A FINAL REPORT BY ENVIROS CONSULTING LIMITED: SEPTEMBER 2008

BERR

BARRIERS TO RENEWABLE HEAT: ANALYSIS OF BIOGAS OPTIONS

Publication title	Barriers to Renewable Heat: Analysis of biogas options.
CAN	DE1510001
Volume number	Volume 4 of 4
Version	Part 2 Final Biogas Report v4_0
Date	September 2008
File Reference	Biogasfinalreport_V4_0.Doc

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LIST OF ACRONYMS

AD	Anaerobic Digestion
BAU	Business As Usual
BERR	Department for Business, Economy and Regulatory Reform
CBM	Compressed Bio-methane
CHP	Combined Heat and Power
DH	District Heating
DNO	(Gas) Distribution Network Operator
DTI	Department of Trade and Industry
EC	European Commission
IRR	Internal Rate of Return
LBM	Liquefied Bio-methane
LEC	Levy Exemption Certificate
NPV	Net Present Value
ROC	Renewables Obligation Certificate

1. SUMMARY

Context

In the first part of this project, Enviros Consulting reviewed supply-side barriers to renewable heat. It was assumed that any heat supplied from biogas (derived from landfill, sewage or anaerobic digestion) was converted and distributed as hot water, either on-site or in district heating systems. That analysis assumed very significant levels of uptake of sewage gas and landfill gas. It also assumed anaerobic digestion (AD) of wastes and energy crops in order to deliver three scenarios for renewable heat. The third scenario applied very challenging assumptions regarding the total potential for the production of biogas and diversion to heat uses in the UK, given the available feedstocks. It was considered unlikely to be feasible to increase the total volume of biogas fuel further, though it would be possible to use the biogas evolved in different ways.

In this study we consider the alternative options for the use of this limited biogas resource to examine whether there is any potential benefit to the UK of making greater use of alternative options such as the upgrade of biogas to bio-methane for injection into the gas grid, in place of burning the biogas in CHP and distributing the heat using hot water pipes.

Purpose of this report

There is a range of alternative methods that could be used to exploit the amount of biogas from anaerobic digestion, sewage treatment and landfill identified Part 1 of this project. The purpose of the analysis reported here is to provide an assessment of the alternative utilisation options of biogas. It reviews their technical feasibility, associated costs and the volume of any additional renewable heat that might be delivered.

Overview of findings

The feasibility of the various exploitation options is summarised in Table 1 on the following page. Three options were considered technically feasible and were therefore considered further in terms of quantifying non-financial barriers and their potential to improve the amount of delivered heat achieved by 2020. These options were 1) on-site or 2) off-site utilisation of biogas and 3) biogas upgrade to bio-methane and injection into low pressure gas grids. The delivery costs associated with these options were considered along with supply and demand side barrier costs. The heat and carbon benefits from a substantial switch towards these options were considered in order to inform on the relative value of these alternatives.

Table 1 Overview of analysis of biogas heat options

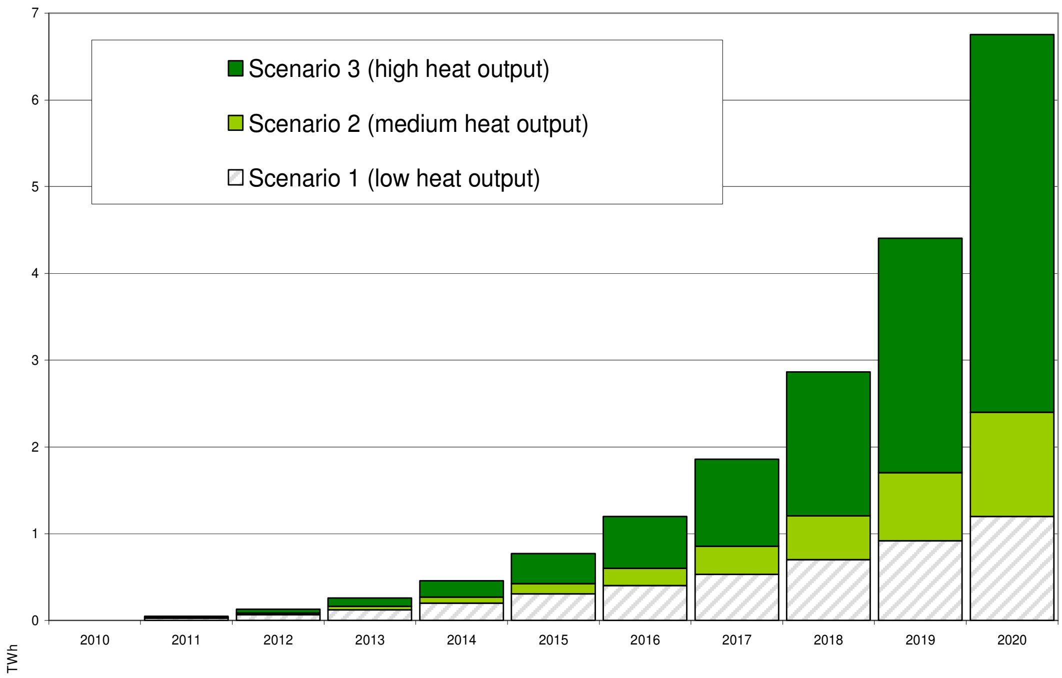
	Exploitation route	Summary comments on precedent and feasibility	Already practiced in		Indicative Distribution cost1 (£/MWh)
			UK	EU	
1	Heat recovery from Combined Heat and Power (CHP) and subsequent heat distribution	Business as usual scenarios from Part 1 analysis i.e. a the core option considered within scenarios 1 – 4 of the phase 1 analysis	√	√	9
2	Biogas combustion to provide local heating	Business as usual scenarios from Part 1 analysis i.e. a the core option considered within scenarios 3 & 4 of the phase 1 analysis	√	√	1
3	Upgrade to bio-methane for use in national high pressure gas transmission grid	Very little proven international experience and relatively expensive. Significant energy cost associated with gas clean-up and compression. No need to use this transmission system since lower pressure networks exist and maximum input of bio-methane under our scenarios would be modest (1.6% of demand) and therefore not swamped. **This option was therefore discounted** – further validation provided in Appendix 1.	x	√	23
4	Upgrade to bio-methane for use in local low pressure gas distribution network	Significant international experience – **considered further**	*x*	√	20
5	On-site industrial raw biogas use	Requires co-location of biogas production *and* appropriate scale and flexibility of demand, but some niche applications and inexpensive option – **considered further**	√	√	1
6	Biogas distribution to remote on-site Industrial use or district heating facility	Practiced internationally but no network of existing DH in UK to take advantage of this, energetically indistinct from BAU scenario apart from increased risk of fugitive emissions – **considered further**	x	√	6
7	Biogas liquefaction & bottled distribution	At this marginal cost of production such containerised fuels could not compete in the heating market. We consider transport fuel would be the competitor market for such activity (as in Europe) and therefore the **option is discounted**	x	√	41

Impact on heat output

The Phase 1 report identified biogas availability for heat uses by 2020 to be derived from 100% of sewage arisings, plus a gradual shift from CHP to heat use for landfill gas, plus approximately one third of theoretical food waste arisings plus energy crops grown on 157,000 ha of land. It is the view of the authors that this suite of measures represents the upper practical limit of biogas generation. In order to quantify the unconstrained additional heat potential that could be achieved from this biogas through direct industrial use and grid injection instead of the assumption of the use of CHP made under the phase 1 work, we considered three alternative scenarios. In these it is assumed that, rather than use biogas for new CHP and district heating, the biogas is diverted to direct industrial use[2] or gas grid injection instead (other options were considered but discarded). It is assumed that demand from industrial locations is met first with any surplus from the switch away from new CHP or heating, and is then diverted to bio-methane injection.

Largely as a consequence of the improved thermal yield gained by not generating electricity, the total amount of heat available from biogas under the most optimistic scenario (Scenario 3) increased from 23.4 TWh to 27.8 TWh by 2020, an increase of 4.4 TWh (19%). This is illustrated in the chart below. However, although renewable heat output would increase, under these assumptions renewable electricity generation would fall by 2.6 TWh. Given the carbon intensity of natural gas is 0.19 $kgCO_2/kWh$ and electricity is 0.43 $kgCO_2/kWh$, this strategy reduced the carbon benefit by 291,924 tCO_2/yr by 2020.

Figure 1 Difference (TWh) between the revised biogas heat output and the original output projected in Part 1



1 These figures are indicative only since the distribution cost is very dependant upon the distribution distances. Costs can vary by an order of magnitude or more
2 Potential industries where co-location of biogas production and use could be achieved were identified as brickworks, sand, gravel, china clay and tarmac production facilities. This was not an exhaustive analysis of sectoral fit but identified significant potential demand.

Impact on barrier costs

These different scenarios would also have an impact on the extent to which supply and demand side barriers need to be overcome. The impact is summarised in the table below.

Table 2 Barriers and barrier costs for industrial on-site gas use and gas grid injection

Barrier	Nature of Barrier	Cost for on-site use	Cost for gas grid injection
Business to business awareness	Demand	£2 million in 2010	£0.5 million in 2010
Public acceptance awareness	Demand	-	£1 million
QA and policy enabling measures	Supply	-	£3 million in 2010
Infrastructure upgrades	Supply	£315/ MW capacity installed	£90/ MW capacity installed

The result of shifting from hot water distribution to direct use or gas grid injection was a modest increase in the barrier costs associated with heat delivery. It would result in an increase of £119.8 million, £422.4 million and £82.2 million respectively in 2020 under Scenarios 1, 2 & 3 respectively. Demand side barrier costs for biogas would largely remain unchanged, except that pursuing a gas grid injection strategy would require farm-based AD to be scaled-up and therefore barriers would need to be overcome at a smaller number of sites. The net reduction in demand side barrier costs was calculated to be £31 million by 2020.

Cost effectiveness

The commercial performance of various biogas utilisation routes was evaluated in order to illustrate the financial barriers to the uptake of different options. Even in the absence of renewable obligation certificate (ROC) and levy exemption certificate (LEC) revenues, electricity-producing exploitation routes outperformed all heat-only systems with the notable exception of direct on-site utilisation. Essentially the low value of heat cannot compensate for the high costs of heat distribution when compared to the high value of electricity generating options. It was concluded that under current conditions gas grid injection would not supplant electricity or CHP routes of biogas utilisation.

Conclusions

In summary, the direct on-site use of biogas for direct or indirect firing is a technically credible and financially competitive mechanism for utilising biogas. However, only niche industrial markets are likely to combine the availability of land for biogas production with the scale and flexibility of demand required. This study has identified the most likely sectors for its utilisation. Biogas upgrade to bio-methane does not appear commercially competitive due to the costs of upgrading and distribution. Although employing these delivery routes (rather than supporting the development of CHP) does yield greater quantities of renewable heat, it does not enhance the carbon savings – indeed these decline quite significantly. Also, the costs of overcoming supply-side barriers are higher than under the alternative option.

2. INTRODUCTION

Context

In the Part 1 analysis it was assumed that any heat supplied from biogas (derived from landfill, sewage or anaerobic digestion) was converted and distributed as hot water either on-site or via district heating systems. Thus it included the conventional forms of heat recovery from biogas that are currently utilised in the UK[3].

That analysis assumed very significant levels of uptake of sewage gas, landfill gas. It also assumed anaerobic digestion (AD) of wastes and energy crops in order to deliver three scenarios for renewable heat[4]. The third scenario (which reflected the highest level of renewable heat uptake) was considered to utilise the full potential of all sources of biogas (and so no further uptake of biogas was included in a fourth, higher scenario). Thus, by scenario 3 the practical potential for biogas production was reached.

Purpose of this report

There are a number of alternative methods that could be used to exploit the amount of biogas from anaerobic digestion, sewage treatment and landfill identified Part 1 of this project. The purpose of the analysis reported here is to provide an overview assessment of the alternative utilisation options of biogas. It reviews their technical feasibility, associated costs and the volume of any additional renewable heat that might be delivered.

2.1 Routes to energy generation from biogas

Figure 2 shows the routes by which biogas from anaerobic digesters, sewage treatment sites or landfill can be converted to heat and/or electricity (excluding transport fuels).

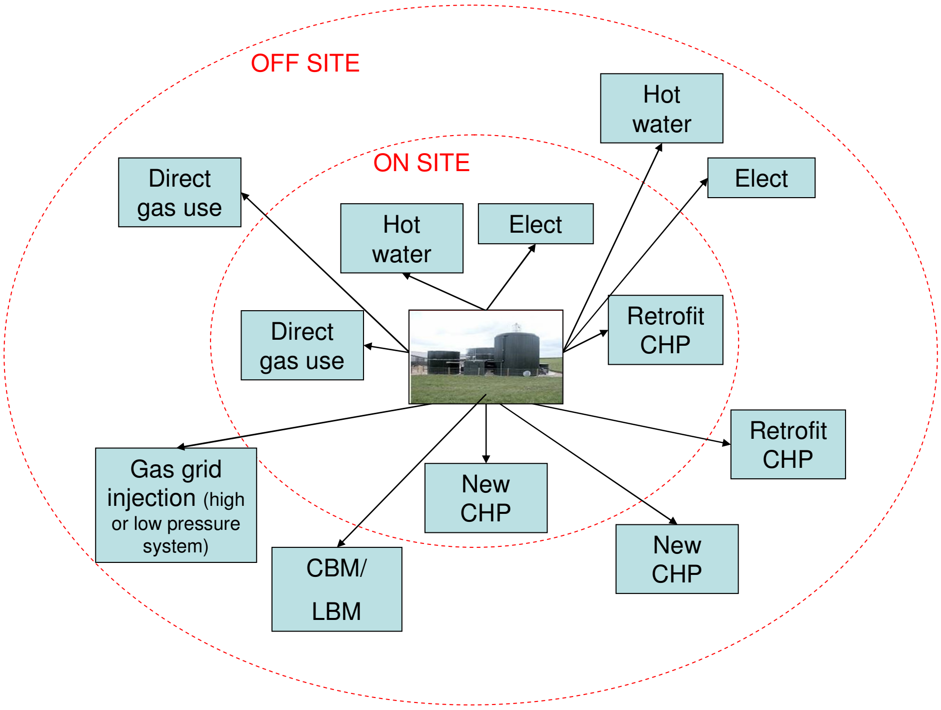
Biogas can be used directly on-site to produce electricity and/or heat in conventional boilers or combined heat and power systems (CHP). The electricity generated can be used on-site, by remote users via a private network or fed into the grid. The heat can be distributed indirectly as hot water around the site or to remote users via a district heating system.

