, how much?**

Question 21: **What action might be taken to make the cost of biomethane affordable to (i) domestic customers; (ii) small to medium-sized businesses; or (iii) large energy users?**

Question 22: **What are your views on how we might reach a sustainable price for biomethane and how might this relate, or not, to the price of natural gas at the National Balancing Point?**

Other options for consideration

3.42 While a local GGSS does not appear to be affordable, there are other potential capital or revenue support mechanisms which may merit consideration at local or UK national level, including:

- **Contracts for Difference (CfD):** a CfD scheme has been used to incentivise investment in renewable electricity projects in the UK. CfDs work by guaranteeing a set price for electricity – known as a strike price – that generators receive per unit of power output. As the wholesale price of electricity fluctuates, the generator is either paid a subsidy up to the set price or pays back any surplus above the set price to the scheme, so that they have the certainty of always receiving the value of the strike price. The cost, or benefit, is passed on to consumers through their bills. A similar approach might help to promote the development of local biomethane production, particularly at large scale.
- **Supplier obligation (SO):** a SO could be set on energy suppliers to provide a proportion of renewable energy, e.g. biomethane, to their customers, either by setting a minimum percentage for renewables in the energy supplied to customers, or by establishing a 'carbon intensity' ceiling on energy produced. A SO could be underpinned by a tradable certification scheme to prove compliance. This approach would aim to stimulate demand for biomethane from energy suppliers.
- **Capital Grants:** could capital grant support for centralised AD biomethane plants be an effective alternative to revenue subsidy?

3.43 If the potential support mechanisms outlined above, or any other suggestions, were to be given serious consideration, the implications for the Executive's budget, and impacts on consumers, would, of course, have to form a key aspect of that consideration. As already stated, affordability and fairness must be central to any policy decisions.

Question 23: Which mechanisms are most likely to promote the development of a sustainable biomethane production sector here at an affordable cost to consumers and why? Do you have any further suggestions that the Department should consider?

3.44 The Department of Energy Security and Net Zero (DESNZ) issued a Call for Evidence in February 2024 on a future policy framework to support biomethane production in GB after the GGSS closes for applications in March 2028. This includes consideration of a range of potential support mechanisms. DfE will liaise closely with DESNZ on our respective Calls for Evidence, particularly in relation to any proposals with potential UK-wide impacts, including possible changes to the UK Emissions Trading Scheme. Local stakeholders may also wish to read DESNZ' Call for Evidence which is available at https://www.gov.uk/government/calls-for-evidence/future-policy-framework-for-biomethane-production-call-for-evidence.

Chapter Four: Treatment of Costs Relating to Gas Connection

4.1 Thus far, we have been considering the costs involved in constructing and operating an AD biomethane plant. For biomethane which is to be injected into the gas network here, we also need to consider costs related to connecting to the gas network and how such costs might best be treated. Connection-related costs mainly fall into the following categories:

- Capex associated with providing the required new infrastructure, e.g. the gas pipeline connecting an AD plant to the existing gas network.
- Opex associated with controlling, monitoring and analysing the connection, for example via the Supervisory Control and Data Acquisition (SCADA) systems.
- Replacement expenditure (repex) associated with maintaining and replacing equipment over time.

Capex costs are a one-off charge whereas the opex costs are an ongoing annual charge. Repex costs are less frequent recurring costs, perhaps every 7-10 years.

4.2 Connection-related costs will, of course, vary according to the volume of biomethane produced, location of the AD plant in relation to the existing gas network, whether the connection is to the high pressure gas transmission network or lower pressure gas distribution network etc. **Table 7** below provides an illustration of connection costs based on the simple scenario of a single AD biomethane plant connecting to the existing gas distribution network.

Table 7: Connection Costs[19]

Type of Cost	Category	What does this include?	Cost (inc VAT)
Capex	Capacity study	Assessment of the proposed biomethane injection on current network loads, pressures, network parameters and relevant flows from other known or imminent biomethane injection sites.	£1.5k - £2.5k
Capex	Delivery pipeline	Site specific design and construction of the connection pipeline	Dependent on size of connection and distance to network. Indicative costs are: • 500scmh – c.£295k/km • 1000scmh – c.£335k/km • 2000scmh – c.£420k/km

Capex	Network Connection Charge	This one-off charge covers ongoing services supporting:
		• Network-related requirements regarding design, development and installation of a Biomethane Network Entry Facility (BNEF);
		  - associated workshops (gas quality/ HAZOP);
		  - factory and site acceptance tests;
		  - work execution/project management (e.g. weekly coordination meetings)
		• Procurement of site telemetry/ communications equipment and installation of SCADA into the Gas Control Centre.
		• Fully commissioning the BNEF's connection to the distribution network.
			c£125k

