Contribution of encouraging the future use of biomethane to resolving sustainability and energy security challenges: the case of the UK

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Abstract

The focus of this research is the potential of biomethane in Britain's gas grid. It examines its relative ability to address Britain's sustainability and energy security challenges from an economic perspective. Such research is important because UK is wedded to gas for heat production and power generation and is increasingly dependent on imported gas, in line with shrinking domestic production, and uncertain future trading relationships. Also, dependency on natural gas, threatens Britain achieving its legally-binding carbon budgets. The study included a thorough literature review, primary research to finally uncover the views of key UK market participants plus analytical modelling. The findings reveal that the market is cautiously optimistic, despite reservations regarding feedstock availability and the impending cessation of subsidy approvals. Investors are in greater need of long-term certainty, however, and the challenge of decarbonising heat and heavy-duty transport warrants this. Retail price premiums are polarised but, in line with wholesale costs, relatively high compared to electricity. The key recommendation is for the policymakers to follow precedents in renewable electricity and liquid biofuels, by mandating that energy suppliers, owners of heavy-duty road fleets and occupiers of new buildings purchase biomethane. In tandem, feedstock and grid-entry restrictions must be tackled creatively.

Keywords

Biomethane Grid Injection; Biogas; Natural Gas; Energy Security; Sustainability; United Kingdom

1. Introduction

The motivation for this research came through realisation of three facts: –

1. Much is said of Britain successfully decarbonising its power generation. Yet its use of natural gas ('gas') for power increased from 27% in 2013, to 41% in 2017 (BEIS, 2018a). Britain's gas grid reaches 90% of homes (POST, 2017), which on average consume four units of gas for every one of electricity (Ofgem, 2017).
2. Heat accounts for 20% of Britain's greenhouse gas emissions (POST, 2017), driven by gas being used to generate almost 70% of heat (BEIS, 2018b). An alternative is the electrification of heat generation, but the cost of this has been estimated at £300bn (Liebreich, 2018).
3. As Britain's gas production has declined; so have its net imports risen: from 33% in 2008 to 46% in 2017 (BEIS, 2018d). The winter net import share has increased from 47% in 2015 to 59% in 2018 [ibid], with winter 2018 showing "the highest recorded volume for any

quarter” since records began (BEIS, 2018e). Due to its exit from the EU, Britain’s future trading relationships are currently uncertain, potentially making gas imports more difficult.

It is evident that Britain is heading for major sustainability and energy security challenges if it does not change its attitude to gas consumption. The need for solutions is pressing.

Biomethane is produced via biological (anaerobic digestion) or, as Bio-SNG, thermo-chemical (gasification or pyrolysis) processes. Biomethane is typically upgraded from biogas, itself capable of being produced from waste streams like manure and food waste. Interchangeable with natural gas as a ‘drop-in substitute’, it can be injected into the grid. However, it made up less than 1% of UK volume in 2017 (BEIS, 2018c). Biomethane production can result in fewer greenhouse gas emissions than natural gas (POST, 2017). It has the potential to answer the challenges.

It is clear that natural gas is set to grow its dominance of UK energy consumption. Its share of total energy consumption is predicted to rise from 68% in 2000 to 74% in 2050, predominantly driven by reduced use of oil and coal for heat production, against a background of flat or slightly reduced total energy consumption (Kannan and Strachan, 2009). The expected continued use of significant volumes of gas, despite all new and replacement gas boilers being mandated to be efficient condensing models, makes it clear that Britain’s gas supply will need to emulate the success of Britain’s increasingly decarbonised electricity supply.

There is a significant challenge in measuring the GHG-reducing potential of bioenergy, partly due to complex supply chains and process options (Thornley and Adams, 2018), with results frequently disputed (Welfle et al., 2017). This is very evident for biogas pathways, especially production of biomethane, as illustrated by the wide variety of GHG figures in the literature, summarised in Table 1.

Table 1 - GHG figures for production of biomethane

gCO_2e/kWh	Source
-50 to 450	(Speirs et al., 2018)
-360 to 219*	(Giuntoli et al., 2015)
-374 to 183*	(Tonini et al., 2016)

*Converted from MJ to kWh

Speirs et al. do not elaborate on the sources for their figures, but the wide range serves to illustrate the variety of upgrading methods, feedstocks and Life Cycle Analysis (LCA) methodologies that they, and likely the other researchers, encountered. Confidence should be attached to Tonini et al. given the wide variety of feedstocks and GHGs listed in their detailed methodology, which utilised an ISO standard, even if the upgrading technology was not evident. Giuntoli et al., however, provide full transparency on figures for multiple permutations of process options, including upgrading technologies, though they understandably limited their focus to just three feedstocks.

Despite their similar range of results, Tonini and Giuntoli do not apparently cite each other, giving assurance of independence. There is still no singular figure for biomethane, however, but it is conservative to adopt the maximum limit of audited emissions for it to qualify for the British Government’s Renewable Heat Incentive (RHI) subsidy: 34.8 gCO_2e/MJ, equivalent to 125.28

gCO_2e/kWh (DECC, 2015). The RHI is a UK government scheme set up to encourage uptake of renewable heat technologies; the producers of biomethane receive financial incentives under the RHI scheme (POST, 2017).