Alternatively the biogas can be cleaned and distributed via a dedicated pipeline to a remote user. The biogas can also be cleaned then upgraded and feed directly into a gas grid. The final option is that the biogas can be cleaned, upgraded and pressurised into either compressed bio-methane (CBM) or pressurised further into liquefied bio-methane (LBM) for distribution by road.

3 This is due to a number of factors including technology precedent, the fact that much of the heat is in fact recovered heat from extant systems and because the vast majority of such facilities will be remote from the points of potential heat utilisation. Thus, energy in the gas is released through combustion and the heat captured in hot water which requires a distribution system to deliver that heat to dislocated points of heat demand. Effective distribution of heat in this manner requires well-matched demand profiles, incurs additional cost of infrastructure plus it incurs heat distribution losses.

4 The Phase 1 report identified biogas availability for heat uses by 2020 to be comprised of 100% of sewage arisings, plus a gradual shift from CHP to heat use for landfill gas, plus approximately one third of theoretical food waste arisings plus energy crops grown on 157,000 ha of land.

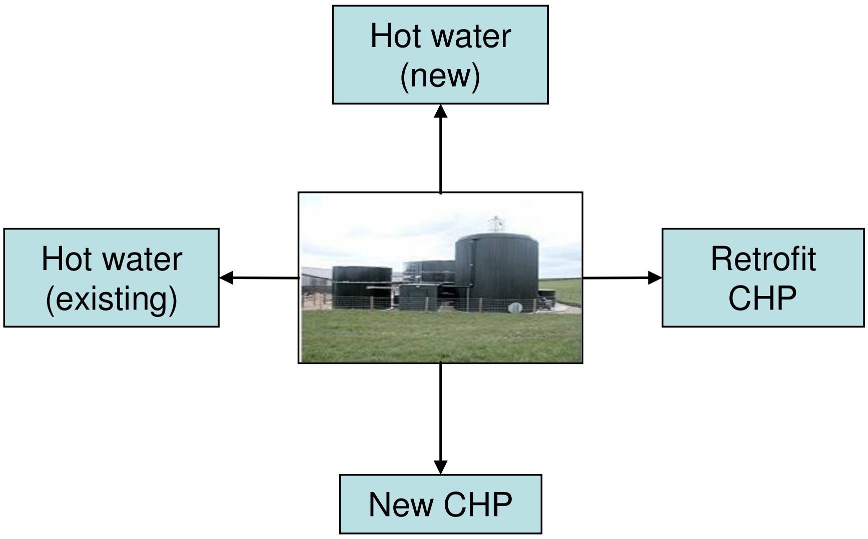
Figure 2 All possible routes to generate heat/electricity from biogas5



As shown in Figure 3 Phase 1 of the project only considered:

- Heat recovery from existing power plants
- Heat from new CHP plants
- Indirect distribution of heat via hot water locally or through district heating systems from heat only systems (both existing and new)

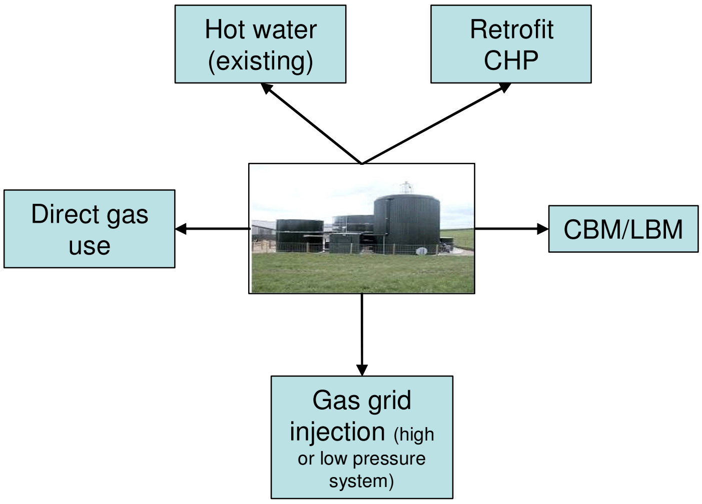
Figure 3 Distribution routes considered in Phase 1



5 Off-site uses require additional infrastructure such as gas or hot district heating networks

In the additional analysis reported here we consider the alternative routes for the production of heat from biogas such as gas grid injection and the direct use of biogas to generate heat in remote sites. The routes considered in this report are shown in Figure 4 .

Figure 4 Alternative distribution routes



2.2 Structure of this report

In the following report we identify:

- The technical issues relating to biogas use in national grid networks.
- The relative commercial performance of biogas used in the various exploitation options.
- The changes in delivered heat, if alternative development routes were used
- The energy penalties associated with the different distribution routes
- Our assessment of how this revised analysis would alter Scenarios 1 to 4 in the phase 1 report
- Where appropriate, the barriers to be overcome and how to overcome them

It considers the technical and economic feasibility of the following uses for biogas as alternatives to retrofit CHP and hot water heating:

- Fully upgraded[6] biogas injection into medium pressure grid
- Partially upgraded biogas injection into lower pressure (local) grid
- On- and off-site industrial use of biogas
- Biogas into pressurised containers for distribution

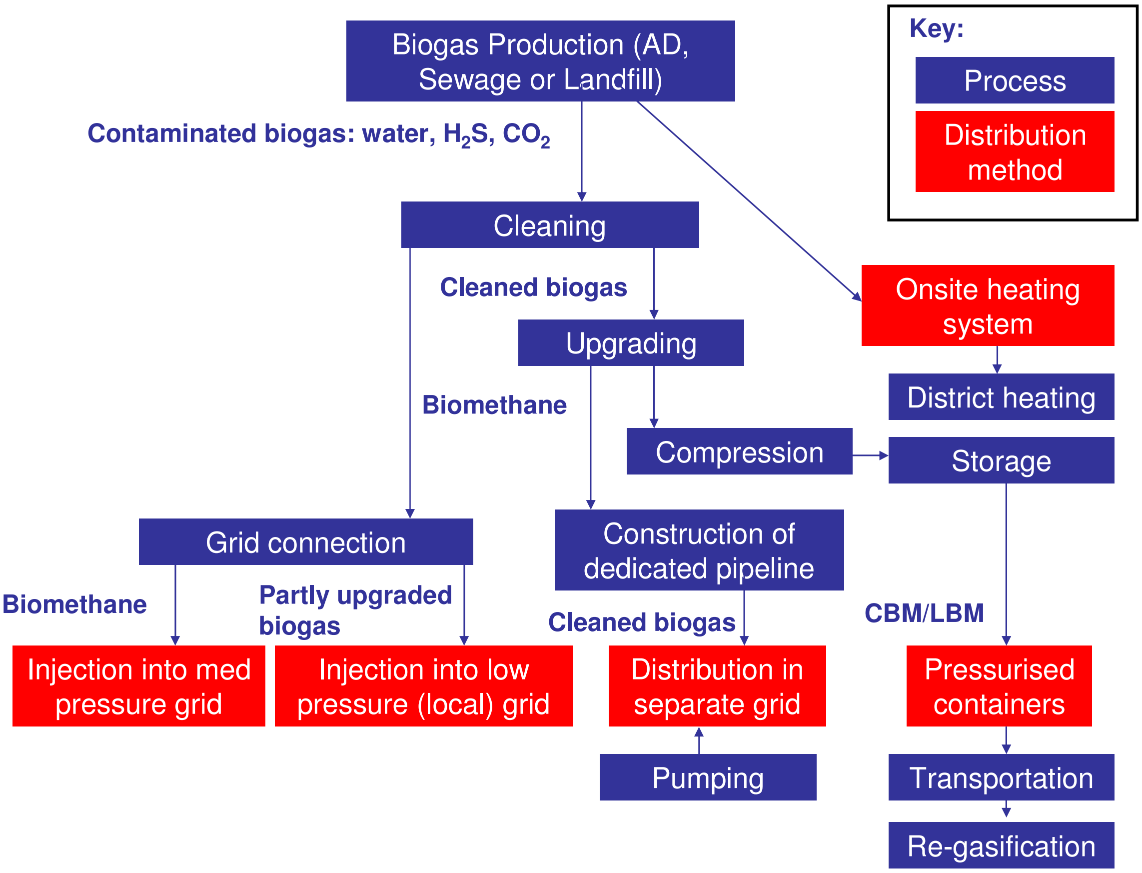
6 Upgrading refers to the process undertaken to bring biogas up to natural gas grid standard

3. HEAT RECOVERY OPTIONS FROM BIOGAS

Biogas produced from anaerobic digestion of sewage, agricultural or municipal wastes or recovered from landfill can be a) used at the point of collection in gas engines or heating systems or b) distributed to remote locations for use via purpose built distribution networks. Alternatively it can be c) pressurised and bottled or d) upgraded/partially upgraded and injected into existing natural gas mains (and thus mixed with natural gas). Figure 5 illustrate the various routes by which biogas can be distributed to generate heat.

Our analysis to date has focused on the barriers and potential of option a). Below we consider the technical potential and barriers associated with options b) to d).

Figure 5 Biogas distribution options (exploitation routes are described in more detail in the following report sections)



3.1 Utilisation routes explained

- *Industrial on-site use* – the raw biogas is used at the point of production in either on-site boilers or direct/indirect firing systems (kilns, ovens). The gas may not need to be cleaned or only need to be partially cleaned to remove impurities.

- *Biogas distribution to remote on-site Industrial use or district heating facility* – here the biogas is only cleaned and may be partially upgraded before it is distributed via a designated pipeline to a remote user. The relative high cost of pipeline construction means that end user must be fairly close to the biogas production.

- *Biogas Upgrade and grid injection* – The biogas is cleaned, dried and propane and odour added so that it meets standard gas grid standards. The gas is then injected into either a local low pressure gas grid or into a medium pressure distribution grid and can be used in any appliance.

- *Storage in pressurised containers* – Biogas is upgraded (to high standard then compressed to either a medium pressure for over-the-road transportation The gas can be compressed to a medium pressure (compressed bio-methane (CBM)) or it can be upgraded further and compressed to a higher pressure so that it becomes liquefied bio-methane (LBM).

This section discusses the processes required to deliver heat from these different biogas distribution methods and their relative advantages/disadvantages in terms of energy and carbon efficiency.

3.2 Summary of options

An initial screening of potential routes of biogas exploitation identified seven options (Table 3) including two 'base-case' options already examined in the Part 1 modelling work. The five alternatives were subsequently short-listed to 3 credible alternative options to the two base-case options.

Table 3 Summary of biogas heat delivery options

	Exploitation route
1	Heat recovery from CHP and subsequent heat distribution (base-case)
2	Biogas combustion to provide local heating (base-case)
3	Upgrade to bio-methane for use in national high pressure gas transmission grid
4	Upgrade to bio-methane for use in local low pressure gas distribution network
5	On-site industrial use of raw biogas
6	Biogas distribution to remote on-site or district heating facility
7	Biogas liquefaction & bottled distribution

To ascertain the potential contribution each route may make to heat generation, one must consider the efficiency of the different pathways and the markets they provide access to. Each process undertaken has a financial and energy penalty which must be considered to assess the relative efficiency of each pathway. However whilst one pathway may be more expensive or energy intensive than another, it may provide access to a much larger biogas market.

The feasibility of the various options is summarised in Table 4. Further information about the detail of certain conversion routes is presented in the Appendices.

Table 4 Overview of analysis of biogas heat options

	Exploitation route	**Summary comments on precedent and feasibility**	**Already practiced in**		**Indicative Distribution cost7 (£/MWh)**
			UK	**Europe**	
1	Heat recovery from CHP and subsequent heat distribution	Base-case option used in scenarios from Part 1 analysis	√	√	9
2	Biogas combustion to provide local heating	Base-case option used in scenarios from Part 1 analysis	√	√	1
3	Upgrade to bio-methane for use in national high pressure gas transmission grid	Very little proven international experience and relatively expensive. Significant energy cost associated with gas clean-up and compression. No need to use this transmission system since lower pressure networks exist and maximum input of bio-methane under our scenarios would be modest (1.6% of demand) and therefore not swamped. **This option was therefore discounted** – further validation provided in Appendix 1.	x	√	23
4	Upgrade to bio-methane for use in local low pressure gas distribution network	Significant international experience – **considered further**	*x*	√	20
5	On-site industrial raw biogas for uses other than hot water heating	Requires co-location of biogas production *and* correct heat demand to avoid gas upgrade for co-use with natural gas, but some niche applications and inexpensive option – **considered further**	√	√	1
6	Biogas distribution to remote on-site Industrial use or district heating facility	Practiced internationally but no network of existing DH in UK to take advantage of this, energetically indistinct from BAU scenario apart from increased risk of fugitive emissions – **considered further**	x	√	6
7	Biogas liquefaction & bottled distribution	At this marginal cost of production such containerised fuels could not compete in the heating market. We consider transport fuel would be the competitor market for such activity (as in Europe) and therefore the **option is discounted**	x	√	41

7 These figures are indicative only since the distribution cost is very dependant upon the distribution distances. Costs can vary by an order of magnitude or more.

