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Department of Energy and Climate Change

ANALYSIS OF CHARACTERISTICS AND GROWTH ASSUMPTIONS REGARDING AD BIOGAS COMBUSTION FOR HEAT, ELECTRICITY AND TRANSPORT AND BIOMETHANE PRODUCTION AND INJECTION TO THE GRID

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ANALYSIS OF CHARACTERISTICS AND GROWTH ASSUMPTIONS REGARDING AD BIOGAS COMBUSTION FOR POWER, CHP AND HEAT PRODUCTION AND BIOMETHANE INJECTION TO THE GRID

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1. Introduction

1.1. Background

The Department of Energy and Climate Change (DECC) appointed SKM Enviros and CNG Services Ltd in 2011 to undertake a review and analysis of the Anaerobic Digestion (AD) biogas and biomethane costs and technology characteristics in the area of combustion for renewable heat/electricity generation as well as clean up/upgrade for injection to the grid (Biomethane to Grid) and use in transport. This included the review of information currently available to DECC as well as additional information available through the Renewable Heat Incentive consultation in order to improve the evidence base underpinning the assumptions on the characteristics of these technologies.

AD is defined as the production of renewable energy by harnessing the biogas released when bacteria breakdown organic matter (such as food waste, livestock slurries, sewage sludge or crops). This methane-rich gas can be combusted directly to generate heat and power. It can also be cleaned up and injected into the gas grid or used as a transport fuel. As well as the biogas, the process produces a nutrient rich "digestate" suitable for use as a fertilizer, so replacing a product normally manufactured from fossil fuels.

AD could make a significant contribution to tackling climate change and meeting wider environmental objectives, including:

- Producing renewable energy
- Increasing energy security
- Displacing natural gas with renewable gas in the gas network
- Reducing methane emissions from landfill and manure management
- Recycling nutrients back to land
- Reducing air and diffuse water pollution

Further information on AD, biogas and digestate can be found at www.biogas-info.co.uk[1]

In the electricity sector AD is currently supported through the Renewables Obligation as well as through the Feed-in Tariffs (FITs) for small-scale generation (below 5MWe).

The Energy Act 2008 provided powers to Government to support the production of heat from on-site combustion of the biogas produced by AD as well as the injection of biomethane to a gas grid network. Proposed support levels for these two activities were published in the *Renewable Heat Incentive Consultation* (February 2010).

The underlying purpose of the study was to support ongoing policy developments where AD is a pertinent technology through the development of a database on biogas costs and build rate assumptions that are consistent across all three sectors where biogas can potentially be used – heat, electricity and transport. The study builds on DECC's existing database (and other external studies) on the characteristics, costs and potential growth rates associated with the uptake of

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[1] The website is an information portal on AD supported by Government following recommendations by the Government's Anaerobic Digestion Task Group

biogas and biomethane injection across the heat sector while also reviewing the technology characteristics for electricity generation to ensure consistency of assumptions.

Technical support was provided to DECC and their economic consultants (NERA) on the determination of the tariffs for biomethane injection to the grid (BtG) as well as biogas combustion for heat (through dedicated heat boilers)' and combined heat and power (CHP) plants. The study was broken into three distinct areas:

1) Analysis of biogas combustion and biomethane injection costs and other characteristics
2) Analysis of potential growth rates of biogas uptake between now and 2030 and related costs/learning rates
3) Advice on the use of evidence for the setting of support levels for renewable heat and biomethane injection to the grid

In order to facilitate this project DECC provided all information available to date, including stakeholder feedback received as part of the Renewable Heat Incentive (RHI) Consultation, international experience and where possible data gathered by other Government bodies such as WRAP and DEFRA.

In reviewing the evidence SKM Enviros consulted with different teams across DECC with an interest in biogas (including economists, scientists and policy teams), other Government bodies, publicly available information and stakeholder feedback.

SKM Enviros also worked closely with NERA, the suppliers of the economic modelling of the RHI for DECC throughout this project in order to provide assumptions to be used for RHI tariff modelling work.

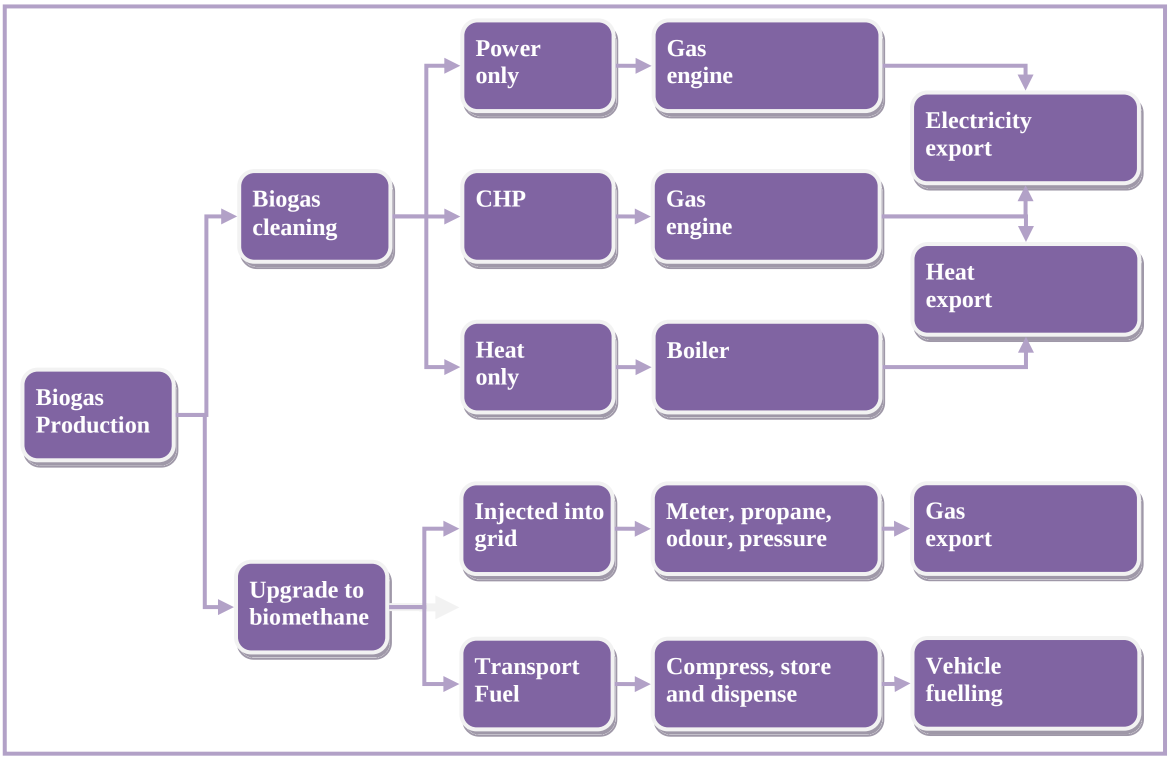
1.1.1. Analysis of biogas combustion and biomethane injection costs and other characteristics

A database was compiled on the costs and characteristics relating to the technology options for biogas utilisation (illustrated in the figure overleaf). The database covered the following elements of a facility:

- Capex for all elements of the process – digester, clean-up, boiler, combustion, gas storage etc
- Opex and other recurring costs
- Efficiencies, load factors etc
- Lifetime expectancies of key elements of the plant
- Feedstock prices

The data was used to model costs and characteristics to cover all scales and configurations at which relevant plants are likely to come forward leading up to 2030 across all options.

▪ **Figure 1: Technology options**



1.1.2. Analysis of potential growth rates of biogas uptake between now and 2030 and related costs/learning rates

The project analysed the potential growth of biogas combustion and biomethane injection to the grid from now to 2030; using three parameters:

1) The availability of feedstock for different processes - this information was provided to SKM from DECC and analysis commissioned by DECC by AEA. The report is currently being finalised prior to publication
2) The potential build rates of AD plants
3) The potential build rates of plant/injection points able to use the biogas from AD processes

Three growth rate scenarios were developed based on:

- **Low growth:** growth rates representing feasible build rates under current policy and assuming that some basic barriers are overcome
- **Central growth:** growth rates which represent realistic potential provided certain key deployment barriers are overcome (other than feedstock availability and financial support)
- **High Growth:** assumes a more optimistic development than the central growth scenario, but lower growth than a maximum build rate scenario that could be expected in the sector which assumes that all barriers are overcome

The assumptions about which barriers are relevant in each of these scenarios are described in detail in the report and appendix The plant capacity (MW) and renewable energy output (TWh) of total biogas production were calculated for the following segments:

- Heat only production through biogas combustion
- Power (electricity) only through biogas combustion
- CHP production through biogas combustion
- Biomethane production through biogas upgrading and injection to the grid
- Biomethane production through biogas upgrading and use for transport

Each segment was also broken down by size of biogas plant (MW of continuous thermal output of the total raw biogas produced before its utilisation) in bands agreed with DECC.

In developing these scenarios, SKM reviewed existing information, consulted with different teams across DECC and other Government bodies and used data from international experience in this sector.

1.1.3. Advice on the use of evidence for the setting of support levels for renewable heat and biomethane injection to the grid

In this third element of the study, SKM worked with DECC and NERA to provide support on the use of the findings in developing RHI tariffs, specifically on the following elements:

- Different RHI tariffs across different plant sizes
- Selection methodology and resulting RHI tariff

2. Costs database and modelling

2.1. Introduction

As described in section one, a cost database was developed for biogas production and utilisation technology options. The study explored in detail the costs associated with biogas production, combustion for heat and/or power production and the upgrading of biogas into biomethane for injection into the natural gas grid or compression into vehicle fuel.

2.2. Methodology

2.2.1. Technology options

As described in section 1.1.1, the technology options explored were as follows:

- Biogas generation: the provision of an anaerobic digestion plant to convert organic substrates into biogas (including biogas clean-up to remove hydrogen sulphide).
  - On-farm facilities are defined as those capable of processing crop residues, energy crops and animal manures and slurries
  - Waste plants are defined as those capable of processing food waste, including separation/sorting plant to remove plastic, metal and glass packaging materials
- Biogas combustion for heat only production: provision of boiler to produce heat (hot water and/or steam) and hot water/steam distribution system.
- Biogas combustion for power (electricity) only production: provision of gas fuelled reciprocating engine (gas engine) to produce power and infrastructure required to export power to the electrical distribution network.
- Biogas combustion for heat and power production: provision of gas fuelled reciprocating engine (gas engine) to produce power and infrastructure required to export power to the electrical distribution network, as well as heat capture and hot water/steam distribution system (e.g. district heating system).
- Biogas upgrading into biomethane: the provision of plant to remove carbon dioxide and other unwanted gases from the biogas to produce gas with a methane content to ≥97% (biomethane) that meets the required natural gas standards (e.g. water and oxygen content) to be injected to the grid or used for transport.
- Biomethane to grid (BtG) injection – the provision of plant to meter the energy content of the biomethane, add propane to increase energy density (Wobbe number/index) where necessary, add an odorant for end-user safety, and regulate pressure to match the point of injection.

2.2.2. Data collection and analysis

The cost data that was used throughout this study was obtained from a number of sources including:

- In-house cost data provide by SKM Enviros and CNG Services based on previous project work
- RHI Consultation responses

- Publicly available information from other organisations (e.g. NFCC[2], DECC) and publications

Data was input into a spreadsheet database (using Microsoft Excel) recording cost and other parameters, such as scale of plant (MW biogas input or energy output, tonnes per annum etc.), conversion efficiencies (e.g. conversion of biogas energy content input into heat and/or power output or biomethane), plant availability (e.g. hours of operation per annum or %).

This database allowed for the data to be summarised into tables showing minimum, maximum, and average values for different costs (CAPEX, OPEX, maintenance etc.) and characteristics over different scales.

2.2.3. Cost modelling

As expected, no single reference provided data for all potential combinations of technologies at all scales. Therefore, data was used to model costs and characteristics of different technology combinations at different scales.

In terms of technology application, two key factors have arisen from the analyses that influence the cost of biogas production and utilisation technology:

- Economies of scale
- Type of substrate used to produce biogas

Economies of Scale

In simple terms, the specific costs per unit energy production (e.g. £/MW) for biogas production and utilisation increased significantly with decreasing plant size.

To model this effect, a set of equations was used to define CAPEX and OPEX costs for different key items of plant items for biogas production and utilisation (e.g. digester, gas engine, upgrading etc.). A specific equation was developed for each item of plant to fit the majority of real costs gathered during data collection and analysis.

The equations are based on a known cost for a known scale of plant (A) and a constant (N) that gives a non-linear change in cost with change in scale (B) to reflect economies of scale. An example is provided below:

Equation 1:

$$\text{CAPEX} = \text{CAPEX of plant A} \times (\text{scale of plant B}/\text{scale of plant A})^{N}$$

For example, if the CAPEX of a known AD plant (excluding gas engine) is £7m for a plant with a capacity of 10000 tonnes of dry matter per annum, then a plant with a capacity of 20000 tonnes of dry matter per annum will cost:

Equation 2:

$$\text{CAPEX} = £7\text{m} \times (20000/10000)^{0.6}$$
$$= 7 \times 2^{0.6}$$
$$= 7 \times 1.5$$
$$= £10.6\text{m}$$

[2] National Non Food Crop Centre

For example, if a the CAPEX of a known AD plant (excluding gas engine) is £7m for a plant with a capacity of 10000 tonnes of dry matter per annum, then a plant with a capacity of 5000 tonnes of dry matter per annum will cost:

Equation 3:

$$\begin{aligned} CAPEX &= £7m \times (5000/10000)^{0.6} \\ &= 7 \times 0.5^{0.6} \\ &= 7 \times 0.66 \\ &= £4.6m \end{aligned}$$

For other plant items different units depicting scale were used as appropriate (e.g. CAPEX for gas engines based on electrical output - £/MWe; CAPEX for boilers based on heat output - £/MWth; biogas upgrading equipment based on biogas input - £/m^3/h).

Type of substrate

In addition to economies of scale, the production of biogas from different technologies and feedstock will result in different yield rates. A range of potential substrates exist for the production of biogas, including:

- **Agricultural (residues):** animal manure/slurry, crop residues, grass/silage and energy crops (e.g. maize)
- **Waste:** municipal and commercial/industrial (e.g. source-separated food/by-products)
- **Other substrates:** sewage sludge and landfill gas from landfilled mixed waste

These different substrates influence costs in a number of ways:

- Biogas and methane yield per unit mass and volume

Different substrates produce different biogas and methane yields. For example, due to its low dry matter content and the fact it had already undergone digestion in the gut of an animal slurry has a low biogas potential. A much larger quantity and volume of animal slurry is required to generate the same amount of energy than food waste or energy crop. Therefore, a larger volume of material must be processed requiring increased infrastructure (e.g. digester tank volume).

The yield rates of a range of substrates and methane content are shown in the table below. It is clear that different substrates produce varying quantities of biogas. Overall slurry and sewage produces the least biogas/methane; energy crops and food waste have the biogas/methane production potential.

- **Table 1: Indicative biogas and methane yields of different substrates (averages)[3]**

Substrate	Specific Methane Yield m^3/t	Specific Biogas Yield m^3/t
Animal slurry	13.7	26.7
Animal manure	39.8	70
Food waste	76.0	125
Energy crop	104.5	185.5
Sewage	12.1	21
Landfill Gas	50	100

- **Substrate processing required**

There is a variation in costs associated with processing the different feedstock. For example process food waste, such as packaged food waste which may require costly upfront sorting and separation equipment to remove biodegradable food from non-biodegradable packaging materials. Any packaging removed that cannot be recycled must be disposed of at cost.

Furthermore, if food waste contains materials defined as animal by-products in the Animal By-Products Regulations (ABPR) it will require this material to be received and handled inside an enclosed building and heat-treated to remove potential pathogens. As a result, while the potential exists for greater biogas production from such organic waste the cost of exploiting such organic waste is relatively high compared to other substrates, such as animal slurry, that require little or no pre-treatment.

- **Gate-fee versus substrate production cost**

At present, biogas plants using food waste as a substrate can charge a 'gate fee' to treat food waste. Based on the consultation process and SKM Enviros commercial knowledge of the waste market the current gate fees for the disposal of food waste have been estimated to range from £37/t to £54/t, thus an average gate fee of £46/t was used. This is an important revenue stream for waste fuelled biogas plants, which, as discussed above, incur additional costs to those not processing other substrates.

The long term existence of the gate fee cannot be guaranteed and it is extremely difficult to predict how gate fees will change over future years. Gate fees will potentially decrease with increased demand/competition for waste contracts by existing and new waste facilities. The price of energy will also influence biogas plant gate fees. For example, increasing energy values will offset the need for gate fee and result in a reduction in gate fees. It is also important to note that quality (contamination content) of waste will have a major effect. Highly contaminated waste will require increased processing and lead to increased processing and disposal costs. The gate fees of local competing waste treatment technologies (e.g. composting, mechanical biological treatment, energy from waste, landfill) will also influence the gate fees that can be commanded by biogas facilities.

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[3] The biogas yield rate from landfill is dependent upon a number of factors including age of site, composition of waste deposited and engineering of landfill. A reasonable value of biogas generated would be approximately 5-10m^3 per tonne of Municipal Solid Waste (MSW). For the modelling purposes the yield rate is based on the "digestible" organic fraction.

Other substrates, such as animal manure/slurry, were assumed to be cost neutral (£0/t) and this was the consensus of RHI consultation respondents.

Energy crops (which include grass silage as well as maize) ranged in cost to produce/purchase from £16/t to £27.5/t; a figure of £24.5/t was used, derived from the data collected.

Other costs/revenues and prices

Other costs included labour which was estimated using an assumption of the number of full time employees (FTE) required related to the amount of substrate processed.

- **Table 2 Costs and Revenues estimates for projects**

Cost / Revenue (price)	Value	Unit
Electricity import cost (gross)	100	£/MWh
Electricity export price	30	£/MWh
Natural gas cost	13.6	£/MWh
Net Propane cost*	20.5	£/MWh
Labour cost	30,000	£/FTE
Heat export price/saving	34	£/MWh
Landfill gate-fee	60	£/t
Landfill Tax	48	£/t
Digestate cost: food waste	2	£/t
Digestate cost: all other substrates	0	£/t

*Full propane price of £34.1/MWh minus Natural Gas price of £13.6/MWh

2.2.4. Technology characteristics and other key parameters

In addition to cost data collection and modelling, key characteristics were also collected and modelled to provide values for ultimate energy production and utilisation.

The energy content of biogas

The energy content of biogas produced was calculated using the methane content solely. The energy content of methane was estimated to be 50.1 MJ/kg (lower heating/calorific value for methane) or 35.9 MJ/m^3, which equates to 9.96 kWh/m^3.

Energy conversion efficiency

Energy conversion efficiency of different technologies relates to the amount of the energy contained in the biogas converted into thermal or electrical energy or biomethane. The following availability figures were used:

■ **Table 3: Energy conversion efficiency values**

Plant	Scale of biogas generated MW	Electrical % of input	Thermal % of input
Gas engine	0.5	31%	35%
	1.0	33%	38%
	2.0	36%	40%
	3.0	37%	42%
	5.0	39%	44%
Boiler	All	-	85%
Biogas upgrading plant*	All	-	98%
District heating network	All	-	90%

** Methane capture rate*

Plant availability

Plant availability relates to the amount of time the plant is operational per year. The following availability figures were used:

■ **Table 4: Plant availability values**

Plant	Availability % of year	Availability hours per year
Digester	100%	8760
Gas engine	93%	8147
Boiler	95%	8322
Biogas upgrading plant	93%	8147
Plant	**Availability % of year**	**Availability hours per year**
Digester	100%	8760
Boiler	95%	8322
Biogas upgrading plant	93%	8147

2.3. Technology Options Modelled

The following technology scales and types were modelled.

- **Table 5: Biogas plant types and scales**

Scale (MW of biogas generated)	Plant types	Scheme: biogas utilisation
0.05, 0.10, 0.25, 0.5	Farm	Heat only Biomethane to Grid
1.0, 2.0, 3.0, 5.0	Waste Sewage	Heat only Biomethane to Grid Power Only CHP
1.0, 3.0, 5.0	Energy Crop	
1.00	Sewage	Biomethane to Grid
3.00	Landfill	

2.3.1. Scale

The scale of each plant refers to the energy content of the biogas produced on a continuous basis. For example, a 0.5MW plant would be producing biogas continuously with an energy content of approximately 50m^3/h of methane; with methane having an energy content of approximately 10kWh/m^3.

2.3.2. Plant type

The biogas utilisation schemes are defined as follows:

Farm: this is defined as a biogas plant sited at a farm whereby the substrates used to generate biogas are sourced from the farm and/or its neighbours. The substrates processed have been modelled on 60% animal slurry and 40% energy crop (e.g. maize silage, grass or similar).

Waste: this is defined as a biogas plant sited at any suitable location whereby the substrates used to generate biogas are source-segregated food/catering waste from local food waste producers (e.g. householders and commercial and industrial sources).

Energy crop: this is defined as a biogas plant sited at any suitable location whereby the substrates used to generate biogas are energy crops (e.g. maize silage, grass or similar) grown or purchased by the operator. The substrates modelled are 30% animal slurry and 70% energy crop.

Sewage: this is defined as a biogas plant sited at any suitable waste water treatment works whereby the substrates used to generate biogas are sewage treated by the site operator. The substrates processed in the modelling are 100% slurry.

Landfill: this is defined as the capture and utilisation of landfill gas at any suitable landfill site whereby the substrates used to generate biogas are biodegradable waste placed in the landfill.

2.3.3. Scheme: biogas utilisation

This part of the project focused on the following biogas utilisation schemes:

Heat only: biogas is combusted in a boiler to produced heat energy in the form of hot water or steam; this heat is then distributed to a heat user via heat storage and distribution (district heating) system; heat required by the biogas plant (e.g. waste pasteurisation and heat the digester tank) is supplied by the same boiler.

Power only: biogas is combusted in a reciprocating gas engine to drive a dynamo/alternator to produce electricity which is exported to the local distribution network; heat energy is produced in the form of hot water coming from the engines cooling system; this hot water is used to supply the heat required by the biogas plant.

CHP (combined heat and power): biogas is combusted in a reciprocating gas engine to drive a dynamo/alternator to produce electricity which is exported to the local distribution network; heat energy is produced in the form of hot water coming from the engines cooling system; further heat can be captured using heat exchangers to capture heat from the engine exhaust; hot water and/or steam is then distributed to a heat user via heat storage and distribution (district heating) system; heat required by the biogas plant is supplied by the same heat source.

BtG (biomethane to grid): biogas is upgraded to biomethane using Pressure Swing Absorption (PSA) or similar technology to remove of carbon dioxide and other unwanted gases, such as, hydrogen sulphide; the biomethane is then injected into the local gas grid to current Gas Safety (Management) Regulations, 1996 ("GS(M)R"), i.e. the energy density (and other components) of the biomethane is metered/monitored, the biomethane is enriched with propane if required; an odorant is added; and the pressure regulated to that required by the point of injection to the grid; the heat required by the biogas plant is supplied by a boiler powered using some of the biogas produced; electricity to power the plant is imported.

BtT (biomethane to transport fuel): biogas is upgraded to biomethane using Pressure Swing Absorption (PSA) or similar technology to remove of carbon dioxide and other unwanted gases, such as, hydrogen sulphide; the biomethane is then compressed into a vehicle fuel and stored in appropriate containers (250bar tank cascade) ready for vehicle refuelling via a dispenser/fuelling station; the heat required by the biogas plant is supplied by a boiler powered using some of the biogas produced; electricity to power the plant is imported. There are many other potential options, such as, injecting biomethane to the grid and taking gas from the grid at a different location and compressing it into fuel, but, for simplicity, the option described above was modelled. **Further details on biomethane to transport fuel are provided in Appendix B.**

2.4. Modelling results

Table 6 to 12, below show the CAPEX and OPEX modelled for the technology options using the methodology described above.

2.4.1. CAPEX

CAPEX for the digester (biogas production) plant is significantly less for the 'farm' style facility (which includes energy crops) than 'waste' facilities. This is a reflection of additional infrastructure required by waste facilities to process food waste (i.e. remove packaging and other contamination and comply with animal by-products regulations).

All other plant and equipment costs are based on the amount of biogas produced and/or the energy contained within it and reflects economies of scale described above.

2.4.2. OPEX

OPEX comprises a number of costs including maintenance of plant and equipment (usually represented by a % of the CAPEX expended annually). In a similar approach to that used for CAPEX, maintenance costs were also calculated reflect economies of scale described above. Other costs (as described above) covered consumables (propane) and utilities (electricity) and other direct costs.

