# Outcome of preliminary discussions with members on a future support mechanism for green gas

## 1. Introduction

The main support mechanism for biomethane is currently the Non-Domestic Renewable Heat Incentive (RHI). This is set to close to new applicants on the 31st March 2021.

Future development of this sector is dependent upon the biomethane industry supply chain being maintained up to and beyond this deadline.

If the RHI simply closes to new applicants at the end of March 2021, and there is no other scheme in place either at that point or soon after to support new projects, development and investment will be stifled. There is a real danger that the associated supply chains will soon start to be disbanded, or specialists re-directed to other sectors as we approach this deadline.

The UK has been one of the fastest growing and most innovative biomethane markets in Europe. Underpinned by the introduction of the Renewable Heat Incentive, the UK biomethane market has been mostly thriving since 2014 - with a hiatus caused by delay in the implementation of the RHI - delivering significant benefits and helping Government meet the 2020 renewable energy targets and its Carbon Budgets. The Renewable Heat Incentive has resulted in ninety eight biomethane sites currently registered under the scheme, capable of injecting to the grid over 4 TWh/annum of biomethane. Since the RHI reforms were adopted, introducing tariff guarantees, another thirty three projects came forward under the scheme and were awarded a tariff guarantee. By 2020/21 the scheme should result in over 6 TWh of biomethane per annum injected in the gas grid.

Within the biomethane sector, the RHI has stimulated business investment in the range of over £900m (on average £10 million per project) supporting the development of competitive supply chains, with a number of AD and biomethane equipment providers currently active in the UK and companies involved in the design, construction, operation of AD plants as well as grid connections and gas trading. According to the REA[1], the biogas sector currently employs around 3,000 people across the UK supply chain and this sector turnover is around £365m.

However, more recently growth has started to slow down considerably, with only a handful of projects coming forward under the scheme since January 2019.

Unless clear signals on a future support scheme post-RHI are given by the Government as a matter of urgency, we anticipate adverse consequences for companies across the supply chain, especially those involved in the manufacturing, construction and installation of biomethane plants, as well as grid connections and grid-entry units. With no prospect of new development and growth, these companies will either go out of business or will have to move away from this sector, with considerable loss in terms of British-based jobs and skills.

[1] REVIEW publication, 2018

One of the key areas where a considerable loss of skills will occur is the design capability, which includes the knowledge of how to integrate the various systems on a biomethane or biogas site. In addition, civil contractors and, even more so M&E contractors, will be particularly difficult to find once they have moved away from the sector.

The long-term decarbonisation benefits of tax payers' money that has been spent so far to support the development of these supply chains and British-based skills will not have been leveraged.

## 2. Short term: a time-limited extension to the RHI

In light of both the above and our previous recommendations[2], **the REA strongly recommends that Government introduces a time-limited extension to the RHI post-March 2021 for biomethane[3].** This could play a crucial role in providing stability to the biomethane sector while new support mechanisms are devised.

We think this is the only realistic option available, at least in the short term, to avoid a hiatus. This is because extending existing policy is much more time-efficient for both the Department and industry than creating a new framework. In our experience it is reasonable to assume that developing a new policy would typically take three years from inception to implementation. Thus, realistically, it is unlikely that a new policy will be in place before 2023.

It should also be noted that Defra has committed to introduce legislation to mandate separate collections of food wastes from January 2023, from both commercial and municipal sources. This will result in significant, additional volumes of household and commercial food wastes becoming available from 2023 or even earlier[4]. Although existing AD capacity can, to some degree, absorb the additional food waste volumes, new investment into AD will likely be needed, especially in areas where there are no existing AD facilities.

Developing an AD plant from scratch would normally take a minimum of two years (two and a half on average). So, in order to cope with the extra volumes of food waste coming to the market as a result of Defra's new policy, we anticipate that new investment into AD plants will need to happen from as early as July 2020. A replacement for the RHI would therefore need to be in place around the same time to avoid delaying the development needed to process these additional volumes.

In addition, given that most planning consents expire after three years unless the conditions are discharged, a policy hiatus would mean that more cost is incurred to 'hold' the planning consents until there is visibility on what scheme will be in place to replace the RHI.