The three options considered to be feasible are discussed further below. Further discussion of the production of CBM and LBM can be found in Appendix 3.

3.3 Technical issues around biogas use within existing natural gas distribution infrastructure (option 4)

There is much experience of upgrading biogas to a level that is suitable for injection into the local distribution grid in Europe and America. The cleaning and upgrading process required to bring biogas up to natural gas grid standards significantly increases production costs and reduces the energy efficiency of the process. Biogas can be partially upgraded for limited injection into local low pressure grids to reduce costs.

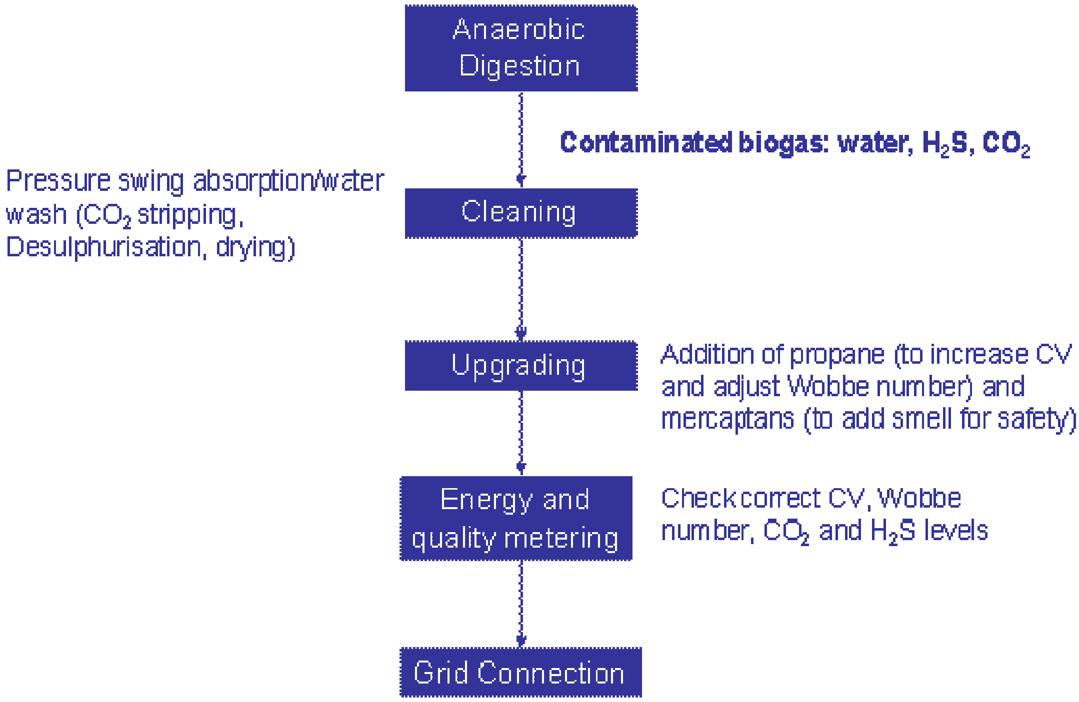
The natural gas pipeline network offers a virtually unlimited storage and distribution system for bio-methane. Since the natural gas pipelines are typically owned by either private or municipal gas utilities, the bio-methane producer must negotiate an agreement with the pipeline owner (i.e., the local gas utility) to supply bio-methane into the natural gas pipelines. One prerequisite for such an agreement would be to ensure that bio-methane injected into the natural gas pipeline network meets the local gas utility's pipeline gas quality (e.g. gas composition) standards.

Biogas is primarily composed of methane (CH_4) and carbon dioxide (CO_2) with smaller amounts of hydrogen sulphide (H_2S) and ammonia (NH_3). The methane content varies from 45% to 65% depending upon the source of the biogas. In order to be utilised within existing low pressure (local distribution) networks in the UK biogas needs to be upgraded to a higher methane content (c. 95%) so that it resembles the qualities of natural gas. See Appendix 1 for further details on UK gas grid specifications and international standards for biogas grid injection.

By upgrading biogas to 95% methane the energy content increases and the energy density resembles that of natural gas, enabling safe use within conventional boiler systems. Biogas upgrade requires the removal of non methane constituents, particularly CO_2, H_2S and NH_3. However, undertaking such clean up incurs financial costs, energy penalties and regulatory compliance obligations. Such bio-methane injection occurs in at least 7 countries delivering a total of at least 0.325 TWh of gas, from biogas production facilities which range from $10m^3$ per hour to 13,000 m^3 per hour.

The pathway for biogas upgrade and injection into gas grids is presented below.

Figure 6 Schematic of gas upgrade for gas grid injection



There are significant costs and barriers to the use of biogas in this way.

Costs

Our literature review (Appendix 4) has indicated that the costs of upgrading biogas to bio-methane are significant[8]:

Table 5 Estimated costs of biogas injection, option 4 (£/MWh[9])

Option	Upgrading costs	Storage	Grid connection costs	Transportation	Total
Injection of upgraded biogas into lower pressure (local) grid	18	-	2	-	**20**

Thus, even at today's high gas prices, the additional cost of gas upgrade would cause a significant increase on the bio-methane sale price (perhaps doubling the cost). By contrast, biogas converted into bio-methane and injected into the gas distribution network would avoid certain costs that would otherwise be incurred under business as usual scenarios, for example the cost of centralised gas boilers to raise hot water and/or electrical generator sets (in CHP scenarios). Thus there will be savings and additional costs of utilisation. The net supply-side costs of overcoming barriers to exploitation are presented in Section 4. The relative capital costs of the different options are presented in Section 5.

8 All data taken from a range
9 Converted from the original reference in euros/MWH at the rate of 0.7 £/euro

Table 6 Barriers to bio-methane grid injection

Barrier	How does it work?	On whom does it act?	How is it overcome?
Lack of Quality Standards	DNOs will not accept gas unless suitably accredited and monitored	Biogas producer	Establish UK QS
Infrastructure costs	As previously identified in Part 1		Capital support to construct networks

3.4 Technical issues surrounding biogas for industrial on-site use (option 5)

There is a very small level of direct industrial use[10] of landfill gas in the UK (Dukes, 2007) based mainly on the direct firing of brickwork kilns with biogas. This is enabled because of the co-location of a small number of brickworks and landfill sites. FES (2007) note "there are currently 282 LFG power stations in the UK, with a generating capacity of 631.7 MW, which between them use 12.5 TWh/y of gas, with only 0.16 TWh/y being used directly (i.e. direct firing rather than through water as the delivery mechanism). Despite this, there is almost no commercial use of the heat generated from landfill gas, let alone any direct use of the gas for heating purposes".

Additional utilisation would be cost effective where co-location occurred however there are only a limited number of industries where co-location of space and potential for gas use has been identified. Sectors that could utilise unimproved biogas include the cement, aggregate and asphalt industries. However, biogas is unlikely to be countenanced in cement industries since they require huge quantities of very high grade heat (e.g. 250 MW capacity and 1,400C temperatures) and they tend to use solid fuels.

Asphalt production requires lower capacity (c. 10 MW) but is sporadic in demand (6 hrs per day). Other brickworks, other industries using kilns or indirect heating or aggregates (calcium carbonate, china clay, sand, asphalt) industries could use biogas in its raw state.

This is undoubtedly not an exhaustive list, but captures the dominant opportunities. Our assessment of the potential demand from such facilities is presented below, with some indication of the potential conversion that might be achievable by 2020. Such shifts in energy provision will be determined by commercial as well as non-financial barriers.

10 i.e. direct combustion on site for industrial processes

Table 7 Assumed level of on-site industrial biogas use by 2020

Industrial sector	scale of demand (MW per site)	operational hours/ yr	number of UK sites	Percentage adoption assumed by 2020	TWh delivered by 2020
bricks	10	8736	100	25%	2.184
asphalt/ china clay/ sand	5	2184	1000	10%	1.092

3.4.1 Costs

Costs of utilising biogas in this manner are extremely low (Table 8), due to the absence of upgrade requirements and short distribution distances. However, barriers to further uptake are the small number of instances where biogas generation and points of demand currently exist. These barriers might be overcome through targeted and financially supported co-location of anaerobic digestion facilities (of food waste) which are currently anticipated to be producing and distributing hot water-following CHP under Scenarios 1 to 4. Barriers to the deployment of anaerobic digestion facilities have been identified previously.

Under some circumstances it may be possible to recover low grade waste heat following industrial utilisation in kilns and ovens. This low grade heat could then be distributed via hot water distribution systems. This is theoretical since it is not practised anywhere yet. However, this would provide a true increase in the amount of renewable heat generated from the same quantity of biogas.

Table 8 Costs of upgrading and distribution of on-site biogas (£/MWh)

Option	Upgrading costs	Storage	Grid connection costs	Distribution 11	Total
On-site direct firing with biogas	-	-	-	1	1

Table 9 Barriers to on-site biogas use

Barrier	How does it work?	On whom does it act?	How is it overcome?
Lack of Awareness	Biogas producers and potential users unaware of each other	Biogas producer and industrial sites	B2B activity brokered by Agencies such as NISP or WRAP
Lack of suitable sites	Lack of co-location	Industrial site operators	Incentives to AD facilities to co-locate on industrial sites
Business risk	Risk to industry of relying on 3rd party biogas supply	Industrial site operators	Development of refined ESCo models

11 Costs may be higher if partial gas upgrade is required

3.5 Technical issues surrounding biogas distribution to remote sites for industrial on-site use (option 6)

Table 10 sets out the costs associated with the distribution of biogas to remote sites, which requires, in summary, some gas cleaning, distribution pipes and pumps to move the gas.

Table 10 Costs of upgrading and distribution of biogas to off-site industrial and district heating uses (£/MWh)

Option	Upgrading costs	Storage	Grid connection costs	distribution	Total
Biogas distribution to industrial sites or DH facilities	3			3	**6**

The constraints to the distribution of bio-gas to remote sites are identical to those for distribution of hot water in heating mains. Significant barriers are planning as well as the additional costs of installing and maintaining the pipe-work distribution systems. A further constraint may be the increased likelihood if higher fugitive methane emissions.

4. REVISED HEAT POTENTIALS AND BARRIER COSTS

In order to quantify the unconstrained additional heat potential from biogas direct use and grid injection, we have considered three alternative scenarios. In these it is assumed that, rather than use biogas for new CHP and district heating, the biogas is first diverted to direct industrial use [12] or where there is a remaining surplus, to gas grid injection instead.

4.1 Heat potentials

Largely as a consequence of the improved thermal yield gained by not generating electricity, the total TWh available from biogas under the most optimistic scenario (Scenario 3) increased from 23.4 to 27.8 by 2020, an increase of 4.4 TWh (19%). This is illustrated in the chart below. However, although renewable heat output would increase, under these assumptions renewable electricity generation would fall by 2.6 TWh. Given the carbon intensity of natural gas is 0.19 $kgCO_2$/kWh and electricity is 0.43 $kgCO_2$/kWh, this strategy reduced the carbon benefit by 291,924 tCO_2/yr by 2020.

The switch from CHP to grid injection would not occur in an unconstrained marketplace, and the relative commercial performance of the various biogas utilisation options is presented in Section 5.

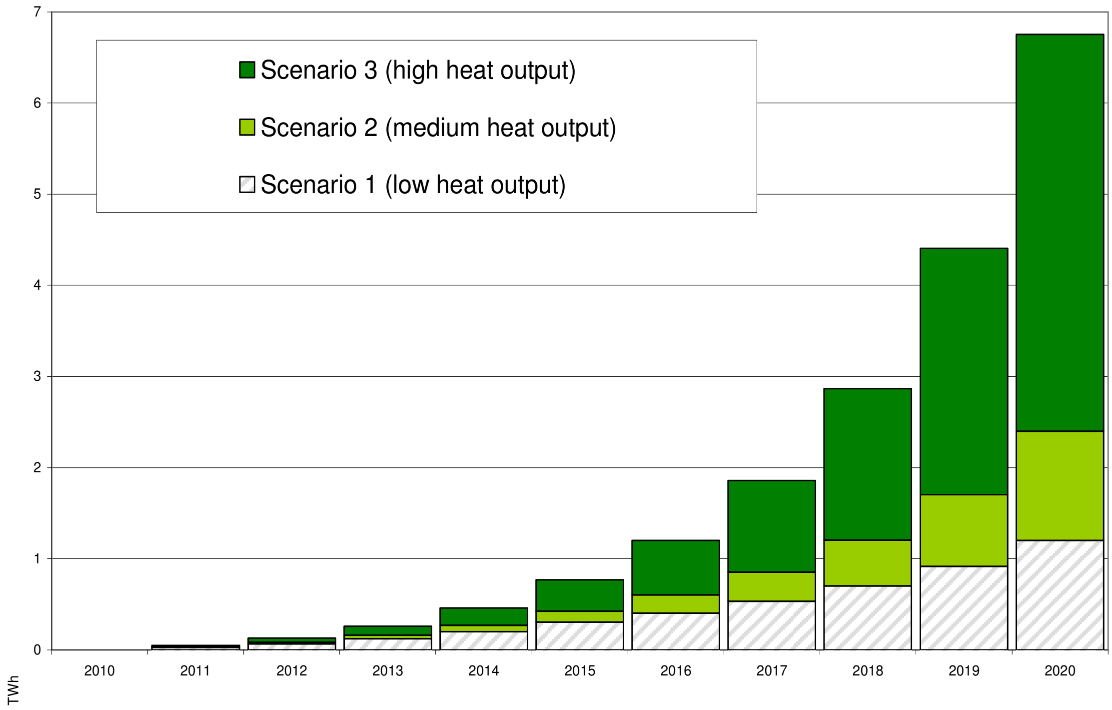
Revised barrier costs are presented in the following table.