■ **Table 6: CAPEX: biogas plant types and scales: heat only**

REFERENCE		SCALE				CAPEX			
Type	Scheme	Gross biogas output	Net electric output equiv.	Net heat output equiv.	Net bio-methane output equiv.	Base digester	Other	Boiler	Total
	Units	MW	kW_e	kW_{th}	kW_{th}	£m	£m	£m	£m
Farm	Heat	0.05	10.0	32.0	42.0	0.3	0.0	0.0	0.3
Farm	Heat	0.1	22.0	64.0	85.0	0.4	0.0	0.0	0.5
Farm	Heat	0.3	62.0	163.0	216.0	0.7	0.1	0.0	0.8
Farm	Heat	0.5	135.0	331.0	436.0	1.0	0.2	0.0	1.2
Waste	Heat	1.0	265.0	654.0	865.0	3.2	0.3	0.1	3.5
Waste	Heat	2.0	586.0	1323.0	1746.0	4.8	0.5	0.1	5.4
Waste	Heat	3.0	931.0	1997.0	2632.0	6.1	0.7	0.1	6.9
Waste	Heat	5.0	1664.0	3353.0	4411.0	8.4	1.1	0.1	9.5
E. Crop	Heat	1.0	298.0	676.0	888.0	1.5	0.3	0.1	1.8
E. Crop	Heat	3.0	1021.0	2055.0	2692.0	2.9	0.7	0.1	3.6
E. Crop	Heat	5.0	1806.0	3445.0	4507.0	3.9	1.1	0.1	5.0
Sewage	Heat	1.0	274.0	612.0	822.0	1.1	0.3	0.1	1.4
Landfill	Heat	3.0	1112.0	2295.0	2940.0	0.0	0.8	0.1	0.9

Table 7: CAPEX: biogas plant types and scales: CHP

REFERENCE		SCALE				CAPEX							
Type	Scheme	Gross biogas output	Net electric output equiv.	Net heat output equiv.	Net bio-methane output equiv.	Base digester	Up-grading	Bio-methane Injection and metering	Fuel compress, store and dispenser	Gas engine	Other	Boiler	Total
	Units	MW	kW_e	kW_{th}	kW_{th}	£m	£m	£m	£m	£m	£m	£m	£m
Farm	CHP	0.05	10.0	6.0	42.0	0.3				0.0	0.0		0.3
Farm	CHP	0.1	22.0	14.0	85.0	0.4				0.0	0.0		0.5
Farm	CHP	0.3	62.0	45.0	216.0	0.7				0.1	0.1		0.8
Farm	CHP	0.5	135.0	104.0	436.0	1.0				0.1	0.1		1.3
Waste	CHP	1.0	265.0	224.0	865.0	3.2				0.3	0.2		3.6
Waste	CHP	2.0	586.0	511.0	1746.0	4.8				0.5	0.3		5.7
Waste	CHP	3.0	931.0	824.0	2632.0	6.1				0.8	0.5		7.4
Waste	CHP	5.0	1664.0	1498.0	4411.0	8.4				1.3	0.7		10.3
E. Crop	CHP	1.0	298.0	246.0	888.0	1.5				0.3	0.2		1.9
E. Crop	CHP	3.0	1021.0	884.0	2692.0	2.9				0.8	0.5		4.1
E. Crop	CHP	5.0	1806.0	1592.0	4507.0	3.9				1.3	0.7		5.9
Sewage	CHP	1.0	274.0	181.0	822.0	1.1				0.3	0.2		1.5
Landfill	CHP	3.0	1112.0	1129.0	2940.0	0.0				0.8	0.6		1.3

Table 8: CAPEX: biogas plant types and scales: power only

REFERENCE		SCALE				CAPEX							
Type	Scheme	Gross biogas output	Net electric output equiv.	Net heat output equiv.	Net bio-methane output equiv.	Base digester	Up-grading	Bio-methane Injection and metering	Fuel compress, store and dispenser	Gas engine	Other	Boiler	Total
	Units	MW	kW_e	kW_{th}	kW_{th}	£m	£m	£m	£m	£m	£m	£m	£m
Farm	Power	0.05	10.0	6.0	42.0	0.3				0.0	0.0		0.3
Farm	Power	0.1	22.0	14.0	85.0	0.4				0.0	0.0		0.4
Farm	Power	0.3	62.0	45.0	216.0	0.7				0.1	0.0		0.8
Farm	Power	0.5	135.0	104.0	436.0	1.0				0.1	0.0		1.2
Waste	Power	1.0	265.0	224.0	865.0	3.2				0.3	0.1		3.5
Waste	Power	2.0	586.0	511.0	1746.0	4.8				0.5	0.1		5.4
Waste	Power	3.0	931.0	824.0	2632.0	6.1				0.8	0.1		7.0
Waste	Power	5.0	1664.0	1498.0	4411.0	8.4				1.3	0.1		9.8
E. Crop	Power	1.0	298.0	246.0	888.0	1.5				0.3	0.1		1.8
E. Crop	Power	3.0	1021.0	884.0	2692.0	2.9				0.8	0.1		3.7
E. Crop	Power	5.0	1806.0	1592.0	4507.0	3.9				1.3	0.1		5.3
Sewage	Power	1.0	274.0	181.0	822.0	1.1				0.3	0.1		1.4
Landfill	Power	3.0	1112.0	1129.0	2940.0	0.0				0.8	0.1		0.9

Table 9: CAPEX: biogas plant types and scales: biomethane to grid (BtG)

REFERENCE		SCALE				CAPEX					
Type	Scheme	Gross biogas output	Net electric output equiv.	Net heat output equiv.	Net bio-methane output equiv.	Base digester	Up-grading	Bio-methane Injection and metering	Other	Boiler	Total
	Units	MW	kW_e	kW_{th}	kW_{th}	£m	£m	£m	£m	£m	£m
Farm	BTG	0.05	10.0	6.0	42.0	0.3	0.1	0.5	0.1	0.0	1.0
Farm	BTG	0.1	22.0	14.0	85.0	0.4	0.2	0.6	0.1	0.0	1.3
Farm	BTG	0.3	62.0	45.0	216.0	0.7	0.3	0.6	0.1	0.0	1.7
Farm	BTG	0.5	135.0	104.0	436.0	1.0	0.4	0.7	0.2	0.0	2.3
Waste	BTG	1.0	265.0	224.0	865.0	3.2	0.5	0.7	0.2	0.0	4.6
Waste	BTG	2.0	586.0	511.0	1746.0	4.8	0.8	0.8	0.2	0.0	6.5
Waste	BTG	3.0	931.0	824.0	2632.0	6.1	1.0	0.8	0.2	0.0	8.1
Waste	BTG	5.0	1664.0	1498.0	4411.0	8.4	1.2	0.8	0.2	0.0	10.6
E. Crop	BTG	1.0	298.0	246.0	888.0	1.5	0.6	0.7	0.2	0.0	2.9
E. Crop	BTG	3.0	1021.0	884.0	2692.0	2.9	1.0	0.8	0.2	0.0	4.8
E. Crop	BTG	5.0	1806.0	1592.0	4507.0	3.9	1.3	0.8	0.2	0.0	6.2
Sewage	BTG	1.0	274.0	181.0	822.0	1.1	0.6	0.7	0.2	0.0	2.5
Landfill	BTG	3.0	1112.0	1129.0	2940.0	0.0	1.1	0.8	0.2	0.0	2.1

■ **Table 10: OPEX: biogas plant types and scales: heat only**

REFERENCE		SCALE	OPEX							
			Maintenance		Other					Total
Type	Scheme	Gross biogas output	Base digester	Boiler	Elec-tricity	Pro-pane	Labour	Insur-ance	Land-fill	
	Units	MW	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a
Farm	Heat	0.05	6	1	2	0	2	3	0	14
Farm	Heat	0.1	9	1	4	0	3	5	0	22
Farm	Heat	0.3	14	2	9	0	8	8	0	41
Farm	Heat	0.5	21	3	16	0	16	12	0	67
Waste	Heat	1.0	90	3	55	0	43	35	143	368
Waste	Heat	2.0	130	4	102	0	86	54	285	662
Waste	Heat	3.0	162	5	147	0	129	69	428	940
Waste	Heat	5.0	214	6	233	0	215	95	714	1476
E. Crop	Heat	1.0	28	3	28	0	27	18	0	105
E. Crop	Heat	3.0	51	5	74	0	82	36	0	249
E. Crop	Heat	5.0	68	6	117	0	137	50	0	378
Sewage	Heat	1.0	21	3	47	0	67	14	0	152
Landfill	Heat	3.0	0	5	0	0	0	9	0	13

Table 11: OPEX: biogas plant types and scales: CHP

REFERENCE		SCALE	OPEX											
			Maintenance						Other					Total
Type	Scheme	Gross biogas output	Base digester	Up-grading	Bio-methane Injection and metering	Fuel compress, store and dispenser	Gas engine	Boiler	Elec-tricity	Pro-pane	Labour	Insur-ance	Land-fill	
	Units	MW	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a
Farm	CHP	0.05	6	0	0	0	8	0	0	0	2	3	0	18
Farm	CHP	0.1	9	0	0	0	11	0	0	0	3	5	0	28
Farm	CHP	0.3	14	0	0	0	20	0	0	0	8	8	0	50
Farm	CHP	0.5	21	0	0	0	30	0	0	0	16	13	0	79
Waste	CHP	1.0	90	0	0	0	45	0	0	0	43	36	143	356
Waste	CHP	2.0	130	0	0	0	67	0	0	0	86	57	285	625
Waste	CHP	3.0	162	0	0	0	86	0	0	0	129	74	428	878
Waste	CHP	5.0	214	0	0	0	116	0	0	0	215	103	714	1361
E. Crop	CHP	1.0	28	0	0	0	45	0	0	0	27	19	0	119
E. Crop	CHP	3.0	51	0	0	0	86	0	0	0	82	41	0	260
E. Crop	CHP	5.0	68	0	0	0	116	0	0	0	137	59	0	379
Sewage	CHP	1.0	21	0	0	0	45	0	0	0	67	15	0	147
Landfill	CHP	3.0	0	0	0	0	86	0	0	0	0	13	0	99

▪ Table 12: OPEX: biogas plant types and scales: power only

REFERENCE		SCALE	OPEX											
Type			Maintenance						Other					Total
	Scheme	Gross biogas output	Base digester	Up-grading	Bio-methane Injection and metering	Fuel compress, store and dispenser	Gas engine	Boiler	Elec-tricity	Pro-pane	Labour	Insur-ance	Land-fill	
	Units	MW	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a
Farm	Power	0.05	6	0	0	0	8	0	0	0	2	3	0	18
Farm	Power	0.1	9	0	0	0	11	0	0	0	3	4	0	27
Farm	Power	0.3	14	0	0	0	20	0	0	0	8	8	0	49
Farm	Power	0.5	21	0	0	0	30	0	0	0	16	12	0	78
Waste	Power	1.0	90	0	0	0	45	0	0	0	43	35	143	355
Waste	Power	2.0	130	0	0	0	67	0	0	0	86	54	285	623
Waste	Power	3.0	162	0	0	0	86	0	0	0	129	70	428	875
Waste	Power	5.0	214	0	0	0	116	0	0	0	215	98	714	1356
E. Crop	Power	1.0	28	0	0	0	45	0	0	0	27	18	0	118
E. Crop	Power	3.0	51	0	0	0	86	0	0	0	82	37	0	256
E. Crop	Power	5.0	68	0	0	0	116	0	0	0	137	53	0	373
Sewage	Power	1.0	21	0	0	0	45	0	0	0	67	14	0	146
Landfill	Power	3.0	0	0	0	0	86	0	0	0	0	9	0	94

Table 13: OPEX: biogas plant types and scales: biomethane to grid (BtG)

REFERENCE		SCALE	OPEX								
			Maintenance			Other					Total
Type	Scheme	Gross biogas output	Base digester	Up-grading	Bio-methane Injection and metering	Elec-tricity	Pro-pane	Labour	Insur-ance	Landfill	
	Units	MW	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a	£k/a
Farm	BtG	0.05	6	3	40	2	1	2	10	0	64
Farm	BtG	0.1	9	6	40	4	3	3	13	0	77
Farm	BtG	0.3	14	14	40	9	7	8	17	0	109
Farm	BtG	0.5	21	26	40	16	15	16	23	0	156
Waste	BtG	1.0	90	44	40	55	29	43	46	143	490
Waste	BtG	2.0	130	83	40	102	59	86	65	285	851
Waste	BtG	3.0	162	121	40	147	89	129	81	428	1197
Waste	BtG	5.0	214	192	40	233	149	215	106	714	1862
E. Crop	BtG	1.0	28	49	40	28	30	27	29	0	231
E. Crop	BtG	3.0	51	133	40	74	91	82	48	0	519
E. Crop	BtG	5.0	68	211	40	117	152	137	62	0	787
Sewage	BtG	1.0	21	50	40	47	28	67	25	0	278
Landfill	BtG	3.0	0	159	40	0	99	0	21	0	319

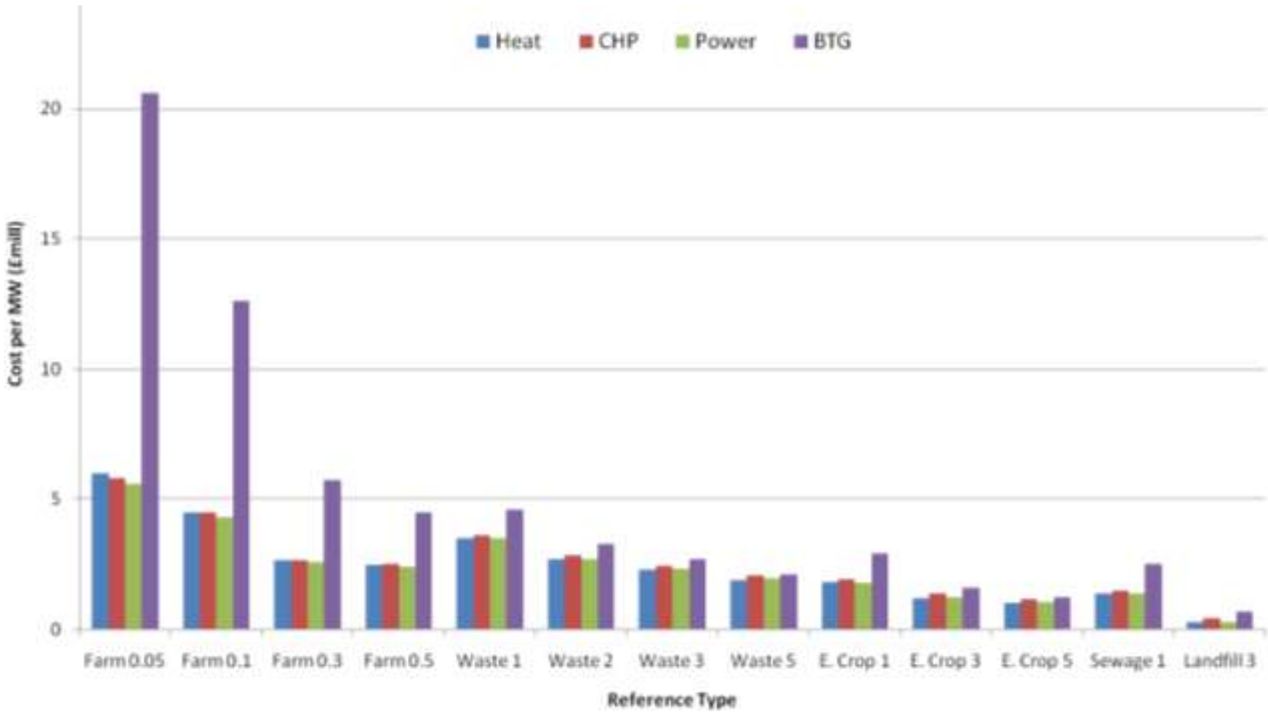
2.5. Cost implications

The technology costs outlined above (in addition to technical factors, revenue and other costs) were utilised by NERA to establish total project costs and assessment of tariff options. In terms of summarising the capital and operating costs alone it should be noted that there is a wide variation in project/technology configuration that influences significantly the viability of an AD project development. For example the influence of feedstock cost and quality will have a direct impact on technology options and revenues, which cannot be modelled at this level of analysis. It should also be noted that whilst showing the capital and operating costs it does not give a true value on a project as external factors such as feedstock costs, revenues and enabling works have not been captured in the tables.

Economies of scale is a key feature for capital costs of anaerobic digestion projects, for example, based on a normalised cost per MW of biogas generated on-farm systems less than 0.1 have higher costs per MW compared to the other reference plants. The same pattern is shown for the waste and energy crops, where smaller capacity plants exhibit higher capital costs per MW generated. In addition waste plants experience higher costs than crops due to pretreatment technology requirements for the feedstock preparation.

Landfill has low capex requirements due to the assumption that the landfill is operating, thus the landfill (and supporting infrastructure) itself does not in any way form part of the costs modelled.

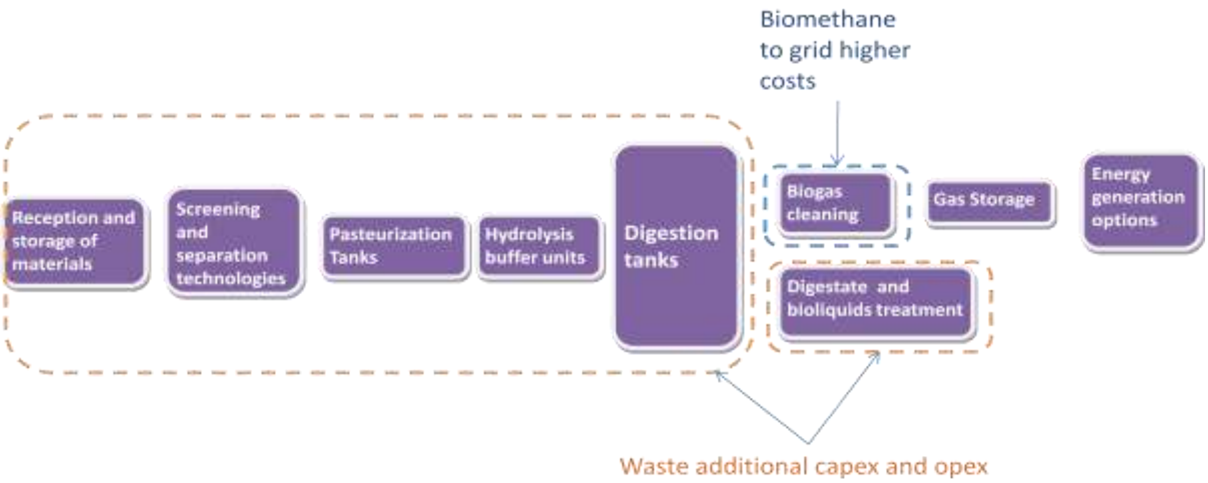
- **Figure 2 Normalised capex per MW biogas generated for the referenced facilities modelled[4]**



[4] Please note that CHP and Power only for small scale on farm plants will technically be very challenging and should be disregarded when reviewing the graphs in figures 2 and 5.

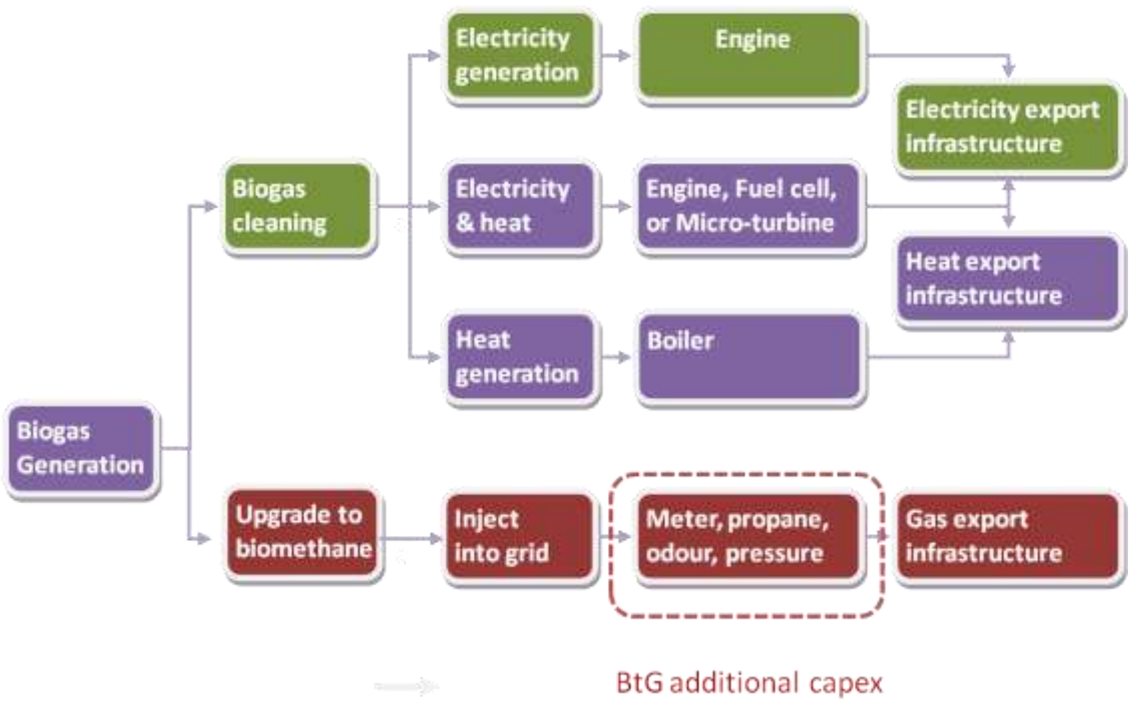
The figure below illustrates where the relatively higher costs are borne for waste projects against crops and on farm plants, whilst also biomethane to grid costs compared to heat and CHP plants.

- **Figure 3 Diagram showing where greater capex will be observed by waste facilities compared to energy plant and on farm**



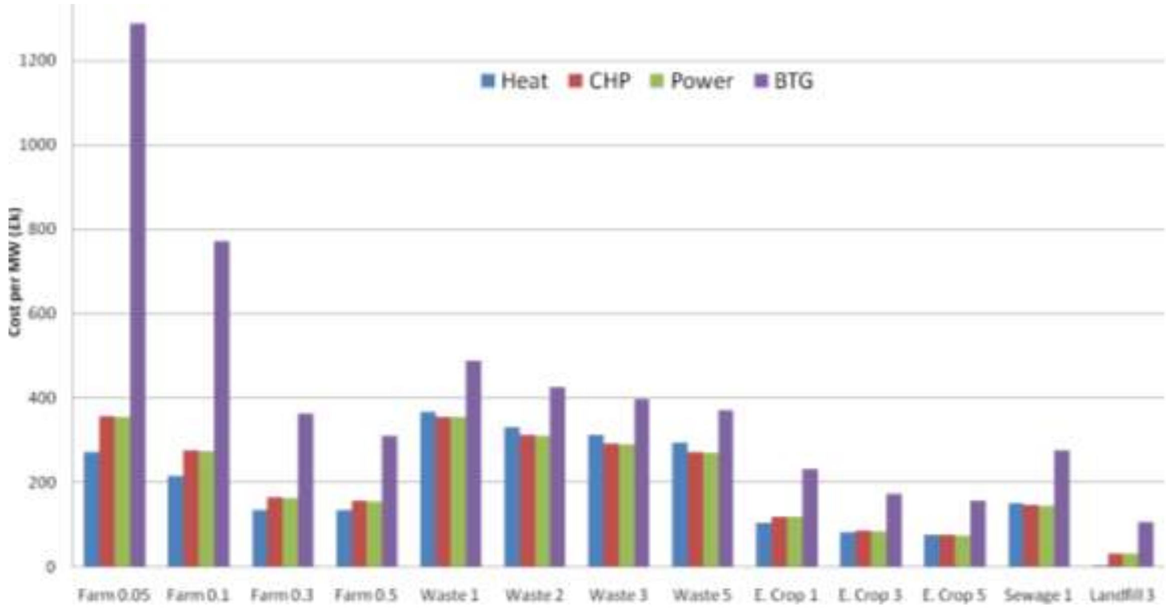
With regards to biogas utilisation options the higher costs for biomethane to grid result from the technologies used for upgrading biogas to biomethane and the integration to the national gas grid.

- **Figure 4 Diagram highlighting where greater capex will be observed by BtG facilities compared heat and power options**



In terms of operating costs this again shows clear economies of scale. CHP and Power only plants show to have a higher cost against heat only, whilst BtG has a significantly greater cost per MW biogas generated largely due to the higher levels of gas clean up required following the digestion process. Waste plants demand higher operational costs than energy and farm plants as a result of higher levels of maintenance, labour costs and a large proportion from disposal costs of wastes generated.

- **Figure 5 Normalised Opex per MW generated for the reference facilities modelled**



It should be noted that the graphs showing the normalised costs represent the biogas generated and not the biogas utilised and efficiencies of the systems. Thus the relative costs for BtG are higher due largely to gas clean up technologies, however it is expected that in the majority of cases the overall efficiencies will be higher in BtG than that of the other options assessed. It is important therefore that when analysing the technologies in more detail this is performed with levelised cost modelling.

3. Growth/uptake rates

3.1. Introduction

As described in section one, growth/uptake estimates were developed for different biogas production and utilisation technology options described previously.

The aim of this study is to create scenarios exploring the potential growth curves for biogas usage in Great Britain (GB). In assessing the potential growth curve of biogas usage a number of key factors were considered that are likely to influence the growth rate of biogas usage in GB, these include:

- The availability of feedstock
- Learning rates (the capacity for the biogas industry to overcome barriers to growth)
- Other factors that may influence growth (e.g. potential build rates of plant, injection points able to use the biogas from AD processes etc.)

The growth scenarios were defined as:

- **Low Growth:** growth rates representing feasible build rates under current policy and assuming that some basic non-financial barriers are overcome
- **Central Growth:** growth rates which represent realistic potential provided certain key deployment barriers are overcome (other than feedstock availability and financial support)
- **High Growth:** assumes a more optimistic development than the central growth scenario, but lower growth than a maximum build rate scenario that could be expected in the sector which assumes that all barriers are overcome.

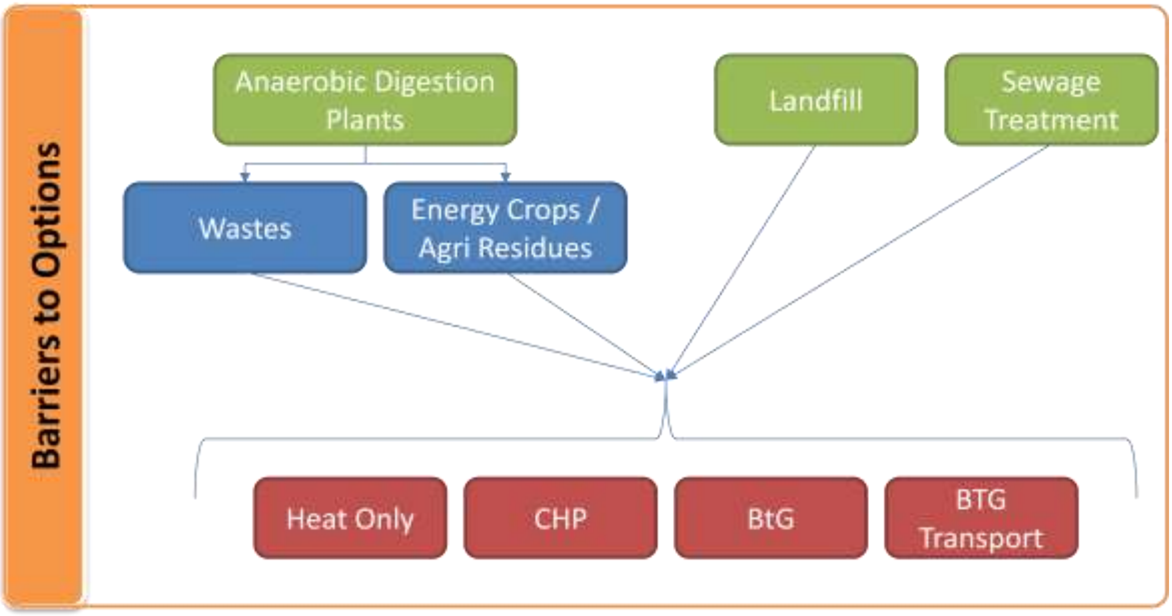
The output from this are estimates of the available energy generated from various technology and substrate configurations and substrates as described below.

