Review Group Report

Energy Market Issues for Biomethane Projects (EMIB)

Introduction

On 16 September 2011, Ofgem issued an invitation to join a Review Group on Energy Market Issues for Biomethane Projects (EMIB). The Joint Office of Gas Transporters was asked to provide a secretariat for the Review. This Report was drafted by the Joint Office and was approved at the 26 March 2012 EMIB meeting. Ofgem's invitation letter included Terms of Reference, which were accepted by the Group. These are attached as Appendix 1 below.

[] EMIB meetings were held to progress the Review, together with supporting meetings of relevant experts to consider a range of issues. A wide range of parties was involved in the discussions – a list of attendees is attached as Appendix 2.

Recommendations

A minimum connection policy should apply

A deep connection charging policy should apply

Provision of entry facilities should be subject to competitive provision

Context

The established requirements for entry to the GB gas network were developed primarily with major beach terminals in mind. Biomethane differs from this traditional entry expectation both in terms of scale and location, being embedded within local distribution networks rather than connected at the perimeter of the National Transmission System.

The first key issue raised in the EMIB discussions was the relative scale of expected biomethane entry. In broad terms, a typical entry point may be about 1,000th of the scale of a beach terminal. Given this, the proportion of costs accounted for by gas transporter requirements for the entry facility (e.g. metering and gas quality assessment and reporting) would be substantially higher if the defined standards and processes are the same as those at beach terminals. This cost, potentially together with complexity associated with entry arrangements, has the potential to deter entry. The group therefore challenged whether the requirements were proportionate in the context of numerous, relatively small, entry points. To the extent that entry costs can be lowered, this could encourage development of additional sources of biomethane, and would help to ensure that undue costs are not introduced to the market.

The scale and number of potential entry points leads to the second key point, which is consistency. Uncertainty was identified as a barrier to entry, with potential entrants not knowing the conditions they have to meet. The REA gave examples to the group of substantial variations in the terms and costs that have been quoted by GDNs to potential entrants. It was recognised that establishing a single national set of standards would remove uncertainty and hence a potential barrier to entry. It would also support the development of competitive infrastructure provisions as different providers could develop competing products to deliver the common specification, and cost reductions should also be delivered as a result of requirements being replicated at all sites.

Report on Areas Considered

The Review Group considered each of the areas outlined in the Terms of Reference.

GDN connection policies

Understand how the existing connection policy operates and establish whether this introduces any barriers or uncertainty to facilitating connections to the grid.

The GDNs presented their existing connection policy, which is consistent across the networks. This is based on a deep connections approach – with those connecting to the network asked to meet the full cost of all the work necessary to support that connection, both at the connection point itself and within the network to the extent that investment is necessary to meet the requirements specified by the connecting party. In the context of biomethane entry, this would involve the connectee meeting the costs associated with developing the entry facility. In terms of deeper, within network, investment, the only potential cost foreseen is when there is insufficient downstream demand to accommodate the planned flow into the distribution network. In these cases, it may be possible for the planned flow to be accepted following investment in the network, such as compression, to support a change in flow patterns – with gas being moved upstream. It was accepted that it would be appropriate for any such investment to be funded by those benefiting from the change, and hence that a deep connections policy remains appropriate and is not an undue barrier to entry.

Concerns were raised that it could be a barrier to entry if the GDNs were to be responsible for providing all aspects of the entry facility. EMIB considered that, as a general principle, market provision should be relied upon as far as practical. It was therefore felt that a minimum connection policy should be applied. This would involve the GDN undertaking the minimum level of investment needed in order to be able to comply with its obligations. In practice, the expected minimum connection would consist of a remotely operable valve that would allow compliant gas to enter the GDN, but leave the GDN with an ability to physically isolate the entry point and exclude gas if compliance was not maintained. The GDNs may choose to offer to provide other aspects of the entry facility, but the connectee would be responsible for determining its preferred provider.

EMIB recognised that, in order to meet their obligations, the GDNs would wish to specify the requirements that any equipment installed at an entry point would be required to meet. To support this, the GDNs have developed a Functional Specification which sets out the requirements to be met at any entry point that is to be connected to a GDN. The intention is that this Functional Specification may need to be built on to include any specific requirements at a particular entry point, but would be a generic specification that would be included in all relevant Network Entry Agreements and be adopted by all GDNs in order to deliver a consistent approach. The latest version of the proposed Functional Specification is attached (Appendix 3). This consistency was recognised as central to avoiding barriers to entry through uncertainty as well as by supporting competitive procurement, and consequently providing confidence about the level of costs incurred which would be subject to normal competitive pressures.

While there was general agreement that the bulk of any entry facility could be owned and managed by the connectee, the process for adding odorant raised specific concerns. The GDNs can face cost increases if gas is over-odorised (since this is expected to lead to an increase in the number of public report escapes). While any failure to odorise the gas can clearly create significant safety concerns, with leaks potentially being undetected, the impact of over-odorisation also raises safety concerns since an increase in the number of reported escapes can divert resources to low risk incidents and consequently have the potential for a delay in dealing with higher risk incidents. While National Grid was comfortable that this risk could be managed contractually, such that odorisation would be treated no differently to other aspects, other GDNs felt that it would be appropriate for the GDNs to retain responsibility for the addition of odor in all cases. Given this, some biomethane producers were concerned to ensure that GDNs insisting on a particular approach would face liabilities that reflected the risk to the producer in the event that a facility was unable to export gas to the GDN as a result of issue with odorisation. It was also suggested that if the GDNs felt that they must provide this aspect of the entry facility, then a logical extension would be that the GDN should also be responsible for all the associated costs.

