BEST PRACTICE CASE STUDY FOR A BIOMETHANE PRODUCTION FACILITY

SITE: EMMERTSBÜHL BIOGAS PLANT, GERMANY

PRODUCED AS PART DELIVERY OF:

Promotion of bio-methane and its market development through local and regional partnerships
A project under the Intelligent Energy – Europe programme

Supported by

Contract Number: IEE/10/130
Deliverable Reference: D2.2
Delivery Date: May 2012
Terms of use/Disclaimer

This case-study contains information obtained directly from companies that could not be verified. The reporting of commercial products, their sources or their use in connection with the material reported herein is not to be construed as actual or implied endorsement of technology or services. All images are reproduced with the permission of the site/company. The information in this report is supplied in good faith and the Partners of Bio-methane Regions make no representation as to its accuracy or content. The Partners of Bio-methane Regions are not liable, so far as law permits, for any expenses or losses including any special, incidental, consequential or similar damage or loss which directly or indirectly arise as a result of using the report or the information available on it.

Case studies were produced following surveys / site visits undertaken between 2011 and 2013 and information is therefore relevant for operating conditions at the time of visit only. Some plants may now operate under different conditions to those specified within the case studies.

The sole responsibility for the content of this report lies with the authors. It does not necessarily reflect the opinion of the European Union. Neither the EACI nor the European Commission is responsible for any use that may be made of the information contained therein.

Authors

<table>
<thead>
<tr>
<th>Authors</th>
<th>Institution</th>
<th>Country</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tim Patterson and Sandra Esteves</td>
<td>UoG</td>
<td>UK</td>
</tr>
<tr>
<td>University of Glamorgan</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Annegret Wolf, Heinz Kastenholz and Andreas Lotz</td>
<td>WFG</td>
<td>DE</td>
</tr>
<tr>
<td>Wirtschaftsförderungsgesellschaft des Landkreises Schwäbisch Hall mbH</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Martin Miltner and Michael Harasek</td>
<td>TUV-ICE</td>
<td>AU</td>
</tr>
<tr>
<td>Technical University of Vienna</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
1.0 INTRODUCTION / OVERVIEW

The biogas / biomethane plant is located at an arable farm in the village of Emmertsbühl which is approximately 120 km to the north east of Stuttgart in the Baden-Württemberg region of Southern Germany. The farmer and AD plant operator originally developed an AD plant at the site in 2005 with wheat being the primary feedstock and biogas utilised in a CHP plant, although there was no local user for excess heat generated at the plant. By 2008 the operator was exploring options for the expansion of the plant and wished to increase the utilisation of the biogas generated. In collaboration with the energy company EnBW Vertrieb GmbH, a scheme was developed whereby the plant could be extended and biogas production would be sufficient to allow the upgrading of biogas to biomethane with injection into the local gas grid. This included a novel means of utilising the local low pressure gas grid as the injection point with excess gas being exported, via the low pressure grid, to the medium pressure gas network.

2.0 PLANT DESCRIPTION

Feedstocks for the anaerobic digestion plant are grown on the plant owner / operators 500 hectare farm. The primary feedstock is whole crop maize and wheat silage with a small tonnage of grass silage also utilised. Part of the farm i.e. 70 ha is also used to grow winter wheat and maize in rotation, also for use as a feedstock. Total feedstock production is approximately 20,000 tonnes of silage per year.

2.1 Pre Treatment

Prior to storage, feedstocks are chopped to approximately 10 mm particle size. Feedstocks are stored in covered silage clamps on site and approximately 50 t per day of feedstock is added to an automated solids feeder which adds feedstock to the primary digesters. Surface water runoff from the silage clamps and digestion plant is collected in a below ground concrete tank to provide all necessary process water for the digestion plant.

Fig.1 Maize, winter wheat and grass silage feedstock in clamp  
Fig. 2 Automated solids feeder
2.2 Anaerobic Digestion

The current configuration of the site has evolved since the construction of the original plant in 2005 and as such comprises a number of tank designs and volumes. The original 2005 plant was constructed by Lipp GmbH and is of dual seam stainless steel construction. An additional tank of concrete construction was later added by Novatech GmbH. In 2010, the expansion of the plant was completed by the plant operator and included the construction of additional digesters and digestate storage tanks of concrete construction.