3.2. Biogas Sectors

3.2.1. Introduction

Biogas will be generated from a number of sectors as follows: anaerobic digestion of various substrates, sewage treatment, and landfill (see Figure 6); and each biogas sector is described below. Also briefly described are the different biogas utilisation technology options that are available.

Figure 6: Configuration options and structure of initial review of barriers to growth[5]



3.2.2. Anaerobic digestion plants

The Biogas[6] website (NNFCC[7]) states[8] there are 11 off farm plants and 27 on-farm plants in operation, with a further five in commissioning. The capacities of these plants range from heat only small scale on farm to 4.8MW biomethane to grid[9] projects. Through discussions with stakeholders, notably industry and NNFCC, it is our understanding that there are some 60 plants that are consented and in the pre-commissioning period of development. Details of potential plants in the pipeline in earlier development stages, for example detailed feasibility and identifying financing options, are not known.

Exact figures are difficult to obtain due to the varying development phase of the projects, for example construction, commissioning and operational. The recent drive to encourage AD development in the UK has played a key role in the current rate of deployment.

3.2.3. Landfill gas

Landfill gas is the third largest generator of renewable power in the UK (following onshore wind and large hydro[10]) and, like sewage treatment works, represents a significant proportion of biogas

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5 Please note that both transport and electricity are options available to biogas, which are not included in the figure. Transport is however integral to biomethane to grid.

6 The UK's Official Information portal for Anaerobic Digestion (www.biogas-info.co.uk)

7 National Non Food Crop Centre

8 As of November 2010

9 Adnams, Southwold: http://adnams.co.uk/news/environment/adnams-bio-energy-the-first-renewable-gas-to-grid-anaerobic-digestion-plant

10 Dukes 7.4 (2009) capacity of and electricity generated from renewable sources

generated. The Environment Agency is responsible for regulating over 2,000 landfill sites in England and Wales, of these:

- 465 are operational sites with a Landfill Directive compliant permit and so have gas control installed with a likely capacity of in the region of 1MW electrical each.
- 812 sites have stopped taking waste since July 2001, when the Landfill Directive came into effect, and should have gas control through Waste Management Licences (although this may be limited in some cases). Of these sites some may still be producing significant gas, but would generate less than 1MWe, and so presents possibilities for continuing exploitation of biogas options.
- 979 sites stopped taking waste before the Landfill Directive came into effect, but continue to have permits from previous regimes. It is considered that these sites will have limited gas control and engineering, but could potentially present feasible biogas opportunities.

3.2.4. Sewage Treatment

Some 220 water treatment plants have anaerobic digestion facilities for sewage (Defra), which is approximately 66% of sewage sludge, generating in the region of 0.7 TWh of electricity in 2008.

Existing capacity at AD facilities in the waste water sector is limited however in terms of its potential to process food wastes due to its classification as 'non-regulated' materials. The water industry currently applies treated sludge (including digestate) to land under the regime of the Sludge (Use in Agriculture) Regulations, and in line with guidance from the Safe Sludge Matrix (SSM). The introduction of food wastes would result in the digestate falling outside the scope of the SSM, and so land application would require an environmental permit or exemption.

PAS110 and associated Quality Protocol for digestate have been developed by WRAP and the Environmental Agency. Under PAS110 and the Quality Protocol digested substrates that meet the required standards are permitted to be spread to land without a permit or exemption. However, PAS110 does not cover sewage sludge and therefore co-digestion of sewage and food waste would not be covered by PAS110. As a result, existing AD facilities treating sewage would need to invest in reconfiguring their processes to ensure that food waste and sewage were processed separately so that sewage digestate can be spread to land under the Sludge (Use in Agriculture) Regulations and SSM, and food waste digestate under PAS110 and the Quality Protocol.

The introduction of food waste to a sewage digester would also mean the plant would fall under the ABP regulations requiring appropriate sanitization and hygiene procedures. As a result, existing AD facilities treating sewage would need to invest in reconfiguring their processes to ensure they meet these requirements (e.g. reception building for the reception of food waste, pasteurization plant etc.).

In recognition of these commercial and technical issues, there is currently no specific mechanism to promote co-digestion. However, co-location of food waste AD facilities with waste water AD plant is feasible due to potential shared infrastructure, such as grid connections and empty assets (redundant digesters) or under-capacity gas engines.

3.2.5. Technology type and configuration

In addition to the varying sources of biogas, is the wide range of AD technology configurations that may be applied (e.g. heat only, power only, CHP, BtG, biomethane use as transport fuel through BtG). The choice of technology configuration is driven by a number of factors including but not limited to:

- economic viability
- feedstock availability
- competing technologies
- location
- energy requirements
- wider policy drivers (for example waste and agriculture policies).

The breadth of drivers affecting AD technology configuration complicates predictions of technology growth given the subsequent range of influences affecting each of the drivers.

In order to limit the potential complexity surrounding the assessment of future growth curves for biogas we have further segregated by feedstock:

- Energy Crops – crops, such as maize, grass or cereals, grown specifically to generate energy[11]
- Agricultural residues – farm generated feedstocks, such as animal slurries and manures, which can be processed alone or with energy crops
- Waste – incorporating food/catering waste from municipal, commercial and industrial sources, such as, food and drinks manufacturing

3.3. Drivers and barriers to growth

A review of the drivers underpinning the growth of each sector is provided in detail in the Appendices. This outlines the key barriers to development and refers to growth experienced in other countries to show how developments have been achieved.

The drivers that will influence the growth rate of biogas fall into five broad categories:

- The cost of technologies for biogas generation and utilisation
- The cost of alternative energy sources
- Technology barriers
- Other factors that may influence the potential build rates of plant/injection points able to use the biogas from AD processes
- Learning curves
- Each factor is discussed in this paper with specific reference to its influence on deployment of biogas technologies.

The barriers that face the various sectors were principally feedstock, land availability, heat demand and operational expertise. It should be noted however that each sector has key barriers to overcome, for example waste generated by municipal and commercial sectors may require

[11] Please note that the modelling undertaken included maize only

changes to the collection of their materials, AD will be in competition with other treatment technologies and the cost/value of the feedstock is likely to change over time largely due to supply and demand pressures. These issues are complex and where possible have been reviewed and reflected in the modelling accordingly.

3.4. Methodology

A mixture of qualitative and quantitative approaches was taken to derive growth curves for the various biogas technology options.

These approaches were used to plot year on year, the number of biogas plants that could be developed from 2010 up to 2030, under the above mentioned growth scenarios. The number of plants was estimated for each biogas plant type at what were considered to be realistic scales in terms of biogas/energy output assuming financial constraints were overcome.

3.4.1. Qualitative approach

The potential number of biogas plants was estimated through a number of iterative discussions between SKM, CNG Services and other stakeholders, including, RHI consultation responses.

During this approach of iterative discussions and number of tables were developed showing of plant numbers year on year. These tables of plant numbers were developed based on discussions covering the driver and barriers to growth discussed in detail in the Appendices.

To ensure these represented a reasonable estimate of future growth in GB, this was followed by a quantitative approach to estimate growth.

3.4.2. Quantitative approach

As discussed previously, many drivers and barriers will affect the growth of biogas production and utilisation. However, the availability and type of substrate is a key barrier.

AEA Technology Ltd conducted work [12](commissioned by DECC) to quantify biogas production potential in the UK (irrespective of biogas utilisation technology). AEA considered different bio-energy feestocks and constructed different supply scenarios for each based on different assumptions about prices and the rate at which non-financial barriers are overcome for the supply to develop. .Table 14, below, shows energy potentials for different feedstocks from selected AEA scenarios and work subsequently undertaken by Government.

The number of biogas plants year on year developed using the qualitative approach were then revised and refined to reflect the total energy potential shown by these estimates by 2030. The particular scenarios used where:

- AEA £4/GJ constrained resource : SKM ‘low’ scenario
- AEA £6/GJ easy constraints overcome: SKM ‘central’ scenario
- AEA £10/GJ medium constraints overcome: SKM ‘high’ scenario

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[12] AEA 2010 UK and Global Bioenergy Resource
http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

The commissioned work did not include digestible energy crops specifically for AD, therefore Government data[13] on maize crops and available arable land in England were extrapolated to identify and estimate the suitability and availability of land for AD energy crops. The following assumptions were made for the 2009 dataset:

- Of the 3.2 million ha arable land in England (excluding northern regions of England[14]) 25% is suitable for maize growing
- Of the 800,000ha suitable land 10% is converted to maize silage
- 4.12% growth assumption is applied for available land[15]

3.5. Growth Curves

3.5.1. Lead-in times

Due to lead-in times, i.e. the time required for to gain planning approval, environmental permitting, construction and commissioning and other consents we have estimated that it will be at least two years to operations. Therefore, as agreed with DECC the growth figures for biogas plants do not appear until 2012, this therefore includes facilities that were in early stages of current project development. Please note however that the growth figures presented overleaf do not include facilities that are already in operation as the assessment is only considering new plants that are coming on line following the implementation of the RHI into law.

3.5.2. Changes in growth over time

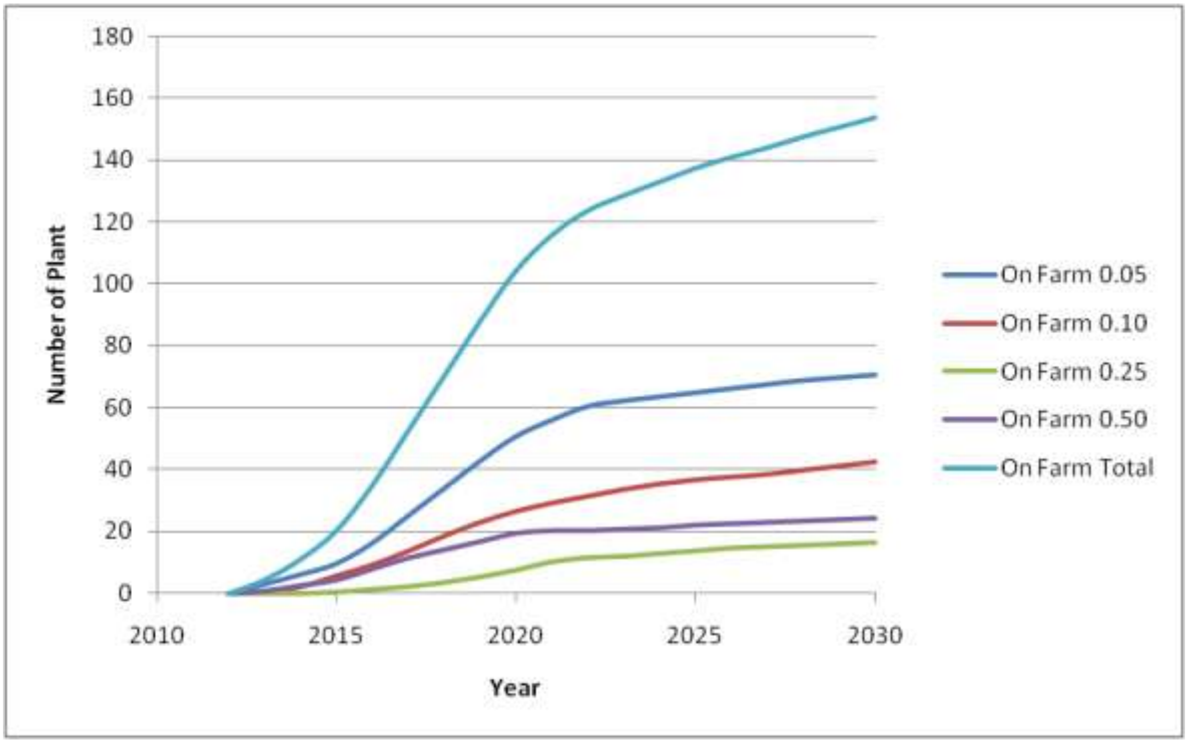
Growth curves have been devised to show an initial lag in growth to reflect mobilisation of the supply chain; followed by exponential growth as plants facing the least constraints and barriers are developed first. After this initial exponential period (predicted to end around 2020) where around 67% of plants have been developed, the growth rate decelerates with another 33% of plants being developed up to 2030 (see example in Figure 7, below).

3.5.3. Low, Medium and High Growth

To differentiate between low, central and high growth the same shape of growth curves were used (as described in section 3.5.2), but with different maximum energy potential by year 2030. Maximum energy potentials were derived from DECC (energy crop data) and AEA recent work (as described in section 3.4.2), see Table 14. Low growth relates to 'Easy' (column headings in Table 14) constraints being overcome whereas 'High' growth relates to 'Hard' (see column headings in Table 14) constraints being overcome.

[13] Defra, Revised 2009 County/Unitary Authority breakdown for Arable crops
[14] Excludes North East, North West, Merseyside, Yorkshire and The Humber
[15] Based on AEA's assumption for growth in land availability for wheat/oil seed rape

- **Figure 7: Estimated number of new on-farm biogas plants plant by year**



3.6. Interaction of growth and costs

There is the possibility that as biogas heat and biomethane to grid plants are developed in the GB, costs will change for a number of reasons:

Learning rates: as plants are developed more efficient and cost effective approaches are developed as well as increased capacity of new and local suppliers who train/learn to deliver similar works and services, pushes prices down.

Inflation and other price indices: will change the cost plant and equipment.

ForEx: many plant items are imported from the EU and so may vary in price with changing foreign currency exchange rates.

Supply vs. demand: on occasion, the supply of certain plant, equipment and services will be outstripped by demand pushing up prices; and vice versa.

Revenues: as revenue opportunities increase for biogas plants (e.g. gate fees and energy prices) so will the costs of works and services the biogas market is willing to bear; and vice versa.

The price of works and services at any point in time will be a result of a complex interaction of the factors described above. It was concluded that this was far too complicated to calculate or model and that current nominal prices should be used. It is likely that demand in the UK will increase for biogas related works and services, but it is understood that there is a large number of suppliers in Europe that can respond to this demand; particularly for on-farm and energy crop biogas plants. One aspect of biogas utilisation that may be affected is BtG, which is still developing in the UK. However, this has already been achieved during learning rates achieved during UK demonstrator projects.

Table 14: Estimates of biogas availability from AEA[16] and DECC scenarios (TWh)

Year	Wet Manures			Waste			Energy Crop			Sewage			Landfill		
	Low	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**
2010	3	5	8	2	8	12	3	4	5	2	3	3	37	38	39
2015	3	5	8	4	9	13	4	5	6	2	3	3	30	31	32
2020	3	6	8	6	10	13	4	6	7	3	3	3	22	23	24
2025	4	6	9	8	11	13	5	7	9	3	3	4	16	16	17
2030	4	6	9	9	12	14	7	9	11	3	3	4	11	11	12

Note: Estimates for Maize/Silage and Farm Yard Manures are from Government sources. Other estimates based on scenarios from AEA 2010 UK and Global Bioenergy Resource as set out above.

[16] UK and Global Bioenergy resource Appendix 2: A report to DECC by AEA, 2010 - to be published

3.7. Growth rate estimate results

Tables 15-19 below show the results from the analysis of the potential number of plants that could come forward under the Central scenarios across all sectors: heat only, Biomethane to Grid, CHP and power only applications. The use of biomethane for vehicle fuel will predominantly be achieved through injection to grid and therefore modelling the potential for this specifically has been excluded from the study.

The tables show the number of plants built in each year[17] and each table represents a different biogas utilisation option. The totals at the bottom of each table show the totals (e.g. substrate required, biogas produced etc.) by 2030.

As noted previously the detailed assumptions and drivers underpinning these are set out in the Appendices.

The work undertaken to estimate growth in the sectors and across the biogas utilisation options is considered high level and provides an indication on the potential. It is acknowledged that there is clearly competition between biogas utilisation options, for example a development being CHP over BtG, which will be determined not least by physical, commercial and economic factors that cannot be modelled comprehensively as part of this study. There may also be changes to the policy framework impacting each of these options; for example water treatment or waste policies or renewable energy financial incentives that would have direct implications on the various configurations and biogas utilisation options. Given this uncertainty the assumptions on the drivers and barriers are considered reasonable to determine growth estimates for this level of study.

[17] Please note that the method (formula) used to model growth allows for partial plants to be included (decimals of one), thus the table does not necessary show the true number of plants but the number of plants that would be need to generated the biogas expected.

Table 15: Central growth up to 2030 by sector: heat only

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Year														
2012														
2013	3	0												4
2014	3	1			4	2								10
2015	4	1	0		2	2								9
2016	7	2	1	0	2									12
2017	9	3	0											12
2018	9	4	0											13
2019	9	4	0	0										13
2020	8	3	0											11
2021	5	2	0											8
2022	4	2	0											7
2023	2	2	0											4
2024	1	1												3
2025	1	1												2
2026	1	1												2
2027	1	1												2
2028	1	1												2
2029	1	1												2
2030	1	1												2
Total	71	31	4	1	8	4								119
Substrate required														
kt/a	62	54	19	8	105	105								353

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Biogas output														
MW	4	3	1	0	8	8								24
TWh	0.03	0.03	0.01	0.00	0.07	0.07								0.21
Net Heat output														
MWth	2	2	1	0	5	5								16
TWhth	0.02	0.02	0.01	0.00	0.04	0.04								0.13
Net Power output														
MWe														
TWhe														
Land required to produce energy crops														
kHa	1	1	0	0										1

- **Table 16: Central growth up to 2030 by sector: CHP**

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Year														
2012														
2013				0		2	2		0	0	0			6
2014				1		4	4	2	1	1	1			14
2015				1	4	4	8	4	1	2	2			26
2016				1	4	6	6	6	1	2	2			29
2017				1	4	6	6	6	2	2	2			30
2018				1	2		4	6	2	2	3			20
2019				0		2	4	6	2	3	4			21
2020				0			4	6	2	3	4			20
2021								4	2	3	5			14
2022								2	2	4	3			11
2023									2	3	3			7
2024							2		2	3	3			9
2025									2	3	3			7
2026							2		2	3	3			9
2027							4		2	3	3			11
2028									2	3	3			7
2029							2		2	3	3			9
2030									2	3	3			7
Total				7	14	24	49	43	27	47	49			259
Substrate required														
kt/a				58	183	629	1886	2751	306	1598	2774			10186

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Biogas output														
MW				3	14	49	146	213	27	140	244			837
TWh				0.03	0.12	0.43	1.28	1.87	0.24	1.23	2.14			7.33
Net Heat output														
MWth				1	3	12	40	64	7	41	78			246
TWhth				0.01	0.03	0.10	0.33	0.53	0.06	0.34	0.65			2.05
Net Power output														
MWe				1	4	14	45	71	8	48	88			279
TWhe				0.01	0.03	0.12	0.37	0.58	0.07	0.39	0.72			2.28
Land required to produce energy crops														
kHa				1					5	28	49			82

Table 17: Central growth up to 2030 by sector: Power Only

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Year														
2012														
2013				0		2	2		0	0	0			6
2014				1		2	2	2	1	1	1			10
2015				1	2	2	6	2	1	2	2			18
2016				1	2	4	4	4	1	2	2			21
2017				1	2	4	4	4	2	2	2			21
2018				1	2		2	4	2	2	3			16
2019				0		2	2	4	2	3	4			17
2020				0			2	4	2	3	4			16
2021								2	2	3	5			12
2022								2	2	4	3			11
2023									2	3	3			7
2024							2		2	3	3			9
2025									2	3	3			7
2026							2		2	3	3			9
2027							2		2	3	3			9
2028									2	3	3			7
2029							2		2	3	3			9
2030									2	3	3			7
Total				7	8	16	33	28	27	47	49			214
Substrate required														
kt/a				58	105	419	1258	1834	306	1598	2774			8352

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Biogas output														
MW				3	8	33	98	142	27	140	244			695
TWh				0.03	0.07	0.28	0.85	1.25	0.24	1.23	2.14			6.09
Net Heat Output														
MWth														
TWhth														
Net Power Output														
MWe				1	2	10	30	47	8	48	88			234
TWhe				0.01	0.02	0.08	0.25	0.39	0.07	0.39	0.72			1.91
Land required to produce energy crops														
kHa				1					5	28	49			82

▪ **Table 18: Central growth up to 2030 by sector: BtG**

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Year														
2012								4						4
2013							2	6			0	27	23	59
2014		1					6	4			1	27	23	62
2015		2					6	4			1	27	23	64
2016		2		0	2	2	6	4			0	36	31	84
2017		1	0	1	4	6	8	6		0	1	45	39	113
2018		1	1	1	4	6	4	6		1	1	45	39	109
2019		1	1	1	4	4	2	6		0	1	45	39	105
2020		0	2	2	4	2	2	4		0	1	45	39	102
2021		0	2	1		2		4			1	45	39	94
2022			1				2	4			0	18	16	41
2023				0			2	2		0	1			6
2024		0	1	0			2	2		0	0			7
2025		0	1	1							1			3
2026			1	0			2	2			1			7
2027			0	0				2		0				3
2028		0	0	0			2	2			1			6
2029		0	0	0						0	1			2
2030		0	0	0			2			0	0			4
Total		11	12	10	18	22	49	63		4	13	361	312	876
Substrate required														
kt/a		20	52	89	236	576	1886	4061		133	755	23234	16452	47495

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Biogas output														
MW		1	3	5	18	45	146	315		12	66	361	935	1908
TWh		0.01	0.03	0.04	0.16	0.39	1.28	2.76		0.10	0.58	3.16	8.19	16.71
Net Heat Output														
MWth		1	3	4	16	39	128	278		10	60	296	917	1752
TWhth		0.01	0.02	0.04	0.13	0.32	1.05	2.26		0.09	0.49	2.41	7.47	14.28
Net Power Output														
MWe														
TWhe														
Land required to produce energy crops														
kHa		0	1	1						2	13			17

Table 19: Central growth up to 2030 by sector: Total

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Year														
2012								4						4
2013	3	0		1		4	6	6	1	1	1	27	23	74
2014	3	2		2	4	8	12	8	2	2	2	27	23	96
2015	4	4	0	2	8	8	20	10	2	3	5	27	23	117
2016	7	4	1	4	10	12	16	14	2	4	5	36	31	146
2017	9	4	1	4	10	16	18	16	3	4	6	45	39	176
2018	9	5	1	3	8	6	10	16	3	5	7	45	39	158
2019	9	4	2	3	4	8	8	16	4	6	9	45	39	157
2020	8	4	2	3	4	2	8	14	4	7	10	45	39	149
2021	5	3	3	1		2		10	4	6	10	45	39	128
2022	4	2	1				2	8	4	7	7	18	16	69
2023	2	2	0	0			2	2	3	7	6			25
2024	1	2	1	0			6	2	3	7	6			28
2025	1	1	1	1					3	6	6			20
2026	1	1	1	0			6	2	3	6	7			28
2027	1	1	0	0			6	2	3	7	5			26
2028	1	1	0	0			2	2	3	6	6			23
2029	1	1	0	0			4		3	7	6			23
2030	1	1	0	0			2		3	7	6			21
Total	71	42	16	24	49	67	130	134	54	98	111	361	312	1468
Substrate required														
kt/a	62	75	72	214	629	1729	5030	8646	613	3329	6303	23234	16452	66387

Type	On Farm				Waste				Energy crop			Sewage	Landfill	Total
Scale	0.05	0.10	0.25	0.50	1.0	2.0	3.0	5.0	1.0	3.0	5.0	1.0	3.0	
Biogas output														
MW	4	4	4	12	49	134	390	671	54	293	554	361	935	3464
TWh	0.03	0.04	0.04	0.11	0.43	1.18	3.42	5.88	0.47	2.56	4.85	3.16	8.19	30.34
Net Heat Output														
MWth	2	3	3	5	24	57	169	342	7	52	137	296	917	2015
TWhth	0.02	0.02	0.03	0.04	0.20	0.47	1.38	2.80	0.06	0.43	1.13	2.41	7.47	16.46
Net Power Output														
MWe				2	6	24	76	118	16	96	176			513
TWhe				0.01	0.05	0.19	0.62	0.96	0.13	0.78	1.43			4.18
Land required to produce energy crops														
kHa	1	1	1	2					11	58	110			184

3.7.1. Biogas Generated

The estimated total annual biogas generated by 2030 (under 'Central' growth) has been calculated to be 30 TWh. Of this, it is estimated that up to 0.2 TWh is expected to be used for projects producing heat only from biogas and 17[18] TWh for projects upgrading biogas into biomethane and injecting it into the gas grid (BtG), the remaining could generate power and heat through CHP engines. These conclusions are subject to considerable uncertainty as to end use sector that the biogas could potentially be used. The estimates should therefore be treated as broad indications of a possible outcome, based on the assumptions and drivers considered. The final incentive mechanism in place to support different applications could have a large impact of the distribution of this resource across sectors and applications.

The following discussion looks at both the gas utilisation options and sectors. The latter is a summary of growth based on the barriers and opportunities as set out in the appendix A.

3.7.2. Biogas Utilisation

Heat Only

Small scale on farm AD plants dominate the growth in heat only configurations. There are two principal reasons for this:

- the availability of feedstock
- infrastructure requirements

While this is discussed in more detail in A1 in the appendix it is important to highlight here that small to medium scale AD plants can be effectively installed for farm management reasons, without the need to co-ordinate a large Centralised AD (CAD) development, such that the benefits of heat can be realised for heating and industrial and domestic hot water on site. At the 0.05 to 0.25MW scale it is not considered viable for CHP or power only and the prime mover would be the limiting factor (technically and economically) for deployment. By scaling up the plant size to utilise the biogas for CHP this would require additional feedstock and costs which is seen as a limiting factor thus the growth in these two technologies for on farm (agricultural residues) is reasonably low.