Network capacity availability

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

The group considered that a simple approach is desirable in order to minimize costs and avoid unnecessary barriers to entry. It was therefore recommended that entry capacity rights should be set out in the Network Entry Agreement (NEA) for the relevant entry point. Given that the requirement is generally for a steady flow at all times throughout a year, it was accepted that the maximum capability that could be offered will be equal to the minimum demand downstream of the entry point. It was envisaged that this should be sufficient to accommodate the majority of potential entrants, and that there was little alternative since gas can only enter the network if there is sufficient demand for that gas to be used. EMIB therefore supported capacity being made available up to the minimum demand level.

In cases where the minimum demand is insufficient to accommodate biogas, it was recognised that investment may be able to increase capacity availability. In particular, work is ongoing to establish the viability of adding compression such that gas can be moved upstream and so access demand in other areas of the GDN as a result of being transported to different areas via a higher pressure system. It was agreed that it would be appropriate for the entrant to bear the costs of any such investment since this would be for their benefit rather than any other party – consistent with a deep connections policy approach.

The Group recognised that changes in demand can occur over time. In these circumstances, it was recognised that it would not seem equitable for the entry agreement to be revisited and the amount of capacity available for entry to be reduced to the new minimum diversified demand – allowing this as a possible would introduce uncertainty and be a barrier to entry. It was therefore felt that any necessary investment to allow continued entry should be treated in the same way as other network reinforcement. The group recommends that Ofgem confirm that they would expect any such investment to be regarded in the same way as other economically and efficiently incurred network investment.

An ENA position paper providing further information on capacity issues is attached at Appendix 4.

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.

Dave Lander Consulting undertook some analysis to address this issue. The full report, summarized below, is attached at Appendix 5.

BACKGROUND

Estimates of the accuracy of domestic consumer billing have been made. The approach used is based on the principles given in a guidance note produced by Marcogaz and is based on estimates of sources of bias and uncertainty in bias of each of the steps used to derive consumers' energy bills. Such sources include measurement equipment (notably the domestic meter, NTS offtake meters and NTS offtake CV determination devices), assumptions behind the fixed factors used for volume conversion required by the Gas (Calculation of Thermal Energy) Regulations, and the variation in CV experienced by consumers in a particular charging area.

Having made estimates of consumer billing accuracy, the impact of reducing the accuracy CV determination for entry of small volumes of gas is estimated. The principal driver for reducing the accuracy of CV determination is to reduce obstacles to uptake of use of renewable gas supplies such as biomethane, but the approach is applicable to entry of small volumes of any gas.

CONCLUSIONS

1) For a typical LDZ, where uncertainty in bias in NTS offtake metering and CV determination are around ±4% and ±0.1 MJ/m3 respectively, the bias in domestic energy metering is estimated to be: -0.445% ±7.42%. The dominant sources of bias and uncertainty in bias are associated with fixed factors for conversion of actual domestic metered volume to reference temperature and pressure.
2) For a typical LDZ, the bias in LDZ energy is estimated to be: 0% ±2.04%. The bias in LDZ energy resulting from the LDZ model is zero because the model assumes that daily volumes and daily CVs are unbiased.
3) Current custom and practice is for CV determination equipment to meet a requirement that (absolute) error in CV should not exceed 0.10 MJ/m^3. This requirement results in insignificant impact on domestic energy metering.
4) Some relaxation in Maximum Permissible Error (MPE) in CV determination may be appropriate, particularly in low volume applications, such as biomethane injection, for which the anticipated daily volumes are so low as to make CV determination accuracy insignificant in respect of impact on the domestic consumer. The appropriate MPE should be decided by consideration of other regulatory issues (such as monitoring of compliance with the GS(M)R if shared duty is being practiced), or normal commercial factors for sale of energy. However, daily flows of up to 2.5 million m^3 could be measured with devices having an MPE of 0.5 MJ/m^3 with no material impact on accuracy of FWACV and hence domestic consumer energy billing.
5) In addition to MPE, a formal performance specification for CV determination devices should include a maximum bias shown by CV determination devices with gases that the instrument (or family of instruments) is likely to see.

Gas quality regulation

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

To establish a consistent approach to gas quality regulation, with proportionate requirements, the existing requirements were reviewed and the Functional Specification (see Appendix 3) captures what the group regards as a fit for purpose regime which should be incorporated in individual NEAs. This specification will initially be maintained by the GDNs, but the group recommends that this becomes an IGEM standard in future.

While accepting that all current safety standards should apply, a question was raised over the costs and benefits of achieving the existing standard for Oxygen content. Recognizing that his is not a safety issue, the GDNs are conducting a study into corrosion in order to establish whether it will be acceptable to change the Oxygen limits in gas specifications.