Given that biomethane is a drop-in substitute for natural gas, the equivalent figures for the latter's production are important, and shown in Table 2.

Table 2 - GHG figures for production of natural gas

gCO_2e/kWh	Extraction/transport method	Source
230-318	Not specified	(Speirs et al., 2018)
199-207	Conventional	(MacKay and Stone, 2013)
200-253	Hydraulic fracturing	
233-270	LNG	

Note that LNG could have been originally extracted conventionally, or non-conventionally (i.e. hydraulically fractured: 'fracked'), though it will increasingly be the latter due to rising US production (Crooks, 2018). Speirs et al. do not specify the reason for the wide range, but the high end is likely due to non-conventional extraction and/or liquefaction.

Taking the RHI maximum for biomethane (125 gCO_2e/kWh), it can be viewed that it has the potential to deliver lower GHG emissions than even the lowest figure for natural gas production (199 gCO_2e/kWh). The gulf is wider still when compared with the non-conventional methods of extraction and transport that will increasingly have to be used to supply the UK as North Sea production peaks and then plummets (Bentley, 2016). Suggestions of up to 80% potential GHG reductions have been mooted for biomethane relative to natural gas (Bekkering et al., 2015), though this depends upon maximum optimisation of energy efficiency and supply chain options. There will clearly be trade-offs with capital investment and production volumes. Adams suggests 60-80% is possible (Adams, 2018).

One of Stern's 'co-benefits' of investing in low-carbon energy is the reduction of "short lived pollutants, including soot [and] methane" (Stern, 2015, p. 263) and this he relates to the production of natural gas. Methane emissions also occur during the production of biomethane, however, and it is referred to as 'methane slip'. A paper cited by many researchers in the field concludes that upgrading biogas to biomethane may be an environmentally beneficial alternative to biogas combustion in on-site CHP when considering global and local emissions (Ravina and Genon, 2015). However, they caution a strong sensitivity to methane slip during upgrading. If slip is limited to 0.05% they conclude that it represents just 2% of the total GHG footprint of the end-to-end biomethane production process. But if slip reaches 1.4%, then its share boosts to a 40% share, and to a 66% share if it reaches 4%. The researchers conclude that reaching this 4% point would mean that on-site CHP combustion would instead be the most sustainable biogas pathway.

The question of how much methane slip occurs during upgrading is therefore critical. It would seem logical that the quality of plants' initial installation and subsequent maintenance would have a bearing on methane emissions. It is evident that the chosen upgrading technology has a strong bearing, and the literature on the major ones is summarised in Table 3.

Table 3 - Methane slip (%) of upgrading technologies

Membrane Separation	Water Scrubbing	Pressure Swing Absorption	Source
0.5	1	2	(Bates et al., 2014)
0.5-1	1-2	2-4	(Adams, 2018)

For the UK specifically, membrane separation, which also exhibits the lowest power consumption (Adams, 2018), is used in the majority of plants (Horschig et al., 2016), (Bates et al., 2014). It would therefore be reasonable to suggest that UK production is likely within Ravina and Genon's threshold of 4% methane slip.

Poeschl et al. (Poeschl et al., 2012) suggest that even 3% methane slip cancels out the climate change benefits of biomethane substituting natural gas. This possibly ignores, however, that natural gas production also involves the loss of methane. Stern (2015), citing (IEA, 2013) suggests that 280 $MtCO_2e$ could be saved annually by elimination of the venting and flaring of methane in natural gas production. Venting is far worse, as it is the release of non-combusted methane, which has a Global Warming Potential of 21 times that of CO_2 (Smil, 2015). The US EPA suggested in 2011 that just 0.47% of US natural gas was leaked during production, but a credible paper, published in June 2018, upgraded that figure to 2.3% (Alvarez et al., 2018).

Opinions differ on the relative increase of methane leaks related to fracking over conventional production but one instrumented-aerial survey of the huge Marcellus shale suggested them being two to three times greater than that expected for conventional drilling (Smil, 2015). This is significant as fracking is expected to boost US 2018 production by 10% year-on-year, and grow 60% by 2030 (Yergin and Andrus, 2018). This US shale gas, exported as LNG, will become increasingly important to satisfying UK demand (Sharples, 2018).

Within the context of the UK, the specific objectives of this research are to: –

1. Explore the views of market players on the dynamics of the market, and what is necessary for its expansion.
2. Critically evaluate how more grid biomethane could economically help meet Britain's challenges, compared to the alternatives.
3. Recommend ways to overcome the barriers preventing biomethane from meaningfully contributing to Britain's challenges.

The outcome is a clear picture of where Britain is, and could be, regarding its use of grid biomethane, and the extent to which this could meet Britain's challenges.