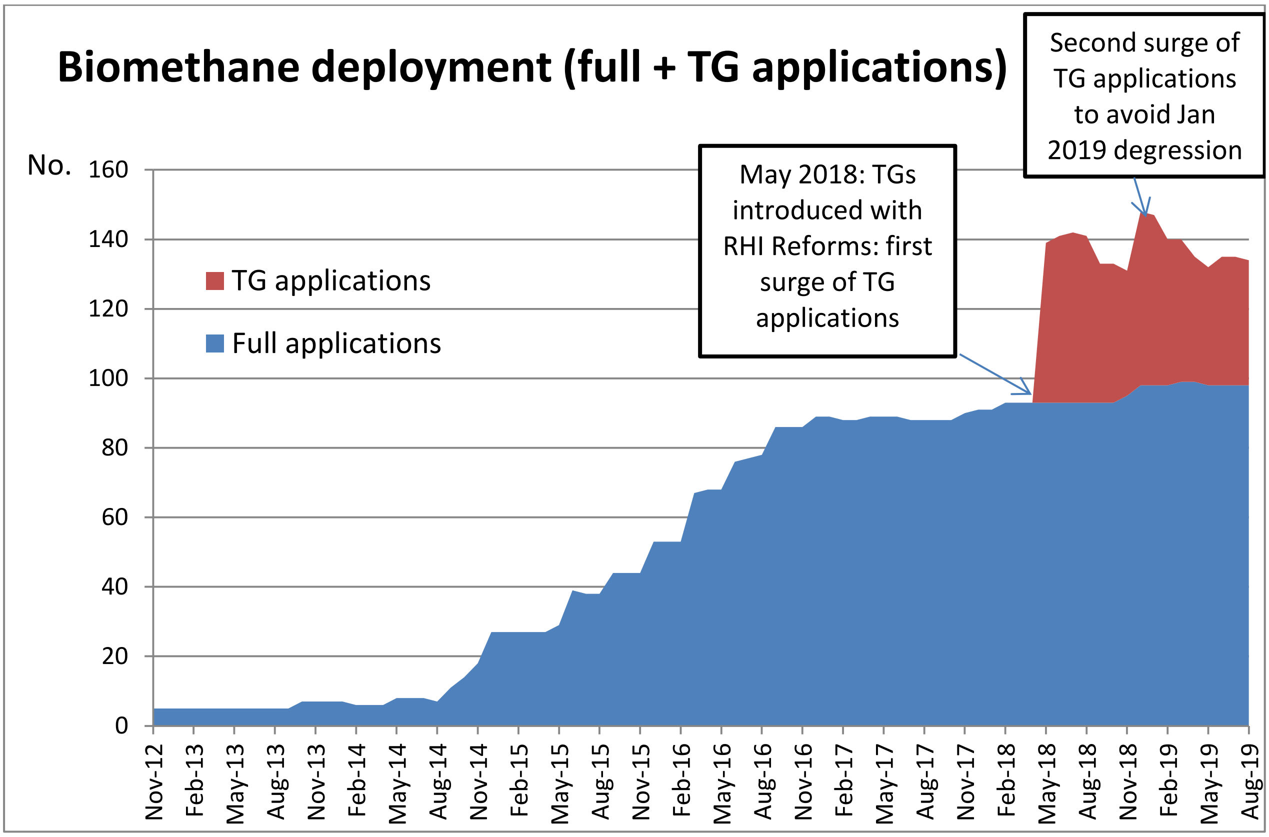
We would recommend that the RHI tariff for biomethane is re-set at a level of **at least 5.7 pence/kWh** (pre-January 2019 degression), as the current tariff of 4.8 pence/kWh is not sufficient to support new AD development. This is clearly indicated

[2] REA's Bioenergy Strategy final report and REA's submission to the BEIS Evidence review on options for long-term heat decarbonisation ('Clean Growth – Transforming heat'), which you can find here.

[3] This includes biomethane from AD as well as from thermal gasification, both of which are currently eligible.

[4] It is possible that some local authorities will decide to introduce food waste collections before that date, once they have clear visibility of the new food waste regulatory framework.

by the extremely low numbers of biomethane plants coming forward under the Tariff Guarantees framework, especially since the last degression applied to the biomethane tariff in January 2019 (as shown in the chart below). The lack of visibility on what comes after the RHI closure in March 2021 is also likely to contribute to a downturn in investment into new projects.




*Source: BEIS RHI Deployment stats*

Our understanding is that most of the projects which have applied for a tariff guarantee at a rate of 4.8 pence/kWh are not new builds, but instead mostly comprise upgrades of existing assets (e.g. AD plants with CHP at sewage treatment works). The capital cost required to upgrade these plants is nowhere near that required for new builds.