Dewpoint was also address in a paper produced by Dave Lander Consulting (see Appendix 6), and the recommendations in this paper were accepted by the group.

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.

The existing approach was clarified and has been captured in the Functional Specification. While some parties would like to see an alternative approach, the risks and benefits associated with this have not been fully explored and it is recommended that further work is undertaken to determine whether or not there is a case for changing the existing approach, and to clarify the steps needed to deliver a different approach if that is considered appropriate.

Appendix 1: Terms of Reference

Purpose
To provide a forum for informed debate on the potential barriers to the commercial development of biomethane projects within the energy market and the appropriate means of addressing such barriers, including but not limited to the following areas:

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.

Membership
By invitation. To include a range of stakeholders with an interest in biomethane injection issues and expertise or views which are directly relevant to the purpose of the group.

Meetings
Monthly or less – with the option of sub-groups being formed. Agendas, presentations and minutes will be published on the Joint Office of Gas Transporters website.

Secretariat
The Secretariat will be provided by the Joint Office of Gas Transporters.

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

Appendix 2: Meeting Attendees

EMIB Meetings

Adam Baisley	Agri Energy
Alex Ross	Northern Gas Networks
Andrew Grigsby	Arup
Andrew Moore	Northumbrian Water
Chris Bielby	Scotia Gas Networks
Chris Phillips	CRS BIO
Dave Lander	Dave Lander Consulting
David Pickering	National Grid
Gareth Mills	Northern Gas Networks
Ian Gardner	Arup
James Lewis	Calor Gas Ltd
Joanna Ferguson	Northern Gas Networks
John Baldwin	CNG Services / REA
John Cornes	Atlas Copco
John Williams	Poyry
Jonah Anthony	DECC
Lesley Ferrando	Ofgem
Mark Bugler	British Gas
Matt Hindle	ADBA
Mike Berrisford (Secretary)	Joint Office of Gas Transporters
Pat Howe	SSE
Paul Holland	EffecTech
Peter Hardy	IGEM
Richard Fairholme	E.ON UK
Richard Lewis	Arup
Richard Pomeroy	Wales & West Utilities
Richard Street	Corona Energy
Roger Warren	Enzen Global
Stephen Skipp	Scotia Gas Networks
Steve Rowe	Ofgem
Steven Sherwood	Scotia Gas Networks
Stuart Bennett	Heat and Power Services
Tim Davis (Chair)	Joint Office of Gas Transporters
Tim Slaven	AMEC

Expert Group

Bob Fletcher (Secretary)	Joint Office of Gas Transporters
Brian Durber	EON UK
Chris Bielby	Scotia Gas Networks
Colin Stock	Wales & West Utilities
Dan Anderson	National Grid
Dave Lander	Dave Lander Consulting
David Pickering	National Grid
Helen Cuin	Joint Office of Gas Transporters
Iain Ward	REA/CNG Services

Ian Taylor	Northern Gas Networks
James Clarke	Skanska Utilities
Joanne Parker	Scotia Gas Networks
John Baldwin	CNG Services / REA
John Edwards	Wales & West Utilities
Jonathan Wisdom	RWE npower
Lesley Ferrando	Ofgem
Mike Berrisford (Secretary)	Joint Office of Gas Transporters
Olu Ajayi-Oyahire	IGEM
Paul Holland	EffecTech
Peter Hardy	IGEM
Richard Lewis	Arup
Richard Pomroy	Wales & West Utilities
Steve Armstrong	National Grid Distribution
Stephen Skipp	Scotia Gas Networks
Steve Howells	Scotia Gas Networks
Steve Rowe	Ofgem
Steven Sherwood	Scotia Gas Networks
Stuart Gibbons	National Grid Distribution
Tim Davis (Chair)	Joint Office of Gas Transporters
Will Guest	Northern Gas Networks

Appendix 3: Requirements for Integrated Biomethane to Grid Injection Facility Functional Specification

COVER NOTE

This functional specification has been prepared on behalf of, and approved by the following Gas Distribution Networks: National Grid, Northern Gas Networks, Scotia Gas Networks and Wales & West Utilities. It will be maintained and edited as necessary by the distribution networks jointly, following consultation with interested parties.

The functional specification sets out the broad requirements that must be complied with by any party seeking to inject biomethane into a gas distribution system. The specific requirements at any particular entry point will be specified with the Network Entry Agreement for that entry point. While the functional specification provides guidance on the requirements which are expected to apply in the majority of cases and be included in the relevant NEA, the Gas Distribution Networks necessarily reserve the right to carry out a risk assessment in each specific case in order to ensure that gas entering their gas distribution system is compliant with legislative requirements in the particular circumstances of each entry point.

Introduction

The UK Gas Industry wishes to facilitate the connection of renewable gas supplies into its gas distribution systems. The injection of biomethane into the gas grids in the UK is still in its early stages with just a small number of pilot projects underway. However the number of projects is expected to expand considerably now that the UK Renewable Heat Incentive has been announced, which provides a financial incentive to biogas producers to inject biomethane into the gas.