This research has value through its contribution to the knowledge of the nascent UK biomethane industry, currently funded by British taxpayers. An industry that aims to reduce the dependence on the decreasingly productive North Sea fields that provide a dominant proportion of Britain's power and heat. It also aims to help solve arguably Britain's toughest decarbonisation challenge: at just 7% of heat produced, the UK is third-from-last in the EU for renewable heat (Eurostat, 2018).

2. Method

The research strategy for objective one involved semi-structured interviews with 19 key UK market participants, spanning biomethane producers, retail energy suppliers, network operators, trade bodies, business users; plus a policymaker. The strategy lent itself well to the exploratory nature of the objective and structured interviews allow for direct comparison of participants' answers whilst allowing for clarificatory questions. They also maximise the likelihood of responses and quotable content. Engaging with practitioners of a fast-developing market is a powerful way to extract fresh insights.

Objective two was satisfied through analytical modelling of observed market differentials; and sustainability and security scenarios. The market modelling focussed on price differentials, involving analysis of UK domestic retail tariffs for 'green gas' versus non-renewable equivalents. A sustainable price premium for green gas could be a powerful driver for market development. The expected outcome was a percentage price uplift for i) green gas relative to green electricity, both relative to their non-renewable equivalents, and ii) green gas price differential relative to the proportion of green gas. Energy suppliers' domestic tariff unit rates for gas were multiplied by the Ofgem[1]-published average per-household gas consumption, and added to a year of daily standing charges. This was done for each green gas tariff, and again for the nearest non-renewable tariff from the same supplier. This would reveal the annual bills for gas and from this the price differential uplift was calculable as detailed in Equation 1.

$$pp = \left(\frac{\{(gg_{sc} \times 365)+(gg_{ur} \times U)\}}{\{(ng_{sc}\times 365)+(ng_{ur}\times U)\}}\right) - 1 \qquad (1)$$

In this equation, pp is the price premium, gg_{sc} is the daily standing charge of the green gas (pence per day), gg_{ur} is the unit rate of the green gas (pence per kWh), U is the annual average domestic consumer gas usage (kWh), ng_{sc} is the daily standing charge of the natural gas (pence per day) and ng_{ur} is the unit rate of the natural gas (pence per kWh). Observed UK green gas tariffs are sold 'dual fuel' with green electricity, so similar logic was used to reveal the premium of that versus non-renewable electricity. It was assumed that there was no cross subsidy between fuels, or with other pricing devices (e.g. contract exit fees, online billing discounts). Note was made of which green gas tariffs employed offsets (e.g. Certified Emissions Reductions certificates) rather than UK biomethane certificates (e.g. Renewable Gas Guarantees of Origin certificates), to expose any differences. An analysis was performed on price differentials relative to the biomethane blend percentage.

The sustainability modelling looked to expose the absolute differentials suggested by the reduced greenhouse gas (GHG) emission potential of biomethane relative to natural gas. The

[1] The Regulatory Body in the UK for the Gas and Electricity Markets

model therefore examined scenarios of potential GHG savings from increased production of biomethane displacing sources of natural gas. The expected outcome was a measure of GHGs, in Megatonnes of CO_2 equivalent, over the period of the UK's fourth and fifth carbon budgets (2023-2032), and savings against a 'business as usual' scenario.

The equation for calculating the production impact of a supply source, in $MtCO_2e$, is shown in Equation 2.

$$pi = \frac{(pv \times ci) \times 0.01}{0.9} \tag{2}$$

Where, pi is the production impact, pv is the production volume and ci is the carbon intensity. The model utilised the gas supply source data from the sustainability modelling, and calculated the percentage of imported sources with each of the scenarios. The equation for calculating this import dependence is shown in Equation 3.

$$id = \frac{(g_n + g_c + g_{LNG} + g_o)}{(ukcs + uks + ukgg) + (g_n + g_c + g_{LNG} + g_o)} \times 100 \tag{3}$$

Where, id is the import dependency percentage, g_n is the imported gas from Norway, g_c is the continent gas supply, g_{LNG} is the LNG supply, g_o is other sources of the natural gas, $ukcs$ is the UK continental shelf, uks is the UK shale and $ukgs$ is the UK green gas supply.

The strategy for satisfaction of objective three involved the synthesis of the research findings and conclusions.

3. Stakeholders' perspectives

The semi-structured interviews provided an opportunity to gauge the feelings of practitioners and policymakers. This included quantitatively via questions that requested that they choose scores on a scale of one (most negative) to ten (most positive). All interviewees scored their sentiment firstly on the current health of the UK marketplace, and secondly on the outlook with a 5-10 year horizon.

The biomethane producers' underpinning scores were relatively optimistic, with 80% showing a static or upward trend. This is despite having witnessed first-hand the stop-start nature of plant development, due to RHI subsidy tariff degression to uneconomic levels and delays in tariff renewal. Also, their knowledge that the closure of the RHI to new biomethane plants in 2021 will halt almost all supply expansion.

