REA Response:

Green Gas Support Scheme Mid-Scheme Review

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above call for evidence. The REA represents industry stakeholders from across the whole sector and has particularly strong representation in anaerobic digestion through the work of its biogas and organics forums. Our members include generators, project developers, suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 500 corporate members of the REA, making it the largest renewable energy trade association in the UK.

1. **Do you agree that extending the GGSS closure date would be beneficial? Yes/No. We would welcome views on a four-month extension (to 31 March 2026). Please provide evidence to support your response.**

General

As noted in the consultation, project developers are seeing significant challenges in timeframes to develop, build and commission projects. Supply chain disruption is a key part of this, with the after-effects of the Covid pandemic and Brexit playing a role. The impacts are most acute in provision of specialist equipment such as CHPs, grid entry units and upgraders, as well as their components. The time taken for on site civil works or construction of tanks is not affected in the same way, so this is principally about the supply of equipment rather than its installation or the actual construction process of AD projects.

Supply chain disruptions are not the only relevant factors. Impacts of **high inflation** (and uncertainty over its future level) also affect project viability, especially if prices change between initial costings and placing orders for equipment. This in turn creates its own deadlines for achieving financial close. Most projects have relatively tight margins for delivering expected returns, so there is a limit to how much cost increase can be absorbed before a project is no longer viable. In this context, it is worth noting that short-term high gas prices may benefit owners of existing plant but are unlikely to make it easier to fund new projects, which are dependent on expectations of long-term prices.

Delays in the introduction of **separate food waste collection** in England and the timing and circumstances in which local authorities are obliged to comply have also had an impact. Even when these are known, there are still significant uncertainties around the impact on increased food waste availability for AD, both nationally and locally. The impact will be greatest in areas where there is currently lowest provision of separate food waste collections and much less where this is already widespread. Since the new policy only relates to England, it would also have little to no impact on feedstock availability in Wales or Scotland. Even where there is a significant increase in food waste availability, local conditions will dictate whether this is available to a new GGSS plant or supplied to an existing AD plant.

The **planning** system is one of the greatest barriers to project development at the moment. Not only are the time periods to make planning decisions lengthening but the whole process is increasingly unpredictable – not just in terms of timing but the additional information and reports that will be required. Provision of additional reports from third parties is a significant cost in terms of both time and money, so it is essential that a responsible developer can understand what is likely to be required of them in advance of submitting an application. This issue falls outside the scope of GGSS since applicants for a Tariff Guarantee must have obtained the necessary planning permissions prior to applying, but it is very relevant to consideration of project development lead times and whether a change in GGSS would be of benefit to entirely new projects or only to those that have already obtained planning permission.

There are increasing concerns over the performance of the **Environment Agency** around the time needed to obtain an Environmental Permit. Although we are not aware of any projects that have been unable to meet RHI or GGSS commissioning requirements as a result of failure to obtain a permit, there are numerous examples that have come close and this is a very real fear for developers and funders of new projects – particularly when commissioning periods are tight.

Finally, there are considerable uncertainties over the **time needed to bring a new AD plant into operation**. When supply chains are not disrupted, the industry has shown that it is capable of completing the construction phase of plants within 12 months of funding, and sometimes in a shorter period – although this can result in increased costs/increased post-commissioning snagging as a result of a rush to meet the deadline.

There is greater uncertainty around the period required to move from seeding the digester(s) to producing enough gas to commission the necessary equipment and commence injection of gas to the grid. In the end, this is dependent on biological processes, and experience has shown that trying too hard to speed these up can be self-defeating. Partly as a result of setting a Tier 1 limit that is 50% higher than for the RHI, GGSS projects are generally larger. It remains to be seen whether this will have an impact on the time projects need to commission - both in terms of actual outcomes and what funders will be comfortable allowing for when making final investment decisions.

<u>Impact of extending GGSS deadlines</u>

Given the above, a four-month extension to the GGSS deadline could be helpful for some developers. If a project has already reached financial close or expects to do so shortly, then an additional four months would provide a meaningful buffer within the project plan.