CHP and Power Only

The deployment of both power only and CHP plants are predicted to be evenly split with the majority of plants being larger scale fuelled by waste and energy crop. The economies of scale for

[18] The estimates of BtG deployment have been revised since the RHI Scheme policy document was published due to changes in assumptions on energy crops that could be delivered. These estimates are uncertain and need further refinement due to the complexity of available land for "digestible" energy crops and competition, however if the volume of maize is different from those used in this analysis, or if there is a different distribution across sectors, then the estimates published in March 2011 could be delivered

the capital spend, requirements for pretreatment and receiving a gate fee for the materials supports the view that medium to large plants will take precedent over small scale. Therefore the smaller waste plants will be limited, in addition heat only waste AD plants is likely to be configured at the smaller scale as the driver for heat only plants would be to service a heat load, for the majority of plants developed over a certain capacity it would be expected that a CHP would be more economically viable than a heat only plant.

CHP

For CHP plants the growth is primarily in the waste and energy crop sectors. The deployment of technologies in waste peaks around 2016/17 in line with policy drivers for waste management, the growth reduces thereafter primarily because of resource constraints and competition from other technologies such as combustion. It is considered that growth in energy crop plants will be reasonably consistent, and restriction in growth will largely be due to application of heat and distribution to potential consumers.

Power Only

The growth in power only waste AD plants was considered to be similar to CHP insofar as it is constrained by waste (feedstock) resources. Assigning plants to power only or CHP will be determined by proximity to potential heat demands and as a consequence location of the AD plant will be instrumental in this.

Biomethane to Grid

Biomethane to grid growth is spread across all feedstock types and scales, which is largely due expected fewer technical constraints to this type of plant and the high energy efficiencies that can be achieved. The highest growth in BtG is considered to come from the sewage treatment and landfill primarily because the infrastructure is in place and thus the replacement of existing assets (engines/flares) to input BtG technology is an opportunity to maximise the renewable resource generated.

The principal technical barrier to the BtG option in all sectors is on the connection and proximity to the gas grid.

There are no significant non financial barriers to developments and construction of BtG and that there is potential for swift growth for BtG. Based on modelling and discussions with stakeholders it is assumed that build rates will peak between 2015 and 2020, which allows for projects to be developed and constructed. Thereafter, the availability of feedstock in waste streams specifically will be reduced, thus increasing the risk of project feasibility and in gaining finance. As a consequence a reduction in new plants is observed after 2020.

3.7.3. Sector utilisation

Agricultural On Farm AD: growth assessment

Heat Only: At a small scale an onsite heat only AD plant may serve the heating needs of a moderate sized dairy farm (150 cows) and capital costs will be low without the investment in a CHP engine. It is expected that the incentive of heat use on farm in addition to the management of residues will enable deployment of technologies generating biogas less than 0.25MW per annum.

In order to exploit the economies of scale associated with a larger heat only AD unit it subsequently increases the requirement for a larger, constant heat load. A large, constant heat load is unlikely to be possible under a farm 'co-operative' approach (Centralised Anaerobic digestion – CAD), where the investment will be based at a single location accessing feedstock from a variety of sources. Overall the number of sites with a heat load sufficient to allow the exploitation of economies of scale of a large heat only AD plants are likely to be relatively few.

The deployment of heat only plants is considered to be largely for capacities of less than 0.25 MW generating biogas, which allows heat to be used on farm and in close proximity of the farm and keeps the capex and complexity of the technology low.

Combined Heat and Power: It is considered that the capacity of CHP plant that will be technically feasible and more practical in terms of power generation will be above 0.25MW. The issue for agricultural residues is the tonnage of materials for plants of this size. For plants generating biogas with an annual energy value of 0.25MW and 0.5MW they will require 11,600tonnes and 23,300tonnes respectively. In considering that the average dairy farm generates around 1,300tonnes of slurry per annum it is clear that the larger scale CHPs will be feasible for only very large farms and CADs.

The growth in the larger scale CAD or co-operatives will not be immediate and may require lengthy discussions and agreements with project partners or developers. It is however considered an attractive option for areas where there are dense farming populations such as northwest England and Wales. The number of plants is likely to be limited, and the heat utilised from the gas engine will be relatively low due to the complexity and technical barriers associated with heat export and district heating, especially considering the assumed locations.

Biomethane to Grid: This sector is not seen as a major contributor towards biomethane volumes on an individual farm basis as the majority are expected to generate heat only projects due to restrictions of feedstock availability and costs noted above.

The larger plants proposed are assumed based on the concept of biogas pipelines collecting volumes to be sufficient for clean-up and grid injection. It is also likely that larger scale plants will require to be supplemented with energy crops such as maize and grass

Energy Crops: Growth Assessment

Heat Only: Due to the current incentives for energy crops and AD and taking into account the cost of feedstock, economies of scale and heat demands it is considered that there is no or little potential for heat only energy crop plants.

Combined Heat and Power: CHP will be the preferred technology configuration over heat only. It is assumed that only plants generating 1MW of biogas or above will be feasible, due to the economies and scale and cost of feedstock. The location of proposed energy crop plants may restrict the potential for heat export, however due to the size of plants suggested these would generate significant quantities of heat that has a value to the developer. As such the siting of the plant and innovative ways in which to utilise the heat could be seen. For example use of greenhouse heating, space and water heating for on-site buildings and wider district heating.

It is assumed that the uptake of energy crops will be gradual due to the complexities of site identification and growing the crops.

Power only: It is assumed that power only plants will be very similar to that of CHP. Where the development has no or very limited use for heat then this is considered power only operations.

Biomethane to Grid: Biomethane to grid energy crop projects are generally large as has been seen in Germany. It is assumed that there are a number of projects on the large scale (5MW biogas generating) post 2014. To put this into perspective the Gustrow energy park in Germany is around 9000m^3/h. Please note that no projects as large as this are assumed, but there are plants developed as large as 3000m^3/h.

As discussed in the appendices the key driver and barriers for uptake are energy prices/incentives and availability of land respectively. Thus forecasting the uptake of energy crops for AD is considerably more difficult than other substrates (e.g. waste).

Waste AD: growth assessment

It is expected that the type of waste plant will vary considerably, for example local authority plants (integral to a collection of green and food waste or as part of a residual waste treatment facility), commercial plants owned and operated principally by the waste industry (which could be sited at existing waste management sites, in particular landfill) and commercial AD plants for example developed in partnership with retail/food manufacturer (sited close to the source of feedstock).

Heat Only: It is considered that a heat only plant configuration utilising wastes would have limited applications and it is expected that the majority of new plants would be small scale due to CHP being a more attractive financial and technical option. An example of a small scale industrial heat only plant would be where a constant supply of process wastes from food and drinks manufacturing is used in an onsite digester for heat (space or process heating).

The principal barrier of the heat use noted above will be in utilisation of the heat, thus lending itself better for process heating. In addition, there will be issues in relation to the cost benefit of the process waste material which may be a commodity material (e.g. animal feed), as opposed to waste.

In light of the limitations it is believed that there will be very few projects generating heat only through a boiler, and these will be reasonably small scale (1 – 2 MW generating biogas).

Combined Heat and Power: The type and configuration of AD projects treating wastes are likely to be of the scale that is attractive both technically and economically to CHP. The current incentives for renewables lends itself to generating power and due to the relative ease of connecting to the National Grid provides a developer a reasonably stable income – subject to feedstock.

The viability of either CHP or BtG option will be dependent principally on proximity to electricity and/or gas connection, heat users and the financial incentives associated.

It is not considered that the majority of developers will include heat export as an integral part of their business case to build an AD facility. It is however expected that when reviewing site options the use of heat users in proximity of the plant will be investigated (as has been seen for biomass developments), and as such it is unlikely they will actively seek to use the heat for process or district heating but that the inclusion of an additional incentive will allow for an opportunistic review of heat distribution options.

The range of heat uses will vary considerably from 24/7 process heating (where a plant is embedded to an industrial process) to district heating network. It is important to recognise that with space heating the load profile will vary throughout the year and that heat will be dumped because of low demand periods. In the modelling undertaken assumptions have been made on the load factors for heat use which takes into account the varying demands that are likely to be observed.

The limiting factor on growth for CHP, power only and BtG is feedstock availability (under the assumption that financial issues are not a constraint). With regards to feedstock the range of plant sizes for the CHP option was from 1MW to 5MW annual generating biogas potential, which is approximately 12,000 tonnes per annum to 60,000 tonnes.

Power Only: AD can also operate in power only mode. These technologies will be generating heat from a gas engine, which will be used parasitically in the digesters but not utilised as part of a wider heating need. In the modelling for CHP we have included plants that will be exporting relatively small amounts of heat, which is reflected in the load factor for heat use, and therefore it is considered that growth in power only plants will be similar in number to that exporting some volume of heat in CHP mode.

Biomethane to Grid: BtG offers the greatest potential for waste AD plants. This is a diverse sector with potential for small niche plants (Bio-Group Adnams) and larger projects (50,000tonnes per annum). In removing the barriers to BtG this presents a more attractive opportunity to developers as the additional capex and administrative burden of heat exports can be removed. As a result this is a highly active sector with a large number of potential projects.

Landfill: Growth Assessment

Landfill is likely to diminish due to legislation and a shift from landfilling to alternative waste treatment. There will be a reduction in landfills operating in the future, but possibly we will see a development of larger landfills for economies of scale and fewer sites suitable for licence.

In addition to active landfills there are a large number of closed landfills that are producing significant quantities of gas which could theoretically be exploited (<1MWe on a spark ignition and electricity export scheme). These could become viable for either heat or gas injection, specifically if sat alongside additional AD technologies.

In general, BtG is likely to technically outweigh the use of engine in terms of cost and maximising the available resource (biogas). If incentives for biogas upgrading and injection to grid outweigh electrical generation and export, then new schemes are likely to adopt this approach, and existing schemes may switch.

Sewage AD: Growth Assessment

Heat only and Combined Heat and Power: As with landfill gas we do not envisage sewage treatment plants to develop heat only or recover significant quantities for heat export as part of a district heating scheme. This is principally a result of the greater cost benefits of biomethane to grid application and technical difficulties in heat export options. Where heat may be used, for example, on site, this is considered to be low volumes.

Biomethane to Grid: It is expected that BtG would be the most cost effective use of biogas in sewage plant. In the forecast, the build-up is based on the following logic:

- Each Waste Water Company implements one reasonably large biomethane project in the period 2011 - 2015. This is for biogas that is diverted from CHP (e.g. export electricity and the portion that does not use its waste heat).
- Each Waste Water Company builds 2 medium sized ADs in the period to 2020 which are developed to be biomethane to grid
- Each Waste Water Company builds a small biomethane plant using flared biogas
- A second tranche of projects comes in later years once CHP plants require replacing and as a result of the decarbonisation of the gas grid which makes base-load CHP less attractive.

4. Setting support levels for renewable heat and biomethane injection to the grid

4.1. Introduction

In this final element of the study, SKM worked with DECC and NERA in order to advise on the use of the findings in developing RHI tariffs.

As part of this work SKM provided advice to DECC on the following elements:

- Advice on the methodology for setting RHI support levels for BtG and Biogas heat only installations
- Advice on the differentiation of the RHI support levels according to the size of different plants (bands)

4.2. Tariff setting approach advice

This section describes the advice/views of SKM on the tariff setting methodology for the RHI. Based on the above analysis (and in conjunction with calculations of the levelised costs undertaken by NERA economic consultants of different plant types and sizes) the following approach was agreed through discussions with DECC, NERA and other stakeholders:

- RHI support levels for BtG are set at uniform level across all scales reflecting risks of gaming
  - There was consensus between stakeholders that setting different tariffs for different scales of plant (bands) would lead to plants being developed just under key bands to obtain highest possible tariffs
  - This would lead to potential inefficiencies as the development of smaller plants may be encouraged with reduced economies of scale

- RHI BtG support set on the basis of 1MW waste plant costs as level that could be expected to bring forward the majority of potential uptake
  - There was consensus between stakeholders that plants at the scale of 1MW or higher would capture the vast majority of biogas potential in the UK and therefore, any tariff level should aim to provide sufficient financial support to make such plants economically viable

- Biogas combustion for heat only support could be limited to up to 200KWth (as above that units expected to be designed for CHP)
  - There was consensus between stakeholders that, except for rare circumstances, most plants using biogas to produce heat only will be small scale as large end-uses for heat are relatively limited and larger biogas plants are more likely to use gas engines to produce electrical power in addition to heat

5. Conclusions

The objective of the study was to support DECC in providing technical support on the various biogas utilisation options from various sectors within Great Britain to support the economic modelling for renewable energy incentive mechanisms.

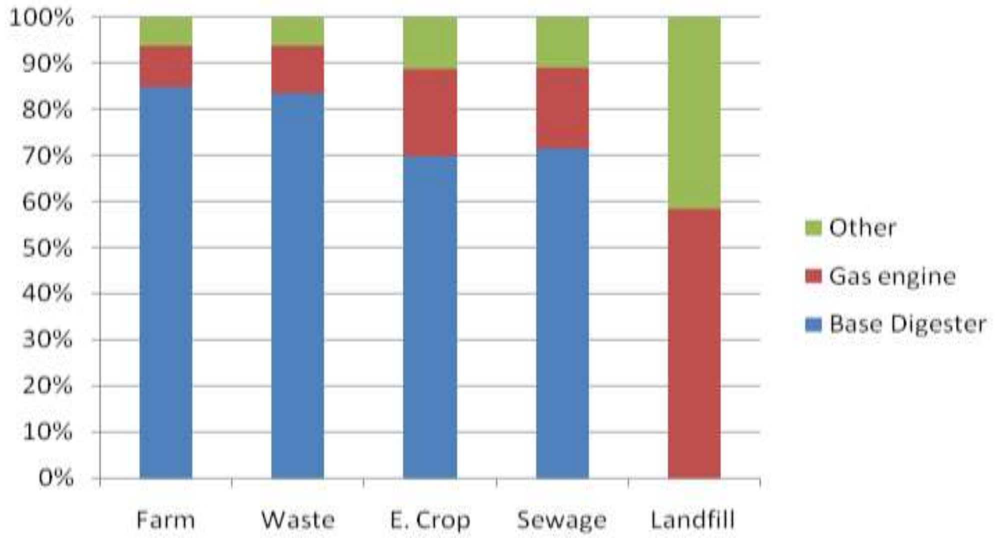
Detailed cost modelling was undertaken on the various options for AD and reference facilities have been presented with the model. This provided a firm understanding of the capital and operational costs, revenues, loadings, efficiencies etc for various configuration of plant based on data from Government sources and commercial knowledge from various stakeholders. The modelling has highlighted the importance of economies of scale and the cost of additional technology requirements for various feedstocks.

In all cases economies of scale is a key component of the capital costs of AD projects, this is particularly prevalent in the cost of the base digester and pre-treatment technologies (e.g. shredders, pasteurisation etc) and biogas clean up. The importance of this is that small to medium scale facilities will pay higher costs per MW of biogas generated and as a consequence could look to maximise the size of a plant through sourcing additional feedstocks. In the case of on farm plants this will be restricted based on available residues either generated on the farm or in proximity to the plant.

The proportion of costs for infrastructure for an AD development will be determined by the type of feedstock and biogas utilisation option. In the case of a plant configured for CHP the graph below shows the proportionate (as a percentage) costs for five reference plants[19]. It illustrates the difference between the waste and energy crop plants, which generate the same volume of biogas. In terms of total cost the waste capex is circa £7.4million and the energy crop £4.1million, yet the waste plant has a higher proportion of cost on the digester (marginally increased size) and upfront treatment technologies.

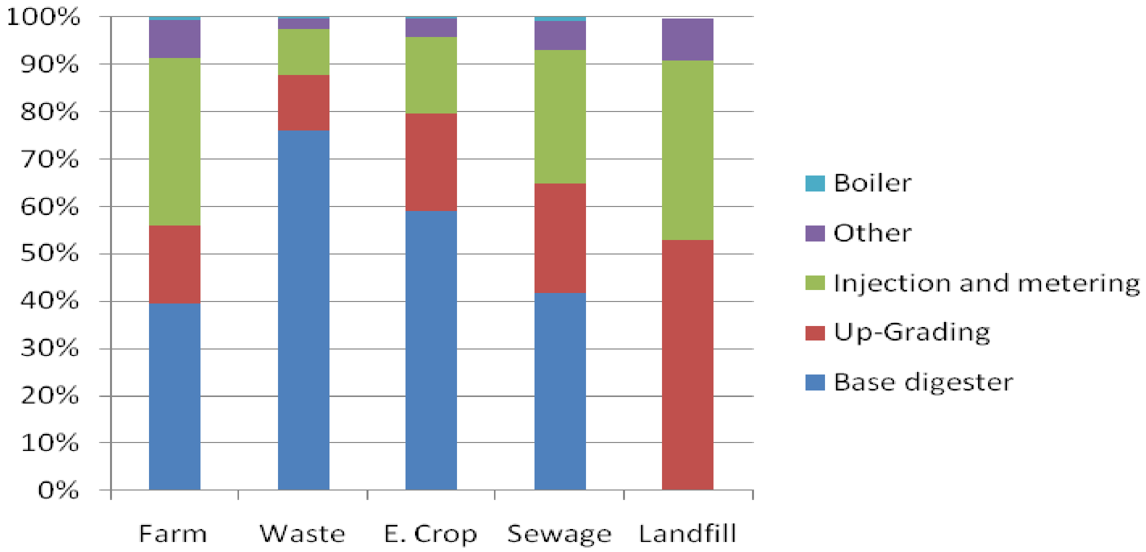
[19] Reference facilities are 0.3MW on farm, 3MW waste and energy crop, 1MW sewage and 3MW landfill.

- **Figure 8 Proportion of costs for capital infrastructure for reference facilities utilising CHP**



By way of comparison with a BtG configured plant generating the same volume of biogas the costs for the waste and energy crop plants show a similar relationship – greater costs for the waste plant, and for the sewage and on farm plants the project capex is more evenly spread across the various technologies. In the case of the sewage plant the upgrading and injection of the biomethane to grid is more or less equal to the cost of the digestion process.

- **Figure 9 Proportion of costs for capital infrastructure for reference facilities[20] utilising BtG**



[20] Reference facilities are 0.3MW on farm, 3MW waste and energy crop, 1MW sewage and 3MW landfill.

Growth Analysis

The growth in the various sectors and configurations (biogas utilisation options) will be determined by a range of technical and economic factors that cannot be thoroughly modelled as part of this exercise, for example proximity to heat consumers in heat only applications, feedstock costs/revenues etc. As such the growth forecasts are indicative based on existing barriers and opportunities for the various sectors.

In terms of on-farm AD projects the greatest growth in the number of plants will be seen in heat only and large scale (1MW) BtG. The principal reason for heat only plants will be the restrictions on feedstock availability and cost of technology. Where opportunities arise for centralised AD (CAD) plants then BtG may be a more viable route due to the potential constraints on identifying large heat demands.

The largest growth for energy crop plants will be seen in the CHP and Power only configuration, which by 2030 may see a combined number of over 260 plants generating over 7TWh of biogas. The use of heat will be key to developments, specifically in terms of opportunities for farming in addition to space and water heating.

While power only and CHP will continue to see significant growth in AD waste plants (72 and 112 by end of 2020 respectively) it is expected that BtG will be similar in terms of deployment. It is expected that BtG will be seen as an attractive opportunity to developers as the additional capex and administrative burden of heat exports can be removed.

The low capital cost and heat requirements required for sewage plants and landfill indicates that there is significant potential for growth in BtG for operational sites to shift from engine/flare to BtG. The key barriers to this will be in the economic case to remove existing assets and replace with upgrading and injection technologies and the proximity to a gas network. In the absence of technical and some financial barriers the growth to BtG could be very significant, generating nearly 10TWhr of heat by 2030.

In Conclusion

In terms of total energy generated we estimate that there could be around 23 to 37TWh of biogas generated by 2030, which would go some way to support Government's longer term energy and carbon targets. These figures reflect the potential generated from the range of feedstocks assessed and based on low growth rates under existing policies and barriers to high growth rates, which assumes a more optimistic development than the central growth scenario, but lower growth than a maximum build rate scenario that could be expected in the sector. The configuration of the AD plants will determine the heat and power generated and based on the assessment undertaken for low, central and high growth this represents between 12 and 21TWhth and 3.1 and 4.8TWhe for heat and power respectively.

Appendices

Appendix A Drivers, barriers and growth assessment of biogas production and utilisation in the UK

This appendix presents a commentary on the drivers, barriers and growth assessment that has been used to supplement the costs and forecast growth (in addition to DECC and AEA figures). It provides a background and detail pertaining to some of the challenges that need to be overcome for the growth in biogas to be realised.

A.1 On-Farm AD

A.1.1 UK On Farm AD Development

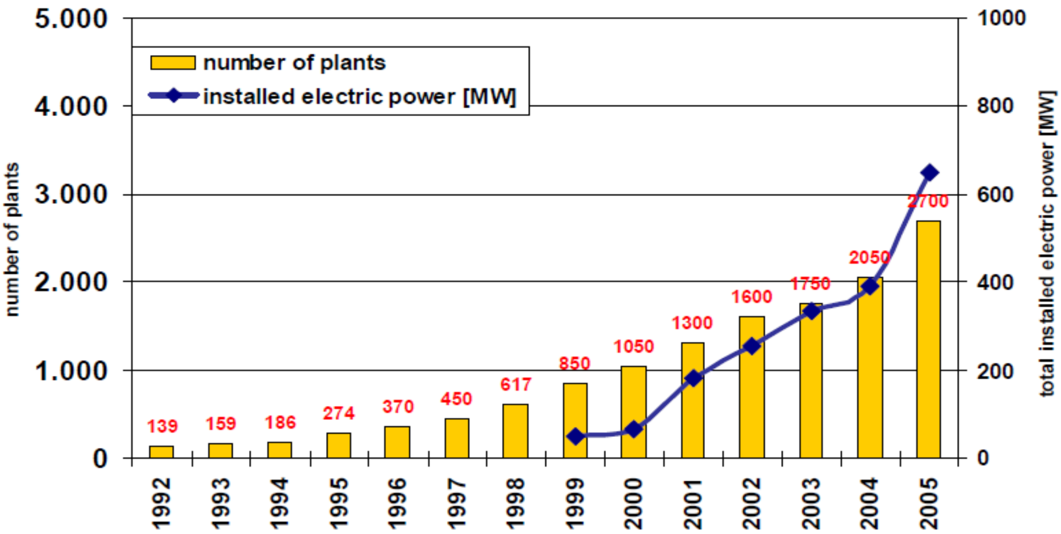
There has been little development of agricultural AD plants in the UK for energy – (a number of plants were established over the last 30 yrs as a means of waste management and pollution control). There are currently only about 32 on-farm systems operational (DEFRA, April 2011), with less than 0.1% of UK livestock manures treated by AD[21]. In addition there is also a handful of centralised systems (e.g. Bedfordia biogas, Bio Gask & Holsworthy), with more under development that are utilising CHP.

While the exact level of future growth is difficult to quantify a good indication of the types and scale of on-farm plants and likely proportionate levels of growth in GB may be given by assessing rates of growth achieved in Germany and Austria where there has been rapid up-take in AD facilities due to the use of feed-in tariffs for electricity over the last 20 years.

A.1.2 The German experience

In Germany legislation was introduced in 2001 by the Government to directly subsidise electricity generated from renewable resources .The subsidy was guaranteed to generators for 15+ years. Since this date the rate of expansion of on-farm AD has been sizeable (Figure 10 shows growth up 2005), with the number of plants in 2008 some 4,000[22]. These plants are producing over 1,100 MW of electricity and 1,500 MW of heat and employing more than 15,000 people.

▪ **Figure 10: AD development in Germany between 1992 and 2005[23]**



Farm scale AD plants commonly have an output of between 250 and 1,000 kW electrical generation via a gas engine (in the region of 800 and 3300kW of biogas energy generated), the majority of the plants recently installed in Germany averaged 500kWe. However, work by Laaber

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21 Scurlock, J. (2009) Anaerobic Digestion – an NFU Vision

22 Weiland, P. (2009) Biogas technology for bioenergy production. Jyväskyä University, Jyväskyä, Finland.

23 Data from the German Biogas Association

et al[24] indicated that the economies of scale were of minor significance on plant larger than 250kWe, in the development of the market. The main advantage of the larger systems would be the cost advantages when looking at up-grading the methane for use in the grid or as a vehicle fuel. It should be noted however that the incentives were primed for electricity generation and not heat supply.

In 2009 the tariffs were amended to take into account higher input costs and rising food prices. This increased the tariff for CHP and therefore the total tariff. In addition, to provide an incentive to use a larger share of waste materials in order to reduce competition for land, small scale plants using 30% manure receive a special bonus.

- **Table 20: German Government's compensation paid for electricity (€ ct/kWh)[25]**

Electrical Capacity	Base feed in tariff	Waste Bonus	Manure bonue	CHP Bonus	Technology Bonus*
< 150 kW	11.67	7	4	3	2
< 500 kW	9.18	7	1	3	2
< 5 MW	8.25	4	0	3	2
> 5 MW	7.79	0	0	3	

* for innovative technology (including biogas upgrading to biomethane to inject into grid or for fuel)

It is important to note that the changes in the tariff structure favoured greater efficiencies and environmental benefits through the use of wastes and manures. The key social and environmental concerns relate to:

- Impact on higher food costs
- Increasing growth in monocultures
- Increased transport movements
- Pressure on nutrition surpluses in soil

Whilst the revised tariffs from 2009 are seen as positive there remain concerns in Germany on the argument over climate protection versus regional environmental impacts and increasing food costs.

In addition, the subsidy stimulus for AD in Germany has led to the expansion of companies (+400) providing AD services and technology, ranging from plant engineers, design, component provision, plant construction, technical services and laboratory services (German Biogas Association). The expansion has also led to new technology resulting in improved efficiency of the AD process. Operating efficiency has been raised significantly from 200 to 2006 (using appropriate laboratory analysis), and new system designs and module / standard components have improved costs and ensure the safety of the plants to a very high standard.

[24] Laaber, M., Madlehner, R.,Brachtl E., Kirchmayr, R. & Braun, R. (2007) Aufbau eines Bewertungssystems für Biogasanlagen- "Gütesiegel Biogas". Tulln, Austria, Universität für Bodenkultur Wien Interuniverstäres Department für Agrarbiotechnologie, IFA-Tulln Institut für Umweltbiotechnologie

[25] Data from the German Biogas Association

A.1.3 The UK Potential for On Farm AD

It is important to recognise that this assessment of AD growth makes a distinction of on-farm AD processing agricultural residues and energy crops. Government policy and the role for AD with regards to agricultural residues and energy crops is detailed in Defra's Implementation Plan: Accelerating the Uptake of Anaerobic Digestion in England.