12 Potential industries where co-location of biogas production and use could be achieved were identified as brickworks, sand, gravel, china clay and tarmac production facilities. This was not an exhaustive analysis of sectoral fit but identified significant potential demand.

Table 11 Revised (potential) biogas heat output in 2020

	Tech	Heat recovery from existing facilities (TWh)	Direct use (TWh)	Gas injection (TWh)
Baseline	Landfill gas	0.6	0.0	0.0
Baseline	Sewage gas	0.0	0.0	0.0
Baseline	Anaerobic digestion	0.0	0.0	0.0
Baseline	***Total by mode***	**0.6**	**0.0**	**0.0**
Baseline	***Total***			**0.6**
Scenario 1	Landfill gas	3.2	0.0	0.0
Scenario 1	Sewage gas	0.3	0.0	0.0
Scenario 1	Anaerobic digestion	0.0	0.7	1.1
Scenario 1	***Total by mode***	**3.5**	**0.7**	**1.1**
Scenario 1	***Total***			**5.3**
Scenario 2	Landfill gas	3.2	3.4	5.2
Scenario 2	Sewage gas	1.0	0	0.0
Scenario 2	Anaerobic digestion	0.0	0.7	1.1
Scenario 2	***Total by mode***	**4.2**	**4.1**	**6.3**
Scenario 2	***Total***			**14.6**
Scenario 3	Landfill gas	3.2	4.4	4.8
Scenario 3	Sewage gas	1.0	0.0	4.2
Scenario 3	Anaerobic digestion	0.0	4.9	5.4
Scenario 3	***Total by mode***	**4.2**	**9.3**	**14.3**
Scenario 3	***Total***		**27.8**	

Figure 7 Difference (TWh) between the revised biogas heat output and the original output projected in Phase 1



4.2 Barrier costs

The basis for barrier costs is set out below and the impact of these on supply side costs for Scenarios 1 – 3 shown in Tables 13 to 15. Barrier costs for on-site industrial gas use and gas grid injection were calculated based upon the following:

Table 12 Demand-side Barriers and barrier costs for industrial on-site gas use and gas grid injection

Barrier	Cost for on-site use	Cost for gas grid injection
Business to business awareness	£2 million in 2010	£0.5 million in 2010
Public acceptance awareness		£1 million
QA and policy enabling measures		£3 million in 2010
Infrastructure upgrades	£90/ MW capacity installed	£315/ MW capacity installed

The result of shifting from hot water distribution to direct use or gas grid injection is a modest increase in the barrier costs associated with heat delivery. This assumes that no additional legislation is required to compel gas grid network operators to accept biogas.

4.2.1 Quantification of supply side barriers

The revised supply side barrier cost estimates for each scenario is set out below. The highest costs are for Scenario 3 (Scenario 4 is not included as its output for biogas is the same as in Scenario 3). They should be summed across columns to give the total cost by 2020, that is, costs reported for 2015 include costs incurred from 2011 to 2015, while costs for 2020 include those incurred from 2016 to 2020. They are all discounted back to 2008 money (using a discount rate of 3.5%).

Table 13 Breakdown of Biogas supply-side barrier costs for scenario 1

Barrier	Assumptions	Cost (£m)			Difference to phase 1 estimates in 2020
		2010	2015	2020	
Cost of cleaning biogas and construction of dedicated pipeline	Preparatory actions and infrastructure development for direct use.	11.6	19.9	47.3	
Cost of cleaning and upgrading biogas, connecting to grid and monitoring	Preparatory actions and infrastructure development for gas grid injection.	13.2	30.8	73.0	
Biogas: Recovery from existing facilities and lack of appetite to use crops for energy	Assumes that to deliver sufficient output from biogas in highest scenario, AD plant using energy crops are required in 2020. To overcome a lack of awareness/ lack of incentive to change existing practices even for cost effective plant[13], assume that support worth an extra 50% of the value of silage (£25/tonne) – the competing use of the fuel – is required. Barrier does not bite for Scenario 1	0.0	22.1	48.8	
Biogas: total Scenario 1					169.0

13 Since this project assumes that financial barriers are overcome as a given

Table 14 Breakdown of Biogas supply-side barrier costs for scenario 2

Barrier	Assumptions	Cost (£m)			Difference to original
		2010	2015	2020	in 2020
Cost of cleaning biogas and construction of dedicated pipeline	As for Scenario 1	9.6	54.1	338.0	
Cost of cleaning and upgrading biogas, connecting to grid and monitoring	As for Scenario 1	10.1	83.6	522.0	
Biogas: Recovery from existing facilities and lack of appetite to use crops for energy	As for Scenario 1	0.0	148.5	310.4	
Biogas: total Scenario 2					422.4

Table 15 Breakdown of Biogas supply-side barrier costs for scenario 3

Barrier	Assumptions	Cost (£m)			Difference to original
		2010	2015	2020	in 2020
Cost of cleaning biogas and construction of dedicated pipeline	As Scenario 1 and 2	7.4	69.5	813.7	
Cost of cleaning and upgrading biogas, connecting to grid and monitoring	As for Scenario 1 and 2	6.7	147.8	1,729.8	
Biogas: Recovery from existing facilities and lack of appetite to use crops for energy	As for Scenario 1 and 2	0.0	148.5	364.9	
Biogas: total Scenario 3					82.2

In summary, in the absence of any commercial constraints the barrier costs for delivering renewable heat through direct on-site use and direct gas grid injection (Table 15) are only slightly higher than the alternative routes of heat recovery through utilisation district heating schemes. However, the net carbon benefit of the switch from electricity to heat supply is poor and this strategy reduces the amount of renewable electricity generated from biogas by 2.6 TWh.

Table 16 Comparison of CHP electricity output (TWh) between the original and revised projections

Scenario		2010	2015	2020	Change from Original
Scenario 1	Original	0.07	0.17	0.46	- 0.1
	Revised	0.07	0.16	0.39	
Scenario 2	Original	0.07	0.32	1.49	-1.0
	Revised	0.07	0.18	0.46	
Scenario 3	Original	0.07	0.42	2.60	-2.6
	Revised	0.07	0.18	0.00	

4.2.2 Quantification of demand side barriers

Re-configuring the modes of delivery of biogas heat caused both new demand side barriers to be identified but also some existing demand side barriers to change in terms of the magnitude of their overall impact. These were specific to the barriers related to on-farm adoption of anaerobic digestion. Here there will likely be an up-scaling of the biogas facilities causing a reduced quantity necessary for processing the same amount of agricultural materials. The revised barrier costs indicate that a saving of £31 million could be achieved, a very small component of the overall demand side barrier costs.

5. COMMERCIAL PERFORMANCE COMPARISON OF THE DIFFERENT OPTIONS

5.1 Approach

In order to achieve a comparison of the commercial credibility of the various biogas and bio-methane utilisation routes a number of options comparing biogas exploitation from a 50 t/day anaerobic digester was examined. In order to provide an un-skewed comparison, any ROC or LEC revenues were discounted from the financial comparison. The following energy values/costs were assumed. It should be noted that this analysis was undertaken in order to illustrate some key comparative points. The exercise does not attempt to be an exhaustive analysis of all permutations of scale and technology system since this is outside the scope of the commission.

Table 17 Energy value & energy cost assumptions in comparative financial modelling

	Energy sale price (£/ MWh)	Energy Purchase price(£/ MWh)
Electricity	60.0	90.0
Heat (hot water)	30.0	n/a
Bio-methane	19.4	n/a

Key commercial performance data are presented in the table above and other input assumptions to this commercial modelling are presented in Appendix.6.

5.2 Findings

In the absence of support mechanisms, electricity generation from biogas with or without heat recovery is cost effective. So is the on-site use of biogas, providing internal rates of return (IRRs) of between 7% and 11%. The best performing options are CHP and electricity-only and on-site gas use. Bio-methane injection only just manages to cover the operational costs associated with production. It should be noted that the financial performance of all networked systems is highly dependant upon assumptions of distance that gas or hot water is conveyed. The costs of gas injection combined with the relatively low value of heat render this a non-competitive option. These findings are detailed in the table overleaf.

Table 18 **Comparison of non-supported options for biogas exploitation[14]**

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6
Description	**50 t / day food waste in CHP mode**	**50 t / day food waste – electricity only**	**50 t / day food waste heat only**	**50 t / day biogas upgrade & injection**	**50 t/ day biogas on site industrial use**	**50 t/ day biogas distributed offsite**
ROCs foregone	yes	yes	no	no	no	no
LECs foregone	yes	yes	yes	yes	yes	yes
Outputs						
Biogas produced (m^3/yr)	2,094,188	2,094,188	2,094,188	2,094,188	2,094,188	2,094,188
Methane captured (m^3/yr)	1,231,382	1,231,382	1,231,382	1,218,817	1,231,382	1,218,817
Electricity (net) (kWh)	3,020,991	3,020,991	-	-	-	-
Heat (net) (kWh)	3,461,552	-	9,163,673	9,668,199	9,767,871	9,668,199
Revenue (£)						
Electricity income/savings	262,826	262,826	-	-	-	-
ROCs and CCL	-	-	-	-	-	-
Heat income/savings	51,923	-	247,419	168,111	188,715	186,790
Gate fees	-	-	-	-	-	-
Digestate solids	7,861	7,861	7,861	7,861	7,861	7,861
Digestate liquids	14,144	14,144	14,144	14,144	14,144	14,144
Total	336,755	284,831	269,424	190,116	210,720	208,795
Financial analysis						
Capital costs (£)	2,846,607	2,089,392	2,572,131	3,273,516	1,211,500	3,075,000
Operating costs (£)	74,945	67,373	135,746	146,536	122,140	140,775
Annual net income (£)	261,809	217,458	133,678	43,580	88,581	68,020
Simple payback* (years)	10.9	9.6	19.2	75.1	13.7	45.2
NPV (£)	1,269,638	1,316,456	-417,130	-2,455,025	193,020	-1,894,358
IRR	9%	11%	3%	n/a	7%	n/a

14 This analysis was undertaken in order to provide an indicative measure of financial performance of various utilisation options, it should not be viewed as a comprehensive analysis of all possible permutations and scales of biogas generation and use.

5.3 Comparative lifetime delivered costs of energy

Assuming fifteen year productive a lifetime of the anaerobic digester and associated facilities the delivered costs of the various options were compared. These costs should be viewed as indicative since the actual project costs in any situation will vary and the outcome of the analysis is highly dependant upon assumptions on district heating or gas pipeline lengths.

Costs for CHP (option 1) are not directly comparable since they omit the electricity generated. Option 2 is not comparable since no heat is captured in the system.

Table 19 Lifetime costs of heat production from relevant Options (£/MWh)

Description	Option 1 50 t / day food waste in CHP mode	Option 2 50 t / day food waste generating electricity only	Option 3 50 t / day food waste delivering heat only via DH	Option 4 50 t / day biogas upgrade & injection	Option 5 50 t/ day biogas on site industrial use	Option 6 50 t/ day biogas piped for offsite site industrial use
lifetime cost (£/MWh of lifetime heat output)	n/a	n/a	33.53	37.73	20.77	35.76
of which:						
Biogas production	n/a	n/a	16.79	16.79	16.79	16.79
Hot water production	n/a	n/a	1.83	-	-	-
Hot water distribution	n/a	n/a	14.90	-	-	-
Gas upgrade/ distribution	n/a	n/a	-	20.93	3.98	18.97

6. ENERGY YIELDS – PERFORMANCE COMPARISON OF THE DIFFERENT OPTIONS

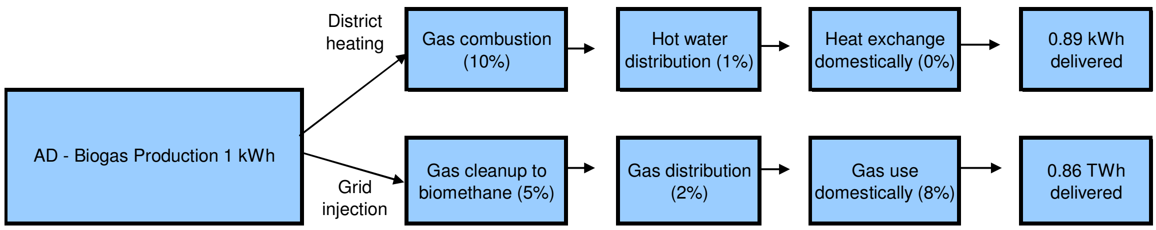
CHP with heat recovery is an energetically efficient way to utilise biogas. Whilst a proportion of the heat generated can be used on-site (e.g. in the AD process) many biogas production points are far from any sizeable heat demand and the majority of the heat produced is typically wasted. The heat can be distributed via hot water in district heating systems over a number of kilometres as only roughly 1^{0}C is lost every km[15] however distribution over any large distance would become prohibitively expensive due to infrastructure costs. Landfill sites frequently experience problems with their electricity generating plant due to the low biogas quality, which results in low load factors and frequent venting of excess biogas.