By the same token, if a potential project on a green-field site has not yet submitted a planning application, it is unlikely to make any difference – such a project would be very lucky to obtain planning, move to financial close, build and commission either by November 2025 or March 2026.

To the extent that project fundability is impacted by the outcome of Defra's decisions on separate food waste collection, it is impossible to be sure in the absence of that decision being taken – but it seems unlikely that an additional four months would make much difference either way.

For these reasons, we would agree that an extension by four months is an improvement on the current position and would be genuinely useful to some projects, albeit a limited number.

We would also encourage DESNZ to consider a longer extension to the GGSS – to March 2027 or March 2028. This would allow time for developers to respond to the changes to the scheme we recommend elsewhere in our response (to reduce or remove the waste feedstock limit and allow expansions of existing plant).

It is also essential to ensure – and to communicate clearly to industry – that there will be no gap between the closing of the GGSS and introduction of a successor policy. Given that policy development on the latter remains at a very early stage, it is likely to prove challenging to introduce a replacement by March 2026, especially since any new policy is likely to require primary legislation.

2. **Do you agree with the recommendation to maintain the current tariff guarantee deadline? Yes/No. Please explain your reasoning and include any evidence you think is relevant.**

Yes. Assuming that the scheme closure date is extended for at least four months, we do not see that extending the tariff guarantee deadlines themselves would add much.

3. **Can supply chain issues be adequately managed within the current commissioning window? Yes/No. Please provide evidence on the impact of supply chain delays on AD plant development and how they can be addressed.**

There is a great deal of uncertainty over delays, both current and in the future and what impact they will have on projects. By their very nature, there is very little project developers can do to avoid them.

We recommend DESNZ consider replicating the flexibility shown in the final stage of the RHI, by allowing projects that have reached financial close (and submitted the appropriate documentation to Ofgem) before the scheme closure date a further 12 months to commission. This approach provides significant additional flexibility to developers while also controlling total scheme costs, as the additional months gained reduce the project's 15-year operational support period.

The RHI flexibility was granted under the exceptional conditions of Covid-19. The current uncertainties around supply chain disruption are extreme and radically different to what went before. Current inflation rates are also extreme and it is far from clear how and when these will be brought to more 'normal' levels – and whether this can be done while avoiding other major disruptions such as a national or global recession. While it is unclear whether these factors are short-term or enduring, they are nonetheless severe, very difficult to predict on the basis of current information and very different to what was considered as part of the policy design for the GGSS.

We note the consultation's observation that there is as yet insufficient evidence on future disruptions to be sure of whether this approach is needed. We would respond that it is precisely because there is no clear evidence on what will happen that this flexibility is needed. Given that a project making use of this flexibility is permanently depriving itself of GGSS income it is not something that a developer would set out intending to use. So the benefit of this flexibility lies principally in de-risking a project, and thus making it more likely to go ahead.

The need for a flexibility mechanism obviously interacts with decisions on whether to extend the closure date for the GGSS. If a decision were taken to extend for longer (to March 2027 or March 2028) then this mechanism would not be so urgently needed. Until the current highly disruptive economic situation settles down, however, we believe there would still be merit in introducing such flexibility.

Finally on this point, the greatest benefit from introducing such flexibility (or for an extension of the closure date) comes from announcing it as soon as possible. Serious consideration should be given to allowing this flexibility as part of the government response to this consultation – the impact on bringing forward potential projects would be far greater than if the same flexibility were introduced only a few months before the scheme's closure.

4. Do you agree that the minimum waste threshold should be maintained at 50% of all biomethane (by energy content)? Yes/No. Please provide evidence to support your response.

We agree that the minimum threshold should not be increased beyond its current level.

We believe, however, that the restrictions should be fundamentally reconsidered based on what outcomes they are seeking to achieve and their actual impacts, and that the thresholds no longer serve a useful purpose. **The restrictions should be removed entirely, or failing that, reduced to a lower level.**

Impact of current restrictions

When the restrictions were originally introduced in the RHI, they were driven both by a desire to increase uptake of food waste into AD and to discourage 100% crop plants. The latter were seen as questionable by some stakeholders, regardless of the uptake of food waste. Concerns were centred around the use of maize silage and whether there were wider environmental risks around its cultivation that would not be captured by the sustainability criteria.