Opex	Operational, Maintenance and Emergency Charge	This annual charge covers: • 24-7/365 management and monitoring of SCADA. • Daily reporting, including any associated alarm activation (flow, out of specification gas/ pressure control/ high or low Calorific Value). • 24-7/365 emergency response to the Network Operator Facility (containing the Remotely Operated Valve and associated telemetry). • Annual maintenance of the Remotely Operated Valve.	c£95k per annum
Repex	Replacement of Site Monitoring Equipment	This charge covers the replacement of the site's monitoring equipment every 7-10 years.	c.£22k every 7-10 years

19 Costs are indicative only and subject to change in ongoing discussions with service providers.

4.3 The local gas distribution companies are in the process of developing their connection policies and the gas transmission companies are also refining their connection requirements which will help to further inform cost estimates. Costs associated with connecting to the high pressure gas transmission network are likely to be greater than those indicated in the table above for distribution connections.

4.4 In Northern Ireland, a biomethane producer is currently required to pay all connection-related costs, covering capex, opex and repex. In some other jurisdictions, including GB, the producer pays capex costs but opex and repex costs are socialised and managed through the gas network company's regulatory cost base. This means that these costs are recovered through consumers' gas bills over an extended period. If opex and repex costs were socialised for biomethane connections to the local gas network, initial indications are that this would have a very modest impact on bills for consumers.

Strategic Network Investment

4.5 As interest in producing biomethane and injecting it into the local gas network grows, there are also broader issues to be considered. The allocation of costs, for example, if multiple biomethane plants use one injection hub, or the treatment of costs associated with an initial biomethane connection to the gas network when additional injection loads in the same area are anticipated.

4.6 This also leads on to the important question of how we might ensure that any capital investment in connections to the gas network is 'future-proofed'. At present, the gas network can accommodate the injection of relatively small quantities of biomethane but further investment in the infrastructure will be necessary to facilitate greater volumes of biomethane moving around the system as the biomethane sector develops. There are a number of technical solutions to achieve this. The bespoke design of such network capacity solutions, whether at distribution or transmission level, would require costing on a case by case basis.

4.7 From a cost-efficiency perspective, it would seem sensible to ensure that biomethane connections to the gas network, at transmission and/or distribution level, are planned and designed so as to facilitate future loads or use by additional producers. This type of strategic investment in the gas network should also provide additional benefits in terms of enhancing security of supply and robustness of the network. But how should such costs be managed? If the first producer to connect is responsible for paying for the whole investment, including for an element of future-proofing, they bear the risk of relying upon further producers coming forward to use the infrastructure for reimbursement of costs. Alternatively, if certain elements of the capital costs were socialised to encourage strategic investment in the network, consumers would bear the risk until further biomethane loads materialise. There is also the issue of how any anticipated revenue from properties passed by new strategic investments in the network should be considered in establishing a biomethane producer's payment requirement.

4.8 The Department would be interested in all views on issues relating to the fair treatment of connection costs and strategic investments in the gas network.

Question 24: **What are your views on how connection-related costs should be allocated in respect of single injection site connections and hubs?**

Question 25: **What are your views on how costs, and the associated risks, should be allocated for strategic network investment (i.e. investment designed to facilitate greater volumes of biomethane on the network and enhance security of supply and robustness of the network)?**

Question 26: **In your opinion, should the Department consider the possibility of socialising some connection-related costs and, if so, what options should be considered and why?**

Question 27: **In so far as costs are to be borne by producers, what are your views on how such costs should be fairly allocated between different active producers/users of a hub?**

Question 28: **Are there any other issues associated with allocation of connection-related costs which need to be considered as part of the development of a policy framework for biomethane production?**

Chapter Five: Other Key Issues

5.1 This Call for Evidence paper has raised questions on a range of issues which impact on the development of a sustainable biomethane sector. The Department is keen to consider all information and views submitted in response to these questions as well as any further issues on which stakeholders may wish to provide comments.

Question 29: **What other key issues should the Department consider in developing a policy framework for biomethane?**

Question 30: **Are there any changes to the regulatory framework which government should consider to enable the development of a sustainable biomethane sector and, if so, what might these be?**

ANNEXES

Summary of Questions

Chapter One

Question 1: What are your views on the primary role that biomethane might play in supporting our path to net zero, e.g:

- decarbonising the gas network?
- sustainable transport fuel?
- for direct use by industry?
- other uses?

Question 2: What are your views on how the optimal use of biomethane might evolve over time, i.e:

- in the short-term (up to 2028);
- in the medium-term (up to 2035); and
- in the long-term (up to 2050 and beyond)

Question 3: Do you think we should set an annual production target for biomethane? If so, on what should the target be based?

Chapter Two

Question 4: How would you propose to increase the proportion of domestic and commercial biodegradable food waste diverted from landfill to AD plants?

