Addressing potential barriers to the commercial development of biomethane projects

A discussion paper by the REA[1] for EMIB Review Group meeting 27 September 2011

1. Background

The EMIB Review Group has been convened to support the UK Government's anaerobic digestion strategy and the related policy instruments, such as the Renewable Heat Incentive (RHI). DECC has indicated that the replacement of fossil natural gas with renewable natural gas from anaerobic digestion could contribute around 7 TWh/annum to the UK's renewable energy targets for 2020. Therefore the identification and removal of any unnecessary barriers (regulatory or otherwise) is an important enabling step.

The gas distribution networks receive almost all their gas from the NTS with less that 5 facilities that inject gas direct into the LDZs and with no new ones built in the last 20 years. As a result, the existing processes and systems were designed without biomethane in mind and need to be reviewed in order to make them fit for purpose and support the development of biomethane whilst maintaining safety standards and protecting consumers.

In Sept – Nov 2010, UNC 251 Review Group reconvened to address a specific issue that related to CV for biomethane projects. Consensus was reached that it was appropriate and necessary for the CV of a biomethane project to be enriched to the FWACV (or blended if possible) and this has been adopted in the NEAs of the GDNs and accepted by the AD industry. DECC has adjusted the level of the RHI to take into account the costs associated with the addition of propane.

In parallel with the EMIB Review Group, a Uniform Network Code working group will be considering a proposal for changes to charging arrangements for distributed gas entry. On 28 July 2011 National Grid Gas raised Modification 391 to address the issue of the different system usage and costs involved with distributed gas entry compared with gas entering LDZs from the NTS. The UNC Modification Panel on 18 August formally agreed to send the proposed Mod to a development workgroup which was requested to report back to the March 2012 Modification Panel. The first meeting of the charging development workgroup will take place on 26 September 2011, and it will be important that the EMIB Review Group takes account of the discussions of the charging group and vice versa.

It is also recognised that the issue of the <0.2% allowable Oxygen concentration in GS(M)R for distributed gas entry currently constitutes a significant barrier to entry for biomethane. A review of this limit is being carried out by the HSE, with support from the GDNs, with a view to recommending an increase in the allowable concentration to 1%, subject to satisfactory evidence being provided of the lack of effect of such a change on the integrity of GDN pipework.

It is suggested that the biomethane entry issues are as follows:

[1] With input from GDNs and Gas Suppliers

2. GDN Connection Policy for Biomethane Projects

- GDNs' existing policy for distributed gas entry is for the DFO (Delivery Facility Operator - in this case biomethane producer) to fund all the costs associated with the entry but for the GDN subsequently to own and operate the entry facilities.
- These include gas quality monitoring, metering, CV measurement, odorant addition, telemetry, pressure control.
- The GDN charges the full cost of the facilities with an overhead, and the assets go into the GDN's RAV (Regulatory Asset Value) but at zero value (analogous to connecting pipelines).
- As the GDN does not earn any return on the assets they are reluctant to provide performance guarantees
- Alternative models have been put forward; funding and ownership by GDN with a tariff charged (essentially the Mod 391 proposal), funding and ownership by DFO or part GDN, part DFO and each of these will drive different behaviour by the GDN. Ideally, one solution should apply to all GDNs to reduce the complexity of the market and simplify processes
- The resolution of this issue may need to feed into the RIIO process as it could impact the capex/opex incurred by the GDNs in relation to biomethane

Appendix 1 sets out possible options and background to the connection policy and ownership issues.

3. Capacity for Biomethane

- All sites need to have confirmed firm capacity available before they can flow gas into the network.
- For NTS projects (e.g. CCGT or new storage facility) the provisions related to capacity bare set out in the UNC. There is no mention of capacity in an NTS NEA/NExA (other than in relation to flow-range for which the metering system is designed)
- Biomethane projects going direct into GDN system require a capacity guarantee and it is suggested that the Biomethane NEA is the appropriate place for this
- This issue needs to be discussed by the industry with the outcome feeding into the next GDN Price Control as well as providing clarity for biomethane producers

Appendix 2 sets out background and issues associated with capacity.