At the time, many in government and the industry believed that it would not be unduly challenging for **farm-based plants** to increase the level of wastes and residues used so that the feedstock restrictions would act not as a ban on agricultural plants but as an incentive for such plants to maximise their use of local wastes and residues. By this reasoning, a number of agricultural projects would come forward with a genuinely 50/50 blend of feedstocks that would otherwise have gone ahead as (almost) entirely crop-fed **in addition to** locally-arising food wastes being captured and used by other projects.

Experience has shown that achieving 50/50 farm-based projects is much harder than hoped for. Straw is a residue, but it has significant other uses and can experience huge price volatility between seasons and over the course of a season. It is also difficult to process in quantity without impacting on performance of the plant – and a number of products marketed as technical solutions have not performed up to expectations.

Wet manures have relatively little value as biogas feedstock and to provide enough to make a serious contribution towards the restrictions would need to be sourced from a vast herd and/or be transported over long distances. Apart from being undesirable on GHG impacts, this is also unlikely to make sense economically given the costs of haulage. Given the geographical layout of farming in the UK, large herds are also not generally found in the same areas as the bulk of arable farming.

Chicken manures are a current source of interest as they have relatively high dry matter. If used in quantity they can disrupt the biology of the digester but mitigation strategies for this are available. Recent enquiries from developers have suggested that interest in chicken manures has significantly increased the prices projects would have to pay to obtain this material, which may be too high for projects to be viable.

Developers can seek other wastes and residues, such as residues from food production or processing, although there may be restrictions on this within their environmental permit or planning consents. New plant at an agricultural site will have to justify the choice of site, which becomes harder if the feedstock used is not from locally-produced agriculture. It is also very difficult to obtain assurances of supplies to the level needed by funders before that digester has begun construction. This gives developers that effectively control these materials a considerable advantage over the rest of the market. It is not likely to be a coincidence that new applications to the GGSS (ie excluding those that previously applied for an RHI tariff guarantee) are dominated by projects from a single such developer.

This leaves many developers considering whether they can import food waste 'soup' to their site – ie food waste that has been collected and processed elsewhere. There seems little benefit to this, since the food waste is likely to be transported a significant distance from where it was first produced, and there is unlikely to be an increase in the amount of food waste captured for AD – the food waste could almost certainly have been used elsewhere, and has only gone to the farm-based site because they were prepared to pay more for it.

All these issues become more acute given the combination of relatively low tariffs and Tier 1 limits being 50% higher than the RHI. Developers are effectively obliged to seek to fund plants that can maximise Tier 1 income, meaning greater quantities of non-crop feedstock are required, and risks concerning their availability and performance in the digesters are correspondingly greater.

As is already understood, there is a shortage of food waste availability compared to AD processing capacity. This can be seen in the impact on gate fees. Only a few years ago, it was common for AD plants to receive a gate fee for food waste (ie to be paid to take it). Many plants are now obliged to pay significant sums to obtain waste. To some extent this has been exacerbated by the impact of high electricity and gas prices. Those in control of the food waste have been able to place a greater value on the feedstock knowing that the AD plant operator will be able to pay on the basis of higher income from the sale of power or gas. We provided substantial input on these points to the Treasury and DESNZ when the Electricity Generator Levy was being developed.

The general expectation from our members is that this pressure has been building for some time and is not likely to ease off dramatically if or when energy prices return to more 'normal' levels. As set out above and in the consultation document, Defra's decisions on new policy in England are yet to be announced and the extent of their impact may not become clear for some time.