The anaerobic digestion plant now therefore comprises of 2 No. primary digesters with a volume of 1,600 m³ and 1,200 m³. The primary digesters include one new concrete vessel constructed in 2010 by the plant operator, and the concrete vessel constructed by Novatech GmbH prior to expansion. The base of both vessels is approximately 2.0 m below ground level to reduce tank height and heat losses. The newer of the vessels is fitted with a flexible dual membrane gas storage roof system. Both primary digesters are operated at approximately 40-45 °C and are mechanically mixed. Micro-nutrients including cobalt, manganese and selenium are added to the digesters on a daily basis. Iron salts are also added in order to reduce H₂S content of the biogas through precipitation of sulphur.

Each primary digester is followed by a secondary digester (1,100 m³ and 1,000 m³) which are also heated to 37-40 °C and mechanically mixed. The original tanks constructed by Lipp GmbH are now utilised as the secondary digesters.

2.3 Digestate

From the secondary digesters, material is passed into two digestate storage tanks of concrete construction (2,000 m³ and 2,600 m³) which were constructed in 2010. These are not heated but include flexible dual membrane roofs for gas storage for the plant. It is estimated that 2-3 % of overall gas production via biogas generated within the digestate storage tanks themselves. Overall retention time within the total system (primary digester – secondary digester – digestate storage) is approximately 130 days.

Mixed digestate is separated into solid and liquid fractions. Liquid fraction is stored on site in a covered tank prior to utilisation on the farmers land as a fertiliser. Separated solids are sold to adjacent farmers for use as a soil conditioner.
2.4 Biogas Production and Utilisation

The anaerobic digestion plant produces biogas at a rate of approximately 500 m³/hr and has a methane content of approximately 52 - 54%. In the original (2005) site configuration, biogas was utilised in 2 No. CHP plants (170 kWel and 250 kWel), although heat from the CHP plants was not utilised other than for heating the digesters on site. Therefore, in order to maximise the utilisation of the biogas produced at the site, a biogas upgrading plant was developed adjacent to the AD facility. The CHP plant remains on site and can be utilised in the event that the upgrading plant is not available (e.g. maintenance or repair periods).

The biogas upgrading plant was developed and is operated by EnBW Vertrieb GmbH. As such the company has signed an agreement with the AD plant operator who will supply the upgrading plant with a specified quantity and quality of biogas at an agreed price. The upgrading plant was supplied by Schmack Carbotech GmbH.

Raw biogas enters the upgrading plant to a 3 m³ storage vessel which is at a few millibars less than atmospheric pressure. The biogas is then compressed to 6 bar following which the gas temperature is approximately 86 °C. Gas is cooled from 86 °C to 46 °C by a tubular (shell in shell) gas to gas heat exchanger. A second stage water cooled heat exchanger then cools the biogas from 46 °C to 23°C before a refrigerant cooled heat exchanger cools the gas from 23 °C to 6 °C to produce a dried biogas. The dried biogas is then heated to approximately 46 °C using the counter current from the first stage heat exchanger.

From here, the dried biogas passes through an activated carbon filter for removal of hydrogen sulphide at a pressure of approximately 5 bar. H₂S is precipitated on the carbon filter as elemental sulphur and it is estimated that activated carbon will require replacement approximately once every two years. In order to maximise the efficiency of the activated carbon filters, a small volume (approx. 300 l/hr) of air is added into the gas mixture.

Following desulphurisation, the gas temperature is again reduced to 26 °C as this has been found to be the optimal operating temperature for the CO₂ / CH₄ separation technology used; Pressure Swing Absorption (PSA). The plant utilises 6 No. PSA vessels packed with activated carbon molecular sieve materials (Carbotech AC GmbH). Gas enters the bottom of the vessel and is pressurised to just over 5 bar. CH₄ molecules are allowed to pass through the molecular sieve material resulting in a high CH₄ content gas leaving the top of the PSA vessel. CO₂ molecules are retained within the molecular sieve.
but are released when the pressure is decreased to generate a CO₂ rich gas that leaves the bottom of the vessel. The plant comprises of 6 No. vessels in total that operate in three pairs such that two vessels are pressurising, two are at full pressure and are generating biomethane, and two are depressurising to generate the CO₂ rich off gas. In this way, a constant output of biomethane is achieved. Each pair of vessels takes approximately 230 seconds to run through its pressurisation – production – depressurisation cycle. The CH₄ content of the product gas is monitored at this point, and if at any time the quality is below the necessary requirement, product gas can be recycled through the PSA system. The plant has a capacity to output a maximum of 320 m³ biomethane per hour with a CH₄ content of 98% and is therefore currently limited by the production capacity of the anaerobic digestion plant (500 m³/hr raw biogas).

