'Future Support for Low Carbon Heat'
REA responses to Green Gas questions

The Association for Renewable Energy & Clean Technologies (REA) is pleased to submit this response to the above consultation. The REA represents a wide variety of organisations, including generators, project developers, fuel and power suppliers, investors, equipment producers and service providers. Members range in size from major multinationals to sole traders. There are over 550 corporate members of the REA, making it the largest renewable energy trade association in the UK. The Wood Heat Association is the members forum within the REA that advocates for the modern wood heating and related biomass heating industry including wood fuel suppliers, biomass boiler and stove installers and distributors, and anyone involved in the supply chain.

Summary of response – Green Gas Support Scheme

It is welcome that BEIS is bringing forward a support mechanism aimed at increasing the proportion of biomethane in the grid as well as avoiding a hiatus in biomethane development. We are also pleased that BEIS is considering and seeking views on a longer-term support for green gases.

We anticipate the proposed change in the interaction between the RHI and the RTFO will result in significant additional biomethane injection from existing biomethane injection facilities as well as enabling any new projects joining the scheme to optimise their output.

As highlighted in the consultation's Impact Assessment, 'biomethane injection offers a low-regrets, cost-effective way of contributing to near-term, legally binding carbon budgets and is also the only commercially-available technology capable of greening the gas grid.'

However, the Green Gas Support Scheme should include support to plant expansions of existing assets as well as new build. Making existing plants eligible for the Green Gas Support Scheme would maximise value for money delivered through the scheme, whilst stimulating further biomethane generation.

We also consider that the Green Gas Support Scheme should be technology neutral and include biomethane from thermal gasification, in line with support provided under the Renewable Heat Incentive.

Generally, the expansion of Tier 1 to 60,000 MWh/annum is seen as a positive step forward to allow better economies of scale. However, the tariff length should not be reduced as this would lead to greater investment risks, higher cost of capital and less sustainable roll out of the industry, as well as rule out the ability of re-finance projects. In addition, the tariff levels proposed -particularly at the lower end of those proposed, may not meet the BEIS target IRR (10%) and may not be adequate to reflect the increasing costs of regulations and environmental permitting.

BEIS's intention to replicate tariff guarantees is seen as a positive step as it will continue to give developers/installers confidence of the tariff they will receive, but tariff guarantee deadlines for a project should be set with sufficient time to enable plants to commission without rushing to meet deadlines. In addition, a degression mechanism for biomethane is no longer required. We would recommend instead a single review point midway through the scheme.

We agree that wastes should be encouraged in line with a circular economy, but we cannot support a further increase of the minimum percentage of waste feedstocks above 50%.

We have also asked that BEIS redefines what is counted towards this percentage and that this should be more aligned with the Renewable Transport Fuel Obligation and RED II.

We consider it would be it would be sensible to align sustainability criteria to RED II, but we strongly recommend that, if this is done, averaging of consignments to calculate lifecycle GHG emissions against the target is allowed in line with RED II. Also, we have asked that BEIS put in place tighter requirements on methane slip to promote industry good practice.

There needs to be a more streamlined and consistent approach within the Fuel Measurement and Sampling Protocol (FMS) to allow for more flexibility in an ever increasingly complex supply chain and feedstock market. More detail on the proposed solutions is included in the response.

A range of strategies to minimise ammonia emissions from digestate and increase their commercial demand do certainly exist, and we have listed the key ones in our response, however the key barrier to their uptake is their cost. This needs to be supported by Government, preferably through dedicated grants.

Feedback from members is that in the longer term industry would want to move to a situation where real market 'pull' signals play an increasing role rather than straight producer subsidies, to encourage a 'real' market to develop in supply and use of biomethane. A long term support mechanism for green gases should also be technology neutral ie its scope is expanded to ensure that it covers all forms of renewable gas supply, i.e. biomethane from AD, bio-SNG from gasification, and green hydrogen. The REA's preferred mechanism would be a green gas obligation on gas suppliers to meet a gradually increasing GHG reduction target over a period of time, which would reward technologies and renewable gases that deliver the largest carbon savings, whilst driving best practice and innovation.

Finally, there is significant scope to decarbonise the farming and industrial sector through the use of onsite CHP applications. These can make a real contribution to reduce GHG emissions from farms and industry, often off the gas grid, as well as reduce their carbon footprint. Government support is needed to ensure this potential can be fulfilled.

<u>Government assumptions on green gas supported under Green Gas Support Scheme (section 4.2 of consultation's impact assessment): key recommendations:</u>

- **Data on resource availability used by BEIS to inform the setting of the biomethane capacity target (TWh/annum) and associated budget should be up to date and dynamic, to reflect changes in the size of the feedstock market. In addition to food wastes, estimates should also consider industrial wastes and sewage sludges, agricultural and processing wastes and residues and sustainable bioenergy crops.**
- **It is crucial that there are no delays in the implementation of Defra's policy to mandate separate food waste collections from households and businesses in England, to improve access to food wastes and underpin further generation of biomethane.**

The outcome of Defra's policy, both in terms of food waste volumes and gate fees, should be closely and regularly monitored by Defra and fed back to BEIS.

- **Government estimates of biomethane potential should include the potential biomethane that could be delivered through expansions of existing assets ie electricity only AD plants, and biogas heat and CHP plants (e.g. in the sewage treatment or other sectors). An upgrade or expansion of these assets to biomethane would in some instances be more cost effective and would maximise value for money from the scheme compared to new build.**

BEIS central assumption is that the Green Gas Support Scheme (GGSS) will support 2.9 TWh/annum of green gas deployed by 2030/31.

During one of the stakeholder workshops hosted by BEIS in May, Government officials have clarified that their intention is to treble the amounts of biomethane injected in the grid by 2030, compared to the 2018 level of 3.3 TWh/annum. So, our understanding is that the overall target for biomethane deployed by 2030 under the RHI and the GGSS is around 9 TWh/annum.

BEIS have based these estimates on the deployment achievable given the constraints on the availability of municipal food wastes.

We have listed below our members' considerations on BEIS' estimates. There are different views from members on whether these are sufficiently ambitious.

Expansion of existing assets

Government estimates should take into account the potential biomethane that could be delivered through expansions of existing assets ie electricity only AD plants, or CHP plants (e.g. in the sewage treatment or other sectors).

The REA Bioenergy Strategy Vision report estimates that currently most biogas (including sewage and landfill gases) produced in the UK (19 TWh) is used for power generation, supported under either the Feed-In Tariff Scheme (FITs) or the Renewable Obligation (RO). As many of these assets, such as those in the wastewater treatment sector, are supported through Renewable Obligation Certificates which will run out approximately in 2027-28, there is significant potential for some of this energy to be upgraded to biomethane.

Uncertainty around food waste volumes

During one of the stakeholders' workshop, BEIS clarified that their estimated potential biomethane capacity is based on internal estimates provided by Defra on total food wastes that will be collected by local authorities. Defra anticipates an increase of 1.38 million tonnes of food wastes by 2029.

It is worth pointing out that there is much uncertainty around the volumes of food wastes that will become available mandatory food waste collections are introduced by Defra. There are existing food waste based plants that have extra capacity to take food waste, so these, to some extent, may absorb some of the additional volumes of food wastes available and, in addition, it is highly unknown how food waste prevention policies will affect the volumes of food wastes provided for recycling in the future. Reductions in the volumes of food wastes produced may to a certain extent offset increased volumes from mandatory food waste collections.

As set out by BEIS in the consultation document, measures from Defra to introduce mandatory collections of food wastes are only expected to commence from 2023. The Scheme is expected to start in the financial year 2021 so there is a time gap between the two which may lead to a lack of sufficient waste feedstocks being available at the beginning of the Green Gas Support Scheme for new plants.

Given all the issues highlighted below, it is crucial that there are no delays in the implementation of Defra's policy to mandate food waste collections to improve access to food wastes and underpin further generation of biomethane. The outcome of this policy, both in terms of food waste volumes and gate fees, should closely and regularly monitored by Defra and fed back to BEIS.

Given the challenges on availability of feedstock, developers and their funders should have a strong incentive in the future to site plant in areas where there is not already excess AD capacity.

<u>Industrial wastes and sewage sludges</u>

It would appear that BEIS estimates do not include wastes from industrial sources (e.g. from agri-food industry), nor the several million tonnes of sewage sludge available that could be used as feedstocks to generate biomethane. These estimates should be included.

The recent industry report '<u>Biomethane: the pathway to 2030</u>' estimates that and also another 4 million tonnes of industrial wastes could be available by 2030.

Investing in emissions reduction through on-site anaerobic digestion must be a priority across the agri-food industry, to reduce the carbon impact of production, processing, manufacture and distribution.

<u>Agricultural feedstocks</u>

There is definitely scope for expanding biomethane production, but that will require extension of BEIS estimates to a broader range of feedstocks beyond current supplies.

We strongly support Government policy to encourage using wastes and residues to generate biomethane, in line with the principles of a circular economy. However, we also consider that BEIS should not underestimate the contribution that sustainable bioenergy crops grown as part of a rotation - in combination with wastes and residues - can play in generating biomethane whilst decarbonising agriculture, enhancing the UK's soils and supporting sustainable and profitable farming. Bioenergy crops would also enable full use of feedstocks such as agricultural and processing wastes and residues, which are in many cases difficult to treat on their own.

When bioenergy crops are grown sustainably in line with high environmental and farming standards, and are integrated into crop rotations (e.g. by increasing the number of crop cycles - three in a two-year period), or grown on marginal land, these will encourage better soil health, biodiversity and carbon capture and fit within the definition of 'public good', regardless of the type and fate of the crops. A further advantage of growing crops for bioenergy is the ability for AD to better integrate into the farming system as local farmers/growers can see the benefits AD brings to their farming businesses. An example of this is the use of digestate on cover crops, which allows nutrients from digestate to be locked into cover crops over the winter period, which is then turned back into the soil in the sowing period thereby delivering nutrients to the soil. These practices have become more widely used on AD plants which rely on crops for digestion as they are more integrated with the cropping cycles. Good practices such as these can then be applied to the wider AD sector. They can also support jobs in rural areas.

BEIS and Defra should also consider the merit and potential role of sequential crops (multiple crops in the same field) in the UK. There may be some parts of the UK where the climate makes it possible to grow these types of crops. This approach has been developed mostly in Southern Europe, pioneered by the Consorzio Italiano Biogas (CIB) to integrate anaerobic digestion with agro-ecology [2]. This highly sustainable model has proven to deliver significant reduction in GHG emissions from agriculture and carbon sequestration, as well as to restore soil health and organic matter. The EBA's position on sequential cropping and the associated benefits can be found here. *'EBA collected from the biogas sector shows that proper biogas production based on sequential cropping is a sustainable activity. On top of that, it is a powerful solution leading to decreased greenhouse gas (GHG) emissions, protection of biodiversity and restoration of soil quality through agro-ecological innovation and organic fertilization.'*

The recent industry report 'Biomethane: the pathway to 2030 estimates 4.2 million tonnes of energy crops by 2030, on the provision these crops are grown sustainably.

See further detail on sustainable crops in our response to question 9.

Recent estimates of biomethane potential

The table below compares recent estimates of biomethane potential from a number of industry and independent reports based on the resources available.

As you can see, BEIS target is very conservative compared to other recent estimates, including that from the CCC in their Net Zero: Technical Report and some members and other trade associations have called for this target to be more ambitious.

Table 1. Recent estimates on the potential for biomethane (from AD) by 2026, 2030, and 2032 (TWh/annum)

Source	By 2026	By 2030	By 2032
REA's Bioenergy Strategy, 2019	31	NA	52
ENA's Decarbonisation Pathways (Balanced scenario), 2019	NA	22	NA
Net Zero: Technical Report, CCC, 2019	NA	20 (heating homes)	NA
Biomethane: the pathway to 2030 (ADBA, 2020)	NA	~54 (conversion from 5,677 million m^3 biomethane potential)	NA
GGSS consultation, BEIS April 2020	NA	2.8 [under GGSS]+ 4 – 6 [under RHI] = ~ 9 TWh/annum	NA

The table shows recent estimates made by a number of organisations on the potential for biomethane (from AD) by 2026, 2030, and 2032 (TWh/annum*)*. BEIS estimates appear to be the most conservative

<u>Biomethane from thermal gasification</u>

We consider that the Green Gas Support Scheme should be technology neutral and include biomethane from thermal gasification as well as from anaerobic digestion, in line with support provided under the Renewable Heat Incentive.

The Non-domestic Renewable Heat Incentive scheme currently covers biomethane that is produced from AD as well as through gasification and pyrolysis. However, it is proposed that the Green Gas Support Scheme is narrowed to the support biomethane produced from AD only.

Gasification and pyrolysis can extend the range of feedstocks that can be converted into biomethane because they can process lignocellulosic materials that are not suitable for wet anaerobic digestion.

However, a significant barrier to the success of these projects is the availability of Government incentives to allow the technology to compete with fossil fuels. Generally, gasification projects operate at a larger scale than anaerobic digestion, which means that to date the tiering structure within the RHI had a major impact. However, recent changes to the Renewable Transport Fuel Obligation (RTFO) have improved the support available to biomethane from thermal gasification (as this renewable gas is now classed as Development Fuel under the RTFO) and it therefore likely that a combination of the RTFO and GGSS will allow gasification biomethane projects to progress to financial close and complete.

The proposed restriction of the GGSS to anaerobic digestion will halt the development of thermal gasification and pyrolysis projects for several years until a new green gas support scheme is developed.

The GGSS should provide sufficient support for a few gasification facilities to be developed. This would provide a base on which the new support scheme for green gas facilities can build on. We would expect at least one or two gasification plants being built in the next five years on the basis of GGSS support with RTFO.

There is evidence from projects in Europe and the UK that the technology is viable, on the costs of commercial plants and their environmental impact. We are happy to provide further information to BEIS on this if needed.

As a final point, current support for heat under the RHI, support for fuels under the RTFO and support for power generation all CfD all include gasification technologies. It would not be consistent to exclude gasification from the GGSS.

However, the spending profile allocated under the GGSS may have to be updated as that highlighted in the proposals is based on the size and potential growth of the food waste market for AD.

Future heat policy to support Geothermal needed

Finally ,we also note it is disappointing that in neither the Stakeholder Note or consultation on the Future of Heat make mention or recognise the potential for Geothermal technologies in the UK. BEIS should be aware of several Geothermal projects currently in development. Geothermal Engineering and Eden Geothermal have raised circa £30 million of public funds with £10 million match funding for two projects set to commission in 2021 and 2023 respectively. Similarly, GT Energy has been working with Stoke on Trent to deliver £20mn investment in a heat network powered by Geothermal technology. While the Geothermal sector is in its infancy in the UK, examples from Germany, where the sector is worth over €10 bn, demonstrates the potential for what could be delivered in the UK. Uncertainty over the RHI and a lack of any mention of Geothermal in the Future Heat consultation has greatly unsettled financiers of such projects. BEIS should seek to make clear their intentions around the technology and establish how the sector can continue to be supported, either through longer commissioning times or stipulating where support for such projects can be expected to come from.

Endnotes

[1] REA (2020) *REview 2020* https://www.r-e-a.net/resources/review-2020/

[2] The so called *Biogasdoneright®* model. Food and feed production are not displaced when producers adopt sequential cropping, therefore this practice should be recognised as low ILUC risk potential. More research needs to be carried out in the UK to understand whether double cropping is possible and could be adopted in the UK given the different climate. Further information https://www.europeanbiogas.eu/wp-content/uploads/2018/10/Biogas-done-Right-extended-2.pdf

Response to consultation questions

Consultation Question 1 - Do you agree that the tiering structure as outlined above is appropriate and would deliver the best value for money? Yes/No. Please provide evidence to support your response.

Yes.

Generally, the expansion of Tier 1 to 60,000 MWh per annum is seen as a positive step forward to allow better economies of scale, especially as some costs remain fixed or don't rise linearly with the size of a project (e.g. tank volumes, civils, upgrader plants, grid connections).

Industry feedback is that the proposed size of Tier 1 (the equivalent of approximately 750 m^3/hour) is a good reflection of the size of AD plants that have been built more recently under the RHI Scheme.

However, some members have raised a concern that the proposed size of a Tier 1 plant would require significant volumes of feedstocks to be secured, which may lead to greater risks compared to those from current Tier 1 plants, unless the plant owner has control over most of the plant feedstocks. Other members raised a concern that a larger size Tier 1 at the proposed levels will result in an uneven playing field with existing plants in operation ie these tiers will create unfair competition with existing plants that are capped at 40,000 MWh/annum and risk putting these assets out of business.