<u>Conclusion</u>

In summary, the existing rules have significant adverse impacts:

- It is increasingly difficult to put together fundable projects, resulting in under-performance of the scheme – and it is unlikely that Defra decisions on food waste collection will change this before March 2026
- The restrictions distort the market, in that developers linked to companies that produce the wastes or residues have a considerable, locked-in competitive advantage over the market as a whole
- They drive sub-optimal outcomes (from both an environmental and economic viewpoint) in transporting waste/residue feedstock significant distances

The restrictions are unnecessary, as the policy goals that led to the introduction of the restrictions are already being met by other means:

- Food waste is already being very widely used, and the evidence on gate fees suggests there is at least as much AD capacity as necessary
- Where residues are available locally they are already being used, and if they are available at a lower price (on a biogas potential production basis) developers are strongly incentivised without the restrictions to use them in preference to crop
- Projects dominated by energy crops are not likely to be viable in the future, unless they have additional income streams (for example from CO2 capture and use/storage):
    - Tariffs rates are much lower than in the early stages of RHI and are too low for project returns to support paying for crop-dominated feedstock

- The lower GHG threshold in the GGSS compared to the RHI is very challenging to meet with crops alone, and can only be met with confidence by averaging GHG calculations of crops with the much lower values emissions values derived from the use of wastes and residues

Given the above, we recommend that the restrictions be removed following the mid-scheme review. If this cannot be agreed across government in the time available, then some mitigation would be achieved by reducing the % level of the restrictions and ensuring that there are no such restrictions in whatever policy replaces the GGSS.

5. **Do you agree with the proposal to maintain digestate mitigation regulations under the GGSS? Yes/No. Please provide evidence to support your response.**

Yes.

We agree with the proposal to leave the digestate mitigation requirements unchanged, given the lack of clear evidence on the cost and benefits of further restrictions. Even where further regulatory interventions may be needed in future, the environmental regulators are likely to be the most appropriate bodies to manage these.

There are a number of ways in which the integration of the waste management system as a whole can and should be improved in relation to organic wastes. Energy policies play a key driving role here as there is financial support available, based on energy output. This requires careful thought for desired outcomes for the waste management system and how energy policy can enable this.

Since these are primarily considerations for the longer term, we set out some initial thinking on these in our response to question 12.

6. **Do you agree with the recommendations not to expand the GGSS eligibility criteria to allow CHP conversions to biomethane injection under the scheme? Yes/No. If not, please provide evidence on capital costs, operating costs, and post-tax nominal rates of return of CHP plants, biomethane plants, and conversions.**

We welcome DESNZ' engagement on this issue. We agree that, when looked at solely in the context of CHP **conversions** (ie when projects switch completely from generating electricity to producing biomethane) the picture is uncertain within the intended period for which the GGSS is open to new applications. We also agree that, if the GGSS rules remain unchanged following this review, the issue should be looked at again when designing the successor scheme to the GGSS.

We note that DESNZ' analysis of the case for conversion of existing plant is highly sensitive to whether or not the plant would have continued to operate without subsidy. We would welcome further engagement on this point as feedback from our members is that it is very unlikely that most plant would continue to operate without ongoing support.

<u>Expansion of existing plant</u>

We believe that DESNZ has only considered a narrow sub-set of possible plants by focussing its analysis on **conversion** of existing plant.

The far greater opportunity lies in **expansion** of existing plant – in other words, instead of producing essentially the same amount of biogas and ceasing to claim its current subsidy (conversion) the plant **increases** its capacity, continuing to produce/claim its current subsidies **and** injects biomethane under the GGSS.

This could be an option for either:

1) An existing CHP project (with either FIT or ROC support – and that may also have RHI heat support)
2) An existing RHI biomethane project (which is highly likely also to have an on-site engine receiving FIT/ROC support and may also have RHI heat support for the engine and/or standalone boiler)

The RHI for biomethane allowed interaction with Feed in Tariff and Renewables Obligation plant (and also with support for heat from biogas under the RHI) and we are not aware of any perverse outcomes that resulted, or problems with tariff calculation methodologies. In our response to the original Green Gas Support Scheme consultation, we argued that expansions should continue to be allowed and we see no reason to change that position.