Existing biogas projects have employed bespoke designs of systems to inject biomethane into the gas grids, often based on equipment more commonly found in much larger scale natural gas systems. In order to facilitate connection therefore, it is essential that minimum functional requirements are set out so as to provide reassurance to GTs that such systems are fit for purpose and suitable to allow their legal obligations to be discharged, and to biomethane producers that such systems are appropriate to their smaller scale of operation.

1 Scope

This document sets out the overarching principles and minimum functional requirements to permit safe, efficient and fit-for purpose grid injection of biomethane. Ownership and responsibility for operation and maintenance of such "Biomethane-to-Grid" (BtG) facilities may rest with the GT, the biomethane producer or a combination of the two. Three models are envisaged and these are discussed in Section 5 in more detail.

2 References

2.1 Legislation

SI 1996 No. 551	-	Gas Safety (Management) Regulations 1996
SI 1996 No. 439	-	Gas (Calculation of Thermal Energy) Regulations 1996
SI 1997 No. 937	-	Gas (Calculation of Thermal Energy) (Amendment) Regulations 1997

2.2 Design Standards

2.2.1 Institution of Gas Engineers and Managers

IGE/GM/8	-	Non-domestic meter installations. Flow rate exceeding 6 $m^3 h^{-1}$ and inlet pressure not exceeding 38 bar
IGE/TD/13	-	Pressure regulating Installations for transmission and distribution systems.
IGE/SR/16	-	Odorant systems for gas transmission and distribution
IGE/SR/25	-	Hazardous areas classification of natural gas installations.

2.2.2 Gas Distribution networks

X/PM/G/17	-	Management Procedure for the Management of New Works

X/PM/G/19	-	Management Procedure for Application of Model Design Appraisals
X/PM/GQ/8	-	Procedures for the Validation of Equipment Associated with the Calculation of Mass, Volume and Energy Flow Rate of Gas.
X/PM/PT/1	-	Management Procedure for pressure testing of pipework, pipelines, small bore pipework and above ground austenitic stainless steel pipework.

Where X= T for National Grid standards, SGN for Northern Gas Networks standards, NGN for Scotia Gas Networks standards or WW for Wales and the West Utilities standards.

2.2.3 Wales and the West Utilities Network

T/PM/GL/5	-	Management Procedure for Managing New Works, Modifications and Repairs

3 Definitions

The definitions applying to this specification are listed below.

Anaerobic digestion	-	Biological process in which microorganisms break down organic matter in the absence of oxygen into biogas and digestate.
Biogas	-	Gas produced by anaerobic digestion of organic matter.
Biomethane	-	Methane-rich gas produced by upgrading of biogas.
Biomethane to grid facility (BtG)	-	Facility to facilitate the injection of biomethane into gas distribution systems.
Delivery facility	-	The facility from which biomethane may be tendered for delivery at the LDZ System Entry Point.
Delivery Facility Operator (DFO)	-	The operator of the delivery facility.
Directed site	-	Site at which the GT has been directed by Ofgem to determine calorific value under Regulations 6(a) and 6(b) of the Gas (Calculation of Thermal Energy) (Amendment) Regulations 1997.
Gas Transporter (GT)	-	A body holding a licence under Section 7 of the Gas Act 1986 as amended by the Gas Act 1995 and by the Utilities Act 2000.
Liquefied Petroleum Gas (LPG)	-	Petroleum gas containing principally butane or propane stored and transported as a liquid under pressure.

4 Principles

4.1 Fundamental Principles

1) The legal obligations upon the GT in respect of gas introduced into its gas systems by a third party, as set out in the GS(M)R and Gas(COTE)R, are such that criminal liability cannot delegated to a third party. The GT may therefore wish to retain control of key aspects of some or all parts of the BtG facility including: ownership, design, operation and maintenance. The closure or the ROV shall be under the control of both the DFO and the GT. The opening of the ROV shall be under the sole control of the GT.
2) Gas not complying with the requirements of Part 1 of Schedule 3 of the GS(M)R shall not be injected into a gas grid unless an exemption has been granted by the Health and Safety Executive from a particular requirement. In such a situation the DFO and GT shall ensure that any requirements conditional to the granting of such an exemption are met.
3) Where the GT has been directed by Ofgem to determine calorific value, the facility and its operation shall be in accordance with the relevant Letter of Direction.
4) The costs associated with the capping of area calorific value in accordance with regulation 4A(1) of Gas (COTE) Regulations are disproportionate to the quantity of biomethane being injected. It is therefore essential that measures are taken to ensure that capping is avoided either by enrichment with LPG or, where technically and economically feasible, by blending with other gas being conveyed by the GT.

4.2 Measurement Risk Assessment

1) The DFO and GT shall participate in a measurement risk assessment in accordance with T/PM/GQ/8 to determine which parameters shall be monitored, the frequency of measurement and the speed of response of measurement system.
2) The recommended limit values shall be assessed by risk assessment.
3) The initial risk assessment shall set out those changes (e.g. change of feedstock to the Anaerobic Digester, equipment change, etc) that will require review of the risk assessment. In the event of one or more such changes, the risk assessment shall be reviewed. Where a particular parameter shows increased risk then a change in the monitoring scheme may be appropriate.