Whilst there will be many occasions where a plant combines the two feedstocks it is deemed prudent in the analysis to separate out the two sectors of on-farm residues (manures, slurries) and energy crops, due to the two drivers of farm waste management and plants designed for energy generation.

Regarding energy crops Government has pressed the need for sustainably sourced crops that supports renewable energy goals. There is concern that crops used for energy compete for land used for food production, and could therefore potentially raise commodity prices and affect food security. There are also concerns that through indirect land use change, the production of certain crops could theoretically result in a net increase in greenhouse gas emissions or have other adverse environmental impacts. Biogas generated from energy crops will therefore need to:

- deliver real and substantive CO_2 savings;
- use land responsibly, avoiding damaging land use change; and,
- do not undermine global food supplies or inflate prices.

The implicit assumption in the analysis presented here is that there is no impact on food prices because the AEA study, on which much of the feedstock supply potential is based, assumes that food and other sector needs are met first, with remaining land resource available for the energy sector.

In terms of potential for on farm AD plants the National Farmers Union and the Milk Roadmap for the UK has identified the following opportunities, however neither stipulate the split in biogas utilisation options:

- The National Farmers Union (NFU) has recommended that the Government set a national target of 1,000 farm-based AD plants (typically sized at 500kWe) by 2020. The NFU estimates these plants would require 100-125,000 ha of land to grow energy crops and would be able to process between 20-24% of the total UK arisings of manures and slurries (90 million tonnes)[26].
- The Milk Roadmap for the UK sets out the vision for the dairy industry towards 2020. The Roadmap sets targets of 30 dairy farms piloting on-farm anaerobic digestion by 2010 and 3 centralised anaerobic digesters at processing sites by 2015. By 2015 the target is for 10% of non-transport energy use to come from renewable energy or combined heat and power systems for large processors, and for zero ex-factory waste to go to landfill for large processors.

A.1.4 Potential Barriers to On Farm AD Developments

There are a range of issues that may prevent the up-take of AD on UK farms, these include:

- Gas mains connection and capacity
- Grid connection and capacity

- Land suitable for growing Energy Crops that does not interfere with food production
- Land suitable for the application of digestate, while complying with Nitrate Vulnerable Zones (NVZ) and other nutrients control directives
- Access to finance
- Viability of the development of renewable energy generation is heavily dependent on planning.
- Availability of land to site the plants
- Waste Segregation and Food Waste Collection
- Operational Experience
- Supply Chain

Each of these issues is briefly discussed below:

Grid connection and capacity electricity

The cost of connection to the distribution network for any form of electricity generation can be significant unless sited near a transformer substation. On some farms where an 11 kV power line crosses the land, connection costs might be in the range of £20,000 to £60,000, but the likely maximum power that could be generated and connected to such lines is less than 1MW. Additional costs incurred can include; overhead lines (between £15,000 and £30,000 per kilometre), monitoring and upgrading from the distribution network operator (DNO). For higher electricity output, such as CAD plant, a 33 kV connection is required, with subsequent costs ranging from £120,000 to over a £1million dependent upon the distance from transformer and any requirements to upgrade.

Alongside upfront costs that need to be overcome, it should be recognised that the technicality of connecting to the Grid is complex and can be time consuming, leading to project delays or even prevention.

Gas mains connection and capacity

For biogas used as a direct replacement for natural gas, or as a vehicle fuel, then the biogas must be upgraded to biomethane. The Swedish experience shows that it is possible now to upgrade biogas with high reliability and at reasonable cost, either for a direct use as a vehicle fuel, of for injection into the national gas grid. It may be possible that if no mains gas network is close to the farm that the biomethane from individual farm scale AD production units are piped to a central processing facility. This model is being considered by Southampton University. The piping of gas is less costly than the heavily insulated pipework required for a heat main, which presents an alternative for the distribution of heat, thus allowing individual gas fuelled boilers to be retained in existing properties.

Land suitable for growing biogas feedstock crops

The use of biogas feedstock crops for AD could be useful in the development of the systems as they provide the farm AD developer with a guarantee of sufficient supply and provides back-up if insufficient supplies of farm residues are available or to make a buffer stock of material.

The cost of energy crops will be influenced by two key factors; the opportunity cost of growing other crops on the land (such as wheat, barley and oil seed rape) and; local feedstock supply and demand considerations for the energy crop.

In simple terms the opportunity cost of other food crops will form the base level cost of crops for AD, therefore the price of these will be related to the price of wheat, oilseed rape and barley. However, other issues will also influence the availability and cost of biogas feedstock crops and prices. If a farm has an on site AD plant, then the value of the crops grown will be linked to the value of the heat and electricity subsidy received for the plant, often providing the farmer with a potentially higher, and more stable return for the land used to grow the biogas feedstock crop than an alternative crop. Similarly, if the AD plant is not ‘on site’ but the farmer is awarded a contract to supply an AD plant, a secure contract will provide an attractive alternative.

Opportunities also exist to reduce the cost of production by replacing some of the inorganic fertiliser with digestate, potentially saving 10% of the production cost and also removing a cost the farmer has least control over (as the cost of fertilizer is closely related to the price of oil). The manufacture of nitrogen fertiliser is an energy intensive operation and accounts for approximately 30% of all agricultural energy use. As the price of energy has increased, the price of nitrogen as a plant food has doubled over the last 10 years. The nutrient content of the digestate from an AD plant is a homogenous product (unlike manure) although it varies with the different feedstock composition. Typically it might contain 4 to 5 kilograms per cubic metre of nitrogen, 1.3 kilograms per cubic metre of phosphorous and 1.9 kilograms per cubic metre of potash, worth in fertiliser value between £2 and £2.50 per cubic metre.

In the future, as potential interest in feedstock crops grows, and feedstock cultivation replaces similar crops grown as a forage supplement for livestock, then the attributes that are critical for increased methane yield for AD can begin to be developed as a plant breeding programme (e.g. higher sugar cultivars for greater gas yields).

Land suitable for the application of digestate, while complying with NVZ and other nutrients control directives

AD plant will be reliant upon securing sufficient land to spread the digestate. Whilst the digestate is of good agricultural value, it needs to be handled with care and used sensitively with the regulatory framework to secure optimum take-up by the plants and restrict losses to the atmosphere and watercourses/ groundwater. Many “on-farm” plants will be able to utilise all the digestate on site, but other plants will require partnership arrangements with trusted partners in order to ensure that digestate is used well and pollution is avoided.

The NFCC in its report, Barriers to Deployment to AD, (for DECC) suggests that this is a low barrier but requires further research and development.

Access to finance

It is clear that an opportunity to invest in AD would require finance for the majority of developers. The availability of finance and the clarity on finance options, including renewable incentives is required, however this is not discussed as a potential barrier in the report as we assume that the relevant tariff will be sufficiently high to incentivise the development of AD.

Development of AD plant is heavily dependent on planning.

AD plants are similar in appearance to existing on-farm slurry stores and can be effectively screened by plantings where necessary. They are generally less controversial in terms of aesthetics than wind turbines and do not have the chimneys associated with biomass combustion. Where feedstock all arise on the farm, or neighbouring farms, and the digestate is spread on that land, there is little change to the current impact from a conventional farm. The degree of extra road traffic generated by the construction and operation of an AD plant will depend on its size, the nature of the feedstock, and the means of disposal of the digestate. Biogen (UK) state that their relatively large, 1MW plant will generate four lorry movements a day importing feedstock.

Notwithstanding the above, on farm projects will need to go through the planning process that may incur delays, often through lack of lack of understanding and public opposition. However, planning is not perceived as a significant risk to developments or the uptake of AD for on farm.

Availability of land to site the plants

AD facilities can be space intensive, for example a 500kWe AD plant requires 4,000m². This space is needed for fermenters, gas storage, electricity generator and auxiliary facilities. In addition it requires storage facilities for the feedstock that could be 5,400m² for high energy value energy crop and considerably more for low energy value feedstock e.g. manure. Lastly there needs to be a 4,000m² store for the digestate, to allow for storage of the digestate until it is able to be spread on to the land to comply with pollution legislation[27].

Experience in countries where AD plants are well established and reasonably common-place tends to suggest that sound partnership arrangements are often key to their successful development and operation. Such partnerships might take a variety of forms including the cooperative ownership of the plant itself. This therefore may add to the time taken to deploy technologies of this scale.

Waste Segregation and Food Waste Collection

Through engagement with stakeholders the NFCC[28] noted that waste segregation and food waste collection are significant issues in relation to the uptake of on-farm developments. Both the issues relate to on farm projects accepting imported waste feedstock including commercial and industrial food and drinks wastes. By accepting non-segregated wastes a facility would be required to have acceptable front end separation, de-packaging technologies. Whilst these are currently available the addition of the technologies would add to capital and operating costs, and also risks, for example increase in contamination of digestate.

Operational Experience

Whereas the generic technical barriers have been presented above, a barrier that may be more specific to agricultural feedstocks for projects of a scale of 0.25MW biogas generated or below will be in the operations of the plant. A key factor in the effectiveness of on farm digestion is the operation of the plant, and notably the management of the feedstock prior to digestion, for example in regulating wastes to gain optimum performance, such as mixing. AEAT in their report to DEFRA noted poor efficiency when compared with theoretical methane yields, for example on temperature controls and fugitive emissions[29]. Furthermore technical problems encountered by farmer operators were compounded by a lack of operational knowledge and technical assistance, for example a lack of awareness and understanding of how to obtain the best yields from the system.

It may be argued that these issues will not be as common for energy crops as the generation of energy is the primary objective whereas for farm waste management the time and dedication may not be available. To put this into perspective a 7,000tonne per annum manure/slurry digester will

[27] Epp C et. al “Guidelines for Selecting Suitable Sites for Biogas Plants” Intelligent Energy Europe

[28] Barriers to On Farm AD (NFCC) 2010

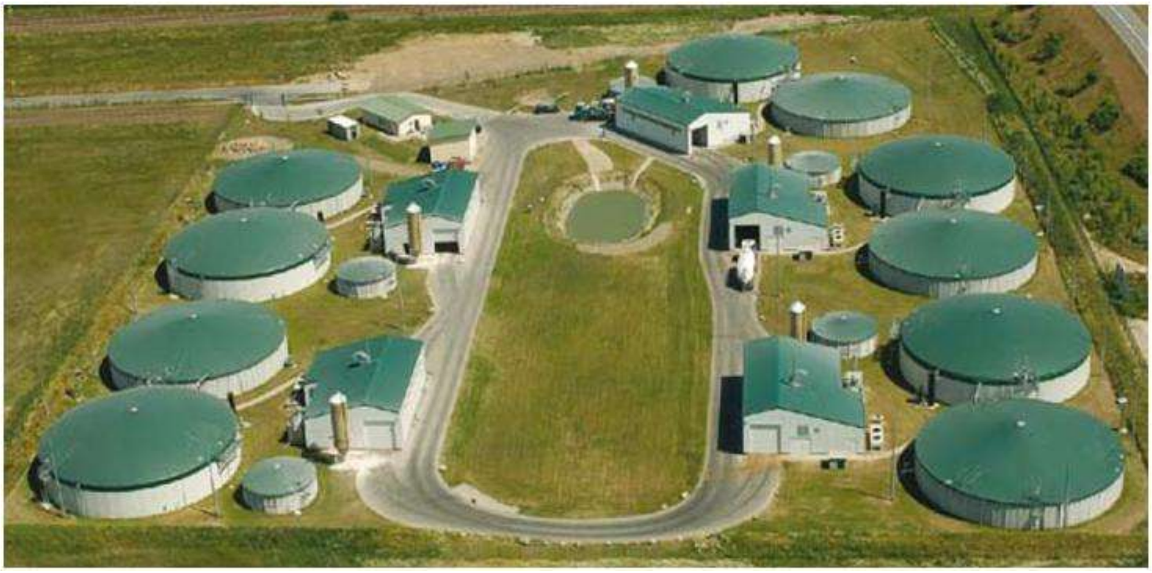
[29] Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries. 2005. AEAT for Defra

require an average of approximately 2 person hours per day[30], which in addition to ongoing farm management may be significant.

Technology Supply Chain

It should be noted that the supply chain for on farm AD technology has not been considered to be a significant barrier to the uptake. This is largely a result of the existing European supply chain that exists and can be readily imported and also is indicative of the relative simplicity of expected on-farm projects compared to large industrial AD plants receiving mixed wastes.

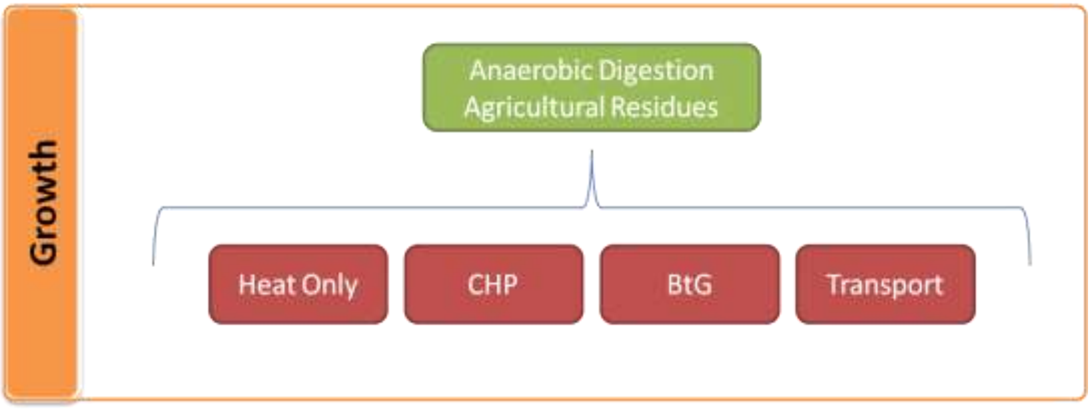
- **Figure 11: Biogas Park in Anklam, Germany[31]**



A.1.5 Agricultural Residues – a brief assessment of Growth

In estimating the growth of on-farm AD plants processing predominantly farm generated residues (slurries, manures) we have considered the generic barriers set out above in addition to specific issues and opportunities for this sector.

31 http://www.aebiom.org/IMG/pdf/Brochure_BiogasRoadmap_WEB.pdf



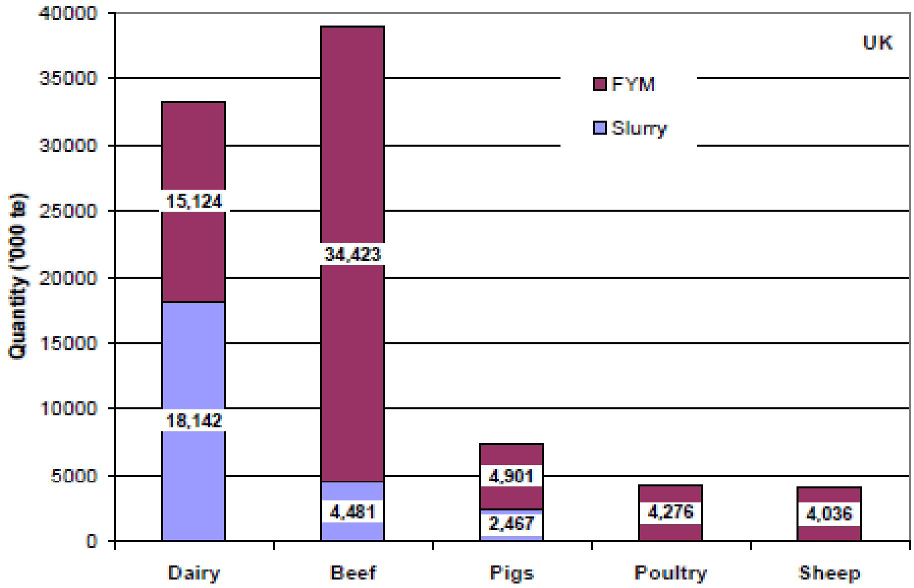
An assessment of options for on-farm AD generating heat only, CHP and BtG needs to undertake the fundamental calculation of supply of feedstock and demand for heat or proximity to the gas grid.

Potential Agricultural Residues Feedstock

The feedstock for any proposed plant is dependent upon the type of farm system, which in turn will determine the type of AD technology employed. An indicative on-farm system would include the waste stream generated by the farm, such as farm yard manures and slurries, in addition to produce wastes such as straw. For reference, the modelling undertaken has split the feedstock between 80% slurry and 20% manure, this is considered reasonable in terms of availability of feedstock. Please note that the modelling of the farm biogas output has been based on 60% residues and 40% energy crops as agreed with DECC and stakeholders, thus in terms of limiting factors for on site farm AD it may be energy crop availability as opposed to residues.

Work undertaken by AEAT in 2005 showed that there are in total 33 million tonnes of slurry and farm yard manure in the dairy sector alone, with an additional 35million tonnes of manure in the cattle sector and circa 15million in other livestock (Slurry and Farm Yard Manure (FYM) in UK by Livestock category Figure 12). This is further supported by more recent work (AEA 2010) which suggests over 60 million tonnes of 'wet manures' could be made available for biogas.

- **Figure 12: Slurry and Farm Yard Manure (FYM) in UK by Livestock category[32]**



The potential to utilise the feedstock however is dependent upon the technical ability to collect the residues, which in turn is dependent upon the type of produce/system employed (dairy or meat produce, intense or free range). For example dairy farms enable the collection of slurry, for example in milking parlours, which makes it a more viable option than cattle or free range farms where the feedstock is dropped on pasture fields.

With regards to poultry farm wastes circa 4 million tonnes could potentially be collected for AD. However, the high proportion of wood shavings likely to be in the waste stream can limit the use in AD, which also makes it more attractive to combustion processes. Furthermore the high nitrogen content in the wastes will also mean that the C:N ratio will need to be balanced with additional wastes.

The greatest opportunity for AD is from dairy farms. In the UK there are approximately 16,500 dairy farms that produce both slurry and manure. Figures produced by DEFRA estimate that slurries will total between 18 and 25 million tonnes per year[33]. The average herd size for dairy in the UK is 113 cows, thus representing approximately 1500 tonnes of slurry per year per average farm.

In addition to slurry and manures, barley and wheat straws, which is currently used for animal bedding, chopped and returned to the soil and sold, can also be used in AD plant. It can be assumed therefore that the straw arisings that are available for biogas production is that which is sold. Competition for straw clearly exists as it is a commodity item, which also includes the use for

32 Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries. 2005. AEAT for Defra

33 Based on slurry produced per head and reference Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries. 2005. AEAT for Defra

biomass in combustion[34]. Please note that for the purpose of the assessment only slurrys and manures have been modelled.

A.1.6 Heat Demand

Whilst there is theoretically a significant volume of slurry and manure feedstock available, the utilisation of heat energy generated will be limited by demand, either on farm or in proximity to a facility. The heat demand for on-farm AD plants is considered to be reasonably limited, with heat demands from the farm and outlying buildings (including farmhouse) to be low and seasonal. Thus the full potential of the energy produced by AD may not be realised.

For dairy farms specifically it is estimated that the heat demand per cow per year is 135kWh/cow/year. Therefore for an average dairy farm of 114 cows this equates to a maximum demand of 15,390kwh per year[35] of heat.

It should be noted however that heating is typically electrical rather than water heating, through the use of dairy water heaters. The reason for this can be due to the difficulties in heating milking parlours due to their open design, which makes radiant heating systems more efficient than space heating systems.

Heat demands for sheep and pigs are low, the average annual energy consumption per pig for creep heating is 5kwh and weaning between 7kWh per pig[36].

In addition to heat being used in farm "operations", there are also opportunities for it to be delivered to other farm buildings and houses in the vicinity, although it should be noted that the heat demands are likely to be reasonably low and seasonal.

Heat export options

It is shown that for an average sized on-farm plant processing residues generated on farm can be limited insofar as heat options. Net heat available following parasitic loading of the digester (between 33% - 20% of biogas generated) can be used on farm water and space heating as identified above. Further options for larger scaled plant can include district heating, process heating and potentially cooling (for example the milking plant). The ability to utilise the heat will be defined by both proximity to heat demand and motivation for the developer (farmer) to enter into third party heat provider contracts, which may entail the creation of an ESCO[37] and contractual requirements on energy, such as pressure and temperature. Whilst these issues may be feasible for an energy company or a centralised AD plant (CAD), the drive in addition to managing a farm could be the limiting factor.

It is important to note that whilst there are barriers to the export of heat there are also significant opportunities to export renewable heat. This will largely be driven by the ability to source end users and proximity to the wastes (for feedstock and transport cost implications). It can be assumed that

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34 E4Tech (2010) report for DECC on the noted that prices for straw were at the higher end of the biomass range (dependent on location).

35 Assessment based on data from Dairyco.org.uk

36 Energy Use in Pig Farming (Energy Consumption Guide Carbon Trust)

37 Energy Services Company

the heat users will have variable demand profiles for heat, for example seasonal space heating or process heating.

A.1.7 Agricultural On Farm AD: growth assessment

Heat Only

At a small scale an onsite heat only AD plant may serve the heating needs of a moderate sized dairy farm (150 cows) and capital costs will be low without the investment in a CHP engine. It is expected that the incentive of heat use on farm in addition to the management of residues will enable deployment of technologies generating biogas less than 0.25MW per annum.

In order to exploit the economies of scale associated with a larger heat only AD unit it subsequently increases the requirement for a larger, constant heat load. A large, constant heat load is unlikely to be possible under a farm 'co-operative' approach (Centralised Anaerobic digestion – CAD), where the investment will be based at a single location accessing feedstock from a variety of sources. Overall the number of sites with a heat load sufficient to allow the exploitation of economies of scale of a large heat only AD plants are likely to be relatively few.

Where biogas heat only options may be attractive is in the high heat demand industries such as cement kiln, brick, asphalt sectors and potentially food and drinks. Whilst these sectors do offer significant constant heat demands in profile and temperature, and they are investigating alternative fuel options due to carbon policy and corporate drivers, it is our view that large scale industrial AD plants will be extremely limited. The energy demands of the sectors would mean significant capital investment, a large footprint requirement and a considerable feedstock supply that would mean uptake would be very much site specific. In addition the technology would be in competition with solid fuels such as Solid Recovered Waste (SRF) and biomass.

These examples are clearly niche and as a result we do not consider that a substantial number of large scale heat only AD plants will be built in the UK.

The deployment of heat only plants is considered to be largely for capacities of less than 0.25 MW generating biogas, which allows heat to be used on farm and in close proximity of the farm and keeps the capex and complexity of the technology low.

Combined Heat and Power

It is considered that the capacity of CHP plant that will be technically feasible and more practical in terms of power generation will be above 0.25MW. The issue for agricultural residues is the tonnage of materials for plants of this size. For plants generating biogas with an annual energy value of 0.25MW and 0.5MW they will require 11,600tonnes and 23,300tonnes respectively. In considering that the average dairy farm generates around 1,300tonnes of slurry per annum it is clear that the larger scale CHPs will be feasible for very large farms and CADs.

The growth in the larger scale CAD or co-operatives will not be immediate and may require lengthy discussions and agreements with project partners or developers. It is however considered an attractive option for areas where there are dense farming populations such as northwest England and Wales. The number of plants is likely to be limited, and the heat utilised from the gas engine will be relatively low due to the complexity and technical barriers associated with heat export and district heating, especially considering the assumed locations.

Biomethane to Grid

This sector is not seen as a major contributor towards biomethane volumes on an individual farm basis as the majority are expected to generate heat only projects due to restrictions of feedstock availability and costs. However, from 2012 a number of projects are assumed at all scales for BtG. Clearly the principal factor for BtG will be the proximity to the gas network and the technical support offered to developers of plants at various sizes.

Larger plants are assumed based on the concept of biogas pipelines collecting volumes to be sufficient for clean-up and grid injection. It is also likely that larger scale plants will be supplemented with energy crops such as maize and grass

A.1.8 Agricultural On Farm AD: high growth

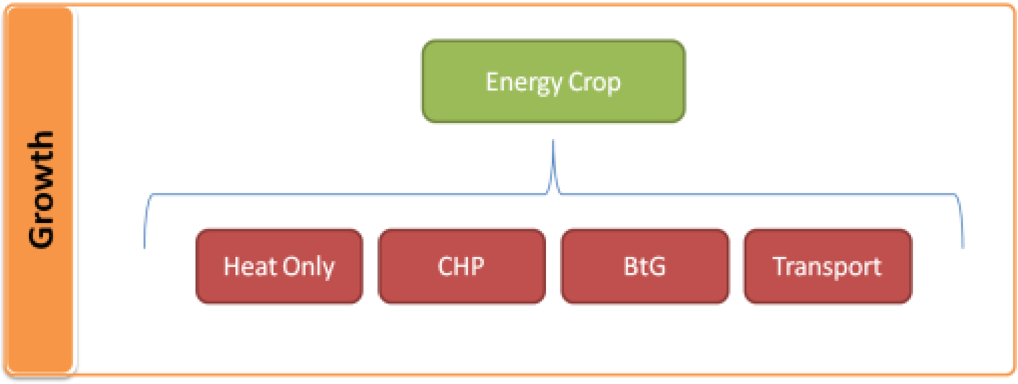
The constraints of meeting high growth figures for agricultural on-farm AD will principally be:

- Grid connection and capacity for gas
  - The rural location of farms can potentially limit the BtG options due to distances and ultimately cost to connect to gas grid.
- Suitable heat demands
  - The heat export option will be constrained by distance to suitable users with reasonable annual heat demands that will make the additional capex and contract/energy administration suitably viable.
- Availability of land to site the plants
  - For larger scaled plant (over 0.25MW the land requirement is not insignificant and may be a barrier to the growth
- Residues and supplementary feedstock availability
  - The volume of wastes (circa 88million tonnes per annum) is not the limiting factor but the technical capability of collecting the volumes consistently across the year.
- Operational Experience
  - Whilst AD is a reasonably simple technology the operational knowledge to ensure maximum efficiencies are being realised, technical issues are being mitigated and time to manage the operations of the technology can be made available are limited
- Supply Chain
  - Whilst there is considerable experience in the technology sector for on-farm AD plants both in the UK and abroad the high and stretch growth will challenge this. Specifically with regards to the energy off-take; grid connections and heating distribution

It should be noted that, in addition to agricultural residues only, these materials have been included as a proportion of the energy crop scenarios modelled.