4. Technical standards associated with CV measurement for biomethane flows[2]

- The current standard for CV measurement is 0.14 MJ/M3 (0.35%). For normal gas entry to NTS this is appropriate and the additional costs associated with this level of accuracy and appropriate data safeguards is not significant

[2] It is possible that the Review Group will suggest that biomethane entry facilities should not be Directed sites (as far as Gas Thermal Energy Regulations are concerned) or they may be Directed but with a different Letter of Direction. In addition, the Review Group may recommend that the small biomethane flows should not count in the FWACV calculation provided enrichment to FWACV takes place

- For biomethane projects incurring the cost of enriching to FWACV it may be appropriate to allow a lower level of accuracy (say 0.4 MJ/M3 = 1%) to allow simpler and lower cost devices to measure CV
- In addition, simpler software can calculate the energy flow from biomethane (as there is only energy in methane and propane)
- Related requirements eg heated room for the gas examiner, large banks of batteries to provide uninterrupted power supply which may not be appropriate for small energy flows

Appendix 3 sets out background and issues associated with CV Measurement

5. Gas Quality Analysis at Biomethane entry

- The GDN's are not allowed to transport gas which does not meet the GS(M)R and hence a gas quality monitoring scheme is important
- Key quality parameters are Wobbe Number, H2S level, water dewpoint but minor trace components (such as siloxanes) are also important. In addition the biomethane must contain the correct amount of odorant to give the characteristic smell of natural gas.
- Biomethane is chemically simpler than fossil gas and alternatives to chromatographs are possible to reduce costs and simplify the system
- The monitoring regime needs to set out what is monitored and how often (continuous or by periodic sampling)
- A possible model involves the GDN providing a temporary chromatograph which is used for the first month of biogas flows. Once composition established this can be taken away (e.g. if no Sulphur other than H2S then no need to measure total sulphur. Same applies to any hydrogen).
- Adoption of a risk-based approach would contribute significantly to capex and opex savings

Appendix 4 sets out examples of possible gas composition changes.

6. Transmission of data to the GDN's agent (xoserve)

- xoserve requires an end of day total energy flow and the existing system (High Pressure Metering Information System) costs around £200k per facility. The suggestion is to have a low cost data logger system for biomethane

Appendix 5 sets out background and issues associated with transmission of data to xoserve.

7. Scope and Deliverables

As noted in Ofgem's letter of 16th September 2011 inviting participation in the EMIB review group, the draft Terms of Reference of the review group relate to the following issues:

GDN connection policies - understand how the exiting connection policy operates and establish whether this introduces any barriers or uncertainty to facilitating connections to the grid.

Network capacity availability - Consider treatment of capacity for biomethane entry to GDN networks and consider areas for reform.

Technical standards for calorific value (CV) - Consider the implication for biogas injection in the context of the existing standards for biomethane CV measurement, and the associated governance regime.

Gas quality regulation - Develop an understanding of the current requirements and whether they remain fit for purpose for the injection of biogas.

Data requirements and transmission - The current industry processes for transmitting flow / calorific value were designed for large offtakes. The group should consider potential alternatives for transmitting data for the purposes of settlement.

8. Composition of Review Group

Membership has been invited from the following parties:

Ofgem
DECC
Consumer Focus
Environment Agency
Energy Networks Association
Energy Retail Association
GDNs
Gas Suppliers
The Gas Forum
Renewable Energy Association
Anaerobic Digestion and Biogas Association
Health and Safety Executive
UK Unconventional Gas Association

The Environment Agency (EA) is working on an End of Waste Test that would be in a Quality Protocol for biomethane as required under environmental legislation. This Review Group can support the EA's work in this area.

9. Timetable

It is anticipated that the group will operate for a period of three months in the first instance. Any future role for the group will be reviewed at that point.

Meetings of the Group will take place monthly, or more frequently, with the option of sub-groups being formed. Agendas, presentations and minutes will be published on the Joint Office of Gas Transporters website

The Secretariat will be provided by the Joint Office of Gas Transporters. The work of the group will be summarised in a report and published on the Joint Office of Gas Transporters website.