4.3 Provisions of the DFO

1) The DFO shall provide biomethane to the BtG facility that is compliant with the requirements of Part 1 of Schedule 3 of the GS(M)R, with the exception that it shall be unodorised.
2) Where the strategy for calorific value requires enrichment with LPG the DFO shall provide biomethane with a gross calorific value that equals or exceeds the target CV agreed with the GT on a daily basis.
3) Where the GT owns and operates the odorant injection equipment and the DFO owns and operates the metering equipment the DFO shall agree with the GT the interface between the metering and odorant injection equipment so as to permit control of odorant injection rate so as to achieve the required odorant concentration.
4) Where the DFO owns and operates the odorant injection equipment the DFO shall add odorant at the rate agreed with the GT. The GT may for operational reasons require injection at rates higher or lower than that generally required.
5) Where the DFO owns and operates the BtG facility the DFO shall also provide to the GT's telemetry system signals from the BtG facility of those parameters identified by risk assessment (see 4.2).
6) The DFO shall agree with the GT a local operating procedure for the management of non-compliant gas, including issue of TFA, advance notification of Remotely Operated Valve (ROV) shutdown and procedures for restoration of biomethane flow following ROV closure. This may or may not involve the installation of a diverter valve.

4.4 Provisions of the GT

1) The GT shall provide full details of the format of data for the telemetry interface so as to enable the DFO to procure suitable equipment to achieve appropriate repeat signals.
2) Where the GT owns and operates the odorant injection equipment and the DFO owns and operates the metering equipment the GT shall agree with the DFO the interface between the metering and odorant injection equipment so as to permit control of odorant injection rate so as to achieve the required odorant concentration.
3) Where the GT owns and operates the odorant injection equipment the GT shall add odorant to meet its obligations under the GS(M)R.
4) The GT shall agree with the DFO a local operating procedure for the management of non-compliant gas, including issue of TFA, advance notification of Remotely Operated Valve (ROV) shutdown and procedures for restoration of biomethane flow following ROV closure. This may or may not involve the installation of a diverter valve.

5 Asset ownership and operating and maintenance responsibility

5.1 Asset ownership models

Assets associated with the BtG facility are those that carry out the following functions:

a) Pressure reduction and control

b) Gas analysis for compliance monitoring

c) Metering

d) Odorant injection

e) FWACV functionality

f) Supervisory system

In addition, the following assets shall always be owned and operated by the GT:

g) The ROV

h) The telemetry unit

For the purposes of this functional specification, other functions required for production of biomethane are assumed to not be associated with the BtG facility. Such functions include:

i) Biogas clean-up

j) Enrichment with LPG and control of calorific value

k) The biomethane diverter valve, if arrangements have not been made with the GT for disposal of non-compliant gas that may have entered the BtG facility.

l) Compression, if biomethane is to be injected into distribution systems at pressures above 7 barg.

Three models of asset ownership are set out below. Note that the figures associated with the models are intended to show asset ownership and not the physical arrangement of equipment or devices associated with a particular functional block. In particular: the location of the ROV under Model 3; the location of compression; and the location of LPG enrichment with respect to the diverter valve may vary, depending on the requirements of individual GTs and arrangements agreed between the DFO and GT.

For the purposes of this functional specification it is assumed that the primary responsibility for operation and maintenance of any asset rests with the asset owner, although it is recognised that commercial arrangements may be put into place with third parties to delegate operation and maintenance.

5.2 Model 1 – The "minimum connection" model

In this model the GT owns only the ROV and the telemetry unit. All other assets associated with the BtG facility are owned by the DFO. Figure 1 shows the functional blocks and asset ownership for this model.

5.3 Model 2 – The "mixed connection" model

In this model, the GT owns, in addition to the ROV and telemetry unit, the odorant injection asset. All other assets associated with the BtG facility are owned by the DFO. Figure 2 shows the functional blocks and asset ownership for this model.

5.4 Model 3 – the "maximum connection model

In this model, the GT owns all of the assets associated with the BtG facility. No asset associated with the BtG facility is owned by the DFO. Figures 3 and 4 show the functional blocks and asset ownership for this model with the ROV located downstream of and upstream of the BtG facility, respectively..

6 Functional Requirements

6.1 Pressure Regulation and control

Pressure regulation and control is required to control pressure at the point of injection into the distribution system. As gas demand increases and pressure in the distribution system falls the pressure regulation and control system shall open the regulator to admit more biomethane. It is anticipated that demand will generally exceed biomethane flow and pressures in the distribution system will be so as to permit biomethane flow up to 100% of the agreed daily flowrate. The maximum flowrate of biomethane shall be controlled by assets upstream of the BtG facility and not by the BtG pressure regulation and control system. Demand in excess of biomethane flow will be satisfied by supplies of gas elsewhere in the distribution system. If demand should fall below the biomethane flow then the pressure regulation and control system shall close to reduce the biomethane flowing into the distribution system.

Pressure regulation and control shall be to IGE/TD/13.

6.2 Gas sampling and analysis

Gas sampling and analysis shall continuously or continually monitor biomethane being injected and provide confirmation that it is compliant with the requirements of Part 1 of Schedule 3 of the GS(M)R and that calorific value meets the minimum requirements agreed with the GT. A schedule of parameters that shall be monitored is given in Table 1.