Energy yields from direct combustion on industrial sites or from piped delivery to off-site industrial uses may therefore be as efficient, if not better than, hot water distribution systems. However, the energy balance is difficult to model since it depends very much on efficiencies of process heat use, which may vary between applications and sites. The connection of AD plants and landfill sites to the natural gas grid allows for any excess bio-methane to be utilised whether there is local demand or not. However, cleaning and upgrading biogas to bio-methane and injecting it into the grid requires considerable amounts of energy, and reduces the effective renewable energy value by around 3-5%.[16]

However the losses can be as high as 20% for landfill gas, as it may need to be liquefied and re-gasified to remove the high level of impurities. Thus, in carbon equivalence terms, 1 MWh of bio-methane delivers less than 1 MWh of heat from biogas utilisation[17].

The Figure below shows how much heat is delivered to the end user from 1 kWh of biogas from an AD plant using district heating or grid injection (as discussed above, losses from landfill gas may be far higher).

Figure 8 Comparative energy performance of district heating with gas grid injection. Figures in parenthesis refer to percentage efficiency losses at each stage.



15 Discussion with Kate Lister Biogen UK Ltd
16 Based on discussion with John Baldwin
17 It is outside the scope of this study to consider the life-cycle analysis of different energy systems and the relative efficiencies of gas and electricity grid versus local use. Therefore we have considered only the direct energy consumption associated with delivering the energy vector.

7. OTHER CONSIDERATIONS AROUND THE ADOPTION OF GRID INJECTION

A number of barriers to the uptake of biogas grid injection have been identified and are summarised below. See Appendix 2 for more information.

Proximity to the gas grid network

In our financial modelling above we have assumed that the non-urban locations of these facilities are 5 km from the nearest point of gas injection. However the distances could be much greater. For piping costs to off-site industrial users we have assumed an even greater transfer distance of 10 km.

Gas Distribution Network Operator Obligations

Access to the gas grid network is covered by the Gas Act (1986), and under this Act it is incumbent upon the 8 gas distribution operators to enable access of all gas supplies that are of suitable quality (calorific value) where that access can be achieved economically. Ofgem has responsibility for ensuring grid access. However, our view is that even if bio-methane quality could be assured and bio-methane delivered at an attractive price there is currently no dialogue or pressure upon the grid operators to take the risk and receive the bio-methane. This view has also been identified by Government in the recent Renewable Energy Consultation.

Fugitive methane emissions

Swedish analysis of 22 anaerobic digestion plants indicate that fugitive emissions (that is to say unintended biogas or methane leaks) from gas upgrade and injection systems is twice that of those where on CHP is undertaken (1% compared with 2%). This marginal increase will have significant impacts since the global warming potential of methane is so high – it further erodes the renewable energy balance of the system.

Public acceptance

European evidence indicates that the general public may be reluctant to accept gas for cooking which is derived from landfill sites or waste digestion or sewage.

“Reluctance from gas customers against gas originating from e.g. landfills, sewage or manure is a potential roadblock for adding upgraded gas to natural gas grids. The reluctance can be based on technical or emotional arguments from e.g. private consumers using the gas in stoves, or industrial clients using the gas for e.g. food production” (Danish Technology Centre, 2001).

Further quantitative evidence of this anecdotal observation is required in order to gauge the severity of these concerns.

The strengths and weaknesses of bio-methane grid injection and industrial on-site use are considered below.

Table 20 Summary of strengths & weaknesses of alternative routes of biogas exploitation

Bio-methane gas injection	
Strengths	**Weaknesses**
Far more flexible fuel once injected into a grid network Bio-methane has a higher energy density, thus smaller quantities are required for every unit of heat Fugitive gas emissions are unlikely to be significant	UK-based quality standards for bio-methane required, as exist in other European countries, to aid DNO uptake Financial performance compared with biogas exploitation is poor – revenues fail to cover operation costs Cannot compete with conventional biogas exploitation options Biogas production facilities will most often not be co-located with the natural gas distribution grid network Public perception of using waste derived gas in domestic appliances particularly cooking
On-site industrial use of biogas	
Strengths	**Weaknesses**
Efficient and cost-effective heat recovery route	Relies upon co-location of biogas production and use – limited examples and probably very limited future opportunity unless new AD facilities are located on-site.
Off-site industrial or district heating use of biogas	
Strengths	**Weaknesses**
Proven technology path.	Potential reliance on 3rd party operator
Could increase the capacity of district heating or CHP facilities	Potential for increased fugitive emissions
	Significant costs for gas distribution

8. CONCLUSIONS

This study has identified that additional potential for heat delivery from biogas – above the substantial increases already included in the phase 1 report outputs - is achievable in the UK by 2020 if effort is shifted from CHP and AD heat projects (where heat is distributed via hot water systems) towards direct industrial utilisation and gas injection. However, this additional heat is delivered by causing a reduction in CHP generation and the net impact is a significant loss of carbon savings (291,924 tCO_2/yr). Whereas the commercial viability of on-site utilisation of biogas appears strong, off-site use or direct grid injection appear very poor due the relative higher value of electricity and the estimated costs of gas transfer or/and cleanup.

Lack of distribution infrastructure (gas upgrading, distribution to the injection point and injection itself) remains the largest supply side barrier to bio-methane gas injection, with enabling actions the required near-term activities necessary to achieve adoption.

Whilst greater flexibility of heat delivery may be gained from bio-methane grid injection this does not compensate for its relatively poor commercial performance (combined with the higher barrier costs and poor carbon benefit) when compared with the counterfactual of CHP with district heating. On the other hand additional on-site generation and use of biogas in industrial processes does seem a tenable proposition where co-location can be achieved.

Table 21 Alternative biogas delivery options summarised

	Industrial on-site biogas use	**Biogas distribution for on-site use**	**Bio-methane gas grid injection**
Is the option technically credible?	Yes	Yes	Yes
Are there financial barriers?	No	Yes	Yes
Are there barriers caused by lack of policy/ statute efficacy?	Yes	Yes	Yes
Is the method carbon efficient compared with the base case?	Yes	Yes	No
Will the option lead to an increase in renewable heat, compared to Scenarios 1 to 4?	Possibly	Possibly	Possibly
Would the option provide improved ease of application compared to district heating?	Yes	Possibly	Yes
Is the option financially robust under current support mechanisms?	Yes	No	No

APPENDICES

1. GAS QUALITY STANDARDS

Gas distribution grids in Europe are divided into two categories – L-gas grids and H-gas grids. The terms L and H refers to low and high Wobbe index. L and H-gas are supplied to the customer in separate grids. Wobbe index (*WI*) characterises the energy content of a gas through a specific orifice and is defined by the equation

$$WI = \frac{H}{\sqrt{d}}$$

where *H* is the heating value [MJ/nm^3] and *d* is the relative density of the gas (Fachverband Biogas, 2002). The typical properties and composition of biogas differ from natural gas and vary depending on its source as shown below (IEA Bioenergy Task 37, 2006).

Table 22 Composition and parameters of gas from different sources

Parameter	Unit	Landfill gas	Biogas from AD	North Sea natural gas
Lower heating value	MJ/nm3	16	23	40
	kWh/nm3	4	7	11
	MJ/kg	12	20	47
Density	kg/nm3	1	1	0.84
Higher Wobbe index	MJ/nm3	18	27	55
Methane number		> 130	>135	70
Methane	vol-%	45	63	87
Methane, variation	vol-%	35-65	53-70	-
Higher hydrocarbons	vol-%	0	0	12
Hydrogen	vol-%	0-3	0	0
Carbon dioxide	vol-%	40	47	1.2
Carbon dioxide, variation	vol-%	15-50	30-47	-
Nitrogen	vol-%	15	0.2	0.3
Nitrogen, variation	vol-%	5-40	-	-
Oxygen	vol-%	1	0	0
Oxygen, variation	vol-%	0-5	-	-
Hydrogen sulphide	ppm	< 100	< 1000	1.5
Hydrogen sulphide, variation	ppm	0-100	0-10000	1-2
Ammonia	ppm	5	<100	0
Total chlorine (as Cl –)	mg/nm3	20-200	0-5	0

Biogas can be 'upgraded' to bio-methane, a product equivalent to natural gas or other higher-grade fuels. Bio-methane, which typically contains more than 95% CH_4

(with the remainder as CO_2), has no technical barrier to being used interchangeably with natural gas, whether for electrical generation, heating, cooling, pumping, or as a vehicle fuel (March et al, 2007).

Not all gas appliances require the same gas standards however and there is a considerable difference between the requirements of stationary biogas applications and fuel gas or pipeline quality (IEA Bioenergy Task 24, 2000). Table 23 shows the cleaning requirements for biogas to be used in different applications. It can be seen that only hydrogen sulphide (H_2S) needs to be removed if the biogas is to be used in a CHP engine whereas CO_2, H_2S and water need to be removed if the biogas is to be used in a natural gas grid.

Table 23 Requirements to remove gaseous components depending on the biogas utilisation

Application	H_2S	CO_2	H_2O
Gas heater (boiler)	< 1000 ppm	No	No
Kitchen stove	Yes	No	No
Stationary engine (CHP)	< 1000 ppm	No	No condensation
Vehicle fuel	Yes	Recommended	Yes
Natural gas grid	Yes	Yes	Yes

Source: IEA Bioenergy Task 24

UK gas grid quality requirements

In Great Britain (GB), domestic and industrial appliances are designed to operate within a certain gas quality specification range. The current gas quality standards are based on the quality of gas sourced from the UK Continental Shelf (UKCS) as this has traditionally been the primary source of supply for the GB market (ofgem, 2008).

Concern over the compatibility of different gases with the grid is not limited to biogas – conventional natural gas also varies in composition and quality. The rise in gas trading across international borders through new pipeline interconnectors and LNG shipping brings with it concerns for the variability of gas quality delivered from different sources.

The UK gas specification is set by Gas Safety (Management) Regulations (OPSI, 2008), which use the Wobbe Index[18] as the main parameter of interchangeability[19]. The GSMR set the limits of Wobbe at between 47.20 MJ/m^3 and 51.41 MJ/m^3. This is a narrower band of acceptable Wobbe, however, than many other countries specify, including those in mainland Europe (Oil and Gas Journal, 2007).

18 The Wobbe Index represents a measure of the heat released when a gas is burned at a constant pressure. The permitted Wobbe Index range in the GS(M)R is between 47.2 - 51.41 MJ per cubic metre.
19 The ability to substitute one gaseous fuel for another in a combustion application without materially changing the operational performance of the application (its safety, efficiency, or emissions).

Upgrading Process

Biogas produced in AD-plants, sewage gas or landfill sites is primarily composed of methane (CH_4) and carbon dioxide (CO_2) with smaller amounts of hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2), saturated or halogenated carbohydrates and oxygen (O_2) are occasionally present in the biogas. Usually the gas is saturated with water vapour and may contain dust particles and organic silicon compounds (e.g. siloxanes) (IEA Bioenergy Task 37, 2006).

In order to obtain pipeline quality gas the biogas must pass two major processes:

- A cleaning process, in which trace components harmful to the natural gas grid, appliances or end-users are removed.
- An upgrading process, in which the calorific value, Wobbe index and other parameters are adjusted in order to meet the pipeline specifications.

The various impurities must be removed as they have a negative impact on power generating equipment, degrading the equipment and reducing efficiency. The more sophisticated the technology, the greater the gas cleaning required to ensure its satisfactory operation. Diesel engines are more tolerant of impurities than are gas turbines, which in turn can tolerate a poorer quality gas than can fuel cells.

The cleaning process is usually undertaken in three steps: removal of CO_2 and trace contaminants, removal of H_2S and finally drying.

- Several technologies to remove CO_2 exist however Pressure Swing Absorption (PSA) and water scrubbing and are the most commonly deployed.
- Water scrubbing, activated carbon and biological desulphurisation (using micro-organisms and oxygen) are used to remove H_2S.
- Refrigeration is a common method for drying biogas. The gas is chilled with a heat exchanger and the condensed water is separated. In order to reach higher dew points the gas can be compressed before it is cooled.