Biomethane generated at the plant is stored in a buffer tank at a pressure of 4.2 bar. From here, the gas is odourised and its quality is measured using an in line gas chromatograph which measures CH₄, CO₂, H₂S, H₂ and O₂. The volume of biomethane exiting the plant is metered.

The biomethane is injected to the local low pressure (500 to 800 millibar) gas network, owned and operated by EnBW Gasnetz GmbH, that supplies approximately 300 end users including domestic and industrial customers. The distance to the low pressure network is approximately 800 m. Customers on this low pressure grid purchase their gas based on a volume basis in combination with its calorific value (the calorific value is measured every 3 minutes and is calculated to a one month average calorific value). As the common natural gas in the gas grid has a calorific value of about 11.3 kWh/m³ and the injected biomethane only has a calorific value of max. 10.85, natural gas entering the low pressure grid is mixed with a small volume of atmospheric air to reduce the calorific value to 10.85 kWh/m³. Standard practice in Germany and elsewhere would be to increase the calorific value of the biomethane to match that of natural gas by adding liquefied petroleum gas (LPG) e.g. propane, however in Emmertsbühl natural gas calorific value is reduced to save on LPG costs.

A significant proportion of the gas in the low pressure grid is utilised by a small number of industrial customers, however, when demand from these customers is reduced (notably, every weekend) the low pressure network does not have sufficient capacity to accept all of the gas supplied by the Emmertsbühl plant. At these times, the gas flow is reversed towards the junction between the low pressure and medium pressure (40 bar) grid. Here, a second plant compresses the gas from the low pressure grid up to 40 bar and LPG is added to standardise the gas with that already in the medium pressure grid. Gas in the low pressure grid (i.e. biomethane) is then injected to the medium pressure pipeline.
An enclosed gas flare is present on site for use in the event that biomethane cannot be injected to the gas grid. In addition, as described previously, in the event that the upgrading plant is unavailable (e.g. maintenance periods), the biogas can be utilised by the on site CHP plants.

The conventional model would have been to inject the biomethane directly into the medium pressure grid at 40 bar in order not to exceed the capacity of the low pressure network. However, the advantages of the model employed are that:

1. Distances for new pipelines were reduced to 800 m, where as a new connection to the medium pressure pipeline would have required approximately 5 km of new pipeline.
2. Compression costs are greatly reduced. The majority of gas is added to the grid at 500 to 800 millibar with only excess gas at weekends requiring compression to 40 bar.
3. Propane addition is also reduced as the majority of gas is utilised in the low pressure grid which operates at a lower calorific value. Only gas injected to the medium pressure network requires propane addition for reaching the calorific value of the natural gas in the pipeline.

This approach means that biogas upgrading plant (or other renewable sources of gas) could be cited in locations that previously were considered unsuitable due to limited capacity of the local gas grid.

2.5 Emissions Treatment (Water, Wastewater, Exhaust Air)

The CO₂ rich off gas from the PSA plant still contains approximately 2-4% CH₄ and should therefore not be directly released to the environment. At the Emmertsbühl plant, a vacuum pump moves the off gas to a small storage vessel following which it is compressed before being burned in a combustor specifically designed to burn low calorific value fuels (eflox GmbH). In order to achieve a stable flame, compressed air and a small volume of raw biogas is also required. The off gas combustor generates approximately 115 kW of thermal energy. Around 100 kW of this is utilised to heat the fermenters of the AD plant and the remaining 15 kW is used for general site heating. Off gas from the combustor is treated via a catalytic oxidiser.

2.6 Visual / Local Impacts

No adverse visual impacts of the plant have been described. It is noted that the majority of ancillary plant is located within ISO standard steel containers.

3.0 ENERGY USE, COST AND ECONOMICS

3.1 Energy Balance

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Demand of Digesters</td>
<td>Not Known</td>
</tr>
<tr>
<td>Electricity Demand of Upgrading Plant</td>
<td>~105 to 115 kW</td>
</tr>
<tr>
<td>Electricity Produced by CHP (Backup Only)</td>
<td>420 kW</td>
</tr>
<tr>
<td>Heat Demand of Digesters</td>
<td>110 kW</td>
</tr>
<tr>
<td>Heat Demand of Upgrading Plant</td>
<td>None</td>
</tr>
<tr>
<td>Heat Generated by off gas combustor</td>
<td>150 kW</td>
</tr>
</tbody>
</table>
3.2 Cost & Economics

The upgrading plant and configuration of the grid injection model is possible due largely to the legal requirement of energy companies to provide renewable energy to their customers, and the way in which the energy industry is structured and regulated in Germany.