Calorific value shall be determined using an instrument approved by Ofgem for determination of calorific values for the purposes of determining the number of kilowatt hours, under Section 12 of the Gas Act 1986. The instrument shall comply with the requirements listed in an appropriate Letter of Approval from Ofgem.

The gas sample point for monitoring of parameters in Table 1 shall be located upstream of the BtG facility and upstream of the diverter valve, if installed by the DFO.

A facility shall be provided to permit representative spot samples of biomethane for laboratory analysis to be safely taken.

6.3 Remotely operated valve

An ROV valve shall be supplied, which shall be capable of manual remote or automatic closure in the event of variation in biomethane outside of the agreed conditions given in Table 1, failure of odorisation, or inability to provide sufficient blending where this is practiced (see 7.1). A more detailed description of trip and reset philosophy is given in the Gas Quality and Supervisory system functional block. The means of actuation of the ROV shall be the choice of the GT.

6.4 Metering

Metering systems shall be designed in according to the principles of IGE/GM/8 – Part 1.The metering system shall meet the accuracy requirements of Table 2 and shall be based on any principle of operation that is acknowledged as suitable for this application.

Volume conversion devices for conversion of metered volume to volume at reference conditions shall take account of pressure, temperature and compression factor. Systems employing a flow computer are preferred, but alternative systems may be acceptable provided that the overall accuracy requirements of Table 2 are met. Whatever solution is chosen, instantaneous flow and integrated daily volume shall be available for acquisition by the FWACV functionality system (see Section 6.6) and instantaneous flow shall be available to the Odorant Injection system to enable delivery of odorant at the required rate.

6.5 Odorant injection

The odorant injection system shall be designed in accordance with the principles of IGE/SR/16, with appropriate allowance for the small-scale of operation of BtG facilities.

The odorant injection system shall inject odorant in order to achieve - under normal circumstances - an odorant concentration of 6 mg/m^3 in the biomethane exiting the BtG facility. In some circumstances variation from this concentration may be required in order to achieve satisfactory odour intensity and so the system shall be designed to achieve odorant concentrations over the range 2-16 mg/m^3.

Three options for odorant are available depending upon the required concentration and daily volume of biomethane injected:

a) Odorant NB - 80 wt% (± 2 wt%) TBM, 20 wt% (±2 wt%) DMS

b) Diluted odorant - Odorant NB 34 wt% (±2 wt%), hexane 66 wt% (±2wt%)

c) Diluted odorant - Odorant NB 8 wt% (±2 wt%), hexane 92 wt% (±2wt%)

The odorant injection system shall employ a suitable liquid pump; evaporative or wick odorisers shall not be used.

The odorant pump controller shall accept a signal from the metering system corresponding to the instantaneous flowrate of biomethane at reference condition and compute and control the required odorant injection rate to achieve the required odorant concentration.

The odorant tank at site shall be suitable for containing liquid odorant and be capable of being transported to facilitate re-filling by the appropriate service provider. Unodorised biomethane cannot be injected, so the design shall consider how the replacement tank is put into operation. The odorant supply shall be designed for around 6 months continuous site use at an odorant concentration of 6 mg/m^3 at maximum design flowrate.

An odour assessment test point suitable for use by trained rhinologists shall be installed downstream of the odorant injection point at a location agreed with the GT.

6.6 FWACV Functionality

The system shall deliver the functionality required for the FWACV regime, namely requirements set out in the Gas (COTE) Regulations and the conditions specified by both the Ofgem Letter of Direction for the BtG facility and the Letter of Approval for the chosen CV determination device. Conditions currently specified include the following:

1) Acquisition and storage of gross CV from the approved CV determination device, together with a flag indicating its quality/suitability for use. For non-continual CV determination devices, the System - CV determination device interface shall be such that only one value of each CV determination is acquired.

2) Acquisition and storage of instantaneous volumetric flowrate at the time of acquisition of gross CV.

3) Initiation of daily calibration of CV determination device.

4) Automated tests of apparatus and equipment at periods not exceeding 35 days in accordance with Regulation 6(e) of the Gas (COTE) Regulations. The facility to manually initiate tests of apparatus and equipment either by, or at the request of, the Gas Examiner. Provision of a report of results of automated or manual tests in accordance with Regulation 6(e) of the Gas (COTE) Regulations.

5) Calculation of the daily average CV at the end of each Gas Day in the manner specified by the Letter of Direction. This will require confirmation of the quality of individual records (records are Good if the CV determination device is operating within agreed limits) and averaging of only those records that are Good and for which gas is flowing past the sample point. In addition a flag shall be stored indicating whether the resulting daily average CV is Valid (i.e. the maximum time between Good records is less than 8 hours). Gross CV values during calibration or tests of apparatus and equipment shall not be included for averaging.

6) Acquisition and storage of integrated daily volume at the end of the Gas Day.

7) In addition to local storage of individual data acquired, appropriate means of secure transfer of data to the High Pressure Metering Information System (HPMIS) owned and operated by the GT. HPMIS currently accepts data as CSV files with appropriate check sum to ensure corrupted data is identifiable and not accepted. A list of files and file structure is provided in Appendix A.