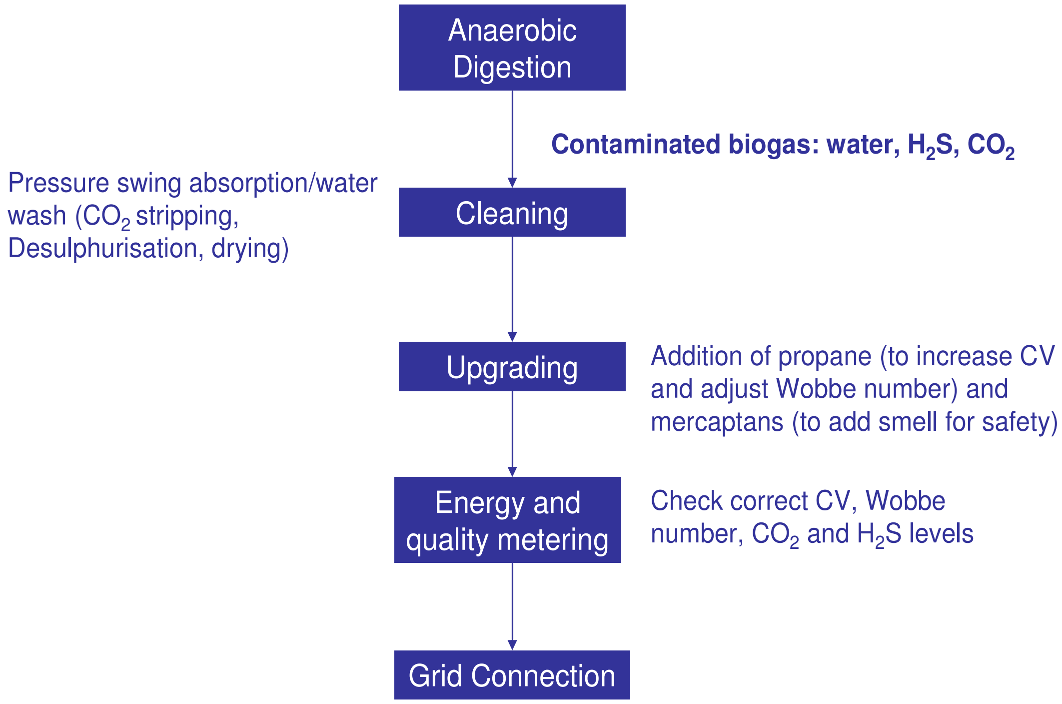
CO_2 is removed to increase the heating value of the gas and its Wobbe index. The removal of CO_2 can result in some methane losses. This should be limited for economic and environmental reasons (due to the high global warming potential of methane).

In addition propane is often added (around 4.6%) to further increase the calorific value of the gas and adjust its Wobbe number.

The upgraded biogas must then be made to smell like natural gas ("odorisation"). Very small amounts of mercaptans are added to the biogas so that it has the same distinctive smell as natural gas so that leaks are easily detected.

Finally the gas has to be metered for its energy content and quality checked (e.g. for levels of CO_2 and H_2S) to check it meets the requirements of the gas grid.

Figure 9 Biogas upgrading and grid injection



The gas is compressed during the cleaning/upgrading process to around 20 bar and the resulting upgraded biogas leaves the plant at around 4 Bar. It does not require further compression if it is to be injected into a low-medium pressure grid (local distribution network). A small amount of compression may be required if the bio-methane is to be injected into intermediate pressure grid however only a small pump is typically required.

Upgrading Landfill gas

Landfill gas has a lower calorific value than biogas from AD and more impurities. As a result more propane must be added to landfill gas to increase it Wobbe number to that of natural gas. In addition to the cleaning and upgrading process described above, it must be liquefied to remove the high levels of nitrogen present.[20] It is therefore more expensive and energy intensive to upgrade landfill gas than biogas from AD.

Grid quality standards

The European directive 2003/55/EC aims to open the existing natural gas grid for gas from other sources than natural gas, including gas from renewables. The directive states that

"*Member states should ensure that, taking into account the necessary quality requirements, biogas and gas from biomass or other types of gas are granted non-discriminatory access to the gas-system, provided that such access is permanently*

20 However the energy used to liquefy the bio-methane can be partially recovered as the cooled fully cleaned liquefied bio-methane is used to cool the incoming bio-methane as it returns to a gas.

compatible with the relevant technical rules and safety standards. These rules and standards should ensure, that these gases can technically and safely be injected into, and transported through the natural gas system and should also address the chemical characteristics of these gases" (Burgel et al, 2006).

The stringency of the quality requirements for grid injected biogas will depend on various factors including the type of grid (local vs. national), the requirements of the end-users and the concentration of the biogas in the overall network.

"Off-spec" gas can be added to the grid so long as there is sufficient flow to ensure that concentration levels of the biogas do not become too high. If e.g. the Wobbe index of the natural gas is somewhat higher than the minimum limit, the Wobbe index of the upgraded gas can be lower than the specified index as long as the overall mixture meets the specification.

If lower qualities of upgraded biogas can be allowed, the efficiency and methane yield of the upgrading process can be improved, and the investment and operating costs can be reduced. If biogas is distributed in a closed biogas network or in a town gas network the biogas only has to be cleaned not upgraded (odorisation and adjustment of the calorific value and Wobbe index is not necessary). This option has been demonstrated in Sweden and Denmark (Danish Technology Centre, 2001).

However whilst addition of on-spec gas is generally well accepted, the addition of off-spec gas can meet considerable resistance as end-users tend to question the quality of the delivered gas. The mixing of off-spec biogas also requires an adequate feedback measuring and control system to ensure that the overall gas quality remains adequate. It also requires close communication between the upgrading plant operator and the grid owner. Therefore, off-spec delivery is most suitable when the upgrading plant is owned and operated by the grid owner (Danish Technology Centre, 2001).

International biogas injection standards

There is no international technical standard for biogas injection but some countries have developed national standards and procedures for biogas injection. MARCOGAZ, the technical association of the European Natural Gas Industry has developed guidance (yet to be published) on the technical and gas quality requirements for delivery of non-conventional gases e.g. biogas into gas networks (IEA Bioenergy Task 37, 2006).

Details of standards for grid injected biogas in Switzerland, Germany and France are given in Annex 5. The standards vary in the contaminants and properties they cover and the accepted limits. All three limit the amount of CO_2, O_2, and Sulphur the gas can contain and the Wobbe number range or methane content. France has the most stringent standard which covers a number of properties and contaminants including: higher heating value, higher Wobbe index, hydrocarbon dew point, mercury, chlorine, fluorine, hydrogen and carbon monoxide.

2. ADDITIONAL INFORMATION ON BARRIERS

A number of non financial barriers to the increase in heat generation from biogas were identified during the literature review and discussions with the following biogas specialists:

- Owen Yeatman – farmer and MD of Biogas Nord UK Ltd
- Clare Lukehurst – biogas specialist
- David Collins – Renewable Energy Association (REA)
- Kate Lister – Biogen (UK) Ltd
- Graham Jennings – London Climate Change Agency (LCCA)
- John Baldwin – CNG Services

Competition with other uses

There are a number of alternative options for utilisation of the biogas (boiler, CHP, use in separate gas networks etc.). The possible lack of an economic incentive might be one of the major roadblocks for a substantial utilisation of biogas introduction into the natural gas grid, since alternative options for utilisation in many cases will be more profitable. Taxation and subsidisation are possible tools to promote biogas introduction into the natural gas grid (Danish Technology Centre, 2001).

Government is currently considering supporting biogas injection via a new heat financial incentive, as outlined in the UK Renewable Energy Strategy consultation document.

Location

Biogas introduction into the natural gas grid requires that the biogas production is located near a gas pipeline. Transportation of the feedstock, of which the biogas is produced, over large distances is not suitable for economic and environmental reasons. A major share of the potential biogas production is based on manure and waste products from the agricultural industry. Due to the nature of this industry, the biogas production is often located in sparsely populated areas, which means that introduction of biogas from these sources in significant volumes requires a widely distributed natural gas grid, which is not present in all regions (Danish Technology Centre, 2001).

Lack of regulation over access to grid

The current lack of regulation and legislation governing access rights, and transparent methods to calculate the network operator's costs etc. can inhibit biogas introduction in some cases.

In order to promote investments in biogas upgrading plants there is a need to establish clear guidelines and regulations for the rights and obligations for the involved organisations, including the owners of the upgrading plants, grid owners, customers (who buy the upgraded gas) etc. These measures are seen as parallel to the similar regulation for introduction of 'green' electricity to the power grid (Danish Technology Centre, 2001).

The Gas Act (1986) places an obligation on gas distribution operators to enable access of all gas supplies that are of suitable quality where that access can be achieved economically. However, there is no evidence that current legislation is sufficient to ensure that distributors take the risk and allow access for biogas injection, even if the quality and economics were right.

In the recent UK Renewable Energy Strategy consultation document Government is proposing to work with gas transporters (including National Grid and the Gas Distribution Networks) and Ofgem to make a more detailed assessment of the legal, technical and regulatory requirements for flowing biomethane directly into the gas pipe-line system.

The GLA and LCCA have commissioned an independent study into the possible uses of biogas from different processes. The report is yet to be finalised however it is anticipated that it will focus on the conversion of biogas to liquid fuels to either be used for on-site energy generation (e.g. in CHP) or as vehicle fuels. The use of biogas grid injection is unlikely to play a major role due to concerns over gas losses during pressurisation and distribution. In addition grid injection would not help London meet its ambitious on-site renewable generation and carbon reduction targets.

As a result of concern over poor gas quality, there are likely to be severe requirements for gas quality monitoring and fail-safe disconnection of the bio-methane supply from the natural gas pipeline network, which may lead to prohibitively high costs for bio-methane producers (March et al, 2007).

Need for co-operation between several parties

The various options discussed will all require a high level of co-operation between parties along the supply chain (feedstock suppliers, AD plant/landfill operators, regulators, grid operators etc. In particular there may be issues if pipelines have to be built across several pieces of land.

Contaminants

The impact of micro organisms on the integrity of the pipeline system and/or to end-users (appliances) is still unknown and may need further investigation. The environmental and health impacts of trace contaminants may also need further investigation (Burgel et al, 2006).

The Swedish Institute of Infectious Disease Control, National Veterinary Institute and the Swedish University of Agricultural Science evaluated the risk of spreading disease via biogas injection and concluded that the risk was very low; the number of micro organisms found in biogas was equal to the level found in natural gas.

Timing

The most time consuming part of any biogas grid injection project is time taken to get planning permission, obtain permits from the Environment Agency and build the biogas production plant. This can take 18 months or longer. Grid connection should not be a lengthy process once the plant is commissioned.[21]

21 Discussion with Clare Lukehurst

3. STORAGE IN PRESSURISED CONTAINERS

If distribution of bio-methane via dedicated pipelines or the natural gas grid is impractical or prohibitively expensive, over-the-road transportation of compressed bio-methane (CBM) or liquefied bio-methane (LBM) may be a distribution option.

The low value per unit volume and corrosive nature of low-medium pressure biogas makes transportation unsuitable. Biogas must be cleaned, upgraded and pressurised to make transportation economic. The biogas can either be upgraded and pressurised to a medium pressure to make compressed bio-methane (CBM) or upgraded further and compressed to a high pressure to make liquefied biomethane (LBM). LBM can be transported relatively easily and it can be widely used as a transportation fuel.

CBM

Prior to pressurisation the biogas has to be cleaned thoroughly which is both expensive and energy intensive. Gas scrubbing is even more important at high pressures because impurities such as H_2S and water are very likely to condense and cause corrosion. CBM is pressurised to between 2,000 and 5,000 psi whereas which is both expensive and energy intensive. CBM is stored in steel cylinders such as those typically used for storage of other commercial gases. Storage facilities must be adequately fitted with safety devices such as rupture disks and pressure relief valves. The transportation of CBM is likely to be subject to same restrictions as CNG e.g. must be contained in special approved tanks only and marked as hazardous material etc (March et al, 2007).

LBM

To produce LBM the biogas needs to be meticulously purified, as even slight impurities (H_2O or CO_2) can cause significant problems during the liquefaction process (e.g., deposits on heat exchange surfaces, clogging of piping, etc.). Inclusion of air must be carefully avoided, as entrained O_2 would create danger of explosions (which is perhaps more of a problem with landfill gas, where air entrainment is common).

Typical LNG storage tanks are double-walled, thermally insulated vessels with storage capacities of 15,000 gallons for stationary, aboveground applications. LBM is likely to be subject to the same restrictions as LNG which requires special handling as it is a cryogenic liquid (i.e., its nominal temperature is -260º F) it considered to be a (flammable) hazardous material.

LBM is only likely to be applicable to large scale biogas upgrading projects. During storage the cryogenic liquid heats ups which results in loss of LBM to evaporation through a release valve on the tank. To minimize these losses, LBM should be used fairly quickly after production. It is generally recommended that LBM be stored for no more than a week before it is either used or transported to a fuelling station. Since standard LNG tankers carry about 10,000 gallons, a small-scale liquefaction facility should produce at least 3,000 gallons of LBM per day.

One of the most attractive features of over-the-road transportation of liquefied bio-methane is that an infrastructure and market already exist. It also allows for flexibility between heat generation and transportation.

However CBM and LBM are likely to mainly be used in transport fuel markets where they can command far higher prices than in heat markets.

4. FINANCIAL ANALYSIS

The financial costs of each process in each distribution pathway must be assessed to determine the relative costs of the different distribution methods. This section considers the relative costs of each pathway and does not compare costs faced by all options such as the operation of an AD plant. The income from the biogas is not considered (such as whether producer would be paid a rate that is lower than the wholesale natural gas price by the grid operator) neither are other potential sources of revenue e.g. from useful by-products such as fertiliser.

Cleaning and upgrading

The total cost for cleaning and upgrading biogas derives from cost of investment as well as of operation of the plant and maintenance of the equipment. The most expensive part of the treatment is the removal of carbon dioxide. The investment increases with increased capacity but investment per unit of installed capacity decreases for larger plants. Cost estimates for fully upgrading biogas were found during the literature review however the reductions in cost of part upgrading the biogas were not found.