The Government should aim at supporting the construction of at least another 20 plants per year (equivalent biomethane production of approximately 1 TWh/annum) following the RHI closure, to keep the AD construction industry sustainable whilst a new support mechanism is designed and is in place. This is in line with the deployment projection of 20 plants per year presented in the updated version of the December 2016 Impact Assessment which accompanied the Government's response to the March 2016 RHI consultation. If the output from these plants was supported entirely under the RHI, the cost to the UK taxpayer of supporting this number of plants over the 20 years tariff lifetime would be just under £2 billion - for a 2 year extension, or under £3 billion – for a 3 years extension. However, it is likely that a significant amount of the output could instead be supported via the Renewable Transport Fuel Obligation, and therefore be funded by motorists rather than taxpayers. We refer you to the paper we wrote in 2018 arguing for flexibility for RHI-accredited biomethane producers to be able to claim RTFCs or the RHI. BEIS supported our proposal (but the wording in the RHI legislation inadvertently prevents it, although it is intended that it will be rectified within the RHI closure regulations.

# 3. The medium- and long-term: a future green gas mechanism that encourages innovation and good practice

### 3.1 Green gas obligation

An alternative support mechanism for green gases should be developed to ensure continued deployment in the medium- and long-term.

The majority of our members consider that a new green gas scheme should include a mechanism to encourage technologies and gases with the lowest carbon profile, in line with Government's commitment to net zero by 2050. In addition, they support a mechanism that encourages innovation and best practice.

The most supported option amongst our members is an obligation placed on licensed gas suppliers[5] to reduce the average carbon intensity of the fuels they supply. For example, gas suppliers would have to reduce the average lifecycle GHG emissions of the gas they supply by a gradually increasing GHG reduction target (i.e. a declining carbon intensity target per unit of energy) over a period of time, relative to a fossil fuel baseline.

The suppliers' GHG obligation would be the amount of emissions (e.g. in kg $CO_2e$) which they need to offset to meet the GHG target level). Any gas supplied would generate credits or debits depending on whether it is better or worse than the target level.

The suppliers could meet their obligation by redeeming GHG certificates/credits, or paying a buy-out price (£/tonne of $CO_2e$ above the target). One certificate/credit would be earned per kg $CO_2e$ saved.

Green and low-carbon gases would earn a certain number of GHG certificates or credits depending on their associated carbon intensity.

It should be noted that a similar mechanism is already operated by the DfT under the Motor Fuel GHG Reporting Regulations, alongside the ROS (the RTFO operating system). This is referred to as Greenhouse Gas Operating System (GOS) and is clearly 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).

[5] Any person who holds a Gas Supply Licence, which is a licence granted or treated as granted under section 7A(1) of the Gas Act 1986. This is restricted gas which has been conveyed through pipes to the relevant premises. Very small gas suppliers could be exempted.

*Why licensed gas suppliers?*

We would propose that an obligation is placed on licensed gas suppliers, as these are the organisations that buy and sell the gas to the domestic and non-domestic markets. If the aim of the policy is to increase the proportion of green and low-carbon gases in the grid, an obligation on these companies would seem the logical way to do it. Suppliers would have the obligation to buy gas from green/low-carbon gas producers.

An obligation on the gas distribution network operators (GDNOs) seems illogical, as it is not in their gift to increase the renewable/low-carbon proportion of gas in the network up to any particular level. GDNOs distribute gas, and whilst they can respond to requests to inject green/low-carbon gas, they don't own the gas, they don't procure it themselves, and if they started to do this they would be in breach of their licenses.

Notwithstanding this, there is no doubt that the GDNOs have a critical role to play in help decarbonise the UK gas network, by supporting and facilitating the connection and operation of biomethane and other renewable gas to grid plant.

The networks have a vital role to play in lowering the cost of connections, for example by simplifying the energy measurement regime for biomethane sites and standardising their connection specifications and eliminating the need for propane addition. A revision of their current network pricing methodologies will also be paramount to facilitate future entry capacity investments.

*Floor price*

Stable and predictable prices are required to provide project bankability. The RHI provides a stable income stream, whether the value of certificates within a market based obligation will vary depending on market conditions. To overcome this issue, BEIS should consider whether a floor price for the certificates or other equivalent mechanisms would be required to help stabilise the certificate price.