Question 5: Do you believe farmers should be encouraged to produce grass silage for AD plants to produce biomethane?
If so, how?

Question 6: Should farmers be encouraged to participate in the widescale separation of slurry to produce feedstock for AD?
If so, how can farmers be encouraged to separate their slurry?

Question 7: How do you believe digestate from AD should be managed to assist in dealing with the excess nutrient issue in Northern Ireland?

Chapter Three

Question 8:	Are there any other feedstocks/feedstock blends which we should model and analyse? If so, please provide any available data which might assist with modelling of the costs and revenues for biomethane production from these feedstocks.
Question 9:	Do you think the development of the local biomethane sector should be based on large-scale, centralised AD plants? Why/why not?
Question 10:	In your view, might adoption of a co-operative model contribute towards growing the local biomethane sector? If so, what are your views on the optimal model?
Question 11:	Do you agree with the above findings on costs and revenues for an AD biomethane plant? Do you have any data which would indicate different outcomes and, if so, could this be shared with DfE?
Question 12:	Are there other costs or revenues that DfE should consider in its financial modelling? If so, what are they?
Question 13:	What are your views on the level of return on investment (in percentage terms) necessary for an AD biomethane plant to appear attractive to a producer or investor?
Question 14:	In your view, could digestate and/or biogenic CO_2 be developed as viable income streams to support the economics of biomethane production? Can you provide any data on potential costs and revenues?
Question 15:	What other income streams or future revenue streams might be considered? Can you provide data on potential costs and revenues from any other revenue streams?
Question 16:	Is 6.5p per kWh a reasonable assessment of the level of financial support offered by the RTFO scheme?
Question 17:	In your view, can the RTFO scheme make a useful contribution towards the development of local biomethane production? Why/why not?
Question 18:	Are you aware of alternative certification schemes or other options which might better fit with local needs? If so, what are they?
Question 19:	What are your views on the above illustration of the potential impact of a green gas levy on consumers' gas bills and other possible unintended consequences? Do you think (i) domestic gas customers; (ii) small to medium-sized businesses; or (iii) large energy users would be willing to pay a levy to support the development of the biomethane sector? If so, how much would each be willing to pay?

Question 20: In your view, would (i) domestic customers; (ii) small to medium-sized businesses; or (iii) large energy users be willing to pay a premium to purchase biomethane, i.e. per kWh?
If so, how much?

Question 21: What action might be taken to make the cost of biomethane affordable to (i) domestic customers; (ii) small to medium-sized businesses; or (iii) large energy users?

Question 22: What are your views on how we might reach a sustainable price for biomethane and how might this relate, or not, to the price of natural gas at the National Balancing Point?

Question 23: Which mechanisms are most likely to promote the development of a sustainable biomethane production sector here at an affordable cost to consumers and why?
Do you have any further suggestions that the Department should consider?

Chapter Four

Question 24: What are your views on how connection-related costs should be allocated in respect of single injection site connections and hubs?

Question 25: What are your views on how costs, and the associated risks, should be allocated for strategic network investment (i.e. investment designed to facilitate greater volumes of biomethane on the network and enhance security of supply and robustness of the network)?

Question 26: In your opinion, should the Department consider the possibility of socialising some connection-related costs?
If so, what options should be considered and why?

Question 27: In so far as costs are to be borne by producers, what are your views on how such costs should be fairly allocated between different active producers/users of a hub?

Question 28: Are there any other issues associated with allocation of connection-related costs which need to be considered as part of the development of a policy framework for biomethane production?

Chapter Five

Question 29: What other key issues should the Department consider in developing a policy framework for biomethane?

Question 30: Are there any changes to the regulatory framework which government should consider to enable the development of a sustainable biomethane sector?
If so, what might these be?

List of Acronyms

AD	Anaerobic Digestion
BNEF	Biomethane Network Entry Facility
Capex	Capital Expenditure
CASE	Centre for Advanced Sustainable Energy at Queen's University of Belfast
CfD	Contracts for Difference
CNG	Compressed Natural Gas
CV	Calorific Value (of gas)
DAERA	Department of Agriculture, Environment and Rural Affairs
DESNZ	Department for Energy Security and Net Zero (GB)
DfE	Department for the Economy (the Department)
GB	Great Britain
GGL	Green Gas Levy
GGSS	Green Gas Support Scheme
GHG	Greenhouse Gas
HAZOP	Hazard and Operability Analysis
NI	Northern Ireland
NIAUR	Northern Ireland Authority for Utility Regulation (the Utility Regulator)
NIRO	Northern Ireland Renewables Obligation
Opex	Operating Expenditure
Repex	Replacement Expenditure
ROI	(Rate of) Return on Investment
RTFC	Renewable Transport Fuel Certificate
RTFO	Renewable Transport Fuel Obligation
UK	United Kingdom