The arguments in favour of conversion also apply to expansions, but there are further reasons:

- A far wider range of projects could be supported – since GGSS support is not required to be more attractive than older FIT/RO incentives
- GGSS has under-performed on expectations for the number of applications – and within that, the majority are either legacy RHI tariff guarantee applications or linked to a single developer. This would enable more general stimulation of the market and would be **additional** renewable energy, rather than shifting the same biogas from electricity generation to biomethane production
- By setting the tier one limit at 60,000MWh annually, GGSS provides a strong push for projects to be at least this size – ie 50% larger than was typical under the RHI. This can lead to sub-optimal outcomes, particularly when interacting with the feedstock rules on wastes/residues/crops[1]. It is far more likely that an expansion based on an existing site will be optimally sized to reflect the wastes/residues in the local area
- It should generally be cheaper to expand an existing brownfield site than build from scratch. Funding costs may also be lower since there is an existing asset to help fund cashflow of the build/commissioning phase
- For similar reasons, delivery should be faster since it should be quicker (and with less uncertainty on the final result) to get changes to planning permissions at an existing site rather than a greenfield one

We see no reason in principle to continue to exclude expansions of existing plant and many good arguments in favour of inclusion – in particular the opportunity to secure additional renewable energy within the planned lifetime of the GGSS. It would be relatively straightforward to allow for expansions by amending the list of restrictions in the regulations[2] to remove some or all of the restrictions on pre-existing plant.

[1] See also our response to question 4 of this consultation.
[2] The Green Gas Support Scheme Regulations 2021 (legislation.gov.uk)

Tariff setting for plant with existing biomethane RHI support

This should operate essentially as if the new capacity were additional capacity under the GGSS (regulation 8). Tiering would operate for the additional capacity based on the **total** biomethane injected at the site, so the tiering mechanism would guard against risks of over-compensation from economies of scale just as it would with an expansion of a project that started out in GGSS[3].

Points to consider within this approach:

1) Differences in tier 1 threshold size between RHI and GGSS[4]
2) Duration of support for the additional capacity[5]

Tariff setting for existing CHP plant

Most of the equipment needed will be the same for an expansion as a new build of the same size. In particular the connection to the gas grid, upgrader and Grid Entry Unit.

Even where the 'shopping list' of construction items needed will differ from a greenfield project, DESNZ already holds data on these costs and has now launched its Annual Tariff Review[6] to seek information on whether/how these have changed recently. We will liaise between our members and the DESNZ team to understand what is required for an expansion project and how to build up an understanding on project profitability, using data that DESNZ already hold wherever possible.

In our view, it is likely that the result of this analysis will be that the existing tariff is also suitable for expansions of existing CHP projects. It is certainly clear from applications to the scheme to date that the tariffs are not unduly generous and may be too low to stimulate the market as a whole.

In the event that this analysis shows that CHP expansion projects should have a lower tariff then this could be dealt with by defining that category of projects and setting a specific initial tariff in the regulations. Although this would require a little more complexity for the scheme it would be worth it, since the value for money case for any biomethane produced as a result would be even stronger than it would otherwise be.

[3] A small number of biomethane plants secured RHI subsidy prior to the introduction of tiering – an even smaller number do not have a maximum capacity set in their NEA at all. It may be appropriate to continue to exclude such plants from applying to GGSS.

[4] If the plant is currently injecting 40,000MWh annually under RHI, would the next 20,000MWh (under a GGSS expansion) be tier 1 or tier 2? Given that the GGSS tariffs will almost certainly be lower than the RHI tariffs, our initial thinking is that it would fall under tier 1, but this would need testing for value for money purposes.

[5] If treated as additional capacity then it would be limited to the lifetime of the original subsidy (ie rather than a full 15 years). Also to consider interaction with decisions on expansions of existing CHPs. It may be simpler to set a flat 15 year period of support for expansions in either scenario

[6] Green Gas Support Scheme 2023 annual tariff review: call for evidence - Department for Business, Energy and Industrial Strategy - Citizen Space

Inclusion of landfill gas

Another source of gas that should be considered for inclusion in the scheme is biomethane made from landfill gas. Since 2002, the Renewables Obligation has incentivised landfill site operators to maximise the amount of methane they capture. As well as providing affordable renewable electricity (around 3TWh annually), it helps minimise leakage of methane to atmosphere – which is has a global warming potential many times worse than CO2.