Appendix 1 Possible ownership options and background to connections policy

Option 1 Biomethane producer funds, GDN owns and maintains, no RAV/return to GDN, GDN takes limited liabilities for plant performance:

- This is the existing policy of the GDNs and needs Ofgem consent to change it
- Liability for performamce of BtG plant but with no RAV return
- DECC are believed to have made allowance for these costs in the calculation of the RHI but at a lower level that has been incurred at Didcot and Adnams
- Duplication of design, construction, civils, installation and maintenance for small facilities may lead to higher overall costs
- May be difficult for new entrants to provide BtG plant as this would be provided as regulated assets and procured via OJEU tendering as per all other GDN work
    - Useful to understand how many service providers currently provide BtG plant and whether these existing companies would be dominant in this model because of their existing relationship and contracts
- At present, GDNs do not provide entry compression and hence this model means that the compression has to be before (ie upstream) the BtG plant which means that the BtG plant has to be designed for high pressure with higher cost and technical issues associated with disposal of off-spec gas

Option 2 GDN funds the plant, owns it, maintains it, receives a return and takes appropriate liabilities, charging a fee to the biomethane producer:

- This is broadly similar to the German model (75% GDN, 25% customer funding), high capital cost, more redundancy
- Has similar competition implications as in Option
- The option of paying for the plant through use of system charges is attractive to some biomethane producers. The producer can give some guarantees on the plant use, say by underwriting the costs for the length of time to recover the costs. If the project were to fail before the costs were recovered then the producer could pay the balance.

Note: At present the GDNs own and operate the BtG plant at entry into their networks. These assets were installed in 1997-8 when the switch to LDZ odorisation (previously was NTS entry) and FWACV (previously was lowest source CV) were introduced. When the GDNs were created as separate legal entities in 2004-5, these assets were allocated to the GDNs as they had the resource to operate them.

Option 3 Biomethane producer funds, owns and operates having to meet GDN's specification as set out in the NEA:

- This is the National Grid NTS Model (for entry and exit) and means that the development of BtG plant is a competitive activity
- It is similar to the Dutch model for biomethane :
    - Netherlands uses a system called Bio2Net which controls pressure, measures flow and gas quality using a chromatograph (including CV). Whilst it was developed in partnership with a grid owner, Stedin, it is installed and maintained by the biomethane producer (cost around 80,000 Euros)
- Producer can appoint single contractor for design and build of clean-up, upgrading, propane, BtG, pipeline with lower overall costs and clear accountability for safety and project programme
- Producer is responsible for failures and so decides on redundancy and the terms of a maintenance contract, possibly bundled with the biogas clean-up and upgrading supplier who is likely to provide a fast response maintenance service
- Supports integration of measurement, reduces duplication and costs
- For plants that need compression to go into IP or LTS, the compression can be after the BtG plant thus saving costs
- GDNs wary of this model due to serious consequences of transporting off-spec gas
- The Dutch include an insurance scheme with this option

Option 4 Biomethane producer has GT Licence, they fund, own, operate BtG plant and pipeline with the DNO network a connected system

- This also allows an integrated project with the BtG plant integrated with the clean-up and Upgrading Plant
- In effect the GDN grid is a Connected System Exit Point
- Biomethane producers probably do not want to have a GT licence as it is not their business

Option 5 BtG assets are part GDN and part Biomethane Producer

- It may be that certain assets (eg telemetry, final ESD valve, maybe odorant addition) are financed, owned, maintained by the GDN

  - Are there any Gas Act reasons for GDNs to own/operate some of the plant?
  - The odorant plant at Teesside entry was owned by Transco but Enron were paid to operate and maintain it

- The remaining plant would be financed, owned and operated by the Biomethane Producer
- This is hybrid of Options 2 and 3
- The big technical and financial benefit from Options 3 and 4 above would be that the BtG plant can be incorporated into the entire biogas Clean-up and Upgrading and Enrichment Plant. One civil contractor, one mechanical, one Electrical and Instrumentation, single point accountability for safety, single HAZOP, single maintenance provider etc.
- Schedule is also important, any Option 1 or 2 solution needs to take into account the schedule for building an AD plant from planning permission (9 – 12 months)
- An important issue relates to the liabilities associated with failure of the BtG plant. The biomethane producer will have to flare the biomethane with a daily direct cost in terms of flaring (not consequential) of around £7,000 per day for a 1 million/annum flow. From experience, plant that can fail includes analysers and odorant pumps. It may be that the NEA is the appropriate contract to address such liabilities in the event that Options 1, 2 or 5 are adopted. For Options 3 and 4 the issue does not arise as the GDN has minimal plant.