A.2 Energy Crops

The growth in energy crops for AD has greater uncertainty than for on farm residues and food wastes, due mainly to the key driver being to generate energy as opposed to managing wastes and diverting wastes., Therefore the key policy framework driving energy crops is renewable energy. There are other drivers such as farm diversification, however, these will be directed by the incentives for power and heat.



A.2.1 Supply factors

The limiting factors for the supply of energy crops are discussed in section A.1.4. However, the principal barrier is the availability of agricultural land. Integral to the availability is the competition to use the land for other agricultural purposes and quality of the soil, climate zone and conditions suitable for energy crops. The drivers and barriers specific to energy crops, which will lead to identifying the area suitable for crop growth, are extremely complicated and outside the scope of this project. The assumptions used to underpin the estimated volume of maize are detailed in 3.3.2 above. These are uncertain and any change in these will impact on the energy potentials available across sectors.

In modelling the energy values of energy crops we have taken the assumption that all will be maize silage and a further assumption that 30% of the feedstock will include on farm slurries.

A.2.2 Energy Crops AD: growth assessment

Heat Only

Due to the current incentives for energy crops and AD and taking into account the cost of feedstock, economies of scale and heat demands it is considered that there is no or little potential for heat only energy crop plants.

Combined Heat and Power

CHP will be the preferred technology configuration over heat only. The location of proposed energy crop plants may restrict the potential for heat export, however due to the size of plants suggested these would generate significant quantities of heat that has a value to the developer. As such the siting of the plant and innovative ways in which to utilise the heat could be seen. For example use of greenhouse heating, space and water heating for on-site buildings and wider district heating.

It is assumed that only plants generating 1MW of biogas or above will be feasible, due to the economies and scale and cost of feedstock.

It is assumed that the uptake of energy crops will be gradual due to the complexities of site identification and growing the crops.

Power only

It is assumed that power only plants will be very similar to that of CHP. Where the development has no or very limited use for heat then this is considered power only operations.

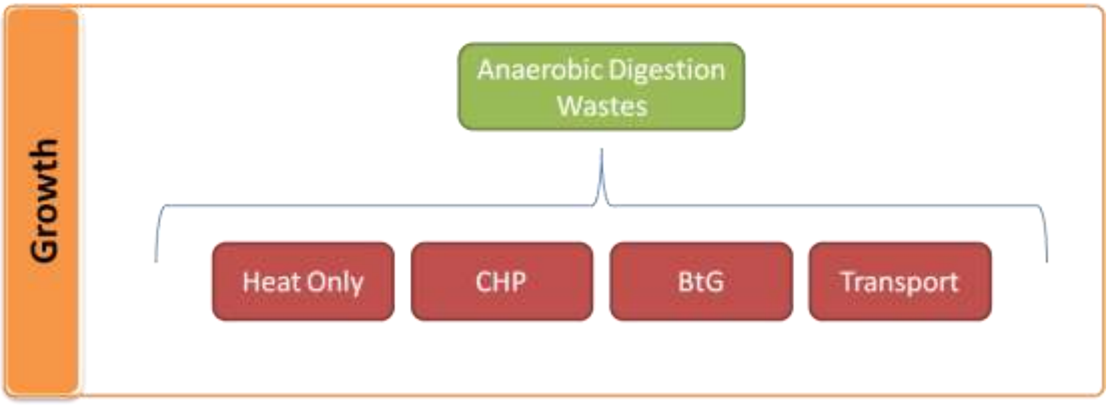
Biomethane to Grid

Biomethane to grid energy crop projects are generally large as has been seen in Germany. It is assumed that there are a number ofprojects on the large scale (5MW biogas generating) post 2014. To put this into perspective the Gustrow energy park in Germany is around 9000m^3/h. Please note that no projects as large as this are assumed, but there are plants developed as large as 3000m^3/h.

As noted throughout this section the key driver and barriers for uptake are energy prices/incentives and availability of land respectively. Thus forecasting the uptake of energy crops for AD is considerably more difficult than other substrates (e.g. waste).

A.3 Municipal, Commercial and Industrial Waste AD

In estimating the growth of waste AD plants processing predominantly wastes generated from householders and commercial and industrial sectors we have considered the generic barriers set out below as well as specific issues and opportunities for this sector.



A.3.1 The Availability of Feedstock

Waste materials available for AD facilities range considerably and include:

- biological wastes incorporated in municipal solid wastes (MSW)
- segregated household food and green wastes
- mixed commercial and industrial wastes
- segregated food and drink wastes (all categories of Animal By Products wastes)
- segregated organic process wastes
- horticultural/landscaping waste
- abattoir wastes

The absolute limiting factor for the anaerobic digestion industry is the availability of the feedstock. Within the waste management sector there have been many studies on the need for waste treatment technologies, most notably as part of a regional waste strategy or regional spatial strategy, these will provide reasonably good figures for municipal and commercial and industrial biological waste arisings suitable AD treatment. However it is understood that this data is not available at the national level.

A range of high level assessments have been made about the availability of feedstock resource in the UK and its subsequent energy yield. However, due to the varied nature of feedstock, limitations of data, assumptions/calculations and lack of clarity on energy use these should be read with caution.

A range of biogas feedstock potential exists, depending on assumptions made. While the range is wide, the figures presented indicate that the volume of feedstock is unlikely to be a limiting factor on the development of biogas over the short to medium term. It should be acknowledged that at a local level, in planning a proposed AD plant, the availability of feedstock is in reality the key factor in the potential funding and success of a development.

DEFRA figures state that between12-20 million tonnes of food waste (approximately half of which is municipal waste collected by local authorities, the rest is hotel or food manufacturing waste) is potentially available for AD. WRAP[38] report that approximately 8 million tonnes of food waste is generated from householders.

AEA (2010) estimated that there is around 20 million tonnes of total waste available for biogas production in the UK; with an energy content of 63PJ or 17.5TWh. These are the figures used to estimate waste biogas plant growth.

Displacing Animal Feed

It is to be acknowledged that large volumes of food wastes are currently recovered for animal feed, this can include damaged fruit and vegetables and by products such as grains or bakery wastes. In the majority of cases this is currently not consigned as a waste stream and therefore the tonnages are not included in the DEFRA figures above. The inclusion of foodstuffs currently going to animal feed would be considerably complex, both in terms of volumes and the availability.

The use of such materials in an AD clearly has downstream effects, such as on the economics of a plant, agricultural (potential supply chain) and food costs. In having regard to the difficulties in gaining data and the complexity these volumes have not been accounted for in the modelling undertaken.

A.3.2 Drivers

Landfill diversion drivers

The greatest driver for the diversion of wastes to AD plants is the regulation on the use of landfill. The principal tool to support the landfill regulation and divert biodegradable wastes from landfill is the Landfill Tax Escalator, that will raise the landfill tax to £80[39] by 2014, improving the economic viability of alternative waste treatment technologies for public and private sector waste.

In Germany no landfill tax exists, only the TASi and Landfill Ordinance that ‘ban’ landfilling untreated wastes. The German approach has led to the expansion of combustion facilities and mechanical biological treatment (MBT) plants with AD and/or producing ‘biostabilised’ wastes. Other Member States operating similar landfill ‘bans’ include: Austria, Sweden and Denmark.

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[38] WRAP: Waste and Resources Action Programme

[39] The proposed figure for landfill tax as announced by the then Chancellor Alistair Darling in March 2010 does not include the gate fee or any cost if transport.

Whilst current regulatory mechanisms in the UK do not impose an outright ban on sending untreated residual waste to landfill, the proposed costs of treatment by new waste technologies is becoming more competitive, and with an increasing Landfill Tax over time, commercial and industrial waste producers are actively seeking alternatives to their current disposal routes. Alternatives include greater diligence in source separating waste streams (e.g. food wastes), which represents a driver for investment in new AD facilities.

Corporate Drivers

The rising costs of waste disposal are a key driver for the commercial and industrial sector to address their waste management and disposal, either through more efficient process/manufacturing and thus reducing the waste generated or through alternative management routes for recovery.

Corporate Social Responsibility targets are also playing a role in the diversion of waste from landfill, primarily through the ambitious targets set (e.g. Zero Waste to Landfill) and secondly by the value placed on such target at Board level. Driven predominantly by the food and drinks sector (including supermarkets), this has led to a drive in the need for alternative technologies such as AD, and pressure on the waste management industry to provide for alternatives including combustion.

Notwithstanding the current fiscal and revenue incentives for renewable energy generation many commercial and industrial waste producers have implemented corporate targets to procure or generate renewable energy for corporate responsibility reasons and also in response to the framework of carbon policies, including the Carbon Reduction Commitment (CRC) and Climate Change Levy and EU Emissions Trading Scheme.

A.3.3 Barriers

The technical barriers to the deployment of AD technologies processing wastes are commonly related to the complexity of the feedstock, the subsequent digestate and heat markets.

Gate-fee revenue uncertainty

Income from third party wastes currently provides further revenue to offset the capital and operating costs of a facility. The cost per tonne for the collection and/or treatment of source-segregated food and catering type waste is between £30 and £60 per tonne. Conversely, clean, high energy value, non-ABP wastes in some cases can command a fee for the supplier.

It is expected that the cost of collection and treatment of waste will rise due to limited landfill capacity and incremental increases in landfill costs and the Landfill Tax. In terms of the disposal of animal by-product wastes, cost increases have also been observed in the last three years.

However, it has been suggested that demand will increase for wastes suitable for anaerobic digestion with high energy content as a result of renewable energy incentives. This could result in more competitive pricing of gates fees to secure waste supplies. This may push the price of gate-fees down and some predict that gate-fees may eventually turn from revenue into cost as waste in essence becomes a commodity.

Many local authorities tender short term contracts for the treatment of source-segregated waste (<5years) and long term contracts (+25 years) for non-source segregated mixed residual waste. This greatly restricts the certainty of waste supply to AD plants once provided by long term municipal waste contracts.

Given that uncertainty surrounding the future level and availability of the gate fee, project developers (and their financiers) are unlikely to consider the gate fee as a stable source of revenue for financial evaluations, and/or may discount them in their financial appraisal.

Technology Costs

Technology costs, as outlined by the cost model, are directly related to the complexity and quality of the technology employed. For example the higher the quality of digestate, wastewater and energy generation, the higher the technology cost. This may not be a priority for many waste management companies that have access to waste markets such as compost units, landfill or land assets, however for corporate bodies investing in technologies the quality of technology would be a prerequisite in order to manage corporate risks. However our analysis suggests that it is likely to be a very small proportion of the facilities deployed in the UK.

Planning

It is noted above that on farm planning is not considered to be a significant barrier to AD development, however waste AD plants will be considerably more complex and involve a subsequently longer planning and consenting process. A number of factors will determine the length of the planning process and ultimately the decision, including; location, waste streams, use of heat, proximity to residents and size of plant. DEFRA[40] also note that a complication to the planning process is the lack of deployment in the UK. Therefore many of those involved in planning decisions can be unfamiliar with how the procedures apply to anaerobic digestion. Many technical lessons have been gained from existing facilities that need to be communicated to the sector in order to mitigate the risk of objections to planning, for example the odour issues observed due to a change in the feedstock at Biocycle South Shropshire[41].

In terms of heat export location is clearly key and therefore it could be argued that the ease at which a project can gain planning due to location may limit the heat export potential, for example located on existing waste management land such as adjacent to a landfill.

Feedstock

The choice of feedstock for an AD plant will influence the front end technologies that prepare the wastes for the digestion process. For example mixed wastes will require significant technologies that can separate out the biological fraction of the wastes, as seen in MBT facilities, whereas 'clean' packaged foodstuffs for the food and drinks industries will require specialist technologies to separate out the digestible fraction from the packaging. Whilst this is a critical component of the configuration design these are existing 'off-the-shelf' technologies that are not considered to be a issue on the supply chain in the deployment of the technologies.

Employing upfront technologies to prepare the feedstock makes it difficult to be feasible at small scale, for example less than 20 – 30,000tonnes per annum.

As noted in the on farm section above, a key technical constraint is in extracting the 10 – 20 million tonnes of available wastes from the waste stream. This is heavily influenced by local authority

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[40] AD Implementation Plan

[41] Biocycle South Shropshire is an AD plant processing food wastes from Ludlow, which was part funded by the Defra New Technologies Programme www.defra.gov.uk/environment/waste/.../Biocycle-final.pdf

collection systems, procurement and corporate segregation at source, the latter will be supported by the increase in landfill tax.

Despite this material being available for AD there remains competition from other forms of waste treatment technologies and outlets that should be considered including combustion, advanced thermal, composting and animal feed. It is important therefore that the technical ability to segregate and the additional costs are reflected.

Technology Risk

The general technology risk for both the AD process and heat export is low. DEFRA's AD Task Force do note however that there is relatively little experience of running AD plants on feedstock containing a high proportion of nitrogen, such as food wastes. However, it can be argued that this is more an operational risk in managing the waste streams being fed into the digestion process.

By added waste streams or alternative feedstock substrates (e.g. energy crops) will have an impact on the digestion process and additional technology or modifications will need to be made on a case by case basis.

Supply chain

As the configuration of AD plants processing waste is significantly more complex than single substrate (mono-digestion) plants such as energy crop plants the supply chain is more complex and specialist. In the UK there are a limited number of companies and technology providers operating waste processing plants and it can be argued that in Europe the number of technology suppliers processing wastes is also limited. For example, a study for Renewables East by Juniper Consulting identified 21 companies that could deliver biomass AD plants in East of England[42], this only included companies that they considered to be commercially available to develop projects. The potential growth will therefore have an impact on and be impacted by both technology resource and human resource in delivery of the facilities.

We do not envisage supply chain issues on standard pieces of equipment, such as shredders and trammels, however propriety equipment and turnkey suppliers of AD technologies will be strained in the short to medium term.

A.3.4 Distribution of heat

It is expected that the size of plant processing waste materials will be higher than that of on farm plants. As a consequence the volume of heat generated available for use on site or for export will be greater and in terms of location and proximity to heat user it is likely to be more feasible.

The key barrier to the distribution of heat will be proximity to heat consumers.

The barriers to renewable heating associated with all energy from waste technologies have been identified in studies for BERR and DEFRA by Enviros[43] and AEAT[44] respectively. The core issues emerging from these studies are described below with brief commentary on potential opportunities

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42 Juniper Consulting Services for Renewables East Bioregen. Commercial Assessment. Anaerobic Digestion Technology for Biomass Projects (2007).

43 Enviros (2008) Barriers to Renewable Heat. Report to BERR September 2008.

44 Barriers to uptake (AEAT) AEAT (2005) Renewable Heat and Heat from Combined Heat and Power Plants – Study and Analysis. Report for DTI & Defra. Online: http://www.berr.gov.uk/files/file21141.pdf

that exist in light of such issues. It should be recognized that these barriers and options for heat are relevant for all AD applications.

Stable Heat Market

Whilst electricity can be sold via the National Grid and has a guaranteed market, perhaps the greatest concern for developers considering configuration of a waste treatment facility to provide heat is the requirement for a secure market. The supply of heat to an industrial recipient requires detailed understanding of the long term strategy or potential changes to the business, with potential guarantees before developers are able to accept the risk for a long term contract. Where a stable heat market is identified for industrial heat off-take there is a requirement for considerable cooperation and contractual agreements between the supplier and heat users. One approach towards guaranteeing a heat customer is to develop a facility to supply your existing heat requirements (embedded energy generation), this has been seen for thermal treatments but limited for AD projects. One example is the combined slaughterhouse/biogas plant is located at St.Martin/Innkreis in the North-West of Austria[45].

Where the heating load is seasonal, there exists additional potential to use heat to drive an absorption chiller to provide cooling. Typically, chillers can be used to produce water chilled at temperatures down to 3 to 5 degrees.

An overview of the potential opportunities for delivering heat to a number of sectors is presented below. These are based on a recent study by Enviros on the barriers to renewable heat undertaken on behalf of BERR.[46]

Industrial Facility/Park

Where an industrial installation has a large base load process heat demand, this is suited to the supply of heat from a waste facility, as the demand is likely to be constant and so potentially more stable and predictable. A key consideration in supplying heat, e.g. steam or hot water, for such applications is to ensure the supply is integrated so that in the event the waste facility were to be off-line, the industrial process will not be affected.

Commercial Buildings

The potential to supply buildings with heat is limited to space heating and domestic requirements, e.g. hot water for washing, cooking etc, and therefore the opportunity is often relatively small. The potential for district heating for this type of development, however, can be improved if cooling is also provided. Commercial buildings can benefit from small scale, strategically sited facilities generating in the region of 0.5 – 2MWth.

Retail

Retail offers a good opportunity for the utilisation of heat as it requires both heating and cooling. Key issues influencing demand are store hours and seasonality. Retail development might be considered to represent a long term outlet for heat/cooling, for example supermarkets and retail centers (shopping malls) and can therefore be attractive for developers seeking heat markets.

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45 Further details can be seen at IEA Bioenergy Task 37.
46 Enviros Consulting, Barriers to Renewable Heat report for BERR (2008)

Key issues could include the complexity of relationships between property owners and tenants along with public perception issues of heat / cooling produced from waste facilities located nearby, specifically if there is any potential issue with odour.

Local Government/Public Facilities

Buildings such as Government estates, hospitals, schools and leisure facilities are prime candidates for potential heat supply from an AD facility. Firstly they are driven by internal targets and policies for renewable energy, and secondly, in many cases they offer a reasonable base load for heat and cooling requirements. Hospitals and Universities, for example, will have on site boilers that could be by-passed and the existing heat network infrastructure used, whilst the value of the heat imported could be set such that savings are made by the public sector.

Large Scale District Heating Networks

Directing heat from a plant to a number of different users with varying needs of heat load requirements will optimise the efficiency and cost effectiveness of a project. Delivering limited heat to a small number of recipients at varying distances from a plant, however, will almost certainly not be economically feasible unless these are all major heat consumers.

It is acknowledged that larger plants represent more cost effective options for district heating, however, the difficulty in this approach will be land availability, proximity to heat demands and availability of waste substrate.

Disruption caused by Heat Networks

A major barrier to heat provision is the requirement for the installation of underground heat networks for district heating (DH). Whilst the issues associated with the costs of this kind of infrastructure are highlighted above, it should be acknowledged that (with either a retrofit or a new build scheme) there will be a requirement for significant changes to existing heating infrastructure and disruption to roads and other amenities, which would potentially raise local objections.

Parasitic Heat Demand of New Waste Treatment Technologies

AD facilities can have significant heat demands on site, which is dependent upon technology and external temperatures. In addition AD facilities may also require heat for drying of the digestate prior to maturation or for use as a fuel. Consequently, a proportion of the heat derived from the energy generation process is often re-circulated for such uses. In the case of small to medium scale AD facilities this may leave little for distribution outside the facility.

A.3.5 Waste AD: growth assessment

Heat Only

It is considered that a heat only plant configuration utilising wastes would have limited applications and it is expected that the majority of new plants would be small scale due to CHP being a more attractive financial and technical option. An example of a small scale industrial heat only plant would be where a constant supply of process wastes from food and drinks manufacturing is used in an onsite digester for heat (space or process heating).

The principal barrier of the heat use noted above will be in utilisation of the heat, thus lending itself better for process heating. In addition, there will be issues in relation to the cost benefit of the process waste material which may be a commodity material (e.g. animal feed), as opposed to waste.

In light of the limitations we believe that there will be very few projects generating heat only through a boiler, and these will be reasonably small scale (1 – 2 MW generating biogas).

Combined Heat and Power

The type and configuration of AD projects treating wastes are likely to be of the scale that is attractive both technically and economically to CHP. The current incentives for renewables lends itself to generating power and due to the relative ease of connecting to the National Grid provides a developer a reasonably stable income – subject to feedstock.

The viability of either CHP or BtG option will be dependent principally on proximity to electricity and/or gas connection, heat users and the financial incentives associated.

It is not considered that the majority of developers will include heat export as an integral part of their business case to build an AD facility. It is however expected that when reviewing site options the use of heat users in proximity of the plant will be investigated (as has been seen for biomass developments), and as such it is unlikely they will actively seek to use the heat for process or district heating but that the inclusion of an additional incentive will allow for an opportunistic review of heat distribution options.

The range of heat uses will vary considerably from 24/7 process heating (where a plant is embedded to an industrial process) to district heating network. It is important to recognise that with space heating the load profile will vary throughout the year and that heat will be dumped because of low demand periods. In the modelling undertaken assumptions have been made on the load factors for heat use which takes into account the varying demands that are likely to be observed.

The limiting factor on growth for CHP, power only and BtG is feedstock availability (under the assumption that financial issues are not a constraint) . With regards to feedstock the range of plant sizes for the CHP option was from 1MW to 5MW annual generating biogas potential, which is approximately 12,000 tonnes per annum to 60,000 tonnes.

Power Only

AD can also operate in power only mode. These technologies will be generating heat from a gas engine, which will be used parasitically in the digesters but not utilised as part of a wider heating need. In the modelling for CHP we have included plants that will be exporting relatively small amounts of heat, which is reflected in the load factor for heat use, and therefore it is considered that growth in power only plants will be similar in number to that exporting some volume of heat in CHP mode.

Biomethane to Grid (BtG)

BtG offers the greatest potential for waste AD plants. This is a diverse sector with potential for small niche plants (Bio-Group Adnams) and larger projects (50,000tonnes per annum). In removing the barriers to BtG this presents a more attractive opportunity to developers as the additional capex and administrative burden of heat exports can be removed. As a result this is a highly active sector with a large number of potential projects.

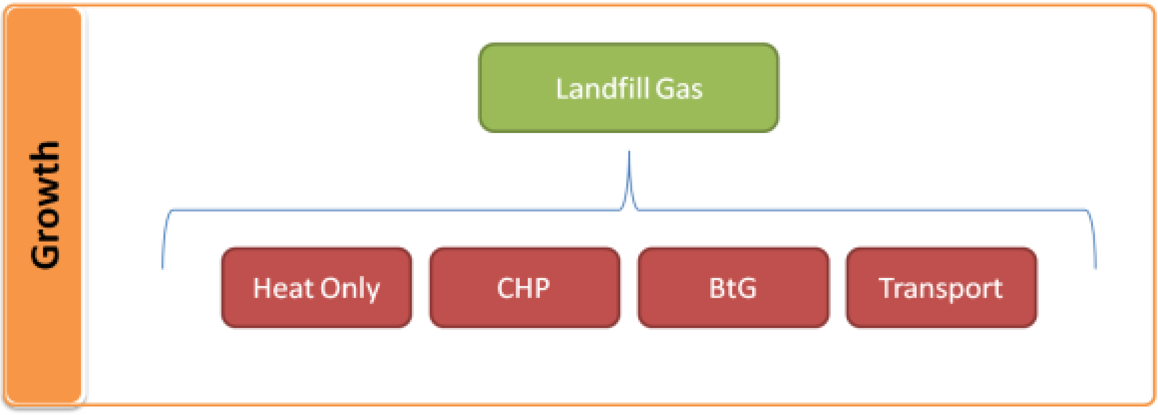
A.3.6 Waste AD: high growth

There are various figures available for waste feedstock suitable for AD. In terms of food wastes from the households we have considered WRAP's figure of 8million tonnes per annum to be the maximum available. However, in considering current residual waste contracts, extraction rates as part of food waste collection systems, and competition from other technologies including composting and combustion it is reasonable to assume that the maximum available food wastes that can be made available from the householders will half of that generated.

The volume of commercial and industrial wastes suitable for AD is by and large unknown. DEFRA figures suggest that between 6 and 10 million tonnes are generated from hotel or food manufacturing, which is considered reasonably accessible. In addition to these there will be food wastes in the residual waste stream that could be extracted through technologies such as merchant MBT, however this is likely to be relatively few. As noted early there will additionally be wastes that are currently sold as animal feed that could be diverted to AD, which is wholly dependent upon energy costs and incentives. It is not clear whether these figures are included in DEFRA's statistics, however based on our experience in this sector it is considered unlikely. Such wastes include brewing residues (e.g. spent grain), abattoir fats (currently sent to oleochemical sector) and food manufacturing (vegetable off-cuts).

The constraints of meeting the high growth figures for waste AD will principally be:

- Waste Feedstock availability as discussed above
- Suitable heat demands
  - The heat export option will be constrained by distance to suitable users with reasonable annual heat demands that will make the additional capex and contract/energy administration suitably viable.
- Operational Experience
  - The operational experience for waste AD is much more advanced than on-farm and energy crops in the UK, specifically for the management of energy and feedstock preparation prior to digestion. The operational knowledge and management of wastes to ensure maximum efficiencies are being realised, technical issues are being mitigated and time to manage the operations of the technology can be made available are limited.
- Supply Chain
  - In Europe there is considerable experience, but in terms of number of technology providers that are processing wastes this is limited. The growth of AD developers in the UK will need to be significant to meet demand of high scenarios.



A.4 Landfill

Landfill Gas utilisation is one of the dominant renewable technologies within the UK and contributes approximately one quarter of all renewables production. The bulk of utilisation is achieved through power generation and export (generally reciprocating ignition engines) and this is considered a well developed and mature market within the UK.

The gas generation and composition of landfill gas from landfill sites varies greatly, depending on age, biodegradable content of the waste and other site specific factors. However, the amount and composition of LFG output depends on the composition of waste and site-specific conditions.

In this analysis it is assumed that the potential for heat from landfills will be predominantly generated through biomethane to grid. This is analogous to sewage treatment insofar as the option to switch from gas engine to biomethane to grid could be financially attractive to operators.

The opportunity for landfill to generate heat and play a key role in the delivery of heat targets is not regarded as being significant. The modelling for landfill to biomethane to grid has been included in the waste section modelling. Here we discuss the opportunity and barriers for use in this technology.

A.4.1 Landfill gas utilisation

The uptake of landfill gas utilisation scheme expanded dramatically in the 1990s and through to 2005 due to the availability of funding mechanisms including initial NFFO schemes and, latterly, ROCs and also due to the legislative requirement to control landfill gas.