Members have also noted that the differential between Tier 1 and Tier 2 tariffs is significant and may deter industry from developing plants larger than Tier 1 and create even better economies of scale. BEIS should consider reducing the gap between the two tiers: this would help encourage continued production of biomethane, rather than stopping production after Tier 1.

To avoid the risk of overestimating committed spend and a greater use of the tariff guarantees budget allocation resulting from participants securing 750 m^3/hour capacities in their Network Entry Agreements (NEA), we suggest that developers are required to provide more accurate information on the expected injection rates (ie more accurate estimates of likely injection). This should be on the provision that there are no adverse consequences to participants in providing this information so long as it is a reasonable estimate ((ie if their number goes down they don't risk permanently losing capacity).

Participants could be asked to update these estimates periodically (possibly on an annual basis) if these changed significantly.

Some members highlighted there is a risk that a higher Tier 1 will result in developers applying for Network Entry Agreements (NEA) at or around 750 m^3/hour, regardless of whether they are going to use all this capacity during the tariff lifetime. This will potentially result in a greater committed scheme spend , greater use of the tariff guarantees budget allocation which may in turn result in degressions, and 'bed blocking' of NEA capacities (ie capacity booked that is not consistently used).

Biomethane plant expansions

As highlighted before, we strongly encourage BEIS to ensure the scheme enables plant expansions of existing assets (e.g. electricity only, co-generation plants or biomethane plants). Making these plants eligible for the Green Gas Support Scheme would maximise value for money delivered through the scheme. It would be an opportunity to stimulate further biomethane generation, whilst delivering best value for money.

There may be changes to local circumstances that may result in a plant needing to expand and there is no need to exclude this possibility from the scheme. For example, there may be more capacity available on the grid, additional feedstock may become available. Similarly, the full scale plant might be seen as too risky/expensive starting from scratch but the additional spend for an expansion might be justified once the plant is built and is operational, has secured its principal subsidy and has an existing income stream (meaning the need for working capital as part of the funding is largely removed).

As an example, there are likely to be more feedstocks available from 2023, when Defra introduces mandatory collections of food wastes. If a food waste AD plant wins a local authority contract in the future but is not able to expand, the waste may have to be trucked much further afield with a potential impact on the associated GHG emissions. Furthermore, as explained earlier in this response, there are several biogas plants at sewage sludge treatment works that will come to the end of their ROCs and, in some instances, could see this as an opportunity to upgrade their assets to biomethane sooner than their ROCs' expiry date. This could boost additional biomethane production and injection into the gas grid.

There may be two possible scenarios in terms of biomethane plant expansion: an existing site registered under the RHI that expands using the GGSS; or a site originally registered under the GGSS expanding subsequently under the scheme.

In both situations, the GGSS should assess the total gas injected at the site. For the additional capacity it should pay out at the GGSS tiering levels and rates that apply at the point the additional capacity is applied for. In terms of tariff length, it is likely the policy decision would be that the additional support should be available only to the end date of the original installation support (whether that was RHI or GGSS). This would avoid the risk of over-compensation.

The total support available to the plant would be the same or lower than if the plant was built and applied on the scheme in one go, however building a plant in two stages will always be more expensive in capex terms than doing it at the same time (this is because some items will have to be redone, there will be a cost associated with construction oversight, design etc.). So, there will be no risk of overcompensation.

If the choice on tariff length of support is made as suggested above, then developers would also have every incentive to progress with such an expansion as soon as it was feasible.

We would be happy to input more information to BEIS on this proposal if required.

Consultation Question 2 - What are your views on the impact of a 15-year tariff period to support biomethane? Please provide evidence to support your response.

The tariff length should not be reduced. BEIS should be focusing on reducing risk as much as possible: this sector requires long-term investors, rather than short-term high-risk investors, to drive down the cost of capital. Having a tariff period longer than 15 years would help deliver this.

Most members have fed back that shortening the period from 20 to 15 years would lead to greater investment risks, leading to higher cost of capital and less sustainable roll out of the industry. This is even more relevant if the tariff period is shortened without increasing the level of the tariff, resulting in significantly less overall support available to projects under the scheme.

Generally, feedback from members is that investors require longer periods ie the longer the tariff period, the more secure/less risky the investment is seen by funders. From a long-term investment perspective and to ensure the industry financial health, this tariff length may not provide sufficient certainty to investors.

Experience from members shows that a shorter tariff is likely to drive developers to take higher risks which would likely result in lower standards of projects being built ie where operation and biomethane generation do not match the project financial plan.

This can be seen by the number of biomethane plants deployed towards the lower end of the tariffs (different to length of tariff, but they both have an impact on risk). BEIS should look at the historic performance of AD plants funded under the RHI under different tariffs ie Ofgem generation data of plants that were commissioned with the lowest tariffs vs plants that were commissioned with the highest tariffs. Generally, the REA is aware of a higher proportion of plants that are not generating and are on lower tariffs compared to a low proportion of plants in the same situation that are on a higher tariff. This is partly due to circumstances of having struggled to finish/commission (due to unrealistically tight deadlines for commissioning projects under the scheme) or have found that the plants are not financially viable to operate with the lower tariffs.

The above also depends on whether the policy is intended to drive new project development or rather focuses on the expansion/optimisation of existing sites. Feedback from members that have developed several AD plants is that the proposed tariff levels coupled with a shorter tariff period are unlikely to stimulate new project development and encourage new investors and developers in the sector but may result in a number of expansions if they were eligible.

Refinance

A shorter tariff length would risk ruling out entirely the ability to re-finance projects.

The cost of funding construction phase will always be relatively high. There will always be risks on timing and functionality when this equipment is integrated and we are a very long way from a project developer/technology provider being so well established that these risks fall to the sorts of levels seen for wind and solar. Fundamentally, this is an equity-type of risk.

These projects are also far more expensive than stand alone CHP so it is not plausible that a farmer could fund this using their own resources. External funding will be needed.

Therefore, anyone funding a project using (relatively expensive) money for the construction phase will be looking to sell on once the plant is built, operational and has been granted registration. This could then be bought by an owner interested in lower-risk projects with a long term guaranteed source of funding – and with correspondingly lower cost of capital.

The period over which someone would be prepared to lend that money would be 12-15 years (with a strong preference for the 15) otherwise this sort of asset is not of interest to this category of investor. Given the time taken to build, commission and demonstrate full operation of plant (and the sale process itself could easily take 6 months) this would risk ruling out entirely the ability to re-finance projects.

Two-stage tariff:

Biomethane plants will always require ongoing support on an energy basis, unlike other technologies. Because of this, some members have suggested that it may be more appropriate to this technology to be supported through a two-stage tariff: a shorter higher capex tariff (e.g. for 15 years), followed by a lower tariff to cover operational costs for the remainder of the plant life. We would be happy to input more information to BEIS on this proposal if required.

Consultation Question 3 - What are your views on the advantages and disadvantages of a shorter 10- or 12-year tariff period and whether they would help maximise value for money? Please provide evidence to support your response.

The risks highlighted above over shortening the tariff from 20 to 15 years would be exacerbated by reducing the tariff period further.

This would lead to even greater investment risk, leading to higher cost of capital and the delivery of lower quality projects. Developers may build plants quickly and potentially take short cuts. These would result in lower standards of projects, which would either shut down or would not be able to operate in their lifetime anywhere near the expected outputs. This could compromise the sector's reputation, causing an image issue and could reduce the public support for green gas.

As explained later in the answers to questions 4 and 5, there are measures that will be adopted by Government and the regulators to raise industry standards. The current direction of travel taken by other Government departments, the environmental regulators and across Europe is that the industry will need to adopt best available techniques and best practice to minimise its impact on human health, communities and the environment, as well as to maximise its value. Any policy designed by BEIS should not move away from this by encouraging high risk, lower quality projects.

A joined up approach is therefore required across Government and the regulators to ensure any support provided by Government to stimulate deployment of AD plants does not encourage developers to build lower quality projects because the level of support is inadequate, rush projects to meet commissioning deadlines or take short cuts.

Consultation Question 4 - Do you have any views on the appropriate tariff level, within these ranges? Please provide evidence to support your response.

We broadly agree that BEIS target IRR (of 10%) is appropriate, but we are concerned that, for a number of reasons, the tariff levels proposed may not meet it (particularly at the lower end of those proposed).

The feedback we had so far is that industry considers that the upper bracket of these ranges are just about viable, but raised serious concern over the impact that degression will have on plants' viability. These sorts of levels are already very close to the point at which any unnecessary reduction will cause a hiatus in deployment. In other words, if the tariff starts at those levels, even one single degression would likely make it impossible for new AD plants to deploy under the Scheme.

Members have also highlighted that the drop from Tier 1 to Tier from 5.5 p/kWh to 3.75 p/kWh is too great and will create a cliff edge in plant sizing and generation output. Some members have suggested that this could be avoided by having a two stage Tier 2.

Some members have pointed out that to inform the setting of an appropriate tariff level, it is crucial that BEIS does not only consider the numbers of plants that have deployed under the RHI at these tariff levels, but also the actual performance of these plants i.e. how many plants have stopped operating, or are underperforming, and to what extent they are generating green gas. From members' experience, a low tariff is unlikely to stop industry to deploy/develop, but it may drive poorer standards of projects and lower levels of operation. Costs should be collated from a sample of representative plants that are generating to the expected levels.

The costs of designing and operating a plant in line with the upcoming changes brought in by the environmental regulators to permits and new regulations brought in by Defra need to be foreseen and reflected in the level of support provided and the design of BEIS policy.

It is crucial that the scheme drives best practice and encourage development of plants that can deliver and make a real contribution to meet the Government's net zero target.

Given that this policy is intended to be open to new applicants until 2025/26, it offers an opportunity for major changes to energy and other policies (e.g. environmental) to be fully aligned.

A number of policies across other Government departments, and new regulatory requirements will be implemented in the coming few years, which mean that the AD sector will need to move to higher build and operational standards, aligned with best available techniques. These will place additional capital and operational costs on the industry. We have listed those below for information.

Government funded plants should be designed to these standards to ensure a long term, sustainable and financially healthy AD sector. To achieve this, it is paramount that the costs of designing a plant in line with these requirements is adequately reflected in the level of support provided to new projects. Also, elements of the scheme such as the tariff length and commissioning deadlines should be designed in a way that does not encourage developers to rush through build and take short cuts, resulting in lower standards of projects This would be a move away from the general direction of travel across other Government departments and the environment protection regulators. For information, we have listed below the key policies where changes are being brought over the coming months and years.

Measures to minimise ammonia emissions

- Defra's Clean Air Strategy, which is also mentioned in BEIS consultation, is committed to introducing legislation that will require digestate in England to be spread using low-emission spreading equipment by 2025, and digestate stores to be covered by 2027 (but both of these measures may be phased in earlier for digestate or large volumes of slurries). There will be a full public consultation before decisions are made as to the types of covers required and the date they will be required from. A range of currently acceptable covers are described in Defra's Code of Practice to minimise ammonia emissions but these come at a range of costs.

Measures to limit any negative impacts on human health, communities and the environment from biowaste activities

In 2020 the Environment Agency consulted on a review of permits for biowaste treatment including anaerobic digestion. This is as a result of the publication of the revised Waste Treatment BREF [3] and is aimed at bringing permits in line with it and ensuring they operate to the Best Available Techniques (BAT). It follows from the EA's incidents and audit data from anaerobic digestion plants. The review of permits will result in the implementation of the BAT requirements set out in the BREF in the reviewed permits (i.e. plants will have to be designed and operated with best available techniques). The EA will also publish a guidance document describing 'appropriate measures' for the biological treatment of wastes. The appropriate measures are the minimum standards that operators must meet to comply with their environmental permit requirements. In summary, the review will see the implementation of higher design and operational standards (standard good practice requirements and more capital investment improvements) for AD facilities that will certainly result in higher capital and operational costs.

<u>Measures to improve the quality of digestate produced (e.g. reduce plastics) and support digestate markets</u>

Earlier this year the Environment Agency issued a call for evidence to inform the review of the current Quality Protocol for Anaerobic Digestate. When the EA publishes its review, we are expecting it will say they no longer support this QP as it stands and if industry wishes to continue using it to demonstrate End of Waste for digestate, then the QP will need to be revised and industry will have to fund EA time spent on this. This revision is also likely to result in the introduction of higher standards that the sector will have to comply with, i.e. a stricter set of limits on plastics in digestate. Meeting these tighter limits will likely require additional treatment processes to remove plastics and improvements to operational procedures. The potential presence of plastics in digestate and other organic materials being spread to land represents a significant concern for the environment protection regulators and can potentially undermine market confidence in quality digestates, so it is critical this problem is addressed across the supply chain.

In summary,

- **Due to a number of policies and new regulatory requirements being implemented over the next few years, the AD sector will need to move to higher build and operational standards aligned with BATs, which will require additional capital and operational costs.**
- **This policy is intended to be open to new applicants until 2025/26 so it offers an opportunity for major changes to energy and other policies to be fully aligned.**
- **BEIS should consider a sanitised project model of costs and ensure the tariff levels are appropriately set to accurately reflect these costs.**
- **Provided the tariff levels are appropriate, then support of plants under the Green Gas Support Scheme should be conditional upon plants holding a relevant environmental permit (if required by the environmental regulator).**

<u>Endnotes</u>

[3] The reference document adopted by the European Commission setting out best available techniques (BAT) for the waste treatment sector

Consultation Question 5 - Do you have suggestions of other mechanisms that could be introduced to ensure tariffs deliver the best possible value for money – for example, additional evidence on costs and revenues that applicants to the Green Gas Support Scheme could be required to provide?

A number of members involved in the development and funding of AD plants have put together a sanitised model of costs that has been supplied to BEIS separately to support this response.

Consultation Question 6 - From experience of degression, how do you think elements such as the frequency and size of degression, and spend triggers, should change in order to ensure value for money, whilst meeting the need for investment certainty? Please provide evidence to support your response.

A degression mechanism for biomethane is no longer required.
It is important for BEIS to reconsider what is the purpose of degression. This was initially introduced to ensure the budget is not overspent and to drive value for money. This is for the following reasons:

1) There is no need to rely on degression to control overall spend. Tariff guarantees provide a more certain way of doing this, and we note the proposal that the scheme can only be accessed in this way. On the assumption that the decision is made to allow additional capacity, then BEIS could also state that such applications will be treated in the same way (ie would be held in a queue and not processed if the scheme is already over-committed). This would be fine on the assumption that the suggestion made in this response is taken up that could apply for additional capacity by providing amended NEA (this would not work if present system retained, in which total injection over the quarter must exceed that allowed for by NEA).
2) There is not much scope for cost reductions ie it would only make sense to adjust the tariff if the costs have fundamentally changed. A mid-term review of the tariff would make more sense, to allow BEIS to consider whether the tariffs should be changed to reflect significant changes to capital and operational costs. There are certainly changes in place that could change the economics, including availability of feedstocks costs of compliance with regulatory controls – not least in the management of digestate. It should also be noted that some of these might result in tariffs needing to be adjusted upwards.
3) Even if there is potential for further cost reductions, the balance of risks of over and under compensation has changed significantly since the RHI was introduced. Current levels and the levels proposed in the consultation are already much closer to the point at which any reduction would make the tariff unviable and stop deployment, which the chances of any project making egregious returns must be close to zero. Even a single degression would likely cause a hiatus / halt deployment.

If BEIS really consider that having a degression mechanism is necessary, then the frequency of degression for biomethane should be reconsidered as it is not appropriate for this technology. Costs for this technology are not likely to change on a quarterly basis, so reviewing the tariff levels at this frequency makes little sense (if the purpose is drive value for money and reflect cost reductions). The trigger levels should be set as close as possible to the full budget allocation to minimise the risk of degression. However, if a degression occurs, a this will likely stop deployment, as highlighted already, and cause the scheme to under deploy (depending on how large is the margin between the trigger and the actual budget level).

<u>Further proposals made by BEIS (here):</u>

We would support a review of the tariffs instead of the degression mechanism as a way to adjust the levels to reflect any dramatic changes in the cost base and to ensure the tariff levels are appropriate.

We would recommend that this is done as a single review point midway through the scheme. An annual review may seem attractive, but in the first year there would be no meaningful evidence of the impact of the scheme to assess and in the final year a review (and any changes made following it) would be too late to affect deployment under the scheme by 2026. A mid-term review would also fit reasonably well with the expected timings of changes in other government policy areas, particularly those led by Defra and the environmental regulators on farming, environmental protection and collection of waste feedstock

We would recommend that cost are collated by BEIS (not Ofgem) from a representative samples of AD plants on the Scheme and interpreted with the help of an appropriate consultancy firm who has experience in assessing costs associated with AD across the industry.