*Guard against stranded assets*

Currently most biogas used in the UK is used for power generation. In 2018 biogas was used to produce 7.6 TWh of power (made up of around 4 TWh from landfill gas, 1.0 TWh from sewage gas and 2.7 TWh from anaerobic digestion)6. This implies the use of some 19TWh of gas (70PJ) for this purpose.

There is scope for converting and/or expanding some of these assets to biomethane production in the future, which would result in additional volumes of biomethane that can be injected into the gas grid.

Any future support mechanism for green gas would need to guard against the risk of these assets becoming stranded, for example once the lifetime of their tariffs or income from renewable power generation (FITs or ROCs) comes to an end.

There are examples in Europe where specific mechanisms have been included in support schemes for renewable gas to encourage existing biogas CHP plants to convert some or all of their production to biomethane. The incentive scheme

[6] Dukes, 2018.

adopted in Italy is one of these examples and we would be happy to discuss this further with BEIS in due course, if helpful.

*Energy vs carbon intensity obligation*

We originally discussed with our members an energy based green gas obligation, along the lines of the Renewables Obligation but for renewable gas. The obligation could start out as a number of certificates required per volume or MWh of gas supplied. Each supplier's obligation would be calculated by multiplying their total annual gas supply to customers in the UK by the level of the obligation (number of certificates per volume or MWh of gas supplied), along the lines of the Renewable Obligation.

This option should still be on the table, however, most of our members consider that this mechanism is too complex, particularly due to the fact that banding will almost certainly be required to accommodate different costs of productions.

If it was felt that this type of mechanism is easier to adopt than one based on carbon intensity, then we would still recommend that some sort of banding is included to reward gases that deliver the lowest GHG emissions.

Some members commented that, as with the Renewables Obligation (RO), there would be a need to predict the total energy demand 18 months in advance. This, for gas, would be much harder than with electricity. The only way to address this (as with the RO[7]) would be to have headroom, which would have to be relatively high to ensure that even in a very mild winter the amount of biomethane as a % of total demand was not too high to cause collapse in the value of certificates. In a carbon based obligation, the headroom calculation would not be needed.

*Important factors to be considered on the carbon accounting methodology*

There are some challenges in using the above approach that must be carefully considered if a policy of this kind is designed. These are set out below.

- A carbon intensity based obligation would create the need for a robust carbon accounting methodology and independent auditing of the GHG emission values to ensure these are credible and robust. Much of this already exists under the RTFO and other financial incentive schemes.
- There will be more pressure on the carbon intensity calculation as a project income will be dependent upon this value. It will make it very difficult for a funder /developer to predict the value of certificates/credits for a project at the point of securing funding. Making a business case for a project based on this calculation and its interpretation may be very challenging.

[7] In the RO, the level of the obligation each year was determined by using a 'headroom' calculation. This works by providing a set margin between the predicted generation (supply of certificates) and the level of the obligation (demand for certificates). This helps reduce the possibility of supply exceeding the obligation in any given year that could cause a reduction of the market value of a certificate. Headroom lets investors feel more confident that there will always be a market for their certificates and it helps stabilise the certificate price. Stable and predictable prices are required to provide project bankability. Unlike the RO, the Renewable Transport Fuel Obligation does not provide a guaranteed income stream as the price of RTFCs fluctuates, there is no limit to how much biofuel could be imported and put into the fuel system, and there is lack of demand relative to potential supply.

- Currently, the entire lifecycle emissions of natural gas are not considered in Government policy e.g. the real upstream GHG impact is ignored. This is in contrast to biomethane, which accounts from across its lifecycle. Therefore the fossil baseline should include upstream emissions.
- There is a risk that a GHG-based Green Gas Obligation mechanism would encourage lower carbon intensity sources of gas that in REA's opinion should not be encouraged. For example shale gas has a lower carbon intensity than that of imported LNG. Given that shale gas would have a higher carbon intensity than biomethane injection, more of it would be required in order to generate the same number of GHG certificates. To address this issue it may be necessary to include a minimum GHG savings threshold.
- It could also create an incentive for exporters of LNG to preferentially send their lowest carbon intensity product to the UK, and their higher carbon intensity elsewhere. This would not necessarily drive the overall upstream emissions of LNG production down, and it would lead to subsidy leakage. Giving all imported fossil gas a default GHG value would remove this incentive.
- The life-cycle methodology to calculate carbon intensity of different gases needs to fully recognise the benefits associated with anaerobic digestion and other waste to energy technologies that are currently not accounted for in the current GHG accounting methodology. This includes as an example carbon capture and storage from AD, soil carbon sequestration, and also avoided emissions of artificial fertiliser production by using digestate.