The majority of landfill gas utilisation schemes tend to be 1MW or over due to financial restrictions. Landfill gas qualifies for a 0.25 ROC per MWh since the reform of the Renewables Obligation, 2008. Smaller schemes are technologically feasible but they have associated comparable capital and operating costs to larger schemes, and it is likely that BTG is a more cost-effective option for growth in this sector.

When considering landfill gas utilisation the financial benefits will (or should) be passed down to offset the cost of regulatory compliance and landfill aftercare. These associated costs may also restrict the implementation of some smaller schemes on older sites where legislative requirements are not present or are not being rigidly enforced. However, it is recognised that installation of schemes on these sites will provide potentially large environmental benefits as methane otherwise lost to atmosphere will be utilised.

There is potential for gas extraction and injection to the grid. The most suitable site to target will be the ones operated on Waste Management Licenses (WML) (post-1995) as they are likely to have gas extraction equipment already installed and have engineered capping thus removing this expense.

Options for older or lower yielding sites could also include combining technologies for example installing AD plant as a supplementary gas stream. In this scenario where combined yield from the landfill and AD plant could be sent to common scrubber or clean up plant prior to export to the grid, thus providing economies of scale for expensive equipment. Landfill sites are often suitable for the siting of these types of technologies due to the presence of mothballed infrastructure, available space and their brownfield status.

It is understood that the Environment Agency is currently interested in targeting the control of landfill gas at older landfills for climate change purposes as these are considered to be a significant emitter of landfill gas. Work has been undertaken on old PPC Part IIa sites and the Agency is currently compiling a risk register of all WML sites with a view to implementing gas control enhancement and potential utilisation of the gas. The Agency is currently considering ways of providing incentives to promote extraction, treatment and possible utilisation of landfill gas on older lower yielding sites but this is at the early stages of development.

In 2005 SKM Enviros (then Enviros Consulting) produced a report for DTI on the costs of supplying renewable energy which provided the following estimate of the Emissions of Landfill Gas from Landfill Sites in the UK. The report stated that gas generation and composition of landfill gas varies greatly depending on age, biodegradable content of the waste and other site specific factors. However, the actual volume and composition of LFG output depends on the composition of waste and site-specific conditions. The report grouped landfills into 4 different categories:

- *Type 1 – Closed sites without an effective cap or any flaring on site.* All landfill gas that is generated is vented directly to atmosphere. However, the quantity of methane produced for each tonne emplaced is expected to be lower due to less densely packed waste and a high rate of oxidisation whilst passing through the upper layers of the landfill.
- *Type 2 – Closed sites with a limited cap and limited flaring.* The majority of landfill gas generated from sites within this group is vented directly to atmosphere. These sites may have some flaring to reduce the potential risk of lateral migration of landfill gas. Placing flares along the edge of a landfill near residential or other sensitive areas became industrial practice following an accident in 1986.
- *Type 3 – Active (or recently closed) sites that have a completely engineered cap and comprehensive flaring.* Typically these sites accepted waste from 1986 onwards. These sites are likely to have a completely engineered cap, with an effective gas collection system and flaring.
- Type *4 – Active (or recently closed) sites that have a completely engineered cap with comprehensive flaring and utilisation.* Typically these sites accepted waste from 1986 onwards. These sites are likely to have effective gas collection, flaring and gas utilisation.

The estimation of total gas generation is based on a number of very broad assumptions including high level assumptions on waste arisings and the impact of legislation such as LATS. It is estimated that due to increasing diversion of biodegradable waste from landfill, the potential yield of landfill gas is considered to decrease over the long term.

A.4.2 Heat Only

The use of LFG biogas in boilers for heat only options will be technically straightforward with limited alterations to existing boiler technology, minor issues will include:

- LFG is ‘wet’ and contains corrosive trace components so replacement of boiler parts with non-corrosive elements may be required and moisture ‘knock-out’ provision
- As with spark ignition engines siloxanes may be a problem (site specific depending on wastes accepted) and boilers may require more frequent overhaul/cleaning
- Will require gas pipeline installation – cost, planning, rights of way etc.
- Landfill gas compression system may be required at the landfill, this system must be capable of overcoming the pressure drops along the pipe route. If it isn’t then additional gas boosters may be required.
- Landfill gas is delivered 24/7, therefore end use with constant heat requirement generally required
- Local options to sites are often limited

A.4.3 Combined Heat and Power

Whilst LFG is burnt in reciprocating engines to generate power (when not flared) the use of heat from the engine is very limited. In order to utilise the heat from the engine the following is noted:

- The use of heat will increase the efficiency of ‘traditional’ LFG schemes from 30 – 40% to >80%
- It is proven technology but usually on larger scale than currently offered by LFG projects
- Can be included with spark ignition engines which are used on majority of UK LFG projects
- Local options for heat utilisation are often limited due to the location of landfill sites
- The uncertainty over future gas yields from landfill adds significant risk to the business case for installation
- As with AD, landfill will generate a constant heat load and therefore a constant heat requirement is necessary
- The option would be more technically and economically viable for larger/newer landfills largely due to cost

A.4.4 Biomethane to Grid

The issues and opportunities for landfill gas upgrading to biomethane to grid are similar to those for all AD plants and as such is discussed earlier.

Given that there more than 400 sites generating electricity and 30 with biogas flows of >3,000 M3/h it is reasonable to expect at least one large landfill gas to biomethane project per annum from 2014 and 2 medium sized ones. Large is classed at 2000 m^3/h, medium sized 1000 m^3/h (whilst there are technical issues with landfill gas they are not insurmountable and biomethane from such projects is injected into grids in other countries such as the Netherlands and the USA).

A.4.5 Landfill Summary

Landfill is likely to diminish due to legislation and a shift from landfilling to alternative waste treatment. There will be a reduction in landfills operating in the future, but possibly we will see a development of larger landfills for economies of scale and fewer sites suitable for licence.

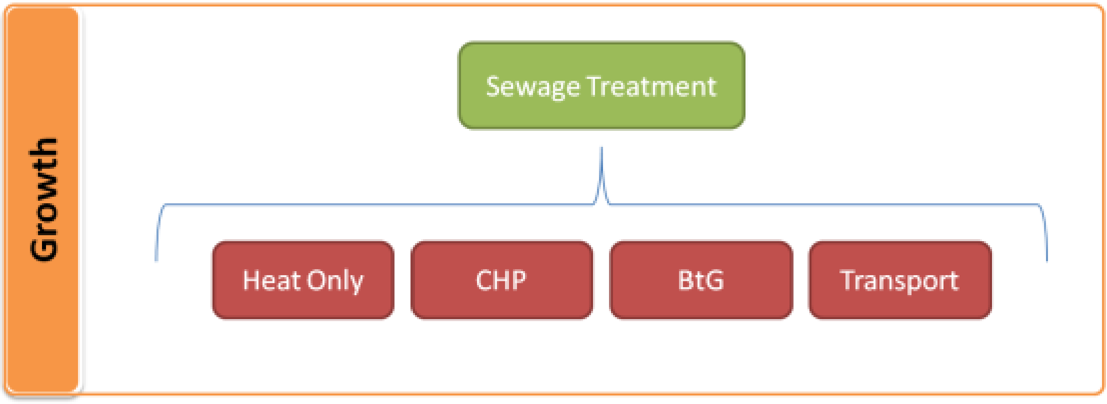
There are a large number of closed landfills that are producing significant quantities of gas which could theoretically be exploited (<1MW on a spark ignition and electricity export scheme). These could become viable for either heat or gas injection, specifically is sat alongside additional AD technologies.

If incentives for biogas upgrading and injection to grid outweigh electrical generation and export, then new schemes are likely to adopt this approach, and existing schemes may switch.

Landfill gas companies have historically dealt with engines and power export, these companies have most of the existing landfill tied up contractually (some are internal entities to the waste operators) and as such there may be resistance to change in technology due to need to change suppliers, unfamiliarity and need to change technology.

A.5 Sewage Treatment

Sewage treatment is unlikely to develop significant heat only capability unless a significant demand for heat existed. For most sewage treatment works, given their location, significant heat demand will be low. However, where a sewage treatment works is currently flaring gas technically the development of heat capability could be considered an opportunity to invest in infrastructure for heat use. Again, this opportunity is likely to be limited by heating demand.



A.5.1 AD electricity and CHP combustion

A more common application of AD technology is the generation of electricity from the treatment of sewage sludge and landfill gas. The majority of anaerobic digesters in the UK are run by the water industry for the treatment of sewage sludge, with around 550 digesters on 220 sites. These treat over half of the sludge produced in the UK. Outside waste water treatment, there are currently in the region of 40 other AD operating facilities, most of which are small-scale "on farm" plants.

The generation of electricity has been supported through the Renewable Obligation and, more recently, through the FIT mechanism. It can be argued that the Feed in Tariff introduced in April 2010 has had a limited effect so far on the further expansion of anaerobic digestion, although it should be acknowledged that the time for a project to reach construction from initial inception can take up to three years (depending upon size and location) and thus the true impact may not be observed.

While an established technology, the further exploitation of sewage and landfill gas will be limited by site availability and planning issues. As a result, while some further exploitation will continue, the growth rate will be moderated.

In terms of landfill gas and sewage CHP exploitation, utilising the waste heat from the generation process will depend on the availability of a heat load and corresponding heat network. While the potential for some small scale district heating schemes may exist, given the age of housing stock in the UK, greater application is likely to be achieved through heating industrial sites. However, again issues of site availability will provide a natural limitation of the application of CHP to sewage and landfill gas.

A.5.2 Sewage AD: growth assessment

Heat only and Combined Heat and Power

As with landfill gas we do not envisage sewage treatment plants to develop heat only or recover significant quantities for heat export as part of a district heating scheme. This is principally a result of the greater cost benefits of biomethane to grid application and technical difficulties in heat export options. Where heat may be used, for example, on site, this is considered to be low volumes.

Biomethane to Grid

.It is expected that BtG would be the most cost effective use of biogas in sewage plant. In the forecast, the build-up is based on the following logic:

- Each Waste Water Company implements one reasonably large biomethane project in the period 2011 - 2015. This is for biogas that is diverted from CHP (e.g. export electricity and the portion that does not use its waste heat).
- Each Waste Water Company builds 2 medium sized ADs in the period to 2020 which are developed to be biomethane to grid
- Each Waste Water Company builds a small biomethane plant using flared biogas
- A second tranche of projects comes in later years once CHP plants require replacing and as a result of the decarbonisation of the gas grid which makes base-load CHP less attractive.

A.6 Learning rates

AD heat only

We consider the learning curve associated with AD heat only application will be relatively shallow due, largely, to lack of application opportunities of the technology and therefore demand for the product.

AD electricity and CHP generation

The application of AD technology for the combined generation of electricity and heat is relatively well established technology. As discussed above, the majority of anaerobic digesters in the UK are run by the water industry for the treatment of sewage sludge, with around 550 digesters on 220 sites. These treat over half of the sludge produced in the UK. Outside waste water treatment, there are currently in the region of 40 other AD operating facilities, most of which are small-scale "on farm" plants.

The relative maturity of the technology suggests that the learning curve will be shallow for AD CHP and electricity generation costs. However, plant availability and subsequent costs are more likely to be influenced by the supply chain than technology maturity – supply chain issues arise from the availability of plant and supply components within the UK and the requirement to import plant and equipment with exposure to exchange rate fluctuation.

Biomethane to Grid

While BtG costs in the UK are currently high, reflecting the peculiarities of some application to the UK market and the pilot phase of application, we consider it likely that the current high costs of the pilot plants in the UK will decline. We consider a number of reasons will lead to the cost reduction and therefore greater investment rate:

- Revision to GS(M)R is completed to extend the oxygen limit to 1% or more (for comparison, the level is typically 1 to 2% in Scandinavia and Europe, 3% in parts of Germany with very similar network materials and components). A change to the oxygen level will require analysis to demonstrate there are no additional safety risks arising from higher oxygen levels
- Review of relative measurement accuracies of consumer metering to maintain consumer protection but which are compatible with low flows into the gas network and consistent with network metering and FWACV tolerances
- A competitive market for supply of BtG plant is developed so that
- Additional instrumentation is approved for usage in general or specific applications
- Expansion of BtG sites encourages additional market supply entrants
- A range of equipment suppliers have approved instruments in particular Gas Chromatographs to enable supply competition
- Propane plant costs reduce as a result of supply competition and economies of scale. For example, the same control logic that commands the injection valve will be developed fully in the first few projects and thereafter will be independent of flow rate
- Propane storage tanks are normally included in the supply tariff. Above a threshold (to be determined) this is not possible and projects will need to purchase storage tanks and accept the associated (modest) Capital and Opex costs
- Current regulatory hurdles affecting BtG projects are removed, for example plant ownership and cost recovery mechanisms, (notably those relating to Propane storage and injection)

As a result we conclude that learning curve effects, economies of scale, competition, but also regulatory changes could be implemented to reduce capex and operating costs. However, these are difficult to quantify and these haven’t been estimated in the current report.

A.7 Biomethane Injection to Grid

BtG is a new technology being deployed in the UK. As fledgling technology it poses a number of challenges to the industry that will have a significant bearing on the growth rates of AD with BtG. For completeness this report has outlined the principal barriers to BtG and outlines the key requirements and constraints for the technology.

A.7.1 The current UK market

Biogas from AD can either be used to generate electricity or converted to biomethane. If converted to biomethane the gas can either be injected into the grid in place of natural gas, or used as a transport fuel. In terms of efficiency of resource use, conversion to biomethane is a more efficient option than the generation of electricity (although not in a CHP unit).

Biogas arising from AD can vary in composition depending upon the substrate digested. Typically biogas from food processing waste contains around 60-65 mol% methane and around 35-40% carbon dioxide. Smaller amounts of nitrogen and oxygen, together with trace amounts of contaminants such as hydrogen sulphide may also be expected. Siloxanes are not expected to be present, based on the anticipated substrate. For biogas made from farm crops/slurry, the methane content is lower, around 55%.

Removing carbon dioxide from biogas increases its calorific value and, when most of the carbon dioxide has been removed, the gas remaining (usually in excess of 95-97mol% methane) is termed “biomethane”.

Depending upon the inert gas content biomethane is generally acceptable for use as a vehicle fuel, although for injection into natural gas distribution systems enrichment of calorific value using commercial propane is often carried out. Under the current regulatory and commercial regime for the UK gas industry propane enrichment of biomethane is expected to be necessary to avoid customers living close to the injection point receiving gas with a CV that is considered too low (customer bills are calculated on the basis of an accepted average CV).

Finally, natural gas piped at pressures below 7 bar cannot be conveyed in gas networks unless odorised to give a characteristic and distinctive odour, so there will be a requirement to add odorant prior to injection.

Around 30 BtG plants are currently operational in Germany, with around 20 plants under development. The UK has wo demonstration plants in operation, However, an additional potential disincentive to BtG development in the UK is the relatively high cost associated with injection to the gas grid given the the natural gas quality standards that place greater ‘clean up’ costs on BtG injection in the UK than in other European countries. Below we discuss a range of factors that currently influence BtG development in the UK.

A.7.2 Factors influencing development in the UK

Gas upgrading technology

Gas upgrading from biogas to biomethane involves lowering the carbon dioxide content from around 40 mol% to typically 2 mol%. Other trace components removed include hydrogen sulphide. There are various separation technologies available to effect upgrading of biogas but the most common approaches employ water-wash (WW), pressure-swing adsorption (PSA), and chemical absorption (CA). The technologies can be considered mature and all technologies currently can be purchased from 5 companies operating in the UK market.

The existence of multiple, large and competing technology suppliers of mature technology indicate that availability of biogas upgrading technology is not a significant barrier to grid injection of biomethane. However, the issue of costs in the short term is important given the relative infancy of application to the UK and lack of UK supply chain. Similar lack of UK experience will also affect maintenance costs.

Biomethane-to-grid technology

BtG technology consists principally of enrichment with commercial propane, odorisation, and monitoring and metering.

The enrichment of biomethane is already widely practiced in the EU and supply of propane enrichment system technologies are considered 'off the shelf'.

Odorisation consists of injection of liquid odorant into pipework whilst biomethane is flowing. The odorant rapidly evaporates within relatively short pipe lengths and the gas is completely odorised before arrival at the consumer. Two different odorant pump systems have been employed at the UK pilot projects from different manufacturers and there are other proven systems for biomethane that are available.

Monitoring

Monitoring of biomethane gas quality is required for two purposes:

- Demonstration of compliance with the requirements of Schedule 3 of the Gas Safety (Management) Regulations, 1996 (the "GS(M)R"). Principally this entails monitoring of combustion properties (Wobbe index, incomplete combustion factor and sooting index), hydrogen sulphide and total sulphur content, oxygen content, and water dew point temperatures.
- Determination of daily average calorific value at the point of grid injection for calculation of the calorific value to be used for billing consumers in the relevant charging area.

Historically the two purposes were carried out separately, i.e. at two different locations – the former at entry to the National Transmission System; the latter at entry to the Local Transmission/Gas Distribution Systems. For biomethane injection into a Gas Distribution System both functions must be monitored at one site. There is some scope for use of common systems – for instance combustion properties and calorific value can be measured using the same gas chromatograph. It is also possible that some of the requirements for GS(M)R compliance could be relaxed for biomethane injection because of its less complex nature. However it is likely that monitoring of water dew temperature, oxygen, hydrogen sulphide and total sulphur would always be needed.

There are only two gas chromatographs currently approved by Ofgem for determination of calorific values for consumer billing. The instruments are widely used in the natural gas industry and although costly, availability of technology is not thought to be a barrier to grid injection of biomethane. In addition a further two lower cost chromatographs are undergoing the approval process.

Accurate flow metering of biomethane into the grid is required for the two UK BtG demonstration projects so-called "fiscal quality" metering systems have been specified by the Gas Distribution Networks receiving biomethane, largely because this is currently employed at large scale NTS offtake sites, where the majority of natural gas enters Gas Distribution Systems. For small flows of biomethane such high standards of metering may not be appropriate and lower cost metering options appropriate to gas consumer metering systems may suffice.

Whatever level of accuracy is employed, gas metering systems are mature technology and are readily available from suppliers to the natural gas industry and availability of technology is not a barrier to grid injection of biomethane.

Location and capacity in the gas grid

Injection into the gas grid can only occur where the gas grid exists, and so is unlikely to be viable in those rural areas predominantly off gas grid. More significantly, in rural areas, even if a gas grid exits there may not be capacity to accept biomethane flows. If the biomethane flows into a Medium Pressure (MP) network (2 bar) at 200 m^3/h then the customer demand on that network must always be >200 m^3/h. In summer, at night, with no central heating demand and reduced hot water/cooking, demand will be low. At such times the Gas Distribution Network (GDN) will indicate it does not have capacity to take the 200 m^3/h on a 365 day basis – clearly negatively influencing the economics of the BtG project.

Our analysis suggests that a supply/demand capacity constraint as described above exists for around 40% of potential projects. The medium term solution is for the GDNs to install compressors to lift gas from (in the above example) the Medium Pressure (MP) network into the higher pressure Intermediate Pressure network (4 bar) or Local Transmission System (LTS) (19 – 40 bar). The existence of the gas network and ability of that network to accept BtG forms a potentially major barrier to growth of biomethane.

Planning Issues

Biogas upgrading and BtG technology are both straightforward and offer no additional significant risk over conventional above ground installations in terms of safety, health and the environment. Depending on the feedstock the plant may be located in rural or built-up areas. Noise is generally not excessive and arises mostly from compressor operation. Biogas upgrade using water wash technology can involve relatively tall towers and planning permission may be a factor to consider in some areas. In some biogas production operations (e.g. sewage works) odour emissions may be a consideration, but would be a consideration for any intended use of biogas and not just BtG use.

Overall, planning issues are not expected to be a major barrier to grid injection of biomethane in addition to any other configuration of anaerobic digestion.

Plant Size and Economies of Scale

There are significant fixed costs in relation to biomethane injection that lead to plants with biogas flow <100m^3/h may not be economic unless the gas is already produced and flared. Farm waste schemes are often smaller than 100m^3/h and biomethane production may be inappropriate for a single project. A more viable option to exploit economies of scale would be to join farms together as a co-operative, with clean up and upgrading at one location adjacent to a gas grid. We have reviewed such an option in a project for Reaseheath College (DEFRA funded) and it is credible in dairy cow rich areas such as Cheshire and Somerset (see section A.1).

A.7.3 Regulatory Constraints

GS(M)R Oxygen Specification

Although AD technology is considered mature, typical UK biogases tend to contain relatively high oxygen content (typically up to around 0.5 mol %, resulting in around 0.8 mol% in biomethane following CO_2 removal) considering the process is anaerobic. Schedule 3 of the GS(M)R currently limits oxygen to a maximum of 0.2 mol% and sustained significant biomethane injection will require either exemption from this requirement or revision of the policy. Exemption for the two demonstration projects in the UK has been based on demonstration of the minimal impact on corrosion of cast iron gas mains or use of blending with natural gas.

It is estimated that the cost to obtain an exemption is in the regions £30-£50K that will be added to current BtG project capex. As at present there is no guarantee that the HSE will grant the exemption, there are currently no biomethane projects funding the exemption work. They are either on hold or are confident that they can keep their O_2 below the 0.2%.

The issue of oxygen specification is a major technical barrier to BtG development.

Gas Transporter Licence

It is not clear whether the gas producer at biomethane sites needs to have a Gas Transporters licence to convey gas from its plant into the GD network. It is likely that a Licence is required if the biomethane producer adds the propane and odorant and delivers compliant' gas. However, a legal opinion has been requested by the biogas industry, but this has yet to be resolved.

Ownership of BtG Assets

It is not clear which model for plant ownership and operating responsibility is best suited to sites. The options include:

- DN funds the plant, owns it, receives a return and takes appropriate liabilities (in German the assets are 75% funded by GDN, 25% by biomethane producer)
- Customer funds, DN owns and maintains, no return to DN, DN takes some or no liabilities for plant performance (this is the existing UK model and is the one that the GDNs are currently presenting to the biomethane producer)
- Customer funds and owns, having to meet DN's specification - This is the National Grid NTS Model and the model that applies in the Netherlands. It has the advantage of allowing the biomethane producer to integrate the BtG plant with the clean up and upgrading plant.
- Customer has Gas Transporters Licence, they fund, own, operate BTG plant and pipeline with the DN network a connected system

Ideally all the GDNs and Ofgem and the biomethane industry would agree a common framework for ownership, maintenance, funding but this is not in place yet.

Capacity

There is currently no incentive on GDNs to provide firm capacity on a long term basis which may mean that firm capacity is not offered in cases where there is a risk that local demand may fall (e.g.

large manufacturing plant closure) which would reduce ability of the GDN to accept biomethane flows.

Until there is agreement between the GDNs and Ofgem in relation to the ownership framework and the capacity regime, it is likely that some biomethane projects will not have the capacity certainty they require to reach financial close. In some case, the GDN may need to incur operating costs to make available capacity (e.g. adjusting regulator settings), but at present they receive no allowance for this.

Target CV

UNC Review Group 251 met in August and September and agreed a basis for CV as follows:

- Biomethane producers should meet target CV, around the FWACV level
- Capex and opex of propane enrichment plant should be funded by the biomethane producer
- The biomethane producer should fund the Propane Value Loss (i.e. cost of propane minus equivalent energy cost of natural gas)
- GDNs should have incentives to offer blending services if this is technically possible

The UNC Review Group 251 estimated that CV shrinkage cost of £400 Million could be incurred if there was not a target CV for biomethane.

Appendix B Use of Biomethane as a Vehicle Fuel

The following section sets out the concept of upgrading biogas generated to biomethane for utilisation as a vehicle fuel, including its interaction with other policies and costs. The use of biomethane for vehicle fuel will predominantly be achieved through injection to grid and therefore modelling the potential for this specifically has been excluded from the study. This section therefore serves to support future policy development through the provision of information on the technologies and economics.

There are 2 basic Concepts to make Compressed Biomethane (CBM) for vehicles and a parallel scheme for the production of Liquid Biomethane (CBM)

Compressed Biomethane (CBM)

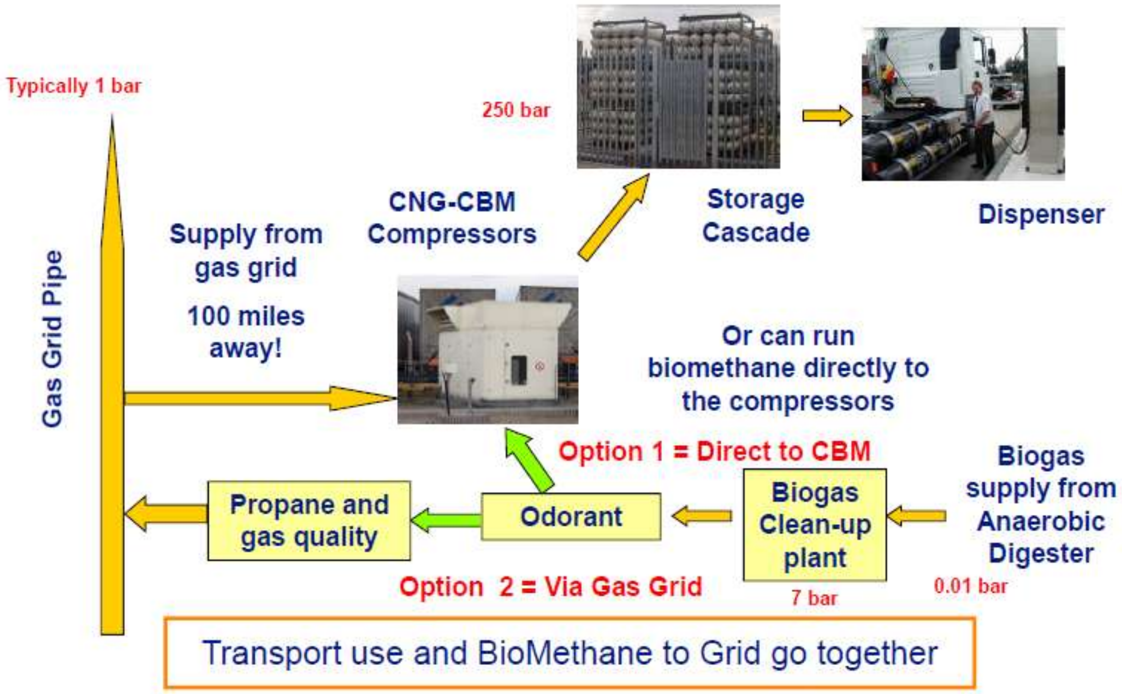
CBM Concept 1: Vehicle fuel station. A vehicle fuel station takes a high quantity of gas and is designed to refuel vehicles at a commercial operation (transport fleet depot). The biogas is cleaned-up and upgraded to biomethane, odorant is added, it is then compressed to 250 bar and dispensed directly into vehicles. A variant on Concept 1 involves injecting biomethane at the AD plant and taking out an equivalent amount of grid gas at another point.