The tariff review should not be based on a mechanism in regulations but rather be a value judgement based on emerging picture as seen by BEIS.

Another important point raised by members is that the review should not be based on a mechanism in regulations. The degression mechanism has shown that this has not worked, and biomethane tariff levels have effectively had to be managed via reviews. It would be difficult to write rules on this until we see what changes are needed and market response to the new policy (and the interaction with changes to food waste collections in England to be introduced by Defra). We strongly recommend this should be a value judgement based on emerging picture as seen by BEIS.

As for the proposal on requesting more detailed information, we agree that it is important accurate information on costs is collated by BEIS to support a review of the tariffs, however the following concerned have been raised by members:

- There is no consistency between models/ developers / funders on how these items are calculated.
- Simple 'line items' don't exist – the way these are scoped and processed will usually vary. The risk is that if the information may be too detailed and therefore requires significant time to provide, or too high level / generic which may result in data that are not better than what is already available to BEIS.
- There is a concern that if this is done through Ofgem (ie requested at each application and then annually thereafter) it will result in additional administrative burden or delay for payments. Members would definitely prefer if this was a request from information from BEIS as opposed to Ofgem, to ensure it does not give Ofgem grounds for questioning or raising queries about costs and even enforcement actions if data was slightly inconsistent.

- Some members have highlighted that collating costs will certainly be positive to ensure policy can respond to changes in the cost base and can help target policies to drive cost reductions in areas where this is possible and would have the highest impact.
- There are consultancy companies out there (e.g. those that carry due diligence) that can use and interpret this data correctly. Key is to obtain meaningful information but also to ensure this is used and interpreted in a meaningful way and that it does not become another administrative issue.
- In light of the above, it may be more useful for BEIS to select a representative sample of plants (e.g. 10 biomethane plants) and assess their costs in detail rather than having this as part of an administrative process resulting in lots of poor quality data.

Consultation Question 7 - Do you have further suggestions, beyond those mentioned in this consultation, which would help the Green Gas Support Scheme to deliver the best possible value for money? Please provide evidence to support your response.

Reducing risks

BEIS should remove the risk that BEIS policy or Ofgem's processes have any influence over the following:

- developers driven to unrealistically tight construction/commissioning timelines due to risk of lower (or zero) support
- risk of rules changing in between funding project and securing the tariff (tariff guarantees do not offer protection on this)
- risk that Ofgem will interpret rules differently to how the developer interpreted them (see also our response to question 8 re commissioning definition).
- risk that Ofgem's previous interpretation was correctly understood but Ofgem have then changed interpretation (see also our response to question 8 re commissioning definition).

Also, as already highlighted below, it is paramount that the policy is not limited to green field only but also encourage expansions from existing plants, which would be in some cases more cost effective than building new plants and realise the same benefits.

Incentivise GHG emission savings

Some members have also suggested it would be useful to incorporate a policy mechanism or incentive within the Green Gas Support Scheme to encourage the largest GHG emission savings from AD plants. For example, there are technologies available that can minimise methane slip from AD plants, however the cost of these technologies is currently a barrier to their uptake. If there was a financial 'bonus' or 'premium' on the top of the basic support level, this could act as an incentive and drive developers to employ these technologies.

This is in line with our position [4] on a future support mechanism for green gas, where we advocated a support mechanism to encourage technologies and gases with the lowest carbon profile, in line with Government's commitment to net zero by 2050.

Similarly, it would be beneficial to incorporate a policy mechanism to support market demand for co-products of AD, such as digestate and CO_2, and drives best practice, encourage innovation, and recognises the wider benefits of green gas.

Encourage gas networks to be more flexible on capacity

The new scheme should also encourage the gas networks to be more flexible on how they make more capacity available to biomethane injection. Better monitoring of the network is required. Gas networks also need to encourage and facilitate use of in-grid compression to make more capacity available in the network. In-grid compression may have higher upfront capital costs, but operating costs are cheaper than other options. The networks should include this as an option in their connection offers as it is a cost effective way to make more capacity available.

'Hub-and-spokes' model

The new scheme should ensure the 'hub-and-spokes' model, along the lines of that in place at the SGN's Portsdown Hill Gas Injection Facility, is allowed and facilitated, as this this could unlock the potential for several on-farm AD sites that are not in close proximity to the gas network, to upgrade biogas to biomethane and inject the green gas through a centralised gas injection point.

The Injection Hub concept, developed by SGN Commercial Services, was for a large volume centralised facility to serve multiple remote bio-methane production sites that are unable to inject gas locally due to unsuitable local capacity. The way it works is described in detail here

Centralised gas injection could help spread the costs of connection across a several sites, making it more affordable. There is also potential for small AD sites to centralised other pieces of equipment, such as biogas upgrade equipment.

Third party hubs an important option for projects with a capacity issue, however there are constraints within the current RHI regulations around multiple plants connecting to a single injection point. Any future regulations need to be reflective that having multiple production sources supplying to a common injection point where there is capacity can be the most cost effective method of encouraging investment in smaller spot production sources, particularly in the rural economy. Each of these are individual investments and should be classed as individual RHI applications, even where gas enters networks at a common point.

Consultation Question 8 - Do you agree with the proposals for tariff guarantees for biomethane? Yes/No. How could this be improved? Please provide evidence to support your response.

Yes

BEIS's intention to replicate tariff guarantees is seen as a positive step as it will continue to give developers/installers confidence of the tariff they will receive.

However, please see important considerations below.

Commissioning window

TG deadlines for a project should be set with sufficient time to enable plants to commission without rushing to meet deadlines. This could be done by introducing some flexibility or grace periods for specific delays, especially when these are outside the control of the developer. We understand that Contracts for Difference have a similar mechanism in place (ie flexibility allowed in the event of Force Majeure or grid delay impacting the project).

Deadlines over winter time should be avoided as much as possible as this is not an ideal time to build pipelines across fields.

The extension of the duration of the funding of the scheme (i.e. circa 4 years) is also extremely welcome, given that a lot of the sub-optimal outcomes industry has seen have resulted from the short windows available for constructing plants and developers having to meet tariff deadlines. The TG system was designed to avoid this, but this was severely compromised by the short period that was available by the time they were eventually introduced.

<u>Commencement of construction</u>

It is also crucial that more transparency and clarity is provided on Ofgem legal interpretation of the requirements that need to be met for the project to be awarded a TG and that this process is not micromanaged leading to significant administrative burden and time delays.

BEIS should seriously consider the risks of introducing a requirement of specifying the commencement of construction in light of the lessons learned in the TG process to date.

BEIS may wish to consider the merit of introducing an independent auditing of the TG process as a deterrent from developers to 'game' the system and ensure any speculative applications are minimised.

BEIS are suggesting the introduction of an additional stage in the TG process, which requires participants to inform Ofgem once construction commences.

This is seen by some members as positive given that a number of plants that were granted a Tariff Guarantee under the RHI scheme and that contributed to trigger January 2019 degression to the tariffs, have not ended up in a physical plant being built. Therefore, the addition of stage 2a would be useful and should ensure TGs that are awarded do end up becoming physically deployed.

However, members have expressed a strong concern that this may drive Ofgem to micromanage a plant construction programme, as there may be different interpretation of what construction means. For purposes of meeting a planning condition for instance, construction can easily start by simply pouring a very small amount of concrete so could easily be gamed or interpreted in different ways and would require a large amount of bureaucracy and Ofgem assessing construction programmes.

Within the TG system there has been a lack of transparency and understanding on when a project is deemed by Ofgem to have achieved TG3 (ie when a plant is deemed to be commissioned) and how Ofgem's interpretation differs from the developer's interpretation. A similar issue could apply to the definition of construction.

<u>Financial close</u>

A more thorough assessment on financial close audits may be required by Ofgem to ensure the funding has been really drawn to cover the project. Leaving ambiguity in this step (as was done previously) accelerated the level of TGs thereby creating a premature degression based on plants which may not have had actual financial close.

BEIS may wish to consider again the requirements for demonstrating financial close and how these have been applied and assessed. In principle the policy is sound – this is a requirement to demonstrate that the funding exists and has been irrevocably allocated. However, this has resulted for some projects in declarations of financial close (signed off on independent audits) that were not genuine.

Commissioning definition

In relation to the requirement to be 'commissioned', for the GGSS (and the final period of the RHI) we suggest the requirement to be commissioned should be replaced by one that the biomethane produced and injected was made in the long term intended biogas production plant.

In the context of the current RHI regs, this could be done by deleting 32(4A)(b) and amending regulation 32(14) so that (for applications made from the point of the changes being introduced) registration will not be granted unless 'injection of biomethane produced by that applicant from the biogas production plant specified in paragraph 4A(a) has commenced'.

As previously mentioned there have been so far a lack of transparency and limited understanding on what is the legal interpretation of when a project is deemed by Ofgem to have achieved TG3 (ie when a plant is deemed to be commissioned / what is a materially delivered project against a deadline).

BEIS should seriously reconsider the requirement for a plant to be 'commissioned'. This was put in place to close out two-phase commissioning, however this has led Ofgem to micromanage the 'commissioning programme' ie raise several queries on the commissioning plan and evidence to support/evidence that the plant has been really commissioned.

As long as a developer has shown that injection has commenced and that the gas used to commence injection comes from the specified biogas plant, that should satisfy the objective of the policy. In addition, for digesters we already have a well-established precedent for what 'commissioned' means as it has been used for many years in RHI biogas heat applications and there is no point for Ofgem to disregard this precedent.

Similar issues may come into place if a definition of commencement of construction is introduced.

It is therefore essential that any rules that are introduced along these lines are not allowed to be applied in this way.

Some members have suggested that whoever administers the scheme (Ofgem) could make use of independent auditing of participant's application shortly after awarding a tariff guarantee. This will be a huge deterrent to the industry of any 'gaming'.

We support BEIS proposal that TGs should be the only way for participants to be able to enter the scheme.

Further detail on the interpretation of 'commissioned'

This requirement was introduced in June 2018 as part of the changes to prevent '2-stage' commissioning – ie a practice in which a developer could secure a tariff before their long-term source of biogas had been built. This raised concerns for BEIS on cost control in relation to timing of when the plants would build out (and risks that the project may not build out at all).

A light touch interpretation of 'commissioned' would therefore be in line with that policy intent. In fact, if the digester and injection equipment is present and physically complete this is met. Since the project must also have produced and upgraded sufficient gas that at least some gas is permitted to enter the network there can be no serious doubt as to whether the project will go ahead and one would expect its chances of ramping up in a timely fashion to be as one would expect (ie it is likely, but nothing is 100% certain when dealing with a biological process and heterogenous feedstock)

'commissioned' was already a defined term prior to June 2018 and was relevant for AD in the context of biogas production plants needing to be commissioned in order to seek support for biogas heat under the RHI.

So, there are 3 components to whether the site as a whole is commissioned:

1) The biogas production plant – precedents have been set for how this is interpreted in relation to RHI heat and these should have been followed
2) Upgrading equipment. This is specialist containerised kit, so it would seem appropriate to adopt a similar approach to that used for many years under the feed in tariff and Renewables Obligation in relation to CHP commissioning (ie supporting letter/certificate from the supplier, backed by a commissioning checklist)
3) Post-upgrader equipment controlling access to the gas grid. There is a well-established process for this in the gas industry and access to the network will not be allowed until this is completed to their satisfaction. The fact that gas was injected and a confirming letter from the gas network stating that it was commissioned should be sufficient – and the gas industry wrote previously to Ofgem setting this out clearly (through their trade association, the Energy Networks Association)

Ofgem launched a call for evidence on this issue in November 2019 – 17 months after the legislation had been introduced and too late for projects that had already committed to their tariff guarantee timings to alter their practices. As this was a call for evidence rather than a consultation on changes to the scheme rules, there was a clear risk of such changes having retrospective effect – in other words, that they would affect Ofgem's interpretation of applications made before they published their response to the call for evidence.

We would note that a similar process shortly before the closure of the Renewables Obligation resulted effectively in a restatement of the previous practice rather than a change of position.

The call for evidence had only 4 responses to it, one of which was from the REA making similar arguments to those made above.

Ofgem's outcome document (published in April 2020) sets out a large amount of additional documentation requirements. Many of our members do not recognise the approach described, and it possible they result in confusion between what is usual for the heavily regulated gas network and for the remainder of the biomethane project site. In any case, requiring these documents is completely disproportionate to the policy intent this requirement was introduced to address (ie to prevent two-phase projects, now that tariff guarantees are available).

At best, this will create months of delay while documents are found or generated that would not otherwise be required by any of the parties involved in building and commissioning the project. At worst, projects will be rejected or receive a lower tariff as a result of alleged deficiencies in their documentation, the need for which was not known at the time of application to the scheme.

We know of some projects already that have had difficulties with the way this requirement is interpreted. If this is repeated, everyone involved in the current market will have had a recent, costly experience with Ofgem that will significantly increase their perception of risks involving Ofgem's administration of biomethane support schemes.

A similar risk arises in the discretion afforded to Ofgem in the ability to reject an application (that holds a tariff guarantee) if the eventual application is materially different to that which secured a tariff guarantee.

Minimising the risk of over estimating committed spend

BEIS should require more realistic estimates of injection from applicants, and their periodic updating – and ensure that there are no adverse consequences to participants in providing this information so long as it is a reasonable estimate (ie if their number goes down they don't risk permanently losing capacity).

As highlighted somewhere else in this response, producers will be strongly incentivised to secure 750 scmh NEA if they possibly can, whether or not they will be able to do that consistently – so the risk of over-estimating committed spend will be far higher than currently unless BEIS require more realistic estimates of injection from applicants, their periodic updating – and ensure that there are no adverse consequences to participants in providing this information so long as it is a reasonable estimate (ie if their number goes down they don't risk permanently losing capacity.

Consultation Question 9 - What are your views on increasing the minimum percentage of waste feedstocks above 50%, now or in the future? What could be a suitable new threshold? Please provide evidence to support your response.

For a number of reasons detailed below we cannot support a further increase of the minimum percentage of waste feedstocks above 50%.

Members have highlighted that there is in fact no need to include a threshold of this kind, as the economics of farm-based AD plants and the cost of crops already mean that we are unlikely to see projects developed on the basis of higher proportion of crops as this would render the project unviable.

REA is very supportive of the commitments made in Defra's Resources and Waste Strategy on food wastes. For a number of years the REA has lobbied Government on behalf of the industry for the introduction of mandatory collections of food wastes, both from municipal and commercial sources, in line with the principles of a circular economy. When food wastes cannot be prevented, anaerobic digestion makes the best use of these materials by producing renewable energy and organic fertiliser while closing the nutrients cycle and reducing greenhouse gas emissions.

Notwithstanding this, we cannot support a further increase of the minimum percentage of waste feedstocks above 50%. This would have a significant impact especially on farm-based plants, for which the current minimum 50% is already a significant challenge. It would also drive further competition for food wastes at a time this resource is already limited in some regions.

Some members have suggested that BEIS may wish to consider introducing a tiering structure that rewards more sustainable (lower GHG) feedstocks with a higher tariff or a financial bonus. This would encourage treatment of the most sustainable feedstocks in a similar way to what is in place under the Renewable Transport Fuel Obligation, and would be preferable to a threshold. For information, a report published by Ricardo for SEAI shows countries where schemes using slurry receive additional support.

1. Uncertainty on waste availability

As set out by BEIS in the consultation document, measures from Defra to introduce mandatory collections of food wastes are only expected to commence from 2023. The Scheme is expected to start in the financial year 2021 so there is a time gap between the two which may lead to a lack of sufficient waste feedstocks being available at the beginning of the Green Gas Support Scheme for new plants.

The size of the current food waste market is limited and it is known there is already an oversupply of AD capacity compared to the volumes of food waste available, especially in England, which leads existing plants to compete for food wastes and has determined over the past few years a downturn in the gate fees.

In addition, the volume of waste feedstocks that may become available when these measures are introduced is still very uncertain. We understand there is already an oversupply of AD capacity in the market: there are existing food waste based plants that have extra capacity to take food waste, so these, to some extent, may absorb some of the additional volumes of food wastes available. In addition, it is highly unknown how food waste prevention policies will affect the volumes of food wastes provided for recycling in the future. Reductions in the volumes of food wastes produced may to a certain extent offset increased volumes from mandatory food waste collections.