However, 40% of the producers gave outlook scores below five, with one of them giving an outlook half their current health score, based upon the ending of the RHI. Another producer, a significant global developer of injection plants, echoed this, saying that their outlook figure would have more than doubled had they certainty of subsidy continuation. As a result, the larger developer had abandoned investigating UK injection opportunities, despite ramping up such projects elsewhere, and would focus instead on biogas CHP plants. The retail energy suppliers were also positive. An executive of one, a supplier with upstream renewable assets, saw the UK biomethane sector as having “the same potential as the grid-solar market, and it’s kicked off”, and another viewed it as “a startup which, with more support, could mature”.

The gas networks were more circumspect. One flagged that bio-SNG plants, which produce biomethane from gasification or pyrolysis of waste, and which are not eligible for RHI payments, might be economically viable with income from the UK’s Renewable Transport Fuel Obligation (RTFO) scheme. Under the RTFO, biomethane destined for road transport use is rewarded through the generation of Renewable Transport Fuel Certificates (RTFCs), which are saleable financial instruments (Bates et al., 2014).The RTFO treats bio-SNG as a Development Fuel, which fuel shippers must buy an increasingly high percentage of until at least 2032 (NNFCC, 2017). Bio-SNG, as with biomethane generally, is directly compatible with natural gas vehicles, so if bio-SNG plants, and their dry feedstocks (e.g. wood waste and treated municipal solid waste) can be scaled up, then it could boost the UK’s nascent heavy duty natural gas vehicle market.

Overall, the majority of research participants’ scores showed an upward trajectory, and whilst several participants had trepidations about the future of government support, the majority expressed optimism regarding future prospects. A theme for exploration with interview participants was their view of the greatest barriers to increased supply of biomethane to the UK market, and possible solutions. Three concepts emerged: feedstocks, biomethane’s lack of parity with natural gas and government policy, and these are summarised in Table 4.

Table 4 - Summary of supply-driven issues

Concept	Issue	Possible solutions
Feedstocks	Limited feedstock availability, at least for anaerobic digestion biogas plants.	1. England to match food waste segregation mandates of Scotland/Wales/Northern Ireland. Ban on incineration of food and non-segregated wastes. 2. Relaxation of 50% crop limit, and/or dispensation for ‘break’ crops (e.g. rye) and those grown on marginal land, in support schemes. 3. Independently co-ordinated national feedstock assessment programme, including for bio-SNG plants.
Lack of parity with natural gas	Grid capacity limited on low-pressure grids.	1. Network operators to fund installation of grid compressors, and share grid connection costs. 2. Creation of producer and network-owned cooperatives to coordinate and share costs of virtual pipeline plants. 3. Ofgem to review and administer network oxygen limit restrictions.
	Expensive/complex monitoring, metering and injection burden on producers.	Network operators to share the cost and operational burden.
	Calorific Value standards mandating propane.	1. Relaxation of ±1MJ calorific value (CV) limit to ±2MJ and creation of producer-owned shipper cooperatives to share commercial impact. 2. Virtual pipeline cooperatives.

		3. CV region fragmentation and reduced CV targets downstream of biomethane plants.
	Plentiful, cheap, fossil gas reducing need for a solution.	Strong carbon pricing for natural gas (but not green gases).
Government policy	Lack of policy certainty creating investment hiatuses.	Longer term policy certainty.
	Lack of co-ordinated policy between UK central government departments (Defra, BEIS, DfT and MHCLG); and devolved regional administrations.	1. National Infrastructure Commission-led programme to increase biomethane production. Special focus on post-Brexit land use. 2. Mandating that water firms switch from Combined Heat and Power (CHP), to injection, at large sewage farms.

The research interviewees were also asked questions centred around demand for biomethane: the barriers and solutions. Four concepts emerged: cost, consumer knowledge, inertia and legitimacy. These, and suggested possible solutions, are summarised in Table 5.

Table 5 - Summary of demand-driven issues

Concept	**Issue**	**Possible solutions**
Cost	Few incentives for vehicle fleet owners and energy suppliers to purchase biomethane.	Stepped mandate for heavy-duty fleet owners/energy suppliers/new building owners to purchase biomethane, with tax credits.
	Cost sensitivity of business users (especially).	Tax credits/exemptions for biomethane purchase.
Consumer knowledge	Consumers not knowing of biomethane, or confusion about its properties.	Do not tackle directly – mandate blend into the grid instead.
Inertia	Government reticence to intervene in user choices.	Supplier purchase mandate, and allow suppliers to distribute or absorb cost.
	Energy supplier concern over limited biomethane supply.	Solving supply issues, and altering or stop marketing tariffs when shortfalls.
Legitimacy	Businesses being put off by lack of regulation of certificate schemes.	Mimic regulation of renewable electricity schemes.
	Lack of official green gas ecolabel / kitemark for tariffs.	Ofgem to certify and rate green tariffs.

Two further quantitative questions were put to the participants, asking them to score their views, one being low and ten being high, on government policy efforts. There were separate questions for supply-driven policies, and those relating to demand stimulation.