Appendix 2 Background and issues associated with capacity for biomethane projects

Capacity Service

The biomethane producer requires FIRM capacity on a 24/7 basis, 365 days a year. This is because the biogas will be produced at a constant rate and storage beyond 1 hour is not practical. The biomethane producer will aim to produce for 100% of the time but a realistic output for 95% of the time is likely, taking into account maintenance and plant failures.

In this regard, the biomethane producer is like a CCGT connected to the NTS or a source of renewable electricity (whether wind, biogas or solar) in that firm capacity must be provided but there is no guarantee that the service will be required on any one day.

For GDNs, having input of biomethane has the same effect as warmer weather in reducing demand and reducing flows through pressure reduction stations. No manual intervention by the GDN Sytstem Control is required whether gas flows or does not flow.

The GDN is requested to provide an indication as to whether capacity may be available, with a funded study (indicative cost £1,500 - £2,500) that will confirm if capacity is available and the risks associated with it (eg if it depends on a large local consumer taking gas).

Network Entry Agreement

The contract between the BM producer and the DN needs to reflect the simpler procedures required for very small flows, the nature of unmanned sites, and the principle that security of supply is not an issue as BM flows will only displace existing fossil gas flows.

Prior to Didcot and Adnams biomethane projects, there had been no new NEAs since DN sales and only a handfull of sites have gas flowing directly into a DN (WWU have Avonmouth LNG, NG have Holford storage, SGN have Isle of Grain LNG and Wytch Farm oil field, NGN have none).

Physical Capacity

In the UK, biomethane will normally go into an MP or IP main. In practice, the biomethane goes into the main, comes out within a short distance. If biomethane flow is 300 m3/hr, then demand on the network needs to also be at least 300 m3/hr. Low demand in summer can mean that the grid does not have capacity because the capacity of the network is equal to its demand. The gas grid operator may be able to provide some additional capacity by adjusting network regulator settings but they would incur costs and at present they have no incentive to do this.

There will sometimes be local large I&C consumers on the local grid and capacity will exist to inject gas if such loads are taking gas out. However, should these facilities close then there would not be capacity in the grid to take the biomethane. It may be reasonable to such large consumers to be identified in the NEA so that if they do not take gas (on a day or for a longer period) then this reduces the obligation on the GDN to provide capacity. The installation of compression plant could provide an option for GDNs but this is not yet demonstrated in practice with no regulatory treatment for such assets (see below).

The key issue relates to specifying the capacity obligation. If it is very firm with liabilities, the DNO will indicate lower amounts of capacity. If it is too loose there may not be sufficient incentive to satisfy banks that there is capacity. This has to be discussed in the context of physical realities, data quality (the GDNs do not have good data related to summer demand as the network design is driven by peak 1 in 20) and RIIO.

Compression within the grid to provide capacity

REA estimates that there is a capacity problem for around 40% of Biomethane projects.

NGN have completed the first part of an IFI Project that shows this can be resolved by using compressors installed within the grid to exporting gas from MP to IP to LTS systems for short term periods, and that this is economic and technically feasible.

Any compression plant would have to be owned, operated, financed by the grid company as they would be embedded in their grid. A cost reflective charge could be levied to the biomethane producer that had requested the service (which needed compression).

If the GDN was able and willing to install compression plant then capacity could be provided in most places. In Germany this is now the position and as a result there is an obligation on the grid owner to provide capacity (subject to an economic test). It is attractive in CO_2 terms for this service to be developed as the compressors only operate in summer (whereas compression direct to LTS for example, requires compression all year round).

The use of the gas grid for biomethane also reduces the load on the electricity grid if the biogas was used in CHP and this is helpful in allowing more electricity grid capacity for onshore wind.