Capital costs

IEA Bioenergy Task 37 estimates that typical capital costs for a plant treating 300 nm^3 (normal cubic meters[22]) per hour of raw gas (typical capacity of small–medium European plant given in Appendix 6 is in the order of €1 million[23] based on investments in 16 upgrading plants in Sweden made between 1998 and 2006 (IEA Bioenergy Task 37, 2006).

Using the following assumptions:

- Conversion efficiency of around 80% (Austrian case study)
- Capacity factor of 70% (Austrian case study)
- Biogas calorific density of 39.6 MJ/m^3 (assume same as natural gas as upgraded to have same Wobbe number)

This gives an annual output of **11 GWh** and a capital cost of 89 €/MWh capacity or **4.5 €/MWh** over a lifetime of 20 years.

A second report estimated for a dairy digester and biogas upgrading plant in California. The costs were based on costs for similar (albeit larger) plants in Sweden, as well as on discussions with equipment suppliers and others. The report estimated that capital costs ranged from **3.2 €/MWh** (low estimate for large dairy) to **6.4 €/MWh** (high estimate for a small dairy). In comparison the AD plant was estimated to cost between 6.2 – 10.9 €/MWh (Anders, 2007).

22 Normal cubic meter volume at atmospheric pressure (1.01325 bar) and 0℃, also called STP (standard pressure and temperature).
23 Does not typically include cost of building

Operational costs

The major operation costs for a plant with full treatment to vehicle fuel quality is electricity, personnel, maintenance and depending on technique, consumption of i.e. water or chemicals. The IEA Bioenergy Taskforce 37 estimate that typical operational cost for an upgrading plant treating 200 nm^3 raw gas per hour is in the order of 15 €/MWh (IEA Bioenergy Task 37, 2006).

The study looking at dairies in California suggest that upgrading operational costs are around 8–14 €/MWh.

A third report gives typical costs in biogas upgrading plants in Sweden of around 30 €/MWh for large plants and 50-60 €/MWh for smaller plants (Fachverband Biogas, 2002).

Additional operational costs may include the introduction of 5% propane to increase the calorific value of the biogas and adjust its Wobbe number.

A German report on upgrading biogas found that cost of upgrading varied depending on the size of plant, upgrading technology and feedstock (silage versus slurry). It broke down the upgrading cost into decarbonisation and desulphurisation. The main cost is for decarbonisation which ranged between 20-23 €/MWh. The cost of desulphurisation for a plant treating 250 Nm3/h varied from 0.9 €/MWh for a plant treating silage to 2.9 €/MWh for a plant treating slurry (Solarenergiefoerderverein Bayern e.V, 2008).

A second German report estimated that typical upgrading costs are around €15/MWh[24] however it costs an additional €15/MWh to add propane to adjust the Wobbe number to that of natural gas (FNR, 2006).

Based on this research the following estimates of the cost of upgrading for the three injection scenarios are as follows:

- Full upgrading for injection into any grid – **30 €/MWh**.
- Part upgrading for injection into local grid – **25 €/MWh**[25]
- Removal of H_2S only for use in dedicated pipeline – **5 €/MWh**

Pressurisation

If the gas is to be injected into a low-medium pressure grid it does not require further compression after the cleaning/upgrading process. A small amount of compression may be required if the bio-methane is to be injected into an intermediate pressure grid however only a small pump (£40-50k) is typically required.

The compression of bio-methane to CBM/LBM requires significant amounts of energy and some of the biogas has to be used in the process. Compression to 2,000 psi requires nearly 14 kWh per 1,000 ft of bio-methane. If the biogas is upgraded to 97% methane and the assumed heat rate is 12,000 Btu/kWh, the energy needed for compression amounts to 17% of the energy content of the gas.

24 Using water scrubbing or pressure swing absorption to clean biogas
25 Injection of propane to reach Wobbe number of natural gas is around 15€/MWh. Assuming cost is directly proportional to Wobbe number increase, it costs around 10€/MWh to increase Wobbe number to German standard for its L grid.

The liquefaction of bio-methane uses around 20% of its energy content (March et al, 2007).

The cost of pressurisation to LBM is factored into the cost calculations as the yield rate of LBM from an upgrading plant used (discussed in the transportation section below) takes into account the amount of biogas required to fuel the liquefaction process.

Storage and transportation

The cost of producing biogas and upgrading it to bio-methane reflect only a part, albeit a substantial one, of the actual costs incurred by a producer. In addition, the producer needs to consider the costs of storing and transporting the bio-methane, in whatever format required by the end market.

Storage

Capital costs for storage vary considerably with the length of time for which the gas must be stored and the amount of gas that needs to be stored.

Storage costs can be high for example the typical cost for a 15,000-gallon LBM storage tank is $170,000. Storage tanks for CNG, which can also be used to store bio-methane, have a typical capacity of 1,000 ft3 and cost $2,250 to $5,000 each.

Each day's storage will add to the capital cost. For example, enough storage capacity to store a day's worth of CBM produced from a 45,000-ft^3/day plant would add $100,000 to $225,000 to the cost of the facility or $0.60 to $1.40 per 1,000 ft3 to the cost of the bio-methane production. Two days' worth of storage would double those numbers.

Transportation

Typically, bio-methane produced on-farm would need to be transported to a location where it could be used or further distributed, such as an industrial plant or a CNG fuelling station. Thus, the costs of trucking the bio-methane or pumping it through a dedicated pipeline would need to be added to its production price. Other than for LBM, transportation of bio-methane by truck costs more per volume than pipeline transport and should only be considered as an interim solution (March et al, 2007).

The higher calorific density of LBM compared to CBM reduce transportation requirements. However as LBM needs to be used quickly it may not be suitable to small installations such as office CHP. The higher frequency of deliveries might overcome any savings from its increased density. A regional CBM production unit could feasibly supply a larger number of customers.

If the energy required for liquefaction is included 1,000 ft^3 of CH_4 will yield about 10 gallons of LBM (March et al, 2007). Thus assuming 10% losses, a methane content of 64% a upgrading plant would need to treat over 1000 m^3 per day of raw biogas to generate around 3000 gallons of LBM/day.

Assuming that a LNH trucks with a 10,000 gallon capacity travels 100 km to and from the site on average 2 times a week. Using typical diesel consumption by an articulated lorry, 100% laden of 0.448 litres/km (Defra, 2005), this gives us a weekly diesel consumption of 224 litres. Assuming a high diesel price of 120p/litre this results in a weekly cost of around €342.

LBM has an energy density of around 84,000 Btu/gallon therefore a 10,000 gallon truck can carry around 244 MWh of LBM, or 488 MWh a week. Thus fuel costs will be equal to around 0.7 €/MWh. This however excludes the capital cost of the specialised truck required which will cost in the region of £150,000.[26]

Dedicated pipelines

For short distances over privately owned property, distribution via a dedicated pipeline is usually the most cost-effective method. Costs for laying dedicated bio-methane pipelines can vary greatly, and may range from about $100,000 to $250,000 or more per mile (March et al, 2007). This would equate to around **4 €/MWh** for a typical plant treating 300m^3/hr over 20 years.

The study looking at Dairy farms in California estimated that the construction of LBM storage (1 day only) would add around **5.8 €/MWh** and the construction of a 5 mile pipeline would add around **1.9 €/MWh** to the capital cost (March et al, 2007).

Grid connection costs

The cost of metering and quality monitoring of the biogas is around £70,000 alone as only approved devices are for large flows of gas from North Sea (David Williams, 2008). This equates to around **3 €/MWh** for a plant injecting 450m^3/h over a lifetime of 20 years.

However discussions are currently underway between biogas suppliers and the National Grid to allow the use of smaller, cheaper metering systems (~5£k).[27] It remains to be seen however whether the producer would shoulder all of the connection and metering costs or whether it would be split between the supplier and grid operator.

A study looking at biogas use in the USA found that grid connection costs varied widely depending on the amount of biogas being upgraded and between natural gas operators:

"The cost to a biogas developer to interconnect with PG&E's natural gas system varies according to the volume of pipeline quality gas to be injected. Projects injecting more than 500 thousand cubic feet per day (MCF/d) will cost the developer approximately $180,000 for interconnection facilities and monitoring equipment with PG&E contributing $85,000 for the interconnection, metering, controls, and engineering. **Projects injecting less than 500 MCF/d will cost the developer $265,000 for all interconnection facilities, monitoring equipment, metering, and controls.** The costs to interconnect a biogas project to the Southern California Gas (SCG) system are identical to those for traditional natural gas interconnection. Interconnecting a project to inject 1 million cubic feet per day (MMCF/d) would cost approximately $800,000. Larger projects benefit from economies of scale. A 10 MMCF/d project would pay about $1 million in interconnection costs" (Anders, 2007).

Assuming that a plant injecting 500 million ft^3/day of bio-methane[28] faced annual costs of $265,000 this equates to around **3 €/MWh**.

26 Discussion with John Baldwin
27 Low standards could be applied based on a risk assessment
28 Assuming it is upgraded to a calorific value of 11 kWh/nm3

Conclusion

Table 24 shows estimated costs per MWh for the various stages of each distribution route. The distribution of LBM only was considered due to a lack of data on CBM distribution and because LBM has a higher calorific value per unit volume.

Table 24 Estimated costs of different biogas distribution options (€/MWh)

Option	Upgrading costs	Storage	Grid connection costs	Transportation	Total (€/MWh)
Injection of fully upgraded biogas into med pressure grid	30	-	3	-	**33**
Injection of partially upgraded biogas into lower pressure (local) grid	25	-	3	-	**28**
Dedicated pipeline	5	-	-	4	**9**
LBM distribution	30	27	-	1	**58**

It can be seen that road distribution of LBM is the most expensive option and injection of partially upgraded biogas into a local low pressure grid is by far the cheapest option (for biomethane). However the cost estimates must also be considered alongside the nature of the final heat demand. For example the use of a dedicated pipeline relies on sufficient heat demand close to the point of biogas production and will have limited application in the UK.

5. INTERNATIONAL BIOGAS STANDARDS

Switzerland has developed two gas standards: one for limited injection and one for unlimited injection (which places more restrictions). The various parameters and their limits for unlimited injection are shown in Table 25. Methane content for limited injection only has to be above 50%.

Table 25 Swiss national standard for unlimited gas injection

Parameter	Unit	Required level
Methane content	vol -%	>96
Gas relative humidity	phi	<60%
Dust	-	Technically free
CO_2	vol-%	<6
O_2	vol-%	<0,5
H_2	vol-%	<5
H_2S	mg/ nm3	<5
S	mg/ nm3	<30

The German standard for biogas is based on the standard for natural gas, DVGW G260.The main requirements in the standard are stated below (for injection into natural gas grids with high heating value).

The German standards allow injection of two types of gas, gas for limited injection and gas for unlimited injection. Unlimited injection of upgraded biogas in H-gas grids is possible if the cited concentrations are maintained. The German standard also requires the biogas producer to present a safety data sheet that describes any health hazards in connection to the handling of the biogas.

Table 26 **Requirements for gas injection according to German standard G260/G262**

Parameter	Unit	Required level
Higher Wobbe index	MJ/nm3	46,1 – 56,53 in H[29] gas grids
		37,8 – 46,85 in L[30] gas grids
Relative density	-	0,55 – 0,75
Dust	-	Technically free
Water dew point	°C	<t7
CO2	vol-%	<6
O2	vol-%	<3 (in dry distribution grids)
S	mg/ nm3	<30

In 2004 Gaz de France produced a de facto standard for gas injection into the national gas grid. As can been seen in Table 27, the standard has more strict limits on oxygen than the other standards and also comprises a number of limits for heavy metals and halogens.

29 High heating value gas
30 Low heating value gas

Table 27 French national regulation for gas injection

Parameter	Unit	Required level
Higher heating value	MJ/nm3	H gas: 38,52 to 46,08 L gas: 34,2 to 37,8
Higher Wobbe index	MJ/nm3	H gas: 48,24 to 56,52 L gas: 42,48 to 46,8
Hydrocarbon dew point	°C	< -5 from 1 to 80 bar
Water dew point	°C	< -5 at MOP downstream from injection point (Gergwater correlation)
CO_2	vol-%	< 2
Dust	mg/nm3	< 5
Total sulphur	mg/nm3	< 100 instant content, < 75 annual average
O_2	ppmv	< 100
Hg	mg/nm3	< 10 (Natural gas) < 50 (Liquefied Natural Gas)
Cl	mg/nm3	< 1
F	mg/nm3	< 10
H2	%	< 6
CO	%	< 2

6. KEY INPUT ASSUMPTIONS TO COMMERCIAL MODELLING

The following data relate to the summary presented in Table 18 of the main report.