The most striking result was that scores for demand policy, designed to encourage consumption of biomethane, were usually lower than for supply policies. British energy policy has historically tended to skew towards supply-side rather than demand-side, though it is understandable if the priority for a fledgling industry was to first build supply. The intermediaries gave the lowest scores, with several citing the total lack of demand-stimulating policies. A further observation is that the scores were generally low, as were the ranges. The total mean was just over four, driven by half the responses scoring below five. This is in contrast to scores for the earlier question regarding sentiments on the outlook for the industry, where two-thirds of responses were above five. From a sectoral perspective, the biomethane producers were the most positive, likely due to them having directly benefitted from subsidies.

4. Market Dynamics

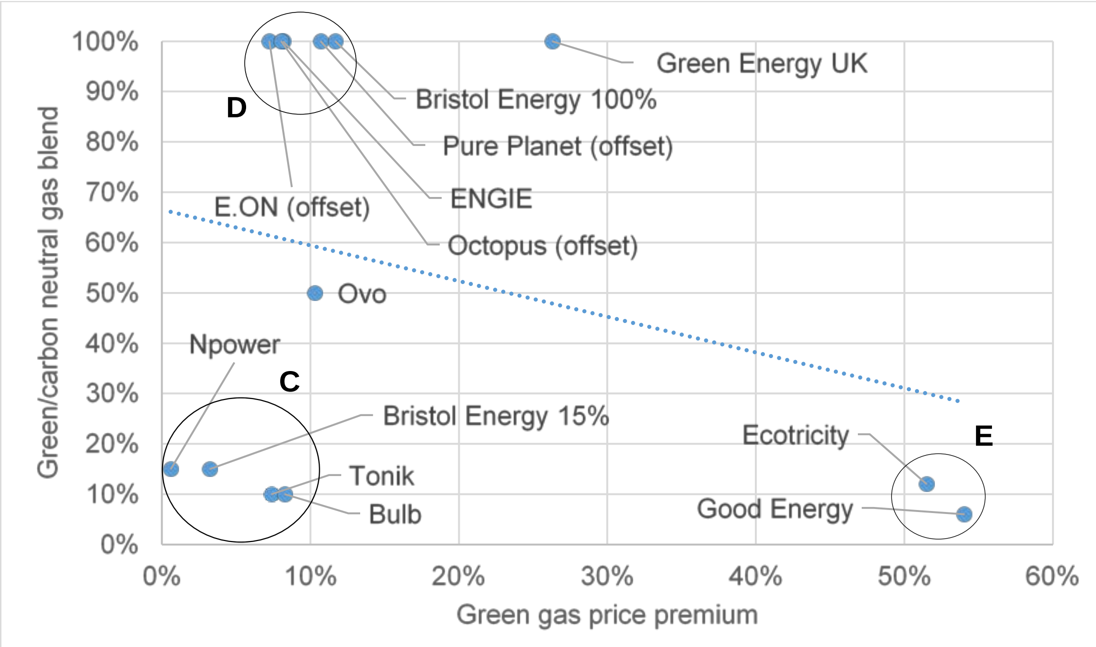
It is likely that for biomethane to become economically sustainable in the UK some market pull – demand from consumers – for a premium product would need to become apparent. This is more so in the absence of strong government policies such as a carbon tax – an economic instrument – or a blend-in mandate. Market pull would be influenced by consumers being aware of green gas, but also by the level of retail price differential compared to natural gas.

To measure this current price differential, a primary research was conducted to gather the retail prices for UK domestic 'green gas' tariffs from the public domain. 'Carbon neutral' tariffs, offered via carbon offsets, were included within scope, due to many consumers likely not understanding the distinction. An annualised price gap was then calculated over the nearest non-green equivalent captured from the same retail energy supplier at the same time.

The operation was repeated for the tariffs' green electricity prices, versus non-renewable equivalent. Where retail energy suppliers only marketed tariffs containing green/carbon-neutral tariffs, the comparison was made against the cheapest non-renewable tariff discovered in the research.

The key output is illustrated in Figure 1, which shows the measurement of the green gas price premium relative to the percentage of biomethane or (as labelled) carbon offsets.

Figure 1 - Green gas price premium versus blend percentage



(NB: Bristol Energy appears twice due to having two green gas tariffs: one with pure biomethane, and one with a 15% blend with natural gas. 'Offset' denotes 'carbon neutral' gas tariffs.)

Three distinct clusters are identifiable in Figure 1. 'C' contains those levying low premiums for low blends; 'D' holds those offering pure biomethane or offset gas for low premiums; 'E' encloses suppliers charging very high premiums for low blends. The four suppliers in cluster C are charging less than 10% premium for low blends (up to 15%) of biomethane, and two in cluster D are charging less than 15% premium for pure biomethane. Suppliers offering 'carbon neutral' gas purely via offsets are charging high premiums compared to biomethane tariffs when considering the much lower cost and greater availability of carbon offsets relative to green gas certificates. Overall, there was a negative correlation (r = -0.27) between the price premium above a retailers' prices for 100%-natural gas and the proportion of biomethane or carbon offsets in the tariffs.