Increasing the minimum percentage of waste feedstocks above 50% would result in a greater competition between projects (existing and new) to secure these feedstocks and may drive down gate gees even further. Furthermore, some members are concerned that new plants supported through the Green Gas Support Scheme would outcompete existing plants as they would be able to offer processing of food waste at lower gate fees. These members argued that BEIS should use a more market based approach that allows new plants to take whatever feedstock is available.

2. Regulatory, technical, and economic challenges derived from an increase in the minimum percentage of wastes/residues

Agricultural plants, which typically use predominantly agricultural feedstock such as manures, slurries, crops and crop residues, are highly unlikely to be set up to take food wastes from commercial sources and local authorities. This is because of the higher capital, processing and operational costs that come with treating these types of wastes, as well as the additional regulatory requirements (i.e. compliance with Animal By-Product Regulations) that would need to be met when these types of wastes are treated.

We understand from industry experience that it would not be efficient to build a plant with the flexibility to take both food waste and energy crops. For example, a food waste plant would need different infrastructure, such as front-end grit traps, other front end processes, different odour management systems and secondary containment (~ £1 million). For agricultural plants, tanks tend to be tougher with stirring systems that can handle higher dry matters. Food waste plants would also require pasteurisation units to comply with animal by-product regulations, and, crucially, de-packaging systems to remove plastics and packaging. The only scenario where it becomes feasible to operate a plant on a 50/50 mixture of wastes/residues and crops is when the waste inputs are represented by slurries/manures or other materials such as beet pulp which do not require expensive equipment for removing the plastics or other contaminants upfront. However, according to members, opportunities for these feedstocks are fairly limited (depending on geographical location and other factors explained below).

Availability of livestock slurries/manures is not even across the country, so in some cases these feedstocks would have to be transported over large distances to be made available at the place where the plants are located. It is therefore likely that there will be extra significant financial costs associated with transporting heavy feedstocks along considerable distances and with storing those feedstocks on site.

A member highlighted that the South West of the country has significant volumes of slurries and manures, but East Anglia has very limited slurries and manures available. As highlighted in Defra's livestock density data [4], there are however hotspots of pigs in East Anglia and East Yorkshire and high density of poultry spread across England and Wales. Some modelling would be required to investigate further the potential access of AD plants to pig or poultry manures within reasonable distances.

In addition, the use of slurries and manures at this scale would make it very difficult to build efficient and economic developments. Plants would have to be much larger and would require significant quantities of manures and slurries to provide equivalent biogas yields, as slurry and manures typically contains low levels of biogas energy per fresh tonne.

Increasing the 50% proportion for farm-based plants may in some cases drive up the transport distances that these residues will travel. In addition, it may create a perverse incentive that could result in AD plants having to buy slurries and manures to make up the minimum percentage.

Poultry manure can contain the highest biogas energy levels per fresh tonne but it also contains relatively high nitrogen levels. These could inhibit the AD process, so they need to be balanced with a low nitrogen high carbon feedstock like energy crops that can maintain the stability and energy output of the AD plant.

Alternative feedstocks will need to be found by AD developers and operators – e.g. from production processes or from agriculture – however many of these feedstocks (for example straw or other grassy and woody energy crops) are not easily digestible and would require additional pre-treatment, and therefore additional capital and operational costs, before they can be digested effectively.

As highlighted in this report published by BEIS, there are different technology options available to pre-treat feedstocks with a high lignocellulosic content, but there is still much uncertainty on their efficiency, reliability and capability to work at scales appropriate to AD sites.

Also, some types of residues are often subject to spot market pricing changes and it is extremely important that AD plants have the ability to secure these feedstocks when they are available. At present, Ofgem's Fuel Measurement and Sampling approval process is creating a significant barrier to the uptake of new feedstocks at AD plants, so this will need to be addressed to encourage wastes and residues uptake at AD plants (see further detail in our answer to question 9.

3. Benefits of rotational energy crops and regenerative farming with AD

It is also important for Government to recognise the benefits that are brought to farming businesses from the integration of AD cropping into arable rotations, by providing robust rotational options, local markets and opportunity for improving soil health and biodiversity. It is important to recognise that, when grown sustainably, in line with good practice and high environmental standards, crops grown for use in AD plants in combination with wastes and residues can have a really positive effect on the wider farmed environment e.g. rotational benefits, broader agronomic benefits, soil carbon and soil health in arable intensive areas of the UK where organic matter is less readily available.
We are pleased to see that in the consultation document Defra recognises that '*energy crops can be incorporated into arable locations as cover crops'*, and that '*where appropriate, such approaches would integrate energy and food production and could bring additional benefits to agriculture and the rural economy*'.

AD operators' and growers' experience shows that when energy crops are grown sustainably and to high standards, in rotation with food crops, this will bring significant environmental and economic benefits to the farming system. However, we understand that industry need to be able to demonstrate that best practise has been adopted in the production, harvest and storage of energy crops.

If BEIS and Defra need more assurance that AD cropping is carried out in an environmentally sustainable way that benefits farming and does not negatively affect food production, we would recommend that an independent certification scheme for growing rotational energy crops is developed by industry or an independent established body. We would like to point out that similar schemes are already in place and it would not be difficult to adapt them to include AD rotational cropping. For example, LEAF (Linking Environment And Farming LEAF is an organisation working with farmers, the food industry, scientists and consumers, to encourage and enable sustainable farming that is prosperous, enriches the environment and engages local communities. They own the LEAF Marque Standard, an assurance system recognising more sustainably farmed products and standing for more environmental sustainability. It is held by farm businesses which meet their rigorous standards of sustainable farming practice. LEAF Marque certified businesses have been independently verified against the robust LEAF Marque Standard. LEAF Marque certification is third party verified by LEAF Marque approved and accredited Certification Bodies (CBs).

A similar standard for growing crops for AD could be developed in collaboration with LEAF or could be integrated within their LEAF Marque Standard. The Code of practice for growing energy crops could be included within the standard and updated if required. This standard was developed by industry to minimise any environmental risks from growing crops and has been adhered to by the biogas and biomethane sector.

4. Regenerative farming with AD rotational cropping can deliver public goods under the future Defra's farming policy

Defra is developing a new farming policy that will only reward farmers for delivering public goods. In February 2020, Defra released a Consultation and policy discussion document to set out the initial proposed design for the replacement of CAP – the Environmental Land Management Scheme (ELM).

The design sees the Department move from one broad scheme, to offering one with three distinct tiers. It is proposed that Tier 1 in particular will be targeted at the majority of farmers, with payments being given based on uptake of methods that promote environmentally sustainable farming and forestry practices. Tier 2 will support land managers in delivering locally targeted environmental outcomes, which focus on local priorities, and Tier 3 will be designed to enable delivery of 'landscape scale' land use change projects.

As already highlighted above, AD of manures or other wastes and residues combined with rotational cropping, where this is done in line with best practice and high environmental standards, will deliver environmentally sustainable farming practices including nutrient management (including manure management), soil management (including soil organic matter content) and field cover (such as cover crops and rotations). Not only will these practices not have a negative impact on the land, but they will also have numerous environmental benefits as described above.

A key driver for the current restrictions was concern around agricultural practices in the cultivation of maize (mainly around soil compaction if harvesting in October/November). Sustainability criteria based on GHG savings would not hinder this, assuming the land used is well established crop land. So if there remains a need to manage risks around maize cultivation then these should be addressed via the new farming policies – and applied consistently to maize cultivation for all purposes, not purely those for energy.

In addition, the European Commission has recently adopted its Biodiversity strategy for 2030 and the Farm to Fork Strategy. These strategies are key pillars of the EU Green Deal and are essential to recognise the contribution of biogas and biomethane to sustainable farming and the protection of biodiversity. Crop rotations and significant reduction in the use of pesticides and inorganic fertilisers will be key measures to deliver these strategies and anaerobic digestion of waste and residues combined with rotational crops, combined with digestate use on agricultural land, can deliver on all three of these measures, as well as

In summary, a joined up and coherent strategy across Government Departments is needed to ensure the benefits highlighted above are adequately recognised and that the Government's objectives to decarbonise the heat, agriculture and waste sectors are met.

We therefore ask that a clearer and stronger link should be established between BEIS' policy on green gas and Defra's new farming policy, which highlights the role of bioenergy crops in delivering both policies.

5. Alignment with transport policy in terms of feedstocks (RED II Annex IX Part A and Renewable Transport Fuel Obligation)

BEIS should consider fully aligning heat and transport policies in the way feedstocks are classified and financially rewarded. Given that AD plants are going to switch from the RHI to the RTFO in the future, it is important that the two schemes are aligned.

All wastes and residues as well as other feedstocks listed in Annex IX Part A of RED II and any feedstock certified under Commission Delegated Regulation (EU) 2019/807 (as low ILUC risk) should be encouraged. Under the RTFO the former are double counted and the later are not subject to the crop cap.

Our key recommendations to BEIS in response to question 9 are:

- **The 50% minimum percentage of wastes and residues should not be changed for the reasons set out above.**
  - **We would also ask that BEIS redefines what is counted towards this percentage (ie the calculation of the biogas yield produced from feedstocks that are non wastes or residues: for the purpose of that calculation, there should be no limitation on payments on biomethane made from wastes, residues and any other feedstocks that are 'not relevant crops' as per the RTFO, or that are included in the Annex IX of RED II part A, or are certified as low ILUC risk feedstocks**

BEIS' policy on biomethane currently limits the RHI payments issued for eligible biomethane where less than 50% of the total biogas yield (by energy content) is derived from wastes or residues. The limitation of the payments is calculated by reference to the biogas yield (by energy content) that is not derived from wastes or residues. This is not aligned with European and national policy on transport for the reasons set out below. If BEIS wish to maintain this threshold, we would suggest that the limitation of the payments should be calculated by reference to the biogas yield (by energy content) that is not derived from:

- waste, and residues, and
- any other feedstocks listed in Annex IX Part A of RED II and low-ILUC risk feedstocks.

Annex IX Part A of RED II

Under RED II, feedstocks listed in Annex IX Part A may be considered to be twice their energy content when considering their share (i.e. they can be double counted). This is because RED II seeks to encourage the production of advanced biofuels made from these feedstocks. In addition to wastes and residues, for example, this list included dedicated non-food energy crops.

In addition, the contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport sector shall be at least 0.2 % in 2022, at least 1 % in 2025 and **at least 3.5 % in 2030.**

Annex IX Part A is currently in the process of being reviewed. The European Commission (DG ENER) has recently asked a consortium led by E4tech to assist them in the evaluation of biofuel feedstocks, which could be added to Annex IX of RED II. As a result of this review, it is possible there will be more wastes and residues as well as other sustainable non wastes and residues added to the list. The process will not remove any feedstocks from the list.

The amended RED gives the option to exclude dedicated non-food energy crops which have been grown on contaminated or degraded land from the limit on crop based biofuels.

As an example, intermediate crops, sequential crops and grasses (e.g. excess perennial grasses: originally grown for fodder mainly for ruminants originally grown for fodder mainly for ruminants) are being considered for addition in the review of Annex IX, along with other residues and by-products. The REA would be happy to provide further technical details on the multiple benefits of these crops, if required by BEIS.

RED II and low ILUC risk biofuels

The Commission Delegated Regulation (EU) 2019/807 supplements the Directive with criteria to certify low ILUC (Indirect Land-Use Change) risk biofuels, bioliquids and biomass fuels from feed and food crops. Criteria are laid down in Art. 5, while Art. 6 regulates the auditing and verification requirements for certification.

Renewable Transport Fuel Obligation (RTFO)

The RTFO seeks to encourage the development of waste-based and sustainable advanced fuels, while limiting the use of fuels made from "relevant crops". Relevant crops are basically food crops (starch-rich crops, sugars, oil crops and main crops) and the definition in the RTFO is reproduced in full below [5].

Currently under the Renewable Transport Fuel Obligation waste feedstocks are double counted in their contribution towards meeting the obligation, as they typically provide greater GHG savings compared to other feedstocks.

The policy addresses the ILUC by capping the amount of biofuels made from "relevant crops". This is known as the "crop cap". It is set at 4% in 2020 and falls incrementally to 2% by 2032. Feedstocks listed in Annex IX of RED II, are not "relevant crops".

We understand that the Renewable Transport Fuel Obligation RTFO) is an entirely different policy scheme governed by a different Government department, however we believe there should be more alignment between the two policies on the theme of feedstocks.

Mechanism to review /update minimum percentage

If BEIS were minded to keep the minimum percentage / threshold of wastes, we recommend there is a mechanism outside the regulations that enables BEIS to update the percentage as new evidence on different feedstocks becomes available.

Constraints on liquid feedstocks

There should be no constraints under the GGSS on processing liquid feedstocks that are non waste.

As a final but important point, the RHI currently places a constraint on the acceptance of any liquid feedstocks that are not classified as wastes (Regulation 41). Excerpt from the regulations:

'A participant use biogas produced by AD may only use biogas that is made from one or more of the following feedstocks:

- Solid biomass
- Solid waste
- Liquid waste'

This renders ineligible any liquid waste that is not classed as waste. This text has significantly constrained the use of liquid feedstocks at AD plants that are clearly sustainable and should be encouraged. Examples of liquid feedstocks that have been constrained are: glycerol from virgin oils, which is classed as a product; crude glycerol from waste oil, which is classed a processing residue and other similar liquids such as pot ale syrup, proflo etc.

Our understanding is that this was introduced due to the original RED. Under that, 'bioliquids' used in power or heat must be subject to the same sustainability criteria imposed on transport biofuels, and member states may not deviate from them. These controls were introduced into the Renewables Obligation as liquids were used for power generation. This involves significant complexity, not least because the RED definition of biomass differs from that used in the rest of the RO (and RHI).

Given the relatively low opportunities for the use of renewable liquids in heating (and that the department was not wholly convinced of the quantity and value for money that these would represent) it was decided not to introduce support for liquids in the RHI at all.

Given the UK's exit from the EU the UK is free to make a decision on this on its own merits rather than to avoid having to administrative burden caused by RED.

REA and other trade associations, as well as Ofgem, have raised this regulatory matter to BEIS on a number of occasions. In addition, there are discrepancies between different schemes, as this constraint applied under the RHI scheme, but not under the RO and the RTFO schemes.

Endnote

[4] See http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-pig2019.pdf
http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-avian2019.pdf
http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-cattle-1118.pdf

[5] http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-pig2019.pdf
http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-avian2019.pdf
http://apha.defra.gov.uk/documents/surveillance/diseases/lddg-pop-report-cattle-1118.pdf

Consultation Question 10 - In light of recent amendments to sustainability criteria in the RED II, do you have any views on whether the UK should look to take into account similar changes for the Green Gas Support Scheme?

Regardless of the UK future trade arrangements, it would be sensible to align sustainability criteria to RED II to avoid any future barriers to green gas trade within the European market.

If BEIS were minded to align their criteria to RED II, we strongly recommend the following is done:

- **Averaging of consignments to calculate lifecycle GHG emissions against the target must be allowed in line with RED II, and**
- **The methodology to calculate the lifecycle GHG emissions must be improved to recognise a number of factors and best practice techniques that are currently unaccounted within the methodology. Similarly, data sharing on good practice should be improved to ensure more robust and quality are fed into the available GHG calculators.**
- **A more stringent threshold combined with an improved methodology would encourage the sector to deliver best practices and achieve minimum or event negative GHG emissions.**

Annex VI of RED II (*Rules for calculating the greenhouse gas impact of biomass fuels and their fossil fuel comparators*) include the GHG emission default and typical life-cycle GHG emission values and saving for different biomass fuel production pathway and the fossil fuel comparators across power, transport and heat.

The new RED II comparators for biomass fuels (biogas and biomethane) are:

- Heat: 80 gCO_2e/MJ
- Transport: 94 gCO_2e/MJ
- Power: 183 gCO_2e/MJ

The minimum required GHG savings, taken from Annex VI, are shown in the table 2 below, along with the new GHG thresholds that biogas and biomethane would have to meet when used in power, heat and transport.

Table 2. Minimum GHG thresholds for transport, heat and power in Annex VI of RED II

	Transport biofuels		Heating and cooling		Power	
Plant operation start date	Min GHG Saving (%)	GHG threshold (g CO_2e/MJ)	Min GHG Saving (%)	GHG threshold (g CO_2e/MJ)	Min GHG Saving (%)	GHG threshold (g CO_2e/MJ)
Before October 2015	50%	47	-	-	-	-
After October 2015	60%	37.6	-	-	-	-
After January 2021	65%	32.9	70%	24	70%	54.9
After January 2026	65%	32.9	80%	16	80%	36.6

The table shows the minimum GHG emission thresholds for transport, heat and power as set out in Annex VI of RED II.