FWACV functionality may vary if alternatives to the CV determination devices currently approved by Ofgem become available.

Any software and hardware solutions are acceptable provided they deliver the required FWACV functionality, but the GT will require demonstration that the required functionality has been delivered. In addition Ofgem may require testing and approval of some parts of or all of such software and hardware by their service provider.

6.7 Gas quality and supervisory system

The Gas Quality and Supervisory system shall monitor biomethane quality signals from the BtG facility instrumentation, the remote monitoring unit instrumentation and the delivery facility instrumentation. Monitoring shall be continuous or continual and provide confirmation that the biomethane injected into the grid is compliant with the requirements of Table 1 or any other parameters agreed by risk assessment (see 4.2). If blending is practiced (see 7.1) monitoring shall also provide confirmation that the biomethane-gas blend is compliant with the requirements of Table 1 for oxygen content and/or CV, as appropriate.

In the event of an excursion in any of the parameters in Table 1 or any other parameters agreed by risk assessment (see 4.2) the trip system shall initiate closure of the ROV and prevent further grid injection of biomethane.

The limit values in the parameters of Table 1 are indicative and site-specific values shall be agreed during design approval and may be subject to review if risk assessment confirms such a requirement (see 4.2). All alarms and trips shall therefore be configurable.

If closure of the ROV has been initiated because of non-compliance with the parameters in Table 1 or any other parameters agreed by risk assessment (see 4.2), then its subsequent opening shall be under the sole control of the GT.

7 Variations

7.1 Remote monitoring unit

Monitoring of gas quality at a location remote from the BtG facility may be required if comingling of biomethane with gas in the distribution system is practised. Two scenarios are envisaged where comingling may be carried out:

a) Where monitoring of oxygen content of the comingled mixture is a specific requirement of any exemption from the requirements of Part 1 of Schedule 3 of the GS(M)R granted by the Health and Safety Executive (see 7.1));

b) Where the requirement to enrich biomethane with LPG may be reduced or eliminated by determination of the calorific value of the comingle mixture.

The remote monitoring unit shall therefore contain a remote oxygen monitoring meter and/or a CV determination device approved by Ofgem as in Section 6.2, together with telemetry to send the measured values of oxygen content and/or CV of the comingled gas back to the main BtG facility or the GT's telemetry unit as appropriate.

8 Design approval

8.1 Assets owned by the GT

Design approval for all assets owned by the GT shall be managed in accordance with T/PM/G/17. Note that if a valid model design appraisal for the BtG facility is available then site specific design approval within T/PM/G/17 by application of T/PM/G/19 is acceptable.

8.2 Assets owned by the DFO

For those assets owned by the DFO the GT shall be afforded the opportunity to review the design of interfaces to assets owned by the GT.

9 Testing

9.1 Assets owned by the GT

Pressure testing of all pressure containing components and systems shall be carried out in accordance with T/PM/PT/1. Testing of electrical and instrument systems and equipment shall be carried out in accordance with BS 7671 and BS EN 60079-14.

9.2 Assets owned by the DFO

All pressure containing components and systems shall be shall be pressure tested and declared safe to commission by the DFO. Testing of electrical and instrument systems and equipment shall be carried out in accordance with BS 7671 and BS EN 60079-14.

10 Commissioning and initial validation

10.1 General requirements

All personnel carrying out commissioning and initial validation shall be competent and adequately trained to do so.

A written commissioning procedure shall be agreed and shall take into account relevant Permit to Work procedures.

Initial validation shall be carried out in order to demonstrate the accuracy of the measurement system complies with the requirements of Table 2. Suitable systems, software or procedures shall be provided or agreed to ensure that compliance can be demonstrated.

10.2 Assets owned by the GT

Following satisfactory commissioning, validation of the flow and gas quality measurement system shall be carried out in accordance with the relevant parts of T/PR/ME/2 or an alternative documented procedure if appropriate.

10.3 Assets owned by the DFO

Following satisfactory commissioning, validation of the flow and gas quality measurement system shall be carried out in accordance with a documented procedure agreed with the GT.

Table 1: Parameters to be monitored and indicative limits to be applied

Parameter	Units	low limit	high limit
Delivery temperature	^oC	(see note 1)	(see note 1)
Delivery pressure	barg	(see note 1)	(see note 1)
Wobbe index	MJ/m^3	47.2	51.41
Incomplete combustion factor	-	not applicable	0.48
Sooting index	-	not applicable	0.60
Gross calorific value	MJ/m^3	(see note 2)	(see note 2)
Carbon dioxide	mol%	not applicable	2.5
H_2S	mg/m^3	not applicable	5
Water dew temperature (see note 3)	^oC	not applicable	-10
Odorant injection rate	mg/m^3	(see note 4)	(see note 4)
Odorant injection pump operation (see note 5)	-	not applicable	not applicable
Odorant tank level	-	(see note 6)	not applicable

Notes:

1. Limits for delivery temperature and pressure to be agreed during design review.

2. Targets for calorific value will be agreed during design review.

3. Water dew temperature to be calculated using the LRS equation of state at a pressure of 7 barg (for injection into below 7 barg systems) or at the highest anticipated pressure (for injection into above 7 barg systems).