CBM Concept 2: Slipstream model. A slipstream model is a small scale biogas cleanup unit with vehicle refuelling facility. It will form part of a biogas production plant and takes a small proportion of the biogas generated for cleanup to biomethane. The cleanup waste gas is returned to the biogas stream and either flared or consumed within a CHP unit. It is sized limited to 5 - 10% of the biogas flow available and preferably has a gas grid connection to maintain security of supply for the vehicles.

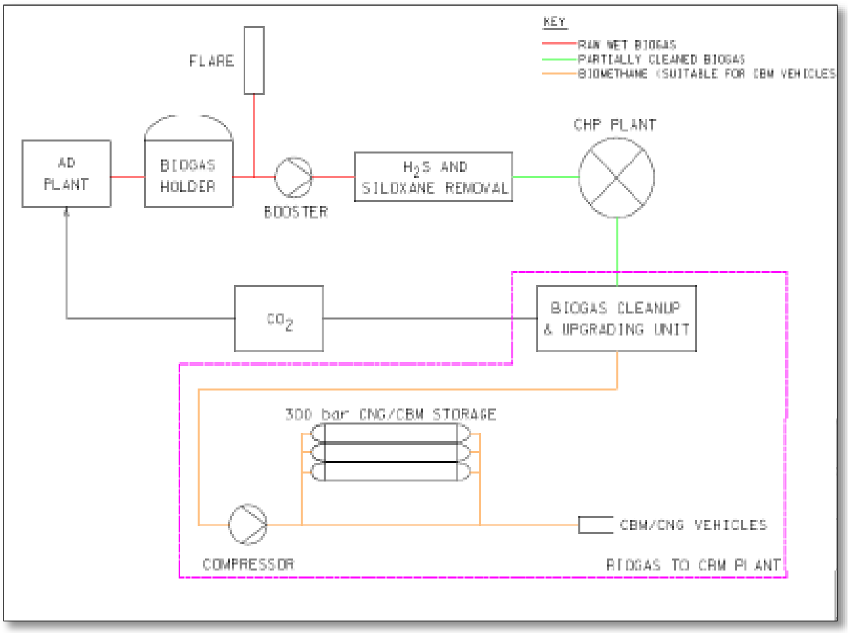
Liquid Biomethane

This takes the output from Concept 1 above and instead of compressing the gas for storage it is liquefied. Small LBM plants are not economical when compared with CBM and the smallest units have a capacity of around 10 tonnes per day output (20,000L) equating to some 850 m3/hr biomethane input.

- **Figure 13 Schematic showing CBM Concept 1 large scale using gas grid**



- **Figure 14 Schematic showing CBM concept 2 slipstream**



B.1 Large scale CBM Plant

B.1.1 Station design

This principal of a large scale CBM plant station design is applicable whatever the gas source is. This section looks at the compression and storage requirements to take Biomethane and compress it for use as CBM. The clean-up and upgrading of the biogas is covered in the main body of the report.

There are strict codes of practice and guidance that needs to be followed in the design, installation and use of CNG plant and equipment. These codes lay out the specification and installation standards to ensure good safe practice is adhered to. The primary objectives of the codes are to ensure the safe operation of the station and include such things as Hazardous Area limitations, safety distances, safety protection and operation.

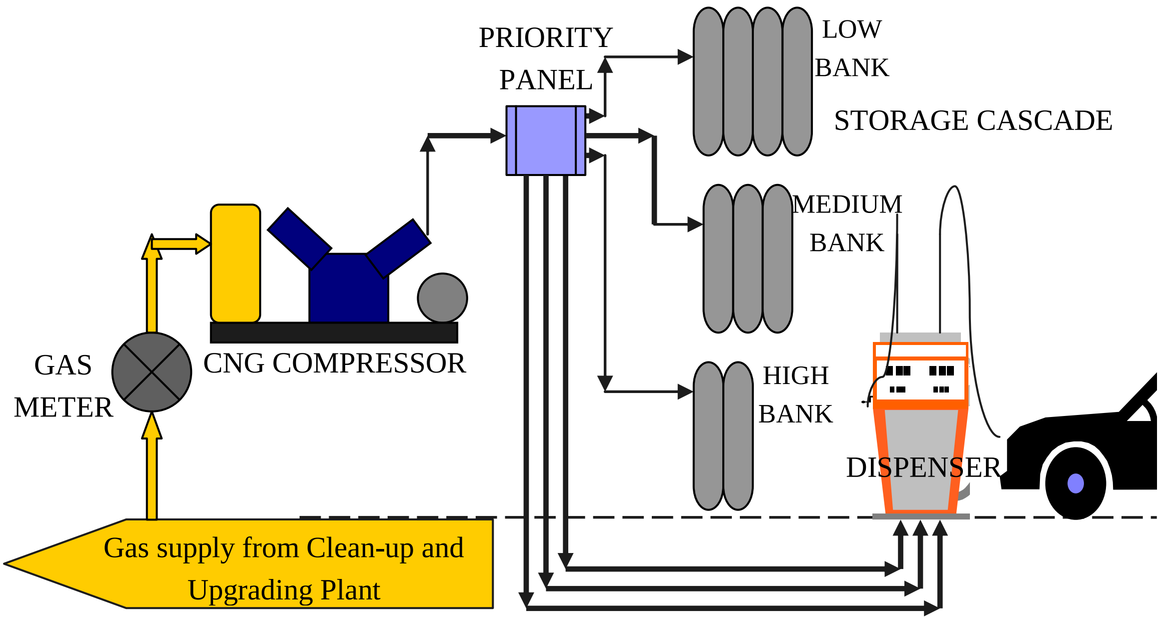
The main components of a CBM station are as follows:

- Biomethane inlet supply (ideally with gas grid connection)
- Electrical supply (415 Volt, 3 phase)
- Gas compressor (electrically driven), 250 to 300 bar outlet
- Control system
- Gas storage cylinders (250 to 300 bar storage pressure)
- Gas dispenser (for filling vehicles or trailers), gas delivery meter
- Interconnecting pipework
- Civil requirements (concrete bases, fences etc.)

B.2 Principle of operation:

Gas is compressed through a multiple stage reciprocating compressor up to 250 or 300 barg. This gas is then stored in a 3-bank cascade storage system, which is then in turn dispensed to the vehicle (max. 200 barg). Refuelling the vehicle drops the pressure in the storage, which is then topped up by the compressor ready for the next vehicle. This is shown in the photos below.

- **Figure 15 Vehicle refuelling facility**



- **Figure 16 CNG-CBM Compressors**

▪ **Figure 17 CMB Compressor**

▪ **Figure 18 Gas storage and CBM Dispenser**

B.3 Station design calculations

By way of an example the following sets out a CBM-CNG station for a small commercial vehicle fleet comprising 11 trucks operating from a depot. Typically:

- 9 x dedicated 12 to 15T rigid trucks, Iveco or MB
- 2 x dual fuel articulated tractor units, Volvo or MB

Calculation for the compressor and gas storage requires an understanding of vehicle use and refuelling needs. How often the truck is filled and how much fuel is needed at that time. For this illustration It is assumed that ~40% of the fleet (4 vehicles) would fill between 7am and 12pm, ~20% (2) between 12pm and 4pm, and ~40% (5) between 4pm and 7pm.

Each vehicle would take on an average of 69m3 of gas when filled.

Gas use is estimated at 190,000 Kg/yr. This requires an 80 m3/hr compressor (based on 10 hrs/day, 350 days per year operation) (Ideally 2 x 80 m3/hr compressors to give backup)

Calculations show that although a 200 scm/hr compressor is required, the smaller 80m3/hr unit can be used when combined with a larger storage of volume of 3,916 litres w/c.

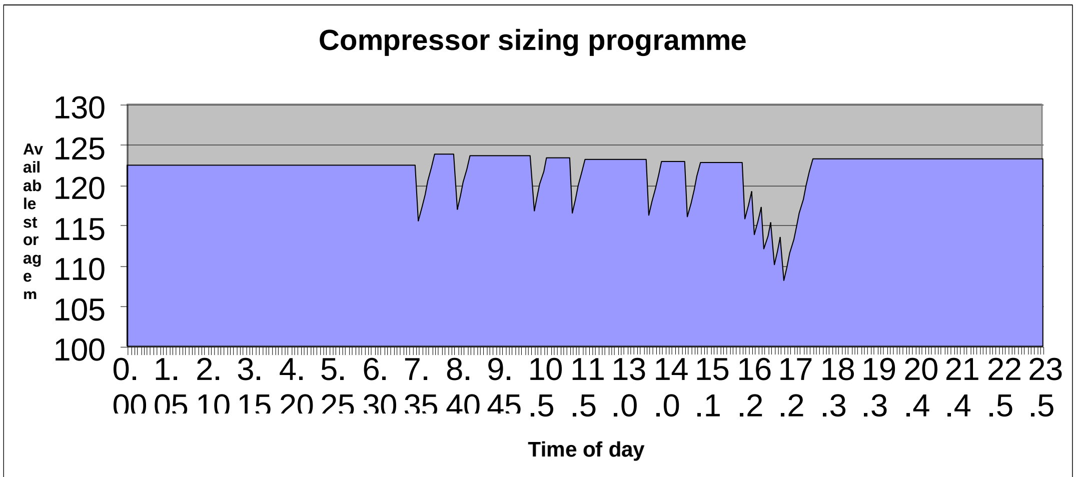
Typical running hours for each of these compressors would therefore be (50% of 10 x 350) = 3,500 hrs/yr.

A good gas Inlet gas pressure would be 4 barg. (note. lower inlet pressures will increase compression costs). The gas quality should be:- Dry (>-25 DegC), no H_2S, >97% CH_4 (typical biomethane specification)

Station calculation model

11 trucks filling max. 4 per hour, 7am-7pm incl.

Starting storage =	1224	m3	(3916 lit w/c = 1224m3@250 bar, but 40% usable means storage >734 bar)
Compressor top up =	16.67	m3/ 5 min	= 200 m3/hr total (i.e. 1xS100 DUO,
Vehicle gas capacity =	69	m3/ fill	0.33 vehicles/5 min (i.e. max. 4 veh's x 69 m3 filling every



B.4 Capital Costs

The following capital costs are for a CBM station to suit the needs of the above:

CNG station

Compressors	2 off 80 m3/hr (S100 DUO L)	£125,000
Storage	1 off 3,916 lwc (SM44)	£25,000
Dispensers	2 off dual hose electronic	£40,000
SCADA system	1 x remote monitoring	£10,000
Utility connections	Gas, Elec, civils	£30,000
Installation	Pipework and labour	£30,000
Civil Works	Concrete bases, fences etc.	£30,000
Project management	Design and PM	£20,000
Contingency	10% Capex (£201,200)	£30,000
Total cost	**£340,000**	
Cost per kg capacity	**£1.79**	

B.5 The RTFO

The Renewable Transport Fuels Obligation (RTFO) requires suppliers of fossil fuels to ensure that a specified percentage of the road fuels they supply in the UK is made up of renewable fuels. The target for 2009/10 is 3.25% by volume. As well as obliging fuel suppliers to meet targets for the volumes of biofuels supplied, the RTFO requires companies to submit reports on the carbon and sustainability of the biofuels.

Most fossil fuel used for road transport in the UK is refined or imported by one of about 14 suppliers, and the RTFO puts an obligation on these companies (‘obligated suppliers'). An obligated supplier must prove to the Renewable Fuels Agency (RFA) that it has met its Obligation by producing Renewable Transport Fuel Certificates (RTFCs) at the end of the year. One RTFC is awarded for every litre of biofuel reported to the RFA, and an obligated supplier can obtain them either by supplying biofuel itself, or by trading with other biofuel suppliers.

This option to trade provides suppliers, even if they have no Obligation, with a potential revenue stream to support the production of biofuel. Suppliers may also buy out of their obligation for 15 pence per litre, rising to 30 pence per litre from the 2010/11 reporting period.

Each kg of CBM consumed in a vehicle will earn an RTFO certificate, which could have a value of 10 – 30 p/kg going forward.

B.6 Grid connection

When a vehicle refuelling station is established and dedicated gas vehicles are operating then the need for uninterruptible gas supply is crucial. Note Dual-fuel (diesel + gas) and bi-fuel (petrol OR gas) gas vehicles have an alternate fuel source on board so can be kept in operation should gas become unavailable. For this reason a mains gas grid connection should be made wherever possible. If the site is part of a biogas to grid system and exporting gas to the grid then this line can be used for taking gas from the grid with a bi-directional flow meter.

B.7 Codes and Standards

The design and operation of a gas refuelling station has to be done to strict codes of practice and health and safety rules. Currently this is covered by the following documents:

- Utilization Procedure IGE/UP/5 Part 1 “Natural Gas Vehicles – Design and installation of filling stations”
- Utilization Procedure IGE/UP/5 Part 3 “Natural Gas Vehicles – Filling station operations
- CEN TC326 – European Directive on NGV filling stations (draft) – supersedes IGE/UP/5 documents in 2008
- The Pressure Systems and Transportable Gas Containers Regulations
- The Health & Safety at Work Act
- The Gas Act 1986
- The Electricity at Work Regulations
- The Environmental Protection Act
- Additional legislation, guidance notes, standards and codes of practice where applicable.

B.8 Operations and Maintenance

CNG refuelling stations have to be operated in accordance with Utilization Procedure IGE/UP/5 Pt 3 “Filling station operations” or the CEN equivalent. In particular this relates to the adherence to the Hazardous Area Zones that are designed and built into any refuelling station, i.e. the separation distances between equipment, and the fencing requirements etc. It also relates to the station owner operating the station only once it is covered by the appropriate Written Scheme of Examination and maintained in accordance with a prescribed service and maintenance plan, which should include items such as plant integrity, safety and emergency provisions, and site maintenance and cleanliness.

Comprehensive operating and emergency procedures shall be produced for all activities and reviewed on a regular basis.

Records of such activities must be maintained at all times, including safety and performance monitoring, modification notices, service and maintenance work, and auditing.

B.9 Slip stream biogas to CBM plant

The Slipstream is a containerised biogas cleanup and compression system that allows a flow of biogas to be turned into biomethane for vehicle refuelling or with the addition of propane injection and gas quality monitoring, supply gas to the grid.

The main components of the slipstream CBM are:

- ISO container housing, typically 20ft type.
- H_2S and or Siloxanes scrubbing unit
- Feed compressor
- PSA or Membrane CO_2 scrubber
- High pressure CNG compressor – 250 or 300 Bar
- High pressure gas storage, three bank cascade system
- Vehicle refuelling dispenser and metering system
- Control system.

System Description and Performance

Biogas from an Anaerobic Digestion system is taken into the Slipstream unit where it is passed through an H_2S and/or Siloxanes scrubber (this is an option if the facility is not already incorporated in the main biogas feed system to a CHP engine). From there a primary stage compressor boosts gas pressure before passing to the CO_2 removal system. From there gas goes through an additional three stages of compression to boost pressure to 250 or 300 Bar where it is stored in the three bank cascade system awaiting dispensing to a vehicle. Vehicle refuelling is the same as for a full-scale system but due to the limited gas flow consideration must be given to the vehicle refuelling pattern and sufficient storage included in the package so that capacity is not impaired.

A waste stream containing scrubbed $CO_2$and a small proportion of methane can be passed back to the inlet of the CHP unit and mixed with feed gas. The dilution of the feed gas due to the low flow rates is minimal and therefore engine performance is not impaired. The ability of a system to deal with this waste gas stream is the limiting factor with this concept.

Any H_2S and Siloxanes trapped are retained in a replaceable active carbon filter.

Biogas flow rate - hourly	40	M3/hr
After CO2 removal, flow rate of biomethane (cleaned up biogas) - assume 65% methane	26	M3/hr
Flow rate of biomethane	19	kg/hr
Clean-up plant availability	97%	
Annual biomethane production	161,277	kg/annum

The biomethane produced is equivalent to approximately 210,000L of diesel (1kg of biomethane = approx 1.25L of diesel). Actual vehicle range will depend on vehicle drive cycle and fuel efficiency; consult the vehicle data for more information on this.

Capital and Operating Costs

The estimated capital cost for a plant to make 150,000 kg of CBM per annum is around £400,000. No such plant exists in UK, these figures based on the cost of the Italian System.

The estimated electricity consumption and maintenance costs are around £50,000 per annum.

B.10 LNG/LBM Plant

Technology

Liquid Natural Gas and Liquid Biomethane has distinct advantages and disadvantages over CNG/CBM:

Advantages

- Higher fuel density being approx half that of diesel and twice that of compressed gas. If vehicle range is an issue and storage space limited then LNG/LBM has this advantage.

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Disadvantages

- The fuel is less stable and has limited shelf life with storage on a vehicle if not operated, unless actively handled the fuel warms up and by necessity is vented to atmosphere to prevent over pressurisation, this leads to a loss of fuel and a potential shift in CV for the remaining fuel in the tank.
- LBM-LNG does not smell of gas as it contains no odorant and so gas detection has to be used to find a leak
- Requires safety precautions when filling a vehicle
- No OEM vehicles exist yet with LNG Storage and so the LNG has to be made into CNG or vehicles have to have conversions to fit LNG tanks

LBM has an energy value of some 21MJ/L and a density of 0.5 (diesel is 36mj/L)

Making LBM

To produce LBM the biogas goes through the following process:

- Clean the biogas (remove H_2S, siloxanes)
- Dry and upgrade (remove CO_2 down to around 2%)
  - At this point the biomethane is suitable for gas grid. To make LBM the additional stages are required:
- Remove all remaining CO_2 and water
- Cool the biomethane from ambient temperature to - 160 deg C
  - If there is significant Oxygen and Nitrogen then additional processing may be required (e.g. landfill gas) but for AD gas the above will normally be appropriate.

The key step is the liquefaction process which can use a number of different technologies. Small-scale units favour using high pressure nitrogen in an expander cycle. A refrigerant cascade system can also be used.

LBM Storage and Refuelling

Vehicle refuelling by LBM uses a cryogenic liquid transfer pump and metering system in much the same was as a conventional petrol or diesel pump but designed to cope with the –165 deg C expected.

Vehicle fuel tanks are made in stainless steel and form a vacuum flask with super insulation between the inner and outer tank layers, fuel can be kept fresh for up to 3 weeks. There is a system of valves and controls designed to maintain fuel temperature and pressure whilst in use and allows liquid fuel to be drawn off for vaporisation in a heat exchanger and supplied to the engines as a gas.

LBM may also be dispensed as a gaseous fuel and refuel CNG/CBM vehicles in a technique known as LCNG or LCBM (Liquid Compressed Biomethane). This involves using a high pressure liquid pump to transfer the LBM at 200 Bar and then vaporising into a gas before transferring to the vehicle CBM tanks. The energy consumed in this process is low and allows an LNG/LBM facility to be dual purpose.

Capital Costs

The following costs are for a 8 ton per day liquefaction facility with a capacity of around 1,000 m^3/hr of biogas = around 4,000 tonnes per annum of LBM

Biogas-clean up and upgrading	£1,500,000
Liquefaction system	£1.500,000
Storage system 26 tonne	£100,000
Dispenser LBM inc pump	£50,000
Dispenser LCBM inc vaporiser and pump	£60,000
Utility connections	£50,000
Installation	£100,000
Civil Works	£50,000
Project Management	£50,000
Contingency 20%	£692,000
Total cost	£4,152
Cost per kg capacity	£2.96

Please note - there is no plant in the EU that makes LBM from AD gas and hence these figures should be seen as indicative. There are a small number of plants that make LBM from Landfill (1 in UK, 1 in Netherlands, 2 under construction in Sweden)

B.11 CNG/CBM Vehicles

Selection of Key UK Market Players in 2010

Vehicle	Manufacturer	Engine/fuel	Status
Small Van	Volkswagen Caddy Ecofuel (OEM)	Bi-fuel	On sale now
	Volkswagen Caddy Maxi Ecofuel (OEM)	Bi-fuel	On sale now
Medium Van	Mercedes Sprinter NGT (OEM)	Bi-fuel	On sale now
	Iveco Daily CNG (OEM)	Dedicated/ Bi-fuel	On sale now
Medium Rigid (11 - 18 tonnes)	Iveco Eurocargo CNG 12t/16t	Dedicated	On sale now
	Iveco Stralis CNG 18t	Dedicated	On sale now
Rigid (26 tonnes	Mercedes Econic CNG	Dedicated	On sale now
Buses	Foton CNG Hybrid Bus (OEM)	Dedicated	Expected now
	Cummins Westport Re-engine Trident 2	Dedicated	Available now
	Optare/Hardstaff	Dual fuel	In Development
	Diesel/Natural Gas Hybrid- Dennis Enviro		In Development (Est 1st Qtr 2011
Tractor 28 tonnes	Mercedes Econic CNG (OEM)	Dedicated Dual-Fuel	On sale now
Tractor 36 – 44 tonnes	Hardstaff Group conversion of Mercedes Benz, MAN and Volvo	Dual fuel	On sale now
	Clean Air Power conversion of Mercedes Benz, Daf and Volvo	Dual Fuel	On sale now
Refuse Collection Vehicles	Mercedes Econic CNG (OEM)	Dedicated	On sale now
	Dennis Eagle (OEM)	Dual fuel	On sale now
	Iveco Stralis (OEM)	Dedicated	On sale now
	BMC CNG (OEM)	Dedicated	Expected now

B.12 Natural Gas Vehicles

Technology/Terminology

Bi-Fuel: A spark ignition engine that runs on CNG or CBM but also has a petrol reserve tank

Dedicated: A spark ignition engine that can only be operated on CNG or CBM

Dual-Fuel: CNG or CBM is mixed with air and drawn into the combustion chamber and ignited by a small pilot flow of diesel. The engine runs on diesel and CNG or CBM simultaneously. It can also operate as a normal diesel engine on 100% diesel. The price list is based on projected launch prices for the later introductions and on an average specification vehicle with likely adjustments depending on the final specification

Gas operated vehicles carry a cost premium of approximately 25% to 30% depending on the model and containment capacity. This is offset by price and tax concessions of the gas and generally results in a payback period for the premium of 2 years.

Vehicle Emissions Standards

Currently we are running at Euro V emission levels in Europe. Retrofit Natural Gas vehicles can meet Euro 6 Emission Standards if fitted with a Methane Catalyst. Most OEM Natural Gas Vehicles meet EEV (Environmentally Enhanced Vehicle) standards, which are beyond Euro VI. Gas vehicles enjoy Vehicle excise duty taxation benefits from the lower taxation of Natural gas due to the benefits of RPC (Reduced Pollution Certification). This can be as much as £500 per annum for a large Truck. Additionally they qualify for a discount on the London Congestion Charge. This could result in additional operating savings for the vehicle of £2,000 per year if operating within London.

It is also important to note that gas vehicles are considerably quieter than their diesel counterpart (in some cases 30%-40% lower) and therefore allowed in some local Boroughs to operate late in the evenings. This leads to improved Logistics and reduced delivery costs.

On Vehicle CNG Storage

Recent developments have seen a change in the certification of the tanks on a gas vehicle. Certification must be carried out every 3 years from the date of installation and with tanks having a 15 year life could involve 5 lots of re-certification. This has been costing as much as £2000/certification as it involves pressure testing of the tanks. However, it has now been agreed that the UK will adopt the European Standards for testing which involves a visual test rather than the original removal and pressure test.

Not only does this dramatically reduce the cost (to £350/certification) and the effect on vehicle maintenance budgets but increases the safety aspect of the vehicle by preventing the possibility of damage by removal of tanks by inexperienced personnel in a vehicle workshop.

The testing however must be carried out by an approved body

Vehicle Maintenance

The maintenance on a gas vehicle system is, in the main low and would result in only a small increase of 0.75p-1.0p/mile for a dedicated vehicle to approximately 1p/mile for a dual-fuel vehicle dependent upon mileage. A technician trained to work on a gas vehicle does not need to be CORGI registered (Gas industry Trained staff), but would require to be trained on the system functionality and hold a certificate for pressure pipe removal and replacement.

Additional Workshop equipment for gas vehicle maintenance is minimal. A methane detector would be required if general maintenance is to be carried out and an industrial laptop plus cable interface to electrics is required for diagnostic work. The gas system on the vehicle should be turned off whilst the vehicle is being serviced in the workshop except for leak detection and diagnostic procedure.

Regulations Covering Vehicles in UK

There are regulations which relate to conversion of vehicles to CNG/LNG. In the UK it is legal to convert vehicles to dual fuel, as done by Hardstaff Group or Clean Air Power. The Statutory Instrument is SI2884

Equivalence between diesel and CNG

Equivalence

1 m3 of fossil CNG	=	0.73 kg of fossil CNG
1 kg of fossil CNG	=	1.37 m3 of fossil CNG
1 litre of diesel	=	1.04 m3 of fossil CNG
1 litre of diesel	=	0.757 kg of fossil CNG
1 kg of fossil CNG	=	1.32L of diesel

Notes:

There is not a universal equivalence because CNG can be used in 2 different sorts of engines. In a dual fuel engine, the CNG/CBM operates at diesel efficiency and so 1 kg of CNG/CBM would allow the vehicle to travel further than in a dedicated CNG vehicle which is a spark ignition (originally petrol) engine.

Consumption of CNG/CBM

CNG-CBM is priced and taxed in pence/kg.

Vehicles express their fuel consumption in km per kg, for example:

- Caddy – 15 km/kg
- Sprinter - 11 km/kg
- Econic - 8 km/kg
- Dual fuel - 6 km/kg (+ 40% of normal diesel consumption)

Fossil CNG has a calorific value of around 39 MJ/M3 (contains methane and propane), while CBM has a calorific value of around 36 MJ/M3 so you need around 8% more CBM compared to CNG (does not contain propane). Hence, for CBM, above figures would increase by around 8%.