Following a Freedom of Information request from the REA, in October 2019 Ofgem supplied to the REA an extensive, anonymised dataset including the lifecycle average GHG emissions values for all the consignments of biogas and biomethane registered under the Renewable Heat Incentive (RHI) scheme. These include 3,578 consignments for biomethane.

Under the RHI scheme each consignment of fuel needs to meet a GHG limit of 34.8 g CO_2e per MJ of heat generated or MJ of biomethane injected (125.28kg CO_2 equivalent per MWh). This represents a 60% GHG saving on an EU fossil heat comparator of 87 g CO_2e/MJ.

For consignments of waste-based biogas and biomethane, producers do not have to report the lifecycle GHG emission values as these are seen as sustainable and therefore deemed to have met the GHG emission criteria. Therefore, the database included only consignments of biomethane from crops like grass silage, sugar beet, maize, rye and wheat as well as residues such as glycerol and whey permeate. The data is therefore useful as an indicator of the greenhouse gas reduction potential of agricultural AD but does not reflect the full GHG emission reduction that the industry is currently achieving due to the way the current reporting requirements have been put in place.

Lifecycle GHG emission data on wastes from the point of collection should probably be reported in the future if the approach of averaging consignments for the purpose of the GHG calculation is allowed under the GGSS, in line with RED II.

We have undertaken an analysis of the data to verify how many consignments of biomethane would fail against the RED II lifecycle GHG emission thresholds. This is illustrated in the table below.

Table 3. Proportions of biomethane consignments failings against GHG emission thresholds

Total Number of biomethane consignments where GHG emissions have been reported in the dataset = 3578	GHG emission threshold	Number of failed consignments	Percentage of failed consignments
60% savings required compared to current EU Fossil Fuel Comparator (87 g CO_2e/MJ)	34.8 g CO_2/MJ	45	**1%**
70% savings required from 2021 in RED II compared to heat comparator (80 g CO_2e/MJ)	24 g CO_2/MJ	1074	**30%**
80% savings required from 2026 in RED II compared to heat comparator (80 g CO2e/MJ)	16 g CO_2/MJ	1638	**46%**
Source: Official data of all UK biomethane plants supported through the RHI provided by Ofgem to the REA in October 2019, following a FOI request			

The table shows the proportion of biomethane consignments failings against current and RED II GHG emission thresholds. The proportion of failed consignment against the RED II thresholds is significant.

As you can see from the table, a significant proportion of biomethane consignments for which lifecycle GHG emissions have been calculated according to the current methodology would fail against the RED II GHG emission thresholds.

1) Averaging of consignments

It is absolutely crucial that averaging of consignment is adopted in the UK, in line with RED II, if the GHG emissions thresholds are made stricter.

Under the Renewable Heat Incentive, supply chain emissions for AD must be calculated for each individual consignment and, as such, any consignment that does not meet the GHG threshold will not receive support under the scheme. However, the Renewable Energy Directive II adopts an alternative approach where lifecycle GHG emissions can be averaged across feedstocks. This is based on the fact that the use of manures in combination with maize is required to achieve GHG emission savings greater than 70% (a JRC report indicates that 70% GHG savings are only possible when maize and manures are mixed (JRC, 2014). The averaging of consignments calculation in RED II is shown in the screenshot below taken from RED II Annex VI.

Figure 1: This is a screenshot from Annex IV of RED II showing the GHG calculation based on co-digestion of different substrates.

Figure 1: GHG calculation in RED II based on co-digestion of different substrates

(b) In the case of co-digestion of different substrates in a biogas plant for the production of biogas or biomethane, the typical and default values of greenhouse gas emissions shall be calculated as:

$$E = \sum_{1}^{n} \cdot E_n$$

where

E = greenhouse gas emissions per MJ biogas or biomethane produced from co-digestion of the defined mixture of substrates

S_n = Share of feedstock n in energy content

E_n = Emission in g CO_2/MJ for pathway n as provided in Part D of this Annex (*)

$$S_n = \frac{P_n \cdot W_n}{\sum_1^n \cdot W_n}$$

where

P_n = energy yield [MJ] per kilogram of wet input of feedstock n (**)

W_n = weighting factor of substrate n defined as:

$$W_n = \frac{I_n}{\sum_1^n I_n} \cdot \left(\frac{1 - AM_n}{1 - SM_n}\right)$$

where:

I_n = Annual input to digester of substrate n [tonne of fresh matter]

AM_n = Average annual moisture of substrate n [kg water/kg fresh matter]

SM_n = Standard moisture for substrate n (***).

(*) For animal manure used as substrate, a bonus of 45 g CO_2eq/MJ manure (– 54 kg CO_2eq/t fresh matter) is added for improved agricultural and manure management.

This approach would also encourage the digestion of wastes or agricultural residues such as slurries with non-waste feedstocks. As wastes are currently exempt from GHG criteria, there is not a clear incentive to use them alongside crops. Averaging of consignment would also protect operators against unknown factors, outside the control of the operator, that can have an impact on emissions from certain consignments (e.g. a poor crop yield due to weather conditions, flooding on crops, COVID-19 increasing transport miles for residues etc.).

BEIS must adopt a more pragmatic approach that takes into account the operational challenges faced by AD generators on a day to day basis with respect to the diverse waste streams they need. Adopting an averaging procedure would allow for this.

Paul Adams et al (2015) mentioned in this paper: *It is inevitable that some consignments may fail BSC due to issues such as poor weather and low crop yields. The averaging of GHG emissions across the year has been implemented under the RO in order to recognise that some consignments of biomass could through no fault of the generator exceed the GHG threshold (DECC, 2014a). This is subject to the provision that the consignment of biomass must not exceed an overall ceiling, i.e. an upper GHG limit. …. By introducing a ceiling and averaging it is possible to limit the use of consignments with high GHG emissions, whilst still encouraging overall emissions to be below the average threshold.']*.

2) Changes to the methodology and sharing data on best practice

If the GHG emission thresholds are made more stringent, it is important that the methodology is updated where possible to ensure good practices are recognised and that digestate is not undervalued. In addition, more effort needs putting into sharing data on best practice and improving the quality of the data that are used to inform the calculations in the tools available. There need to be a better evidence base that is readily accessible to all operators of what typical and best practice values might be.

There needs to be a feedback loop, share data on best practice and improve the quality of the data. The data is often not easily accessible to operators so these tend to use default values. If more data on best practice was shared across industry, more accurate values reflecting good practices could be used to inform the GHG emission data.

A number of technical papers have been published to highlight all the methodological issues of the current methodology set out under the RHI to calculate the lifecycle emissions of biogas and biomethane consignments. The most recent of these papers can be found here and here.

Digestate regarded as a fuel under RED methodology

For the purpose of the GHG calculation, digestate should not be regarded as a fuel As described by Paul Adams and colleagues, it should be possible to set a value on digestate based on its NPK or similar (see also Appendix I for further details and background papers).

The current methodology undervalues the agronomic contribution that digestate can make and whether it is managed according to good practice.

According to the current methodology when co-products are produced, upstream emissions are allocated between different products based on their energy content of each co-product. For digestate this means measuring the energy content of this product as if it was to be used as a fuel.

In most cases digestate is not used as a fuel, but rather as an organic fertiliser that is applied to land replacing the need for energy intensive inorganic fertilisers.

It may also be worth noting that digestate was used as a fuel it cannot (in England) achieve end of waste under the QP.

The reason given for this in the RED is that it would obviously be better to understand co-products based on the 'substitution' method (ie based on what they replace) – but this is more subjective than an energy basis. RED I states that the energy content gives similar answers to substitution and is more objective. It obviously does give similar results if the co-product is a fuel, but not in this case.

As described by Paul Adams and colleagues, it should be possible to set a value on digestate based on its NPK or similar.

Recognition of the fertiliser value of digestate is crucial to a viable, long term industry. Policy needs to be developed that incentives both renewable gas and nutrient-rich organic fertiliser.

Key excerpts from this paper below (Paul Adams et al, 2015).

'The current methodology does recognise digestate as a co-product, nonetheless with the BCC default models 100% of emissions are effectively allocated to biogas (OFGEM, 2014d). Moreover there is no clear guidance from policy-makers on how to perform the allocation calculations, or valid justification on why energy allocation is appropriate. This is an issue for many operators who will distribute digestate to different farms for use on a variety of both food crops and AD feedstocks. An additional complication is how to assign an energy value to digestate. Using the LHV is required by legislation, but this approach doesn't value the nutrient content and potential yield improvements of digestate application (WRAP, 2012). Policy-makers have not provided guidance on how to calculate the LHV of digestate, whether to include the enthalpy of vaporisation, or given a default value. The use of LHV is more appropriate for energy co-products

as digestate has limited primary energy value, particularly in liquid form (OFGEM, 2014d). It could be more suitable to use a credit for synthetic mineral fertiliser displaced, in a similar approach to credits for excess co-generated electricity or CCR (EC, 2009a, 2010a; OFGEM, 2014b). Fertiliser credits could be determined by using the nutrient content and availability of digestate and would remove the need to perform allocation by assigning a value to digestate based on the ability to offset synthetic mineral fertilisers. It is concluded that energy allocation is not appropriate for allocating emissions to digestate.'

<u>Techniques to minimise emissions from cultivation should be recognised</u>

According to the above paper, around 50% of the emissions from cultivation are linked to soil emissions and these are typically these are divided into direct and indirect N_2O emissions. The use of nitrification inhibitors (NIs) and fertiliser nitrogen application timing could be useful strategies to help reduce these emissions. The use of such strategies are actually recognised in the methodology and calculation tools, but industry lacks of good quality and robust data to update the default values and incorporate these in the calculation tools. Again, it is important there is a feedback loop and regular update to the default values used in the calculators with more robust data and as more research becomes available.

<u>GHG credits on upstream emissions from wastes and residues</u>

RED II recognises a bonus for management of raw manures through AD of -45g CO2/MJ. We recommend that the methodology is modified to take into account negative upstream emissions from wastes and residues such as slurries/manures and food wastes. Excerpt from RED II Annex VI:

'The values for biogas production from manure include negative emissions for emissions saved from raw manure management. The value of e_{sca} considered is equal to – 45 g CO_2eq/MJ manure used in anaerobic digestion'.

<u>Methane leakage from the network</u>

It should be flagged that, unlikely the current RHI methodology (which only calculated GHG emissions to the point of injection), RED II GHG calculation includes an input for emissions from transport and distribution of the fuel (which comes from methane leaks in the grid). For example, under the RTFO the default value for lifecycle GHG emissions associated with transport and distribution is 0.15% methane leakage.

This may need to be considered if BEIS decide to align the sustainability criteria to RED II and could of course result in lower savings from AD plants. A number of members of the REA experts in this field could provide further information in the future, if this was needed by BEIS.

<u>Soil carbon stores</u>

So joined-up thinking is once again required across Government departments to ensure the carbon benefits of AD are properly accounted for, and incentivised. The new

Environmental Land Management Scheme should include an appropriate framework to measure soil carbon stores that can be then fed into the GGSS sustainability criteria.

The RED recognises that soil carbon stores should be included in the calculation of the lifecycle GHG emissions of biofuels.

Annex VI Part B 6states: '*For the purposes of the calculation referred to in point 1(a), emission savings from improved agriculture management, esca, such as shifting to reduced or zero-tillage, improved crop/rotation, the use of cover crops, including crop residue management, and the use of organic soil improver (e.g. compost, manure fermentation digestate), shall be taken into account only if solid and verifiable evidence is provided that the soil carbon has increased or that it is reasonable to expect to have increased over the period in which the raw materials concerned were cultivated while taking into account the emissions where such practices lead to increased fertiliser and herbicide use (1)*'.

…

Measurements of soil carbon can constitute such evidence, e.g. by a first measurement in advance of the cultivation and subsequent ones at regular intervals several years apart. In such a case, before the second measurement is available, increase in soil carbon would be estimated on the basis of representative experiments or soil models. From the second measurement onwards, the measurements would constitute the basis for determining the existence of an increase in soil carbon and its magnitude.'

Therefore, provided that a robust and credible framework is developed to measure soil carbon stores and this is recognised in the life-cycle carbon accounting methodology for biomethane production, this would with no doubt play an important role in mitigating GHG emissions and drive good agricultural practices.

It is also worth pointing out that there is a move within Europe towards recognise practices that can increase carbon in farmed soils. The recent Commission' Farm to Fork Strategy states: "*An example of a new green business model is carbon sequestration by farmers and foresters. Farming practices that remove CO_2 from the atmosphere contribute to the climate neutrality objective and should be rewarded, either via the common agricultural policy (CAP) or other public or private initiatives (carbon market). Robust certification rules for carbon removals in agriculture and forestry are the first step to enable payments to farmers and foresters for the carbon sequestration they provide. Member States could use these rules to design CAP payments based on the carbon sequestered; moreover, private companies could also be interested in purchasing such certificates to support climate action, thus providing an additional incentive (on top of CAP payments) to farmers and foresters for carbon sequestration*.

*A new **EU carbon farming initiative** under the Climate Pact will promote this new business model, which provides farmers with a new source of income and helps other sectors to decarbonise the food chain. As announced in the Circular Economy Action Plan (CEAP), the Commission will develop a **regulatory framework for certifying carbon removals** based on robust and transparent carbon accounting to monitor and verify the authenticity of carbon removals.*"

Practices that can help mitigate GHG emissions

We list below good practices to minimise ammonia and GHG emissions that are either not included, or could be better recognised within the GHG calculation, or could be easier to use in calculators.

From an industry perspective, it is really important that the methodology is revisited to ensure good practices and techniques that can deliver lower or even negative GHG emissions are counted for.

For AD, these are some examples of the practices that should help improve the lifecycle assessment figures for biomethane, all of which should be accounted for in the methodology:

- Good practice application of digestate to replace fertilisers derived from fossilised carbon
- Covering digestate stores to minimise GHG emissions (and ammonia) in line with best available techniques set out in COGAP
- Ensuring digestate is spread with low emission spreading techniques in line with best available techniques set out in COGAP
- Use of best available technology to avoid minimise methane emissions or leakage from both biogas production and upgrade
- Processing digestate to reduce the potential for emissions
- Capture of pure CO_2 / CCUS for storage or use in a range of markets
- Co-digestion of agricultural and industrial residues and crops with slurries/manures
- Strict sustainability requirements for crops (e.g. improved agronomic practices to maximise yield/energy output and reduce use of artificial fertilisers)
- Optimised on farm digestate management and use of strategies to minimise direct emissions from soil cultivation
- Combination with green hydrogen to produce methane through in-situ or ex-situ methanation
- Soil carbon sequestration and soil carbon addition through the use of sustainable farming practices such as AD cropping and application of organic fertilisers to the soil.

Methane slip from biogas and biogas upgrade

The consultation makes no mention of methane slip. BEIS should put in place tighter requirements on methane slip to promote industry good practice.

We would recommend that one of the requirements for plants funded under the Green Gas Support Mechanism should be to have mandatory testing and reporting of methane emissions and potentially set a maximum allowable methane slip.

For information, the EBA has recently published an information sheet titled '**Methane emission mitigation strategies**'.

The European Trade Association acknowledges greenhouse gas (GHG) emissions such as methane can be emitted into the air from biogas plants, due to leakages or special events in operation. The information sheet summarises potential emission sources from AD plants and explains how to minimise those emissions. Additionally, several ongoing initiatives for reducing methane emissions in European biogas sector are introduced.

Please download the information sheet here.

UK's plans to implement RED II provisions re Guarantees of Origin

We recommend that the UK and EU put in place an agreement "on mutual recognition of guarantees of origin issued in the Union" – as per RED II Article 19 clause 1 – which will allow the full integration of the UK GoO system for renewable gas with systems operating in the EU.

A mutual recognition agreement will maximise the value that UK biomethane producers will receive for their GoO and therefore ensure the Green Gas Support Scheme provides the best value for money possible.

A competent body will need to be appointed to issue GoO and we recommend that the government consider appointing an existing scheme, such as the GGCS, to minimise disruption to the market and minimise costs. This would also build on the experience that has already been developed such as the GGCS's partnership with GoO issuing bodies in the EU via the European Renewable Gas Registry (ERGaR), including the development of a hub for transfer of GoO, and their involvement in the process of updating of the EN 16325 standard required by RED II.