First of all, the developer of the biogas upgrading plant (EnBW Vertrieb GmbH) had to negotiate with the biogas producer to supply the plant with a guaranteed volume and quantity of raw biogas per year. It is understood that a 20 year contract to provide 20 to 24 million kWh (approx. 3,600,000 m³ raw biogas) per year is in place.

The biogas plant operator himself had to be sure that he was getting a fair price for the gas generated as he had to meet the cost of producing the raw feedstock (silage of maize, grass and winter wheat), as well as the additional capital cost of the plant expansion.

The upgrading plant developer then had to negotiate with the gas network owner and operator (EnBW Gasnetz GmbH) to establish the optimum model for injecting to the gas grid. In this case, the cost of the additional compression and calorific adjustment plant at the low – medium pressure junction also had to be met by the gas grid operator. This had an estimated capital cost of €1.8 million. This had to be balanced across the alternative which was to construct a 5 k pipeline directly to the medium pressure grid, rather than the 800 m required to connect to the low pressure grid.

![Schematic showing the grid connection layout](image)

Fig. 7 Schematic showing the grid connection layout

Source: J. Darocha, EnBW Vertrieb GmbH, April 2012

Only once these agreements were in place was the upgrading developer in a position to procure the upgrading plant. The investment cost for this was approximately €3 million (including buildings and foundations).

The upgrading developer also had to ensure that the market would pay an appropriate price for the biomethane produced. There is no direct subsidy for the injection of biomethane to the gas grid in
Germany, and therefore all costs must ultimately be met by the customers. In Germany there are only subsidies for electric energy produced from renewable sources (i.e. solar, water, wind and biomass, including biogas). In this case, the majority of the biomethane produced is being utilised by a small number of industrial end users who use the biomethane in CHP’s for producing electricity and thermal energy and so benefit from subsidies paid for the electric energy fed into the public grid, whilst the thermal energy is used for their production processes.

Production costs of biomethane in Germany have been estimated by the upgrading plant operator (in April 2012) as:

<table>
<thead>
<tr>
<th>Cost Price for Raw Biogas</th>
<th>5.0 – 6.5 €c / kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Price for Upgrading</td>
<td>1.8 – 1.0 €c / kWh</td>
</tr>
<tr>
<td>Total Cost Price of Biomethane</td>
<td>6.8 – 7.5 €c / kWh</td>
</tr>
</tbody>
</table>

This compares to the border price (i.e. excluding taxes, profit, etc) of natural gas imported to Germany of approximately 2.73 €c / kWh. As such, the upgrading plant operator estimates that the cost price to the consumer of purchasing 100% biomethane is approximately twice that of purchasing natural gas.

Customers do not physically purchase the gas produced at the Emmertsbühl plant, but can buy the green gas virtually. To make sure the balance between injected and sold biomethane is even, the biomethane quantities are certified by the German Energy Agency. Customers therefore have the option to purchase a certain value, or a certain percentage of their gas consumption, as biomethane. For example, an end customer may wish to substitute 30% of their total gas usage with biomethane, and therefore purchase gas from the energy provider (EnBW Vertrieb GmbH) that consists by 30 percent of biomethane and 70 percent of common natural gas.

4.0 DISCUSSION AND CONCLUSION

This case study demonstrates a number of points. Firstly, it shows that the technology is readily available to generate raw biogas and upgrade it to biomethane, in this case using PSA. With over 70 upgrading plants in Germany alone (as of April 2012) this is nothing new, although to date the majority of upgrading plants have been attached to larger AD plants with good grid access where economies of scale make development straightforward.

More importantly, this case study highlights the way in which negotiations between a number of parties, backed up by a legislative and regulatory framework that allows some flexibility, has allowed the development of an innovative scheme where gas flows within a local low pressure gas grid can be reversed to provide gas to the medium pressure grid during periods of low demand. It also demonstrates that this can be achieved economically with costs to end users and payback time to investors within acceptable limits. This opens up the prospect of developing upgrading plants at locations previously considered as being sub-optimal.

ACKNOWLEDGEMENTS

The authors would like to thank the plant owners and operators including EnBW Vertrieb GmbH for allowing access to the plant and for providing additional information included within this case study.