Despite offering low proportions of biomethane in their tariff, Ecotricity and Good Energy (cluster E) are again evident in charging hefty premiums over the natural gas tariff available from another supplier of 100% renewable electricity (Tonik). They are the biggest driver of the lack of a positive blend: price correlation. Admittedly, they provide biomethane by default to all their customers and publish relatively transparent procurement policies for their biomethane certificates. Given their premium market position it is likely that, were they to provide pure natural gas, they would still charge a hefty market premium for it. Underlining their high prices is the smaller brand Green Energy UK, also very vocal and 'deep green', who charge a relatively lower premium for green gas, despite uniquely providing 100% biomethane to all of its customers.

An analysis of the suppliers' premiums for green over conventional gas, versus the equivalent for electricity, produced three insights. First, that there was a strong correlation (r = 0.94) between the relative premium for green gas versus green electricity. Secondly, the rate of premium for green gas versus natural gas was up to double that levied for electricity. Thirdly, despite the wholesale cost of offsets being considerably cheaper than UK green gas certificates, retail tariffs powered solely by offsets did not necessarily exhibit the lowest green premiums.

In conclusion, UK domestic consumers are typically being charged high premiums for green gas relative to both natural gas and green electricity. This effect would be magnified when considering that most British homes use gas for heating and homes consuming more than Ofgem's national average, used in the model, would spend more on gas than on electricity annually. For many customer segments the current premium will undoubtedly be too expensive to justify.

Conversely, there are encouraging signs that there is a wide spectrum of market players offering biomethane tariffs: large corporates (Npower, ENGIE); start-ups (Tonik, Bulb, Bristol Energy) and established 'deep green' players (Good Energy, Ecotricity). Also, there are pure biomethane tariffs being offered by brands such as ENGIE and Bristol Energy, and Bulb including a blend by default for little premium.

However, five of the 'Big Six' suppliers do not appear to offer biomethane, there is little consumer education as to the environmental benefits of 'green gas' and some customers are likely buying it without even knowing. Until this changes, the market pull effect will be muted and relegated to relatively niche players. Arguably, suppliers offering 'carbon neutral' gas that offers none of the UK energy security benefits of biomethane, and which rely on the questionable concept of carbon offsets, are confusing the market. A combination of greater consumer awareness, and lower origin certificate costs allowing sustainably-low price premiums, will be required to develop market pull.

Ultimately, energy suppliers being mandated to buy renewable gas, akin to electricity, is a more practical route to expanding the UK biomethane market. A joint approach, where suppliers have to purchase a known and increasingly large share of biomethane, topped up through consumer tariffs that offer greater proportions, could deliver the best regulated market solution for the UK.

5. Analysis framework for sustainability and security dynamics of biomethane

5.1. Environmental sustainability

This research reviewed the underlying dataset of National Grid's most recent annual 'Future Energy Scenarios' study (National Grid, 2018). This provided four parallel futures for the UK electricity and gas ecosystems, from both supply and demand standpoints. The dataset provides suggested annual levels of demand for gas, and supply from UK conventional, UK shale, European, LNG and finally UK biomethane sources, up to 2050. In its 2018 annual report to Parliament, the Committee on Climate Change (CCC) concludes that the UK is currently set to breach the fourth (2023 to 2027) and fifth (2028 to 2032) carbon budgets, and suggests a gap of up to 65 $MtCO_2e$ based on its central projections of likely policy performance (CCC, 2018). Thus, the data covering this ten year period was extracted from the National Grid dataset, and used as the focus of the model.

Utilising Equation (1), the data was combined with the GHG intensity figures for the production of biomethane – from the RHI maximum – and natural gas sources – from (MacKay and Stone, 2013). This produced GHG outputs in MtCO2e for the ten year period.

National Grid's 'Two Degrees' was deemed the most appropriate scenario, and so two further variants were calculated and put alongside. The first infused a biomethane-over-natural-gas displacement scenario from the work of (Fubara et al., 2018). The other did the same using potential biomethane production volumes from a report prepared for a UK regional gas transporter (Scholes et al., 2017).

The output of the model's results are summarised in Table 6.

Table 6 - Environmental model results ($MtCO_2e$ unless stated)

	National Grid Consumer Evolution	National Grid Steady Progression	National Grid Community Renewables	National Grid Two Degrees	Cadent and Current Study Two Degrees	Fubara and Current Study Two Degrees
Conventional	1,231	1,404	1,088	1,220	1,220	1,220
Shale	372	154	0	0	0	0
LNG	175	171	287	197	54	80
Green Gas	9	4	24	15	86	74
Total	**1,787**	**1,734**	**1,399**	**1,432**	**1,360**	**1,373**
Saving versus Consumer Evolution over 10 years	-	53	387	355	426	413
Annual saving	-	5	39	35	43	41
Green gas %	0.87	0.43	2.90	1.77	9.97	8.50

National Grid's original Two Degrees scenario would appear to be the most feasible outcome. Its 1.8% rate of biomethane in the grid (displacing natural gas), about six times the current share (BEIS, 2018c), could be considered optimistic in the absence of an announced successor to the RHI, but it is not excessive. The levels of biomethane in the scenario variants derived from Cadent, and Fubara, appear too bullish in the current absence of strong government policy. Their feedstock availability assumptions likely outstrip the view of the CCC that there is a natural 5% limit to biomethane based on that availability (CCC, 2018). The original Two Degrees scenario also rejects a major transition to electrified heat, which is prudent given consumer resistance to interference with household decisions. But it has a conservative uptake of gas vehicles by heavy-duty fleet owners and a limited role for hydrogen from the 2030s, which is also prudent. It also assumes no production from the UK shale sector which, despite a very favourable policy environment, has struggled and is unlikely to be any more than a small niche (Jones, 2018).