A "Guarantee of Origin" (GoO) is defined in Article 15 of the Renewable Energy Directive (RED). RED I only referred to GoO for renewable electricity, whilst in Article 19 of RED II the word *electricity* has been replaced with *energy* meaning that GoO now apply to renewable gas (and also renewable heat). Therefore, there will "officially" be GoO for renewable gas in the European Union.

Currently there are registries that issue GoO for biomethane injection in the UK but they are not recognised by the government. The biggest such scheme is the Green Gas Certification Scheme (GGCS) which is operated by the REA subsidiary Renewable Energy Assurance Limited (REAL).

While the GGCS has been operating successfully since 2011 and runs and robust and trusted scheme, this is not enough for the continued integration of the UK and EU markets once RED II comes into effect in June 2021.

RED II (Article 19) states that member states must appoint a single competent authority to issue GoO for gas. The GoOs that are issued must conform to the requirements of RED II which references conformity with standard CEN EN16325 (Guarantees of Origin related to energy). Furthermore it stipulates that a mutual recognition agreement is needed with third countries for there to be recognition of each others GoO.

With respect to the transposition of Article 19 of RED II, BEIS's Brexit team have communicated to the REA that *'As the transposition deadline for the Renewable Energy Directive 2018 ("REDII") falls outside of the transition period agreed with the EU under the Withdrawal Agreement, our expectation is that the UK would not be required to transpose REDII requirements, and the UK Government has no plans to change the arrangements for issuing gas GOOs in the UK at this stage. Going forward, the situation will depend on the* *nature of the free trade agreement negotiated between the UK and the EU and will be kept under review.*

"UK REGOs will continue to be recognised by EU Member States until at least the end of the transition period (31 December 2020). After that point, the situation will depend on the outcome of EU FTA negotiations.

"EU REGOs will continue to be recognised by the UK. This will allow electricity suppliers in the UK to continue to use EU REGOs as well as those issued in Great Britain and Northern Ireland to comply with their fuel mix disclosure obligations, and ensure that existing supply contracts are not compromised, insofar as these contracts depend upon Guarantees of Origin. This position will be kept under review.

'We will continue to engage with the REA and other stakeholders as the nature of the UK's FTAs with the EU and other third countries becomes clearer and our thinking evolves. "

A significant amount of the value that UK biomethane producers currently derive from the GoO market comes from customers based in the EU. It will support the value that the Green Gas Support Scheme is able to achieve if this continues and producers income streams beyond the GGSS are as strong as possible.

We note that government has recently tabled the following draft Statutory Instrument "*The Guarantees of Origin of Electricity Produced from High-efficiency Cogeneration and Renewables Obligation (Amendment) (EU Exit) Regulations 2020*". We welcome such legislation, which provides greater clarity on the future use of Guarantees of Origin (GoO) between the UK and EU markets. We also believe this move also provides a foundation to expand the discussion to renewable gas GoO.

Consultation Question 11 - Do you have any views on how the feedstock reporting process for biomethane should be amended compared to the existing RHI requirements?

Under the current regulations and protocols, Ofgem requires biomethane plant operators (and other eligible technologies) to implement Fuel Measurement and Sampling (FMS) procedures to determine the renewable output eligible for RHI periodic support payments. These procedures detail the agreement with applicants of suitable procedures for the measurement and sampling of their fuels.

FMS procedures must be agreed at the point of application for accreditation and may need to be amended where a new fuel or consignment is used or where a material change has been made on site affecting the agreed procedures.

Ofgem can only make RHI payments on heat (or biomethane) from renewable sources, so they would not make a payment until they have reviewed and approved the revised FMS procedures. However, this is a lengthy process that can take several months and is not working for the industry, especially when they wish to take a consignment of a new feedstock and this is going to be measured and sampled in line with existing procedures. This is actively discouraging participants to use alternative or novel feedstocks.

What is working?

A member with significant expertise on FMS protocols and procedures have highlighted that the protocol works well in terms of measurement of feedstocks, i.e. it provides an accurate way to measure feedstock use accurately and is also implemented consistently across all Ofgem schemes.

What is not working?

Feedstocks which could prove valuable and productive for AD cannot be taken because they are not part of the existing FMS and have not been approved by Ofgem.

New or alternative feedstocks are being found through supply chains where there is a temporary over supply, such as the animal feed sector and specifically residues, such as Trafford Gold, wheat husks, syrups, and other suspended solids or liquid feeds.

Wastes and residues are often available only for short periods so the AD sector needs to be dynamic if it is to maximise the use of these more sustainable feedstocks.

These feedstocks are also subject to spot market pricing changes and it is extremely important that AD plants are able to secure these feedstocks when they are available.

There needs to be a more streamlined and consistent approach to allow for more flexibility in an ever increasingly complex supply chain and feedstock market. Ultimately, if the policy wants more use of waste and residue and transition away from more intensive feedstocks then the approval system for FMS needs to be transparent and efficient.

Proposed solutions
We would recommend a combination of the following approaches:

- **Clearer guidance issued from the regulator on the classification of feedstocks**
- **Ofgem should have a full list or register of all the approved feedstocks (e.g. similar to the BSL list but for feedstocks): this should be made publicly available. Although we recognise there may be some degree of variation amongst the same feedstocks across different sources, an AD operator should not go through an approval process if the same feedstock has already been approved**
- **FMS approval procedures should be expedited – there should be a clear timeframe for Ofgem approvals which takes into account of the commercial realities of AD plants**
- **Ofgem approval process could be entirely replaced by an assessment from an independent auditor (e.g. a person not connected to the company. It could be the same person as the sustainability auditor). For example, an amendment to the FMS (e.g. for a new feedstock) could be signed off by an auditor.**
- **Ofgem should allow participants to have a much wider choice of feedstocks on the FMS (even though they may not use them immediately). We would recommend the 'review period' is removed for Ofgem and that a predefined list of feedstock categories is introduced. As an example, there have been cases where Ofgem have rejected an FMS because a user added many feedstocks. So Ofgem have been**

actively managing this to ensure only feedstock that definitely will be used are added to the FMS. This is an unnecessary restriction.

- **There should be alternative rules for new feedstocks in low quantities (i.e. not requiring an FMSQ if the output is less than 2 - 5% of total energy output).**

Feedstocks audits

A member that has biomethane plants registered under both, the RHI and the RTFO, have said that inconsistencies in the classification of feedstocks under the two schemes causes significant extra administrative burden, as it means two separate feedstocks audits will have to be carried out under the two schemes. Feedstock audits under the two schemes should be aligned. See also our response to question 9.

Consultation Question 12 - What measures and technologies exist for reducing ammonia emissions from digestate and what are the barriers to their widespread deployment?

Based on members' feedback, we have listed below some broad categories of strategies that can be used specifically to minimise ammonia emissions at different stages:

- Before and during digestate storage: ammonia stripping
- During storage: store cover, acidification
- During application: low trajectory spreading, acidification

However, members noted that **in all these cases the key barrier to the uptake of these strategies is the associated cost.**

Use of low-emission spreading equipment and digestate covers

As already highlighted in our answers to questions 4 and 5, according to the Clean Air Strategy, Defra will require digestate in England to be spread using low-emission spreading equipment by 2025, and digestate stores to be covered by 2027 (but both of these measures may be phased in earlier). There will be a full public consultation before decisions are made as to the types of covers required and the date they will be required from. A range of acceptable covers are currently described in Defra's Code of Practice to minimise ammonia emissions but these come at a range of costs. These two measures are clearly seen as key by Defra to minimise ammonia emissions and should be adopted by the sector.

Sufficient provisions for storage

Defra's Code of Practice for reducing ammonia emissions also highlights the importance, in relation to the spreading of organic manures, of ensuring there is enough well-maintained storage to be able to spread slurry (including digestate) only when the crops will use the nutrients. This is key to minimise ammonia emissions. Adequate provisions for storage at AD facilities (or off site storage facilities) are therefore instrumental to ensure digestate is applied when crops require the nutrients and to prevent ammonia emissions from its application. Again, this comes with significant capital costs.

For plants that produce liquid digestate, it's likely that a minimum of 6-month storage period would typically be recommended to comply with Defra's Farming Rules for Water, although this could either be on site, or at satellite storage facilities off-site that could be potentially managed by a third-party operator.

The best place for any requirements on storage and digestate contingency planning is within the environmental permitting system, and we assume the GGSS would replicate the existing RHI requirements in relation to obtaining and maintaining a permit. So, it is really important that both BEIS and Defra feed into the environmental regulator's current review of permits and the publication of their 'Appropriate measures' guidance for the biowaste treatment sector to ensure the above considerations are properly reflected.

Ammonia stripping

Ammonia stripping and other technologies to enhance digestate are certainly an option and may be necessary at some AD plants with storage or landbank constraints to reduce digestate volumes as well minimise ammonia emissions.

There are several case studies of plants that have adopted these techniques overseas (for example in Germany). However, there are very few examples in the UK mainly due to the cost of employing these technologies.

Case study: The Tully Centralised Anaerobic Digestion Plant designed and built by Nature Energy where ammonia stripping technology of ByoFlex® is employed to allow the plant to use, as feedstock, up to 100% poultry litter.

This plant separates out the solids and then takes out the water using vacuum evaporation. They then use sulphuric acid (H_2SO_4) to remove the ammonium nitrogen (NH_4) as ammonium sulphate $(NH_4)_2SO_4$. The resulting clean water is sufficiently clean to be discharged.

However, in the experience of some members, this is being done successfully where farm-based materials are digested leaving a lot of fibre in the digestate. This makes separation reasonably straightforward. On the other hand, it is more challenging to separate the solids in food-based AD plants, where input materials are more digestible and maceration is part of the process. The issue of plastic contamination means that fine screens are frequently included at the back end. The overall effect is that the solids present in food based digestate are very small and comprise a lower proportion in liquid digestate than would be the case if plastic contaminants entering the digestion phase(s) were negligible. These members have had great difficulty of achieving any significant degree of separation even with polymers added to encourage solid particle flocculation.

Evaporation technologies

Other members have also mentioned evaporation technologies such as (Mechanical Vapor Recompression) MVR, like EPCON's technologies, which are suited to manage the nitrogen (N), Phosphorus (P) and Potassium (K) output options (e.g. to focus more on N than P or K).

Up to date, the business case for employing these technologies on site has not been seen as viable, however as regulations on storage, and application of digestate become stricter, and the potential to access higher value markets the business case for these systems may start to become more attractive.

Acidification

High pH and high ammonium content means ammonia emissions can be greater from digestate than from slurry. Lowering the pH of digestate can help reducing ammonia emissions. ADS have carried out several trials under the Defra slurry acidification project (SCF0215) to understand how acidification can control ammonia emissions.

There are also technologies that are starting to be commercially available in the market that can lower the pH of digestate while adding value. As an example, company *N2 Applied* has developed a plasma technology that enables local production of fertiliser from liquid organic substrates such as slurry or digestate with air and electricity. The technology adds nitrogen from the air into the liquid substrate and increases the nitrogen content. The reaction stops the loss of ammonia and reduces emissions, making it an efficient and sustainable fertiliser, and creates a more circular farm system. One of the plasma treatment effect is lowering the pH from around 8 to around 6.

Nitrification inhibitors

Inclusion of N- inhibitors in digestate or use of advanced technology such as Alzon or Koch Advanced Nitrogen fertiliser can help reducing nitrous oxide emissions (N_2O).

Systemic project

The projects looks at several different N-recovery options from AD systems (which would reduce ammonia emissions during storage and spreading). One of the papers also mentions N removal using aerobic treatment as being common in the Netherlands – this is a well-established water industry approach that converts ammonia to nitrogen gas. It is worth bearing in mind that the main driver for nutrient removal in the water industry is regulation and the need to meet discharge consent levels. The costs for this make their way back through the whole treatment process and onto our water bills.

End of Waste rules constraints

In addition to the economic barrier, it should also be noted that there are significant constraints on the further processing of waste-derived digestates under End of Waste rules in UK countries. **The Quality Protocol for Anaerobic Digestate and BSI PAS 110 specification for digestate only do not include in their scope the separation of digestate into liquid and solid outputs (operators can also choose not to do this separation). Other further processing of digestate is not within their scopes.** Examples of further processing options are;

1. solid digestate drying,
2. solid digestate drying and pelletisation,
3. solid digestate composting, in one or more following composting phases, with or without addition of waste/material at the start of the composting phase,
4. stripping or evaporating ammonia from liquid digestates,
5. adding specific nutrients to liquid digestates so they become better fit liquid fertilisers for specific crop production applications, and

6. modifying liquid digestates so they are suitable for use in hydroponic production of crops.

The consequence of this is that if any processing or further treatment of digestate is carried out after separation, the resulting output will have a waste status and therefore will need to be handled as a waste, i.e. the outputs will need to be stored and spread under waste regulatory controls, placing a significant extra burden on AD operators. This acts as a disincentive for AD developers and operators to consider options for further processing digestate after separation.

AD processes with connected composting phase(s) that add in new waste/material at the start of the composting phase do not exist in the UK, yet they do in Italy and are a good option for biodegrading compostable liners and bags that are used as part of food waste collection and also for biodegrading compostable packaging items that are co-collected with the food waste. End of Waste rules for waste derived composts and digestates need to be revised to enable the two processes to be fully integrated.

If Defra is looking for further treatment of digestate – e.g. ammonia stripping or evaporation techniques - as one of the options to minimise ammonia, then **it is paramount that this End of Waste rules barrier is overcome and both BSI PAS 110 and the ADQP are amended to allow these processes and also allow further innovation to happen.** If these EoW rules are not improved, increasing numbers of AD operators' choices to produce waste status digestates would be a retrograde step and could be a threat to market acceptance and the viability of the industry. Please also bear in mind that the EU Fertilising Products Regulation (EU FPR) does not include barriers to the further treatment of digestate and provides a relatively flexible framework for placing a range of compliant ***product types*** on all markets that use those product types (inorganic fertilisers, organic fertilisers, organo-mineral fertilisers, organic soil improvers, growing media, inorganic plant biostimulants and organic plant biostimulants). We believe Defra is considering the extent to which the EU FPR will become mirrored in UK post-Brexit law.

In summary, strategies to minimise ammonia emissions do certainly exist but the significant extra costs and End of Waste issues associated with processing of digestate have so far acted as a strong disincentive to adopt such strategies.

It is important that a joined-up approach is taken across the environment protection regulators, Defra and BEIS to ensure AD plants can be designed and built in line with best practice and can maximise value and minimise environmental impact with no constraints coming from End of Waste rules.

Consultation Question 13 - What are the reasons for the lack of commercial demand for digestate and how can the market for digestate be strengthened?

Definition of commercial demand

According to our members' experience, most farmers tend to appreciate the value of digestate because of its fertiliser value and the water content, however this value does generally not outweigh the costs of storing, transporting and spreading it.

A member noted that the answer depends on the definition of 'commercial'. He noted that there is evidence that farmers like digestate – it is a source of readily available nitrogen and (important in a dry spring) water, and benefits to crops from digestate use are widely acknowledged. However, the inherent nutrient content of digestate means that transport, storage and application costs can (when considered together) be greater than the fertiliser replacement value of the material. This is an innate characteristic of liquid digestates – and is just as true of pig and cattle slurries. So, although there is undoubtedly a willingness to pay for digestate, these fees are in many cases unlikely to cover the whole costs of supply. Does this render digestate non-commercial?

It should also be recognised that most digestates are produced on farms, from agricultural materials – the resulting digestates can be incorporated into farm nutrient planning in the same way that other organic manures are. Since such use is likely to involve transactions between different parts of the same business, digestate will not be intended as a profit centre. Only a minority of AD facilities process biowaste materials, and only a sub-set of these are divorced from available landbank. It is this small sub-set that faces the most significant supply challenges – and there are currently no commercial technologies that address the fundamental 'problem' that digestate is mostly water; by commercial in this context it is meant technology that can process digestate to a point where the resulting outputs have sufficient value to offset the investment associated with the technology.

Another member based in Scotland highlighted that there isn't a lack of commercial demand for digestate in Scotland and they consistently experience a healthy demand. Spring demand outweighs production by 100%, therefore improvements in winter storage would assist and is something which they are working towards. This member consultant, however, would not recommend additional restrictions for digestate that are not in line with the normal fertiliser guidelines as this would discourage the use of digestate. Additional precautions or limits on one product tends to diminish market confidence.

In summary, there is often demand for digestate but its innate value does not always cover the logistics costs associated with its application to land and there are seasonal issues to overcome.