Appendix 3 Background and issues associated with CV Measurement

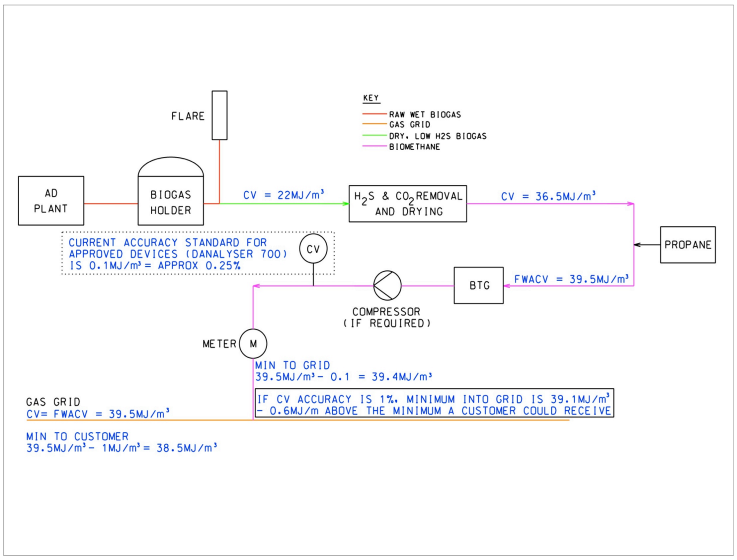
Ofgem can decide if a biomethane facility should form part of the FWACV regime and be 'Directed' or whether it should fall outside FWACV. In such case it could either Not be Directed or be Directed on a different basis.

A normal Directed site within the FWACV regime (all beach terminals, the 5 LDZ direct entrants, LNG sites, gas storage etc and 140 offtakes from the NTS to LDZs) includes the following key provisions:

- Must use a Daniels danayser to measure CV
- Must be calibrated using test gases containing ethane, pentane, hexane etrc which are not present in biomethane
- 0.14 MJ/M3 accuracy for CV measurement (0.35%)
- Must use Dannint software
- Must be in a heated room
- Must have 12 hours uninterruptible power supply

The biomethane industry believes that this standard is not fit for purpose for biomethane flows and that alternative system should be allowed with accuracy of CV measurement of 1% (0.4 MJ/M3) and using off the shelf software and with appropriate modifications to the other design requirements.

Given that biomethane will be enriched to FWACV the change proposed above will still mean that consumers close to biomethane input would receive gas with a CV of at least 0.6 MJ/M3 above the cap, which is the lowest CV that any consumer in the LDZ can receive, as below:



The biomethane industry believes the 1% standard should be defined in the NEA

Appendix 4 Background to Gas Composition measurement for biomethane

Model Risk Assessments (MRA)

The biomethane industry has proposed the development of a number of Model Risk Assessments that would be used to develop the gas quality monitoring scheme for a source of biomethane

- The MRAs would be based on different types of AD feedstock:
  - Sewage biogas
  - Food waste biogas
  - Agricultural waste, crops including manure
  - Mixed feedstock
  - Landfill gas to follow in 2012
- The MRA would use the established GQ/8 process to establish the gas quality monitoring scheme for each type of biogas to biomethane project. This scheme would then be defined in the NEA for that project.
- A typical EU regime is for:
  - Continuous monitoring of CV, Wobbe, H_2S, water dewpoint
  - Spot sampling for siloxanes
- SGN are considering taking this forward as an Innovation Project

Appendix 5 Background and issues associated with transmission of data to Xoserve

HPMIS (High Presure Metering Information System) is a database holding high pressure metering site and quality data. At present, Biomethnae flows are required to purchase an HPMIS in order to get an end of day energy flow number to xoserve.

The cost per facility is around £200k

The biomethane industry believes that is should be possible to allow a datalogger system to be used at cost <£5k.

Question – where does it say that HPMIS must be used? Is it in UNC?

SGN are considering taking forward the development of an appropriate data transmittal system as an Innovation Project. This includes reviewing the necessary interface at xoserve to accept the data and specifying the data that must be provided by the biomethane site.