Table 28 Biogas Scenario 1 inputs

Input category	input	Option 1 Value/ unit	Option 2 Value/ unit
Other factors	Labour requirement	2 hours/day	2 hours/day
	Electricity value (on site)	9 p/kWh	9 p/kWh
	Electricity value (export)	6 p/kWh	6 p/kWh
	ROCs	0 p/kWh	0 p/kWh
	CCL	0 p/kWh (after sales)	0 p/kWh (after sales)
	Heat value	3 p/kWh	0 p/kWh
	Discount rate	6%	6%
	Inflation	3%	3%
Annual production	Utilisation of digester	100%	100%
	Annual total biogas	2,094,188 m3/annum	2,094,188 m3/annum
	Methane content/recovery	60%	60%
	Annual total methane	1,256,513 m3/annum	1,256,513 m3/annum
	Total energy value	46,240 GJ/annum	46,240 GJ/annum
Mass balance	Feedstock	50 tonnes/day	50 tonnes/day
	Feedstock	50 m3/day	50 m3/day
	Biogas	5,737.5 m3/day	5,737.5 m3/day
	Biogas	6.94 tonnes/day	6.94 tonnes/day
	Digestate fibre	4.31 tonnes/day	4.31 tonnes/day
	Digestate liquid	38.75 tonnes/day	38.75 tonnes/day
	Methane	3,442.5 m3/day	3,442.5 m3/day
	Methane	2.33 tonnes/day	2.33 tonnes/day
Costs and benefits	*Capital costs*		
	Project Development	£ 689,321	£ 537,878
	Digester	£ 840,000	£ 840,000
	Heating boiler	£ –	£ –
	CHP unit	£ 399,314	£ 399,314
	Grid connection	£ 109,828	£ 109,828
	DH mains	£ 605,772	£ 202,371
	Other	£ 202,371	£ 2,089,392

Input category	input	Option 1 Value/ unit	Option 2 Value/ unit
	Total capital cost installed	£ 2,846,607	£ 2,089,392
	O&M costs		
	Maintenance of CHP	£ 11,979	£ 11,979
	Maintenance of digester etc	£ 12,600	£ 12,600
	Parts	£ 28,466	£ 20,894
	Total maintenance and parts	£ 53,045	£ 45,473
	Operation	£ 21,900	£ 21,900
	Feedstock costs	£ –	£ –
	Waste compliance costs	£ –	£ –
	Slurry transport	£ –	£ –
	Revenue		
	Energy		
	Electricity value (on site)	£ 244,700	£ 244,700
	Electricity value (export)	£ 18,126	£ 18,126
	ROCs	£ –	£ –
	CCL	£ –	£ –
	Total electricity value	£ 262,826	£ 262,826
	Heat value	£ 51,923	£ –
	Total energy revenue	£ 314,750	£ 262,826
	Waste		
	Gate fees	£ –	£ –
	Waste disposal charge	£ –	£ –
	Total waste handling revenue	£ –	£ –
	By products		
	Digestate (unseparated)	£ –	£ –
	Digestate Solids	£ 7,861	£ 7,861
	Digestate Liquid	£ 14,144	£ 14,144
	Total by-products revenue	£ 22,005	£ 22,005

Table 29 Biogas Commercial evaluation – Scenario 3 & 4 inputs

Input category	input	Option 3 Value/ unit	Option 4 Value/ unit
Other factors	Labour requirement	2 hours/day	2 hours/day
	Electricity value (on site)	0 p/kWh	0 p/kWh
	Electricity value (export)	0 p/kWh	0 p/kWh
	ROCs	0 p/kWh	0 p/kWh
	CCL	0 p/kWh (after sales)	0 p/kWh (after sales)
	Heat value	3 p/kWh	1.932 p/kWh
	Discount rate	6%	6%
	Inflation	3%	3%
Annual production	Utilisation of digester	100%	100%
	Annual total biogas	2,094,188 m3/annum	2,094,188 m3/annum
	Methane content/recovery	60%	60%
	Annual total methane	1,256,513 m3/annum	1,256,513 m3/annum
	Total energy value	46,240 GJ/annum	46,240 GJ/annum
Mass balance	Feedstock	50 tonnes/day	50 tonnes/day
	Feedstock	50 m3/day	50 m3/day
	Biogas	5,737.5 m3/day	5,737.5 m3/day
	Biogas	6.94 tonnes/day	6.94 tonnes/day
	Digestate fibre	4.31 tonnes/day	4.31 tonnes/day
	Digestate liquid	38.75 tonnes/day	38.75 tonnes/day
	Methane	3,442.5 m3/day	3,442.5 m3/day
	Methane	2.33 tonnes/day	2.33 tonnes/day
Costs and benefits	*Capital costs*		
	Project Development	£ 634,426	£ 744,703
	Digester	£ 840,000	£ 840,000
	Heating boiler	£ 48,120	
	CHP unit	£ –	
	Biomethane cleanup & injection costs		£ 557,813
	DH/gas mains	£ 916,367	£ 975,000
	Other	£ 133,218	£ 126,000
	Total capital cost installed	£ 2,572,131	£ 3,273,516

Input category	input	Option 3 Value/ unit	Option 4 Value/ unit
	O&M costs		
	Maintenance of CHP	£ –	
	Maintenance of digester etc	£ 12,600	£ 12,600
	Parts	£ 25,721	£ 32,735
	Electricity running costs	£ 75,525	£ 79,301
	Total maintenance and parts	£ 38,321	£ 45,335
	Operation	£ 97,425	£ 101,201
	Feedstock costs	£ –	£ -
	Waste compliance costs	£ –	£ –
	Slurry transport	£ –	£ –
	Revenue		£ –
	Energy		
	Electricity value (on site)	£ –	£ –
	Electricity value (export)	£ –	£ –
	ROCs	£ –	£ –
	CCL	£ –	£ –
	Total electricity value	£ –	£ –
	Heat value	£ 247,419	£ 168,111
	Total energy revenue	£ 247,419	£ 168,111
	Waste		
	Gate fees	£ –	
	Waste disposal charge	£ –	£ –
	Total waste handling revenue	£ –	£ –
	By products		£ –
	Digestate (unseparated)	£ –	
	Digestate Solids	£ 7,861	£ 7,861
	Digestate Liquid	£ 14,144	£ 14,144
	Total by-products revenue	£ 22,005	£ 22,005

Table 30 Biogas Commercial Evaluation Scenario 5 & 6 inputs

Input category	input	Option 5 Value/ unit	Option 6 Value/ unit
Other factors	Labour requirement	2 hours/day	2 hours/day
	Electricity value (on site)	10 p/kWh	10 p/kWh
	Electricity value (export)	3 p/kWh	3 p/kWh
	ROCs	0 p/kWh	0 p/kWh
	CCL	0 p/kWh (after sales)	0 p/kWh (after sales)
	Heat value	1.932 p/kWh	1.932 p/kWh
	Discount rate	6%	6%
	Inflation	3%	3%
Annual production	Utilisation of digester	100%	100%
	Annual total biogas	2,094,188 m3/annum	2,094,188 m3/annum
	Methane content/recovery	60%	60%
	Annual total methane	1,256,513 m3/annum	1,256,513 m3/annum
	Total energy value	46,240 GJ/annum	46,240 GJ/annum
Mass balance	Feedstock	50 tonnes/day	50 tonnes/day
	Feedstock	50 m3/day	50 m3/day
	Biogas	5,737.5 m3/day	5,737.5 m3/day
	Biogas	6.94 tonnes/day	6.94 tonnes/day
	Digestate fibre	4.31 tonnes/day	4.31 tonnes/day
	Digestate liquid	38.75 tonnes/day	38.75 tonnes/day
	Methane	3,442.5 m3/day	3,442.5 m3/day
	Methane	2.33 tonnes/day	2.33 tonnes/day
Costs and benefits	*Capital costs*		
	Project Development	£ 246,500	£ 735,000
	Digester	£ 840,000	£ 840,000
	Gas line	£ 125,000	£ 1,500,000
	Total capital cost installed	£ 1,211,500	£ 3,075,000
	O&M costs		
	Maintenance of digester etc	£ 12,600	£ 12,600
	Parts	£ 12,115	£ 30,750

Input category	input	Option 5 Value/ unit	Option 6 Value/ unit
	Total maintenance and parts	£ 24,715	£ 43,350
	Operation	£ 97,425	£ 97,425
	Revenue		
	Energy		
	Electricity value (on site)	£ –	£ –
	Electricity value (export)	£ –	£ –
	ROCs	£ –	£ –
	CCL	£ –	£ –
	Total electricity value	£ –	£ –
	Heat value	£ 188,715	£ 186,790
	Total energy revenue	£ 188,715	£ 186,790
	By products		
	Digestate (unseparated)	£ –	£ –
	Digestate Solids	£ 7,861	£ 7,861
	Digestate Liquid	£ 14,144	£ 14,144
	Total by-products revenue	£ 22,005	£ 22,005

7. INTERNATIONAL EXPERIENCE

Upgrading technology is becoming increasingly widespread internationally and there have been a number of projects across Europe injecting upgraded or partly upgraded into both H and L gas grids e.g. in Sweden and Germany. A number of projects around the world are compressing bio-methane into CBM/LBM for use as a transport fuel. Increasingly biogas plants are using private gas pipes to deliver biogas from biogas plants to either CHP systems or biogas refuelling stations. Enviros was unable to find examples of the road transportation of CBM/LBM for use in heat generation systems.

Grid injection

Upgrading of digestion gas has been practiced since 1935 and in Germany there were pilot grid injection projects between 1982 and 1999. Since 1992 there have been a growing number of grid injection projects in several Member States: in Denmark (pilot scale), Sweden (large scale), in Switzerland (large scale), and in the Netherlands (large scale) (Fachverband Biogas, 2002). Grid injection has also taken place in Austria, Canada and the USA. Injection currently mainly occurs in local distribution gas grids. In these cases relatively small volumes are added at low pressures, mostly for domestic end-users. However some projects are now injecting into the national grid (e.g. Pliening plant, North of Munich).

As far as is known, no major problems have been reported related to the addition of biogas to natural gas (Burgel et al, 2006).

Various research programmes into biogas injection are underway across Europe:

- The GERG Project: ‘Biogas Characterization’ developed an inventory of the available information on biogas, focussing on the injection of biogas into the natural gas transmission grid. It summarised regulatory information (production, transport, use) and identified typical biogas compositions.

- A European research project led by the European Gas Research Group (GREG), a pan-European consortium of major natural gas organisations and universities is currently examining the various barriers to widespread use of biogas in main gas grids. The 'BONGO' project ('Biogas and Others in Natural Gas Operations') started in 2007 and will run for 5 years

0 gives information on a number of international reference plants used to upgrade biogas for grid injection (or for grid injection and vehicle fuel production). In addition there are a number of upgrading plants that produce vehicle fuel only.

Table 31 International examples of biogas upgrading plants used for grid injection (IEA Bioenergy Task 37, 2006).

Country	City	Use	Biogas production	Methane requirements (%)	CO2 removal technique	H2S removal technique	Capacity – raw gas flow (m3/h)	Operating from
Austria	Pucking	Gas grid	Manure	97	PSA	Biol. filter	10	2005
Canada	Berthierville (Quebec)	Gas grid	Landfill gas	-	Membrane	Activated carbon	-	2003
Germany	Kerpen	Gas grid	Energy crops	-	PSA	Activated carbon	500	2006
Germany	Kerpen	Gas grid	Energy crops	-	PSA	Activated carbon	500	2006
Germany	Kerpen	Gas grid	Energy crops	-	PSA	Activated carbon	500	2006
Germany	Rathenow	Gas grid	Energy crops, manure	-	PSA	Activated carbon	500	2006/2007
Netherlands	Collendoorn	Gas grid	Landfill gas	88	Membrane	Activated carbon	375	1991
Netherlands	Nuenen	Gas grid	Landfill gas	88	PSA	Activated carbon	1,500	1990
Netherlands	Tilburg	Gas grid	Landfill gas	88	Water scrubber	Iron oxide pellets	2,100	1987
Netherlands	Wijster	Gas grid	Landfill gas	88	PSA	Activated carbon	1,150	1989
Sweden	Göteborg	Gas grid	Sewage sludge	97	Chemical absorption	Activated carbon	1,600	2006

Country	City	Use	Biogas production	Methane requirements (%)	CO2 removal technique	H2S removal technique	Capacity – raw gas flow (m3/h)	Operating from
USA	Houston (TX)	Gas grid	Landfill gas	-	Selexol scrubbing	Selexol scrubbing	9,400	1986
USA	Staten Island,	Gas grid	Landfill gas	-	Selexol scrubbing	Iron oxide wood chips	1,3000	1981
USA	Cincinnatti	Gas grid	Landfill gas	-	PSA	-	10,000	1986
USA	Dallas (TX)	Gas grid	Landfill gas	-	PSA	-	10,000	2000
USA	Pittsburg – Valley	Gas grid	Landfill gas	-	Membrane	-	5,600	2004
USA	Pittsburg – Monroeville	Gas grid	Landfill gas	-	Membrane	-	5,600	2004
USA	Shawnee	Gas grid	Landfill gas	-	Physical absorption	-	5,500	2001
USA	Dayton (OH)	Gas grid	Landfill gas	-	Krysol (methanol)	-	6,000	2003
USA	Renton	Gas grid	Sewage sludge	98	Water scrubber	Water scrubber	4,000	1984/1998
Switzerland	Bachen-bülach	Gas grid and vehicle fuel	Biowaste	96	PSA	Activated carbon	200	1996
Switzerland	Jona	Gas grid and vehicle fuel	Biowaste	96	Genosorb washing	Activated carbon	55	2005
Switzerland	Lucerne	Gas grid and vehicle fuel	Sewage sludge	96	PSA	Activated carbon	75	2004

Sweden	Helsingborg	Gas grid and vehicle fuel	Biowaste household and industry manure	97	PSA	Activated carbon	350	2002
Country	**City**	**Use**	**Biogas production**	**Methane requirements (%)**	**CO2 removal technique**	**H2S removal technique**	**Capacity – raw gas flow (m3/h)**	**Operating from**
Switzerland	Bachen-bülach	Gas grid and vehicle fuel	Biowaste	96	PSA	Activated carbon	200	1996