<u>Storage issue</u>

Another member noted that storage is a fundamental issue for some plants. For example, at the moment there is a drought and demand for digestate significantly outstrips supply. This issue is due to the fact that several plants have been built without or with little storage i.e. they don't have enough storage to enable them to supply the digestate at the time of most demand. In order to commercialise digestate, AD projects would have to build significantly more storage but this would drive up capex substantially. This additional cost will need to be supported, preferably via dedicated funding or grants or under the GGSS. A member highlighted that, since lagoons are normally low-risk investments, it may make more sense to fund storage via specific grants (e.g. through Defra, like the Countryside Productivity Scheme). The current support available to AD makes it financially unviable to justify this build.

In summary, AD plants should be built with sufficient storage capacity in order to be able to commercialise / market digestate, however this additional cost needs to be

covered, preferably via separate grants / funding (e.g. Defra's funding) or under the GGSS.

<u>End of Waste rules barrier: digestate with 'product' status cannot be supplied to high value markets such as professional and amateur horticulture</u>

Quality Protocols (QPs) are End of Waste frameworks recognised by the Environment Agency and used by industry on a voluntary basis to identify the point at which waste, having been fully recovered, may be regarded as a non-waste product. This means the waste derived material can be used in specified markets without the need for waste regulatory controls.

The current Anaerobic Digestate Quality Protocol does not allow the supply of digestate to horticulture and other high value markets such as soft landscaping. The AD QP also does not permit digestate processing (except for a phase of aerobic maturation of dewatered, solid digestate) and only whole digestate, separated liquor and separated fibre digestate can be used in agriculture.

This has been seen by industry as a significant barrier to innovation on digestate and supply to markets other than agriculture. Particularly for digestate fibre which could be a useful ingredient into growing media, potentially as a bulky substrate that could be combined with other bulky non-peat substrates that could replace peat in growing media. There is no incentive to pursue this due to the market limitations within the QP as doing so would revert the material to being a waste and the need for regulatory controls.

The EA is currently reviewing this and other Quality Protocols and so this offers an unique opportunity to address this issue and open up the markets for digestate, more in alignment with the EU Fertilising Product Regulations. Wording within the AD QP needs to be changed to facilitate the further processing or enhancement of digestate that improves the efficiency of nutrients and retains a product status. Additional designated end markets (such as soft landscaping, amateur and professional horticulture and growing media) need to be included to enable operators to implement additional processing and achieve higher value markets for their products. The review of the QPs should take into account the wider aims of Government across departments.

<u>Cost of digestate enhancement</u>

Other members commented that the technologies available to enhance digestate are generally very costly and don't provide a guarantee that there will be a market for digestate. The above barriers outlined with the End of Waste position – the Quality Protocol also act as a disincentive to explore digestate enhancement as to do so would revert digestate to being a waste and needing to be used under waste regulatory controls.

<u>Issues associated with plastics and land contamination</u>

For food waste based digestates the presence of plastics and contaminants, or the perception that these may be present, is a critical factor that could negatively affect digestate demand and undermine market confidence in these products. The Environment Agency is currently considering reviewing the limit for plastics in digestate in the ADQP as well as introducing limits on contamination in feedstocks within the permits. The Standard Rule Permits consultation published at the end of 2019, set a target figure of 0.5 % w/w 'plastic and other litter' contamination in feedstocks delivered to sites. The outcome of this consultation is yet to be published.

Reduction of non-compostable plastics and other contaminants requires concentrated effort at all stages in the supply chain, and more focus is needed on the waste producers to ensure the quality of material coming into sites is better. A whole system approach is needed with more funding for local authorities to deliver comprehensive education and communication campaigns to drive behaviour change. Sites also have a role in ensuring they produce fit for purpose digestates – including composted dewatered digestate fibre - and but this would be easier if the quality of food waste delivered to sites was better. Any changes to limits for plastics in digestates, including further processed digestates, should be based on evidence.

In summary, our recommendations to strengthen the markets for digestate and further processed digestate would be:

- **To ensure AD plants planning and design include sufficient storage of digestate (either on or off site) to meet demand and supply digestate at the right time of the year, when this is needed. The additional cost of this needs to be supported by Government, preferably via specific grants.**
- **To provide some dedicated grants or funds to stimulate the use of and innovation in technologies that enhance the value of digestate, its further processing and increase its commercial demand**
- **To remove two fundamental rule barriers currently in place in the Quality Protocol for digestate: 1) the exclusion of horticulture and other high value markets (including soft landscaping and growing media) from the designated markets specified in the QP for digestate, and b) the exclusion from the scope of the QP (and BSI PAS 110) of digestate treatment processes other than separation into solid and liquid outputs (e.g. evaporation or other enhancement).**

  In line with the approach taken in the EU Fertiliser Regulations and in line with the approach adopted in Scotland by SEPA, we would actually argue that there is no need for the Quality Protocol to place unnecessary restrictions on the markets the digestate should be supplied to.

We also recommend that Government considers introducing a support payment scheme (e.g. an obligation or other similar mechanism) that rewards farmers or users that use low carbon biofertilisers and soil amendments eg 'a low carbon biofertiliser/soil amendment credit scheme' or similar. This would encourage the development of a market for digestates. This could be achieved under the new farming policy (the Environmental Land Management Scheme) or via the UK's implementation of the EU Fertiliser Regulation.

Consultation Question 14 - Do you agree with the proposal not to include an additional capacity mechanism within the Green Gas Support Scheme? Yes/No. Please provide evidence to support your response.

No, for the following reasons:

The ability to expand existing plant is one of the best opportunities available for value for money. Expanding existing plants should present opportunities for improved economies of scale, particularly on the capex. They should also be easier and cheaper to fund since the additional construction required will be relatively modest and the technology and operators will already be demonstrated. Also, having an operational plant with an existing income stream means the need for additional working capital is much reduced.

Expanding existing plant would also be one of the few options available if or when the tariffs degress (assuming they are set at around the levels proposed).

The relatively low uptake of this option under the RHI does not indicate it would not be needed under the GGSS. There are 2 factors that have distorted the picture:

1) the way the regulations 77 is written means biomethane plants can only register additional biomethane if they are already 'producing additional biomethane'. In practice this means that over the course of an entire quarter they must have injected (on average) above the level specified in their original NEA **before** they can apply for that additional capacity.
2) there are many plants commissioned in 2014 and 2015 that sized the NEA much larger than they needed and gradually expanded. So additional capacity is happening but is not immediately visible.

Important considerations made by members are:

Not allowing additional capacity for biomethane may push developers to book as much capacity in the network as possible at the beginning, and then potentially not use it for years until they are able to expand.

Gas networks are reluctant to allocate capacity that is unlikely to be used in the medium term, and there are a number of measures being looked at that could increase grid capacity in general. There may also be specific changes locally that would enable a plant to inject more than was possible when it first applied to the scheme. In other words, a project could be well sized to local limitations initially but have potential to expand due to changing circumstances subsequently.

We propose that an additional capacity mechanism should be introduced for the GGSS. Rather than the existing RHI requirements, the scheme participant should be able to apply for this without a requirement to have injected at this level for a prolonged period before they can apply. We suggest that a participant should be able to apply by submitting to Ofgem the amended NEA showing the increased level they are allowed to inject at. Ofgem should make every effort to ensure that this change is processed and approved swiftly, on the assumption that no other material changes are made to the participant's project.

Consultation Question 15 - Do you have any views on how a change of scheme participant mechanism may differ in the Green Gas Support Scheme to the RHI? Yes/No. Please provide evidence to support your response.

Yes.

Firstly, we support allowing for mechanism under the Green Gas Support Scheme (and the RHI) that enables a change of scheme participant as this is key to avoid stranded assets.

Feedback from members is that under the RHI participants are allowed to sell the project company. This is not an issue if the project is financially healthy. However, the problem arises when the company is not financially sound (for example, has gone into administration). In that case, no other company would want to buy it.

Thus, what is key is to be able to transfer the RHI/GGSS to a clean new SPV: this addresses the issue and it means the assets can be reused. There have been a number of stranded assets to date as a result of the inability to do this.

Given the above, authorisation requirements from transferor and transferee are key to the transfer, but we understand from members no other elements of the existing project registration should change.

A member also suggested that BEIS could set a definition of an installation and include the term 'Gemini Code' which is its unique identity code used to allow a plant to inject into the gas network., similar to the MPAN under FIT. Provided certain unique parameters don't change (post code, Gemini Code) you can then transfer the scheme to new companies.

A sensible and pragmatic approach to replacement of existing equipment should also be included in the Green Gas Support Scheme.

Consultation Question 16 - Do you agree with the proposal to not allow any interaction between the RHI and the Green Gas Support Scheme? Yes/No. Please provide evidence to support your response.

No

As highlighted above, the Scheme should allow expansions from existing AD plants (electricity only, biogas heat/CHP plants supported under the RHI or biomethane plants supported under the RHI).

As explained below, expansions of existing plants would be extremely beneficial in value for money terms.

A member highlighted it should not be a problem from an administrative point of view (it would sufficient to assess the combined biomethane output from the original plants and the expansion and verify which GGSS Tiers it falls under. In addition, from an administrative perspective it would be no more difficult than under the interaction with the RTFO.

Consultation Question 17 - Do you agree with our proposal to allow biomethane producers to decide how much biomethane they wish to claim Green Gas Support Scheme payments for within a given quarter? Yes/No. Please provide evidence to support your response or provide an alternative proposal for scheme interaction.

Yes

We very much welcome this proposal, as this is something we have been advocating for a long time. We agree with the consultation document's analysis that the current situation restricts the potential for producers to benefit from diversified revenue streams and can disincentivise production from some plant. We anticipate this change will result in significant additional biomethane injection from existing biomethane injection facilities as well as enabling any new projects joining the scheme to optimise their output.

It will also make more biomethane available to the transport sector than has been supplied to date.

From a practical point of view, a key issue is related to the deductions of propane energy (and potentially heat supplied to biomethane production process). A general/typical figure could be used, but this would not be 100% accurate as propane addition rates vary - both across the country and over time for a given site.

A more suitable way forward could be to ask the producer to submit meter readings for the date they wish to draw the line for biomethane, propane (and external heat) ie everything before that date is RHI/GGSS, everything after is RTFO. This should not be too much of a administrative burden for the operator as they can take regular readings and can choose at point of making GGSS/RHI quarterly returns where they draw the line. This will need to be spell out in the regulations rather than leave Ofgem to check.

Finally, **we recommend that Government explores the possibility of setting up central registry of green/low carbon gas injection data**, based on secure and independent data provided by the existing GEMINI system. Green/Low Carbon gas producers could then access this registry, provide verification of GHG values and allocate volumes of gas to different support schemes. Administrators of the RTFO, RHI, Renewable Gas Obligation Certificates and Guarantees of Origin could all receive information from this registry which would eliminate the risk of double counting. Relevant bodies should discuss who is best placed to operate such a registry and work together with the aim of minimising administration costs across all support schemes as well as the compliance cost to the gas producers. Clear rules will be needed on the interaction of the obligation and any disclosure to customer of GHG levels of gas supplied (which should/must be done via a GoO system).

Consultation Question 18 - What are the main barriers to the deployment of biomethane AD plants and what potential solutions could help to overcome these?

Barriers include:

Capital and operational costs of AD are significant and are unlikely to see significant reductions in the future

The high capital costs of AD definitely present a barrier to the uptake of this technology.
AD realises on a range of raw materials and components like concrete or aggregates all of which are driven by price inflation and plant such as CHP which are easily deployed for other

projects unlike solar/wind turbines. Cost reductions have not happened quickly and we ae unlikely to see significant reductions in capex in the future.
AD is also a technology that has ongoing operational costs and these are generally increasing as a result of an increased level of scrutiny and stricter requirements from the environmental regulators.

Ofgem are considered one of the largest barriers to the deployment of renewable heat projects.
The REA continues to receive complaints from members concerning delivery of the RHI. The reasons for these complaints have been due to multiple issues including long delays to accreditations; issues with the audit process resulting in very slow reaccreditations; lack of communication from Ofgem concerning the status of applications and changes in how Ofgem is interpreting and applying regulatory issues (e.g. emission certificates).

We are aware that Ofgem is working toward resolving these issues, and had a number of constructive meetings with them to discuss this, however RHI delivery failures means there is now a strong industry perception that Ofgem is one of the largest barriers to the deployment of renewable heat projects.

Competition for food wastes

Over the past few years the AD sector has seen a steady decline on gate fees as competition for the feedstock from councils and businesses became more intense.

Further information on this trend can be found on the latest WRAP Gate fees report, from which we have included some relevant excerpts below.

'The median AD gate fee reported by local authorities for 2018 for the UK as a whole is £27/tonne, which is slightly higher than the £26/tonne gate fee from last year's survey. Before this year's reported gate fee, the figure had shown steady decline, since 2015. However, the median of contracts which have started in the last three years is £19/tonne, which reflect waste contractor expectations of declining gate fees more accurately.

For England, the pattern over the last four years has been of steady decline (£35/tonne in 2015, £30/tonne in 2016, £26/tonne in 2017, to £23/tonne last year) until this year, where data reported by local authorities results in a median of £26/tonne.

The median gate fee of all waste streams reported by the operators is £10/tonne, which is a £3/tonne increase on last year's figure. It is much lower than the £27/tonne reported by the local authorities, although this figure includes gate fees from contracts signed some years ago. The lower figure reported by operators is likely to reflect gate fees charged at the time of the survey ie. December 2018, and therefore better reflect the current market. However, the operator survey was also dominated by respondents in England, where lower gate fees are seen compared to Wales and Scotland.

The median gate fee in Wales has reduced from last year's £49/tonne to £41/tonne. Due to a small sample size for Wales, it is more likely than an individual authority's reported gate fee has an impact on the overall result, and so the result is more sensitive to changes year on year. Despite this decrease, Wales still has the highest gate fees, which is thought to reflect the fact that a high proportion of the contracts in Wales are long-term PFI contracts.

The market continues to be fragmented, affected by local competition and national legislation and policy. For example for in Scotland, food waste collections are mandated in the Waste (Scotland) Regulations 2012 and in Wales, food waste tonnages are boosted through the Collections Blueprint, creating greater demand for food waste treatment capacity, compared to England where separate food waste collections are currently not mandatory. Market perception is very much impacted by what is happening in the markets in London and the south east, where gate fees are under extreme pressure. Scotland, Wales and Northern Ireland, as well as northern England, represent stronger markets with higher typical gate fees, which are reflected in the overall medians generated by this survey'.

It is paramount that Defra's policy to mandate separate collections of food wastes from both, local authorities and businesses, is introduced without delays to provide more access to food wastes and underpin further generation of biomethane.

Barriers to biomethane connections

The key barriers associated with connection are:

1) The high and highly variable cost of connection due to the lack of standardisation of specification across the gas networks,
2) Capacity constraints on the distribution network, leading to high connection costs associated with connecting at a point with sufficient capacity, or the inability to connect, and
3) The need for propane injection.

These are explained in further detail below.

Lack of standardisation across the gas networks

We have highlighted to BEIS and Ofgem on repeated occasions the high and highly variable cost of connection due to the lack of standardisation of specification across the gas networks.

All Gas Distribution Networks (GDNs) have different standards, contracts, policies for biomethane with significantly different costs.

Although all gas networks' RIIO2 business plans mentioned the need to work on standardisation of equipment, there is limited detail on how they intend to do so, how they intend to co-ordinate this work across the networks and what is the timeframe for it.

It should be noted that the Navigant's recent report entitled 'Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain, commissioned by ENA, identifies the need for standardisation across the networks as a near-term action that is important in decarbonising the energy system (so called "low regret actions"). For H_2 it is important that we avoid the biomethane experience of assets that are required in one GDN area and are not approved in another.

This issue has been raised for a significant number of years. In 2011 -12 there was an Ofgem supported series of workshops known as EMIB which set the basic regime for biomethane.

The published EMIB report (May 2012) states that '*It was recognised that establishing a single national set of standards would remove uncertainty and hence a potential barrier to entry. It would also support the development of competitive infrastructure provisions since different providers could develop competing products to deliver the common specification, and cost reductions should also be delivered as a result of requirements being replicated at all sites'*.

Unfortunately, industry has seen major divergences amongst the 4 GDNs with significant a additional cost.

Table 4. REA's estimate of the costs (£) in the 4 GDN areas

GDN	Capex for Grid Entry Unit (GEU)	GDN Charge (for auditing)	Estimated cost to satisfy wider GDN requirements	Total cost
WWU	400,000	15,000	25,000	440,000
Network 2	430,000	85,000	60,000	575,000
Network 3	450,000	40,000	50,000	540,000
Network 4	470,000	40,000	60,000	570,000

Table 4 shows the REA's estimate of the costs (£) in the 4 Gas Distribution Network areas due to lack of consistency across the networks.