Biogas made from landfill was specifically excluded from the Renewable Heat Incentive when it was set up, and this exclusion has been carried over into the GGSS. At the time the RHI was set up, there was very little information on the costs of biomethane production in general and equipment to upgrade biogas from landfill was not generally available. There was consequently no clear idea on what tariff would be appropriate, or how much biomethane might be produced from landfill for a given tariff – and what the impacts on budgetary controls might be.

Since then, a number of things have changed that mean the exclusion of landfill gas should be reconsidered:

- Viable commercial upgrading solutions are available
- The majority of landfill sites currently generating electricity are due to lose support under the Renewables Obligation in April 2027, with the rest following soon after. Feedback from members is that the vast majority of these would no longer be viable generating electricity once RO support is gone
- Far better information is available on the overall costs of biomethane production. The new information required for the specifics of upgrading landfill is relatively modest, so it should be possible to calculate an appropriate tariff with a far greater level of confidence
- It should be easier to calculate the range of likely deployment. Methane production from closed landfill sites declines in a fairly predictable way, and it is unlikely that biomethane production would be viable for any but the largest current sites
- In addition to the above, cost control methodologies are in place and have matured over time. The Tariff Guarantee process provides a means to limit deployment as an emergency brake should it be needed

In terms of tariff setting, we would be happy to facilitate information gathering from technology supplies and our members with interests in landfill gas. Compared to stand alone AD, the gas production could be regarded as much cheaper since the cost of building the landfill facility and obtaining feedstock is already covered (or rather, one would expect to be reflected in the gate fee charged by the landfill site). Similarly, there is no digestate to pay to remove or spread.

Conversely, costs to upgrade and inject the gas are significantly higher. The gas produced contains heavier concentrations of contaminants which will prove more costly to remove (and are more unpredictable both in their presence and levels given the heterogenous nature of the feedstock). Further, landfill gas contains more air (and hence nitrogen) than stand-alone AD, which will require a dedicated stage in the gas clean up – and is not required for stand-alone AD. The cost of this equipment, both to install and operate is the key new information to factor into DESNZ' tariff-setting model.

Given the timeframe for removal of RO support, it is most likely that inclusion of landfill gas within the GGSS would amount to a conversion scenario. There is no prospect of increasing the amount of gas produced. The logic here being that inclusion would continue to support operators maximising capture and use of methane from landfill – and that a far higher % of the energy in the gas is available when injected to the gas grid than when it is burned to produced electricity.

As well as the specific exclusion of landfill gas, the current eligibility rules would also most likely rule it out for the same reason that conversions or expansions are ruled out. The cells in which the feedstock is put could well be regarded as the 'biogas production plant'. Therefore, a decision to include would also need an adjustment to the eligibility rules proposed in this section of our response.

7. **How could post-GGSS biomethane policy best support CHP conversions to biomethane?**

See our response to the above question. If the existing GGSS eligibility requirements are unchanged for both conversions and expansions then these should be allowed in the successor policy to the GGSS.

8. **Do you agree that heat from heat pumps should be exempt from heat deductions for eligible biomethane? Yes/No.**

Yes. We raised these issues with BEIS over the last year and appreciate the department's engagement and proposal to take this forward.

Most biomethane plants under the RHI were built while electricity subsidies for AD were available (and many also made use of support under the RHI for the use of biogas heat). This meant that it was widespread practice for biomethane plants to derive their electricity and a substantial proportion of their heat demand from on-site combustion of their own biogas. Developers had very limited incentive to look for other sources of energy and therefore the RHI's treatment of other heat sources did not unduly distort project design choices.

With the withdrawal of those subsidies, projects are required to look again at the source of their heat. In many cases, the most economic solution will be to import fossil gas from the grid rather than use any biogas or biomethane produced on site. Under the current GGSS payment formula, developers looking to use heat pumps or other technologies are treated in the same way as if the heat were derived from combustion of fossil gas or diesel.

We agree with the proposal to exclude (non-RHI) heat pumps from this deduction, as well as the proposal that GGSS plants already registered under the scheme at the point at which regulatory changes are made would also be able to benefit.