The 355Mt reduction in GHG over the period, approximately 9.7% of the amount of both carbon budgets, would not appear to be extreme given the major role of gas. Though it is acknowledged that absolute reductions in gas use have contributed alongside increased green gas production. Sensitivity analysis showed that a midpoint between the original Two Degrees scenario and the Fubara variant, a green gas percentage of approximately 5%, would result in GHG emissions of approximately 1,403 MtCO2e, presenting a saving of 384 MtCO2e versus business as usual. The midpoint coincides with the CCC's feedstock limit, though it is worth noting that they do not yet include gasification potential in their assessments.

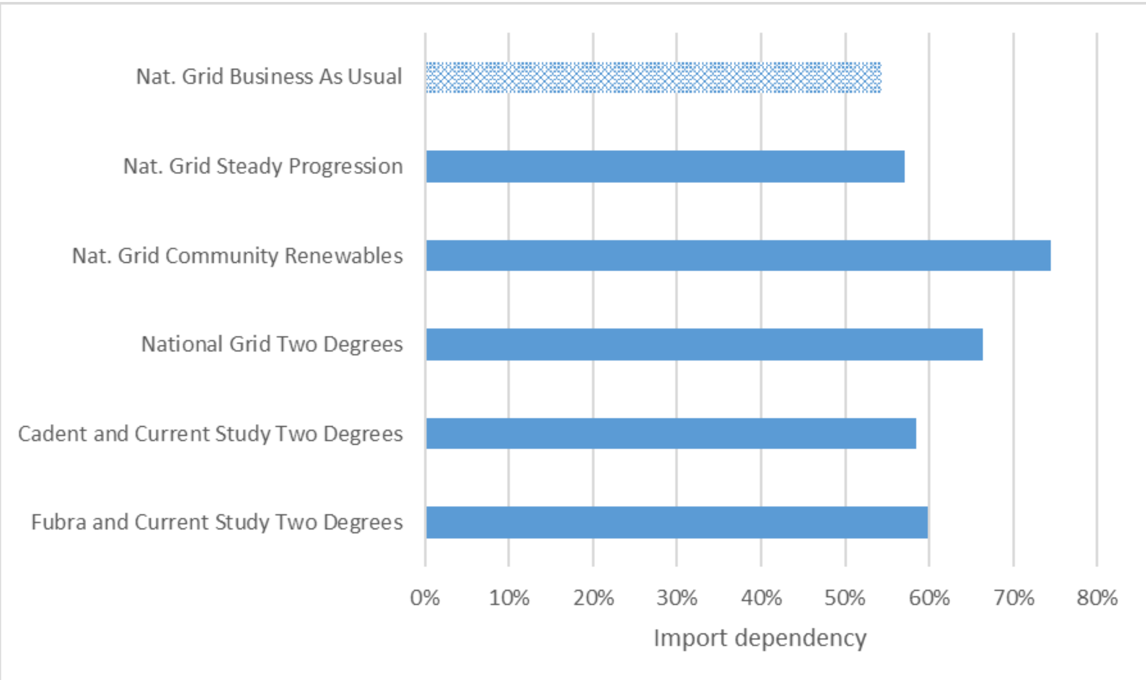
Over the longer-term horizon, to 2050, political pressure will likely make Two Degrees-type scenarios more likely than 'business as usual'. As the early 20-year RHI pay-outs come to an end, and biogas/biomethane plant equipment comes to the end of its useful life, it is hoped that fresh incentives will be in place to refit them with newer, more efficient, technology.

5.2. Energy security

Though there is plentiful literature on energy security, it has defied an agreed definition (Cox, 2016) and accurate measurement (Radovanović et al., 2017). For natural gas in Western countries, the focus is typically on scarcity and import dependence. Given the productivity decline in its North Sea gas fields, this extends to the UK, with the World Energy Council ranking it 18th for energy security, six places behind Germany (World Energy Council, 2018).

The result of this research's modelling, in Figure 2, show that National Grid's Two Degrees scenario, though promising for environmental sustainability, scored considerably worse for import dependency than the business-as-usual scenario, at 66% versus 54%. Whilst the current study variants of Two Degrees, with their heavier weighting of biomethane, exhibited lower import dependencies (58% and 60%), a gap remained mainly due to the Two Degrees scenarios eschewing UK shale.