Examples of where there are technical divergences:

- Odorant system ownership and location in GEU
- Separate shut down plc
- Ownership of RTU
- Time of flight system
- Design details of upstream plant

Solution

In our view the 'WWU''s system as the most economic and efficient as this complies with HSE and Ofgem requirements at least cost. The other GDNs should adopt the WWU's design, ormaintain their designs but make a funding contribution equal to the difference between the total cost in their area and the WWU's total cost. The same would apply to annual maintenance and compliance costs with a difference of around £10K between the highest and WWU 's approach.

This would provide a strong incentive for the gas networks to harmonise their specifications. If Ofgem implemented this, it is likely that all the GDNs would decide to adopt the *WWU*'s design as their shareholders will not see the business case for the additional investment.

Currently, there is much uncertainty around:

- the justification for the main areas of difference between a GEU in all GDNs except *WWU* and the ones in *WWU* which are commonly accepted to be the lowest cost designs to comply with HSE and Ofgem requirements.
- The reason why biomethane producers should pay more than the *WWU* frontier cost.
- What steps are being taken by the networks to ensure biomethane connections are 'economic and efficient'.

There is also a confused position in relation to allowing self lay for >7 bar connections. Cadent have been the leader in this area , with around 10 biomethane projects going ahead as a result of Cadent allowing competitive provision of >7 bar connections. This is an investment of around £200 million that would not have happened in the 2014-16 period in the other GDN areas. Other GDNs do not allow this or allow it but insist on doing the final connection which makes it uneconomic to have a competitive option. Within the RIIO2 process, we have asked that Ofgem review all policies in this area and ensure that for H_2 there is a fully competitive system. This should also apply to within grid compressor projects to create capacity.

Additional GDN Requirements

All the GDNs should adopt a common design of GEU and common processes and this should extend to requirements related to upstream gas processing in the biogas upgrading unit. At present some GDNs require significant additional investment in gas quality monitoring upstream of the GEU and the REA believes this is not economic or efficient. Unnecessary costs should not be pushed onto biomethane producers without a good technical/safety reason. The REA can provide examples of this in areas of maintenance and gas quality monitoring equipment and this leads to significant costs.

Propanation

Propanation is a substantial cost for the biomethane sector and most gas distribution networks mentioned this as an issue to address in their RIIO2 business plans. However, again in the GDNs' business plans there doesn't seem to be a common approach in the way the networks are trying to address this issue and there is lack of focus on the Cadent NIC Future Billing project which would address this issue.

The requirement to add propane is estimated to add cost of £150,000 per year for a 500 m^3 /hour capacity plant. In addition, propane is fossil based so it increases greenhouse gas emissions of the biomethane.

Given that propanation is an issue for other green gases (such as hydrogen) as well as for biomethane, the networks should work together in one single project to reform the GS(M)R and CoTER regulations and address once for all the propanation issue across all green gases.

This is in line with the recommendations provided in the ENA's Pathways to Net-Zero: Decarbonising the Gas Networks in Great Britain report (appendix G, Action 10). This action should be completed by end of 2020.

There is another point in relation to propane and the existing rules in that if the CV is out of specification for 3 minutes (eg during start up) this automatically sends the biomethane to flare or back to the AD. This is not safety related. A degree of flexibility to allow start up excursions of CV rules should be developed to have more flexibility (eg only send to flare if CV out of spec for 15 minutes). There is no adverse consumer impact from having CV of, typically, 0.2 MJ/M^3 below the FWACV level (typically 39.8 MJ/M^3) for 3 minutes as this gas will not reach any consumers. However, it cases significant flaring with adverse GHG impact.

The use of the diverter valve leads to significant flaring over the year and is primarily related to propane. This should only be used when a plant is commissioned as most gas quality issues are propane/CV related and not related to any harmful gas composition such as H_2S or wobbe index.

Capacity constraints

The maximum injection capacity offered by the GDNs to biomethane producers for injection is limited to the minimum demand downstream of the potential gas entry point. This varies significantly at different points of the network, but it is becoming increasingly common that the closest network segment to a proposed biomethane facility does not have sufficient capacity to allow injection.

This leads to high connection costs associated with connecting at a point with sufficient capacity, or the inability to connect.

Pipelines can be installed to carry the gas from the point of production, either to a higher pressure tier which has more downstream demand, or to a location where the network has sufficient capacity at that tier. However pipeline costs, which are typically covered by the biomethane producer, can be very high and can adversely affect the business case for connection and injection to the grid.

In-grid compression is a solution to the issue of capacity and is used widely in the EU. At times when there is insufficient demand on the network to allow all gas sources to inject, compressors can be operated to 'pump' gas to a higher pressure tier. This solution is considered to be the most effective solution, especially where there are severe constraints in the capacity available. There are other solutions that are more cost effective where the constraints in capacity are less severe.

Similarly to what we highlighted above for other issues, there isn't commonality in the way different networks approach this issue.

There is a project on the Isle of Wight that has flared gas since 2015 – the developer had a proposal to sort the capacity in 2016 with a £200K within grid compression solution to export gas from 1 bar grid to 7 bar grid. Unfortunately, SGN did not support this but is now looking at the same project in 2021 which means an additional 5 years of summer night flaring will have taken place. SGN should explain the reasons for this delay. This example shows the lack of innovation and urgency in this area as NGN/Cadent demonstrated with an NIA project in 2012 that within grid compression was feasible. REA is award of around 10 Feasibility Studies that have looked at within grid compression but there remains no plant in GB. For such projects, the REA believes a competitive solution should be provided as design, build and maintenance of compressors is a key skill for biomethane producers (an upgrading plant will typically have 4 compressors meaning over 500 in operation). In addition, around 20 biomethane projects inject directly into the LTS. There is a major risk that the 4 GDNs develop their own standards for within grid compression that add cost and complexity with no benefit – it should be noted that such compressors are related to summer operation only and have no impact on the GDN 1 in 20 security of supply obligations. The fact that over 500 compressors are in operation and maintained by 3rd parties should give Ofgem confidence that a competitive provision of such compressors (as for Gas Unie in Netherlands) is appropriate, with the GDN being the operator only. The GDNs have no competency in relation to compressors and it is not efficient for them to get involved in this activity other than as an operator.

Consultation Question 19 - Do you have views on how the Green Gas Support Scheme could be improved, beyond the ways described in this consultation? Please provide evidence to support your response.

Members have expressed a strong appetite for a policy mechanism that incentivises sustainable practices and techniques that can help achieve the largest GHG emission savings and delver other wider benefits. We have outlined this feature in more detail in our answers to questions 20 and 21.

Consultation Question 21 - Do you have any views on industry readiness for a market-based mechanism to support green gas in the longer term? Please provide evidence to support your response.

Feedback from members is that in the longer term industry would want to move to a situation where real market 'pull' signals play an increasing role rather than straight producer subsidies, to encourage a 'real' market to develop in supply and use of biomethane.

A long term support mechanism for green gases should also be technology neutral ie its scope is expanded to ensure that it covers all forms of renewable gas supply, i.e. biomethane from AD, bio-SNG from gasification, and green hydrogen. It should be noted that the REA is currently developing a position on hydrogen which we will be happy to share with BEIS as soon as finalised.

Green gas obligation that rewards carbon savings

The REA's position on a future support scheme for green gas is set out here. In this document, submitted to BEIS in October 2019, we highlighted the need for a mechanism in the medium and long terms for green gas that rewards technologies and renewable gases that deliver the largest carbon savings, whilst driving best practice and innovation.

The REA's preferred mechanism would be a **green gas obligation on gas suppliers** to meet a gradually increasing GHG reduction target over a period of time. In order to meet this target they would have the incentive to source the gases that deliver the largest and cheapest carbon savings. Similar approaches already exist in the UK (the Greenhouse Gas Saving Obligation) and for somewhere else in the world (e.g. California).

the GHG saving obligation is explained in the DfT's Motor Fuel Greenhouse Gas Emissions Reporting Regulations guidance document. The strength of the proposed approach is that it could provide a technology neutral incentive for gas suppliers to decarbonise their supplies, and for renewable and low carbon gas producers to continually strive to reduce the carbon intensity of their gas, stimulating innovation and investment in technologies and feedstocks with a low (or possibly even negative) carbon profile. Carbon Capture Usage and Storage (CCUS) technology when paired with bioenergy, delivers negative emissions. CCUS would not only expedite the route to net zero via greenhouse gas removals, but increase the supply of renewable and low carbon gases whilst providing wider benefits (e.g. to the bioeconomy).

The paper also explains the reasons why we believe that a contract for difference style mechanism for renewable gas would not be appropriate to biomethane, and other approaches).

In our discussions with members, other support mechanisms were considered which are outlined below. They all have drawbacks compared to a supplier obligation.

Off grid market

The above policy is focused on the gas to grid market and the decarbonisation of the gas grid, however the REA has also been engaged in complimentary discussions with its members and BEIS about the decarbonisation of the off grid market.

The green gas obligation outlined above would not cover road-distributed biomass, biopropane (bioLPG) or liquid biofuels, although biopropane is already eligible for RTFOs For the medium to long term we would suggest that certain off gas grid heating fuels (e.g. solid biomass, biopropane (bioLPG), and bio-kerosene) are captured within a parallel obligation mechanism. Suppliers of these fuels could be issued with certificates which they could sell to licenced gas suppliers. While not supplied through a grid system, the supply chains are suitably closed and audited to allow for such a trade mechanism to operate either in conjunction with, or separate to, a green gas obligation. Given the different nature of the off-gas grid market this needs further consideration which we would be happy to liaise on with BEIS. The biopropane industry would be pleased to engage with BEIS bilaterally on this subject too.

Biopropane (sold as bioLPG) is already available in the GB market and Calor, GB's largest supplier of LPG and biopropane, could meet 30% of its customers' domestic energy demand from its existing supply of biopropane. Biopropane is chemically identical to conventional propane (LPG) so can be blended in any ratio with conventional LPG, allowing a smooth transition to 100% renewable product by 2040, the LPG industry's target. In other words, an existing LPG boiler is also a biopropane boiler: no infrastructure change is required for existing LPG consumers or the LPG industry when using biopropane in any blend with conventional LPG. Whilst an initial step may be to use high efficiency LPG/bioLPG boilers in homes instead of higher carbon alternatives – and this may be an enduring policy particularly in large and/or hard to treat homes - these boilers can be readily integrated with heat pumps to create smart hybrid systems, potentially offering demand side response services.

To deliver significant carbon saving, hybrid systems in off-gas grid areas will need to use low carbon biogas, such as biopropane. As well as use within hybrid systems, biopropane can be used with CHP, gas heat pumps or fuel cells, thus offers the opportunity to increase system efficiencies even further. It is also worth noting that there are a number of production pathways for biopropane including biorefineries (a coproduct of biodiesel or Sustainable Aviation Fuel production), anaerobic digestion, and power-to-gas (using renewable hydrogen), and policy should support the development of different sustainable production pathways for biopropane.

Clean Heat Grant Scheme

Question 39 - Do you agree with not supporting biogas combustion under the new policies? Yes/No. Please provide evidence to support your response, including any wider detail on decarbonisation opportunities for biogas combustion in rural areas.

No.

There is significant scope to decarbonise farming and the industrial sector through the use of biogas CHP and boilers applications, as well as biomethane, to convert these sectors' biowastes and residues into clean energy. These could make a real contribution to reduce GHG emissions from farms and industry as well as reduce their carbon footprint. We look forward to provide further feedback on this topic in our response to BEIS call for evidence on combined heat and power.

The REA's Bioenergy Strategy final report (2020) states that 'use of residues or wastes on-site is, where possible, preferable as the most economic, energy and carbon efficient'.

For example, small scale CHP units can provide both heat and electricity to industrial units. In addition, there is definitely still an opportunity and significant interest in this kind of project in the farming sector, specifically around diary sites and in the yards of larger estates with high heat and electricity requirements. Some consultants members of the REA have recently been approached by a number of different sites that are looking into the development of small-scale CHP sites. However, without Government support these types of projects would not be viable. Especially after the closure of the RHI it is unlikely these projects will ever become feasible and these sites will continue to rely on either grid energy, or in the cases of the agricultural sites oil or gas based generation, to meet demand.

We therefore recommend that these types of projects are supported under the policy the Government intends to bring forward to decarbonise heat, particularly in relation to projects that will not be supported under the Clean Heat Grant Scheme and the Green Gas Support Scheme.

Agricultural sector

Most UK farms are off the gas grid, particularly small ones. In these situations, on-farm anaerobic digestion would enable the replacement of fossil fuel heat required for farm buildings and the farmer's own household with renewable heat from biogas (as both, heating and hot water supply), whilst delivering numerous additional benefits. In addition to decarbonising off-gas-grid heat, significant and cost-effective greenhouse gas mitigation could be achieved by the controlled/managed processing of slurry and fertiliser replacement through the use of renewable biofertiliser.

Food and beverage sector

Similarly, on-site anaerobic digestion deployed at factory sites, especially in the food and beverage sector, could provide part of the heat requirement for the beverage or food manufacturing process, which would replace some of the fossil fuel heat, especially within processes that have a significant heat requirement (distilleries, breweries etc.). Nestlé, Diageo, and First Milk are examples of companies using on-site AD to process biodegradable production residues to generate heat and power that could be used on site to some extent. It would need to be combined with other low-carbon technologies that are dispatchable and can generate high-grade heating, such as biomass.

There are members who are looking a developing AD projects on industrial applications where typically a combination of solid waste and wastewater from the industrial processes is used to generate biogas. We understand from members that these projects are typically high waste water flow / low gas yield systems and so are less suited to CHP or biomethane upgrading. Instead to optimise capital cost the client is typically seeking to burn the biogas in their boilers to replace the purchase of natural gas.

WRAP (2018) estimates that food manufacturing produces 1.5 Mt of food waste per year, with 6,700 SME's accounting for 97% of businesses. A few members of the REA estimate that 100 of these (1.5%) with on-site AD producing 100 m^3 of biogas, each generating circa 4 GW of heat per year (or 1.8 GW electric and 2.2 GW heat in a CHP), could supply 400 GW per annum of clean heat or over 30,000 tonnes of HGV fuel.

While larger agri-food corporates like Diageo or Arla may have the financial and technical resources to make great strides towards zero carbon manufacturing, this is not the case for the many domestic SMEs that proliferate in the agri-food sector. Therefore, it is vital that the some form of support isaccessible to all businesses (including SMEs) and plant sizes (inc. <600kWth) so that the whole of the sector works together and proportionately to decarbonise as quickly and constructively as possible.

July 2020

If you have any questions relating to this consultation and the REA's response please contact heat@r-e-a.net

Appendix 1

Digestate is a valuable co-product of the anaerobic digestion process and as such is it correct that a proportion of the greenhouse gas emissions of the biogas production process are attributed to its production.

There are a variety of methods for calculating the appropriate proportion of the emissions of the AD process to allocate to the digestate. Some examples include:

- By the higher calorific value of the digestate according to recommendations made in the EU Renewable Energy Directive (EU, 2009)

- Mass allocation methods, which allocate emissions by weight of nutrients in the digestate

(Hijazi et al., 2016)

- Economic allocation methods, in which the allocation of emissions is determined by the comparative market value of the digestate and biogas products (Hijazi et al., 2016; Rehl et al., 2012)

The portion of emissions that is allocated to digestate has a substantial impact on the emissions intensity of biogas produced at an AD facility. A study performed in 2019 found that biogas plants consuming a variety of feedstocks would allocate between 29-36% of emissions to digestate when allocating by higher calorific value, but 64-71% when allocating through mass allocation (Timonen et al., 2019).

In the model developed by Ricardo to perform a life-cycle analysis of the biomethane production process at our plants, emissions are allocated to digestate produced by our plants by comparing the higher calorific value of the digestate with the energy content of the other products of the AD process, including electricity exports and biomethane injection. However, unlike the other products of the AD process, digestate is not a fuel. This methodology, therefore, neglects the true value of the nutrient-rich digestate and fails to cover the entire carbon lifecycle of digestion chains.

One particular and important consequence of this methodology is that liquid digestate, a valuable fertilizer, is considered by the current methodology to have no GHG mitigation value as it has a negative calorific value due to its high water content.

Shifting the methodology of the LCA to allocate emissions to digestate based on mass or economic allocation methods would better appreciate the value of digestate produced by biogas plants and incentivise plant operators to ensure that the production and utilisation of this resource are optimised. Furthermore, it will also better demonstrate the capability of AD to produce low carbon energy.

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