*Funding mechanism*

With a green gas obligation on licensed gas suppliers, the cost would be passed on to the gas bills. This has the advantage over general taxation in that only gas consumers pay it, but on the other hand it is more regressive.

There may be other ways to recover this money which should be explored. A simpler route may be to raise the money through the gas transporters, putting them on the transportation charges (ie not on the gas bills or general taxation). Gas Transportation charge - applied to all gas shippers and it is a pass through.

Recovering the cost through network charges may be better as it decouples this from Government budgetary uncertainty, which will never be conducive to long term certainty. This would however need to go through National Grid NTS to be recovered nationally, as it wouldn't be fair for one network's customers to pay all the cost, and gas is traded nationally.

Feedback from a gas network is that if this was a possible approach, it would need legislation which Ofgem would then put into license obligations.

*Administering Certificates Schemes*

Government (DfT) and non-government bodies (Ofgem and Renewable Energy Assurance Limited) now have significant experience of administering Obligation Certificates and Guarantee of Origin Schemes (e.g. the REAL's Green Gas Certification Scheme[8]). Renewable Gas Obligation Certificates could sit alongside mechanisms for awarding RHI payments, RTFCs and Guarantees of Origin (GoO). A

[8] The scheme has been operational since 2010. See www.greengas.org.uk for further details – including GGCS 2019 Annual Report

central registry of green/low carbon gas injection data should be explored, based on secure and independent data provided by the existing GEMINI system[9]. 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).

### 3.2 Other possible mechanisms

In our discussions with members, other support mechanisms were considered which are outlined below. They all have drawbacks compared to a supplier obligation. We would be happy to expand on our thinking on other options should you be interested.

*Feed-in tariff mechanism similar to the Renewable Heat Incentive*

The main advance of this option is that it provides a predictable and stable tariff ie a bankable income stream, compared to the value of certificates or credits that tend to fluctuate upon market conditions. However, if an RHI or similar mechanism was to be continued, we would recommend that:

- Its scope is expanded to ensure that it covers all forms of renewable gas supply, i.e. biomethane from AD, bio-SNG from gasification, hydrogen injection, bio-LPG in the off-grid market etc. Some members would also like to see hybrid boilers and bio-LPG boilers covered by the Domestic RHI (as opposed to only heat pumps).
- There should be a mechanism built within the scheme to encourage innovation, cost effective carbon abatement and best practice.
- Mechanisms based on unrealistic expectations on cost reductions (like automatic degressions) must be avoided.

*Heat 'feed in premium'*

Amongst other recommendations, the recent industry led Bioenergy Strategy report recommends a heat 'feed in premium' which would provide a top-up payment to low carbon heat users, made by the difference between a calculated reference tariff and the full effective cost of the alternative fossil fuel (including taxes, duties and carbon levels). As carbon pricing is gradually implemented, the difference between the reference tariff and the cost of the fossil fuel will reduce so the premium payment eventually falls to zero. At this point, when consumers of high

[9] In the Netherlands and Denmark Guarantees of Origin are administered based on data from the national balancing system. In the Netherlands GoO can, if no feed-in-tariff was received be moved into the biofuel registry

carbon heat pay the full cost, low carbon heating will become economically attractive without further subsidy.

There are merits in this type of schemes, however it relies on other policy mechanism such as an escalating carbon price to be in place.

*CfD for renewable gas*

There may be some appetite from Government to introduce a CfD type policy to support renewable gas. This would probably be a top-up payment linked to the market price of gas. The top-up payment would be determined by the difference between a strike price (price a plant would require to be commercially viable) and the wholesale market reference price.

This may be more politically popular than other options as it introduces competition to support, theoretically driving down costs to consumers, and aligning with State Aid requirements.

However, the REA believes this mechanism is only suitable to large scale generation (like off-shore wind) and would result in very limited or no deployment of biomethane projects. The main reason for this is that it is a very complex and burdensome mechanism throughout all stages - from pre-bidding to construction –, it requires significant upfront costs and has a extremely high allocation risk.