9. **Are there additional non fossil fuel technologies or approaches that warrant consideration? Yes/No. Please provide evidence to support your response with particular attention to costing information and environmental impacts.**

A number of other heat sources could be considered as offering substantially reduced GHG emissions than heat from fossil gas or oil. DESNZ should evaluate these if it becomes clear that developers would like to use them but that the GGSS tariff formula drives them to a less environmentally-beneficial outcome.

One option that has been put forward is for the use of electric boilers to generate heat. Where these use genuinely additional renewable electricity (such as curtailed or new, subsidy-free generation) then this could be removed from the deduction (or discounted in some way). A substantial framework has been developed for how such electricity could be classified and its use demonstrated – both by DESNZ for the Low Carbon Hydrogen Standard and the Department for Transport for the Renewable Transport Fuel Obligation.

10. Do you agree with the approach of using energy input to calculate the deduction? Yes/No. We would welcome comments on the administration required. Please provide evidence to support your response.

Yes. Using the energy input means the size of the deduction that results is directly related to the performance (and effectively energy efficiency) resulting from the use of the heat pump.

Given this, we would question whether it is also necessary to have minimum system performance requirements, as projects will have every incentive to maximise performance. There is the potential for this to be complex to administer and for lengthy approval processes between the project, its designers, equipment suppliers and Ofgem. Ofgem and DESNZ should consider the experience of similarly-sized heat pumps in the non-domestic RHI. If a minimum requirement is imposed it should be a light touch, back-stop level, with absolute clarity from DESNZ and Ofgem on how to demonstrate compliance.

11. How effective are current methane leakage prevention, monitoring and mitigation practices? Please provide evidence to support your response, including examples of good practice.

We support the various initiatives that are in progress to understand, monitor and mitigate methane emissions and look forward to continuing to engage on them.

DESNZ should also consider work being carried out in other regions. Within the EU, the European Biogas Association has recently published a report setting out current best practice.[7]

12. What are your views on how we can best address the areas listed above as part of our future policy design?

Biomethane has a wide range of benefits. In addition to the GHG savings, Russia's invasion of Ukraine and high energy prices have led to an increased emphasis on the importance of energy security – not least in the recent change of name for the energy department. Given the progress made in decarbonising the electricity grid and higher conversion efficiencies it makes sense for biogas to be prioritised for use as heat rather electricity generation.

AD is also the optimum treatment technology for many wet wastes, with the resulting digestate from wastes, residues and crops supporting the circular economy by supporting soil health and reducing the need for mineral fertilisers.

The role of capture, use and/or storage of the CO2 in the biogas is increasingly recognised. Bio-CO2 can be used for a range of purposes, and the recent experience of shortages following the temporary shut-down of fertiliser manufacture in the UK shows the knock-on effects of even a

[7] Design, build, and monitor biogas and biomethane plants to slash methane emissions | European Biogas Association

relatively short-term disruption. As permanent CO2 storage options become available, biomethane is well-placed to make use of them – and with the CO2 stored having been recently removed from the atmosphere, this brings the prospect of real, measurable negative GHG emissions.

We note the initiatives at the EU level to work towards a target of producing 35bcm of biomethane per year by 2030. An equivalent level of ambition is needed in the UK. This is about much more than setting targets. The European Commission has created a Biomethane Industrial Partnership, to bring policy makers, industry and other stakeholders together to identify and resolve challenges. The REA is an associate member of the partnership and the UK government should look to learn as much as possible from this initiative.

As noted in our response to question 5, there are a number of areas where the **existing waste management system** is far from optimal in relation to AD feedstocks.

This goes beyond the forthcoming Defra decisions on separate food waste collection in England. Large questions will remain around how this food waste is collected. REA has long argued that where caddy liners are used for households, these should be compostable. The challenge remains that these may not be suitable for anaerobic digestion and more substantial compostable items (such as packaging for coffee cups and food containers) are very unlikely to be suitable without additional treatment.

Given increased scrutiny on plastics in materials spread to land, it would make sense for conventional plastics to be replaced with compostable materials in these instances, with additional processing steps. This could involve use of an autoclave prior to putting into the digester or post-digestion aerobic maturation prior to the material being spread to land. Since these treatments are more expensive (and in some cases, harder to gain regulatory approval for) than business as usual, they are unlikely to be funded unless there is a more joined up approach on this area from DESNZ and Defra.