Figure 2 – Energy security model results



Just as there is a strong preference for policymakers to focus more on security of supply than reduction of demand, their rhetoric tends to suggest that greater domestic – and lower imported – supply equals a greater degree of security. Superficially, biomethane scores well on this front, given that it can be derived from renewable waste streams including sewage, manure, food scraps and forestry residues, as well as crops and seaweed.

The security of supply, however, is dependent on the prospects of sources. Production on Britain's continental shelf is reducing, and whilst Norwegian gas will continue to be UK largest source in the near term, this too is in decline and competition for it will increase (Sharples, 2018). Biomethane's domestic competitor is the development of the UK's shale reserves, a practice which has struggled with grassroots legal challenges and adverse publicity. Natural gas generally is a declining resource, and could become increasingly difficult expensive to source. Together this brings into question whether the traditional view of energy security, by which gas is primarily judged by its country of origin, rather than its long-term sustainability, is still valid (Radovanović et al., 2017). Arguably, it is not, and a more nuanced view is required.

Biomethane has energy security credentials in that it can reduce the dependency upon dwindling domestic and North Sea production, imported sources such as LNG and also-declining Norwegian gas; and currently unproven sources such as domestic shale. This however depends upon positive policy moves to guarantee sustainable feedstock supply, and likely the rollout of bio-SNG gasification technology to complement production of biogas from anaerobic digestors.

6. Conclusion and Policy Implications

The research interviewees' unease towards a lack of a British Government announcement to extend the Renewable Heat Incentive (RHI) for new entrants beyond 2021 was palpable. Uncertainty about the level of RHI subsidies following the 2017 General Election caused a hiatus in new project development, and today the scheme's impending closure has killed new applications. The interviewees held equally strong views towards government policy efforts more broadly, and the synthesis of these helped form the recommendations in Table 7.

Table 7 - implications for policymakers and industry

Policy areas	**Rationale**
Feedstocks	Significant volumes of waste feedstock resource is locked-up, and crop limits too binary. Assessment and planning needs central co-ordination, especially given that UK bio-SNG production is embryonic.
Grid restrictions	Too great a burden on producers and investors. Relaxed CV limits downstream of plants, and networks sharing the injection burden – especially into higher-pressure tiers – could drive down costs. The cooperative ownership model could assist.
Strategic policies	Long-term policy certainty and an independently-led programme focussed on increasing production of green gasses (plural) will promote investor confidence.
Mandated purchasing	Mimicking green electricity and biofuel mandates combats inertia and ignorance, and sends strong signals to the market.
System-wide focus	A broader view of energy for heat and heavy-duty transport, where decarbonised gas – from biomethane and biohydrogen – and electricity co-exist, is required to solve the challenge. Offshore low-carbon electricity is imported from immediate neighbours; so too could decarbonised gas.

After a period of rapid expansion, the UK biomethane market is at a crossroads, with the catalyst for recent rapid expansion, the Renewable Heat Incentive (RHI), soon to close. The scheme that drives biofuel procurement, the RTFO, has the potential to take the industry in a new direction, especially as gasification (bio-SNG) plants are within its scope, though it offers fewer guarantees. This is a pivotal time for the industry.

The market participants are well-informed on the barriers to biomethane's future progress in the UK energy market. Renewable energy generally faces an uphill task in unseating fossil fuels, but biomethane faces particular challenges given the dominance of the single competitor that is natural gas. Availability of traditional feedstocks, a lack of satisfactory network injection points and high burdens on relatively small production companies are major problems facing new and existing plants alike. Combined with a lack of incentives/mandates driving expansion, it is clear that major change is required before biomethane grid injection can fulfil a significant proportion of natural gas demand.

The production of biomethane over natural gas has the potential to lower GHG output and thus help meet the UK's carbon budgets. The focus on decarbonised electricity, and electrification, crowds out the need to decarbonise gas and to switch from terminally-declining gas fields. This is despite the significant role of gas in heat and power production, and thus its relevance to the electrification of transport and heat. Given the significant reliance on gas, effective total decarbonisation will require a system-wide focus. Thus, an 'all-of-the-above' focus is required: biomethane, blending in hydrogen and/or methane from Power-to-Gas, demand reduction, and hybrid gas-electric heat and heavy-duty transport.

Key to the transition toward decarbonised gas will be the stance of the incumbents: the major gas producers and the networks. Centrica's move to take a 50% stake in the UK's biggest biomethane shipper in 2018 is encouraging, but their motivation could take a while to manifest itself. Equally, the traditional view of energy security and carbon accounting should be flexed to recognise that biomethane imported from neighbouring countries could have merit.

Green gas tariffs are emerging in the UK, though muddied by those utilising carbon offsets that do not strengthen UK energy security. It is clear that the subsidisation of relatively-costly biomethane certificates varies by supplier, and some are charging disproportionately more. Consumer awareness is a challenge, though greater levels were not necessarily what expanded other renewable sectors. The likely more practical alternative is to expand demand through emulation of the supplier mandates that compel them to source renewable electricity and liquid biofuels, in combination with greater promotion of officially-rated biomethane tariffs.

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