The recent CfD auction results have confirmed that the primary beneficiary of this support mechanism is only one technology, off-shore wind. CfD has so far not been a fair and inclusive route to market for all technologies. For example, it has resulted in no deployment of ACT technologies and the REA has already expressed repeatedly to BEIS its concern over the lack of diverse technologies awarded contracts, due to the nature and functioning of this mechanism. Thus, we do not support this mechanism as a route to market for green gas, unless CfDs for smaller scale schemes are made considerably simple.

*Other mechanisms that can help but are unlikely to suffice on their own*

- Stronger GHG emission reporting requirements for the public sector - with incentives for biomethane use through the use of green gas tariffs and/or long term renewable gas purchase agreements with generation plant
- Stronger GHG emission reporting requirements for the private sector – with incentives for biomethane use through the use of green gas tariffs and/or long term renewable gas purchase agreements with generation plant
- Support for biomethane use for parties obligated under a new UK emissions trading scheme
- Exemption of the Climate Change Levy (CCL) for end users who purchase green gas
- Tax incentives for biomethane to grid producers
- Capital grants/innovation support for renewable green gas producers
- GDNO incentives for attracting biomethane to grid schemes
- Stronger push for renewable gas in transport

## 4. Off grid market

This paper is focused on the gas to grid market and the decarbonisation of the gas grid, however the REA has also been engaged in parallel discussions with its members and BEIS about the decarbonisation of the off grid market.

Our latest position paper on the off grid market was in response to BEIS Evidence Review on the long term decarbonisation of heat ('Clean Growth – Transforming heat'), which you can find here.

### 4.1 Complementing a green gas obligation with an off-gas grid decarbonisation obligation for biofuels for heating and biomass

The green gas obligation outlined above would not cover road-distributed biomass, biopropane or liquid biofuels.

Amongst other recommendations provided in our above mentioned submission, for the medium to long term we would suggest that off gas grid heating fuels (e.g. solid biomass, biopropane 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.

Biopropane is chemically identical to conventional propane and as such LPG or biopropane boilers will work with existing (oil or solid fuel) heating systems and the current housing stock in the countryside. Whilst the initial move may be to use high efficiency LPG boilers in homes, these could readily be integrated with heat pumps to create hybrid systems. Hybrid systems in off-gas grid areas will need a biogas to run the boiler. As well as hybrid systems biopropane could be used with CHP, gas heat pumps or fuel cells, thus offering the opportunity to increase system efficiencies even further. It is also worth noticing that there are a number of additional production pathways for biopropane i.e. biorefineries, anaerobic digestion and power-to-gas (using renewable hydrogen), and policy should support the development of different biopropane production pathways, that could be supplied by sustainable domestic feedstocks.

| Annex 1 – pros and cons of main options discussed by REA's members | | |
|---|---|---|
| | **Pros** | **Cons** |
| Volume based obligation | • Familiar / Easier sell – Emulates the RO<br>• Have ability to pick particular technologies or fuels / can pick winners<br>• Fuel poverty argument partially offset as only consumers on gas grid are made paid for it<br>• No diminishing returns to plant scale | • Complex<br>• Banding and banding reviews required<br>• Requires cost info<br>• Obligation level based on predicted demand for following 18 months / volumes of gas difficult to predict<br>• No incentive to innovate / improve GHG performances<br>• No floor price |
| GHG intensity obligation | • Rewards desired outcome: GHG reduction is what we should all aim for<br>• Technology neutral<br>• Places all gases on a level playing field<br>• Encourages innovation and better GHG performance<br>• Precedent set through GHG reporting requirement (DfT)<br>• GHG methodology already established under Biomass Sustainability policy<br>• Bridge to future wider economy support mechanism (e.g. escalating carbon price)<br>• Fuel poverty argument partially offset as only consumers on gas grid are made to pay | • Less familiar<br>• Complex<br>• More pressure on GHG calculation<br>• Places all gases on a level playing field! Whichever gas delivers the cheaper carbon savings would do best: could biomethane be less favoured?<br>• Issues within GHG accounting methodology need sorting to recognise full value of biomethane |

| | | |
|---|---|---|
| CfD | • Price discovery aspect would appeal Gov, drive down costs and align to State Aid<br>• Price certainty once you have contract | • Extremely complex<br>• Significant upfront costs<br>• Burdensome<br>• Rigid<br>• Not suited to ‘small scale’ biomethane sector<br>• No incentive to innovate / improve GHG performances.<br>• Difficult to set benchmark gas price<br>• Unlikely to be designed with no auction as price discovery aspect is what Gov likes about it |