The REA and its members have been engaging with Defra, the environmental regulators and WRAP on these issues for some time and would be happy to continue to do so with the DESNZ team. Possible solutions would include funded trials, grants for installation and use of particular equipment, changes to environmental regulations or specific drivers from whatever policy replaces GGSS. Getting this right would in turn drive improvements in the quality and marketability of digestate and creating a real value for those materials.

<u>Replacement of GGSS</u>
We believe that some form of ongoing energy policy will be required following the closure of the GGSS.

In this context, the absolutely critical point is that there must be no gap between the end of the GGSS and whatever policy replaces it. As set out in our response to question 1, the need to allow plenty of time for policy development but also ensure there is no gap, would be a strong argument for extending the planned closure date of the GGSS to March 2027 or 2028.

As the GGSS was always intended as a relatively short term policy, a number of policy choices were carried over from the Renewable Heat Incentive with little or no change. We have already set out our views on feedstock restrictions (question 4) and allowing the use of existing plant (question 6) and do not repeat those here.

Since the RHI began, there is a far greater body of evidence on costs and reliability of projects. The structure of projects has also changed significantly:

- Several projects now capture CO2 and it is clear that there is potential for this to be far more widespread in future if the right framework is in place – with pushes from government creating a genuine market for the CO2 and resulting GHG savings.
- Guarantees of origin have been set up, creating a real value from consumer 'pull' for robustly documented use of renewable gas. The Green Gas Certification Scheme had retired over 13TWh of certificates by the end of 2022[8]
- Many projects are looking to the potential for some of the gas they inject to claim support under the Renewable Transport Fuel Obligation instead of through RHI/GGSS
- A wider range of sources of heat is being looked at, as set out in our response to questions 8 and 9
- Innovative approaches are being considered for projects where connection to the local transmission or distribution network does not make sense. One of these projects is looking at networking multiple smaller production sites from dairy farms into a single larger point of injection to the gas grid. The merits of these and other approaches need to be considered carefully and supported where they meet overall policy goals
- Similarly, there are a number of areas where biogas or biomethane could beneficially be produced but without the option of connecting to the gas grid at all. With the closing down of the Feed in Tariff and Renewables Obligation schemes there is effectively no viable route to support for these projects

<u>Options for future ongoing support</u>
A number of basic designs are available. We would recommend DESNZ consider all of the following and engage closely with stakeholders on how these could work in practice:

1) **fixed-premium scheme**: essentially an updated continuation of the GGSS. Even if this is not the option chosen, it should certainly remain under consideration for comparison with the alternatives as it is well-understood by industry and government
2) **renewable heat obligation:** this would place an obligation on suppliers of natural gas to source renewable gas, on a similar basis to that operated for electricity by the Renewables Obligation. The key design point here being that suppliers are incentivised to find cost-optimal renewables across their portfolios
3) **contract for difference:** There are two key elements to this policy approach:
   i) payment to producers is based on a 'strike price' of combined energy sales and subsidy income – so the subsidy goes up or down, depending on energy prices
   ii) use of auctions to set strike prices has proved effective at driving cost reductions between technologies of the same type

[8] PowerPoint Presentation (greengas.org.uk). The GGCS is operated by Renewable Energy Assurance Limited, a wholly-owned subsidiary of REA

4) **Pay on GHG savings rather than energy:** any or all of the above options could be adjusted to pay on the basis of GHG savings. This would incentivise developers to maximise GHG savings, whereas the current sustainability criteria require everyone to meet the same minimum standard but give no incentive for better performance – whether through major one-off investments or a series of incremental improvements. This approach could include heat sources, maximising gas production, how digestate is used and CO2 capture, use and storage. The industry has over 10 years of experience of using the GHG calculation methodology so this is far better understood than when the RHI was set up. We would also note that the Department for Transport has committed to the forthcoming Sustainable Aviation Fuel mandate[9] being expressed in GHG rather than energy terms so there may be opportunities for learning from that approach

[9] Pathway to net zero aviation: developing the UK sustainable aviation fuel mandate - GOV.UK (www.gov.uk)