4. Odorant injection rate (typically 6 mg/m^3) and high/low limits to be agreed during design review.

5. Confirmation is required that the odorant pump is operating.

6. Low level on odorant tank shall trigger alarm and at extra low level shall initiate closure of the process shut down valve.

Table 2: Accuracy requirements for metering system

Design daily volume	MPB (Note 1)		MPE (Note 2)	
	Daily volume	Daily energy	Daily volume	Daily energy
Less than 250,000 m^3	0.90%	1.0%	2.9%	3.0%
Greater than 250,000 m^3	0.09%	0.10%	1.0%	1.1%
Note 1: Compliance with MPB shall be deemed if |mean error| ≤MPB Note 2: Compliance with MPE shall be deemed if |mean error| + U(mean error) ≤MPE Note 3: Subject to agreement with Ofgem that the above accuracy requirements are "requisite to the calculation of daily calorific value" (see regulation 3.(3) (b) of the Gas (COTE) Regulations)				

Figure 1: Asset ownership under Model 1 ("Minimum Connection")

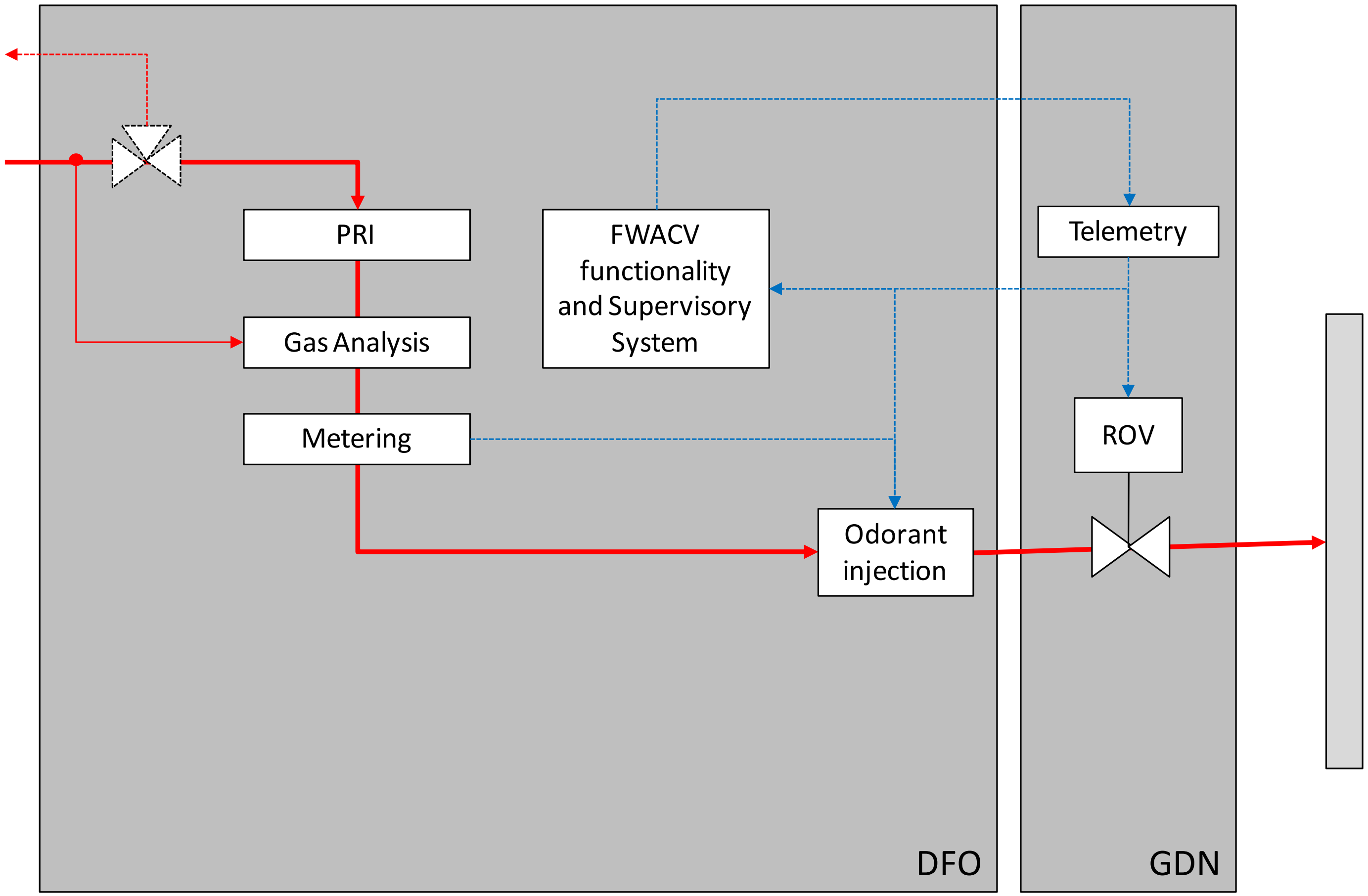


Figure 2: Asset ownership under Model 2 ("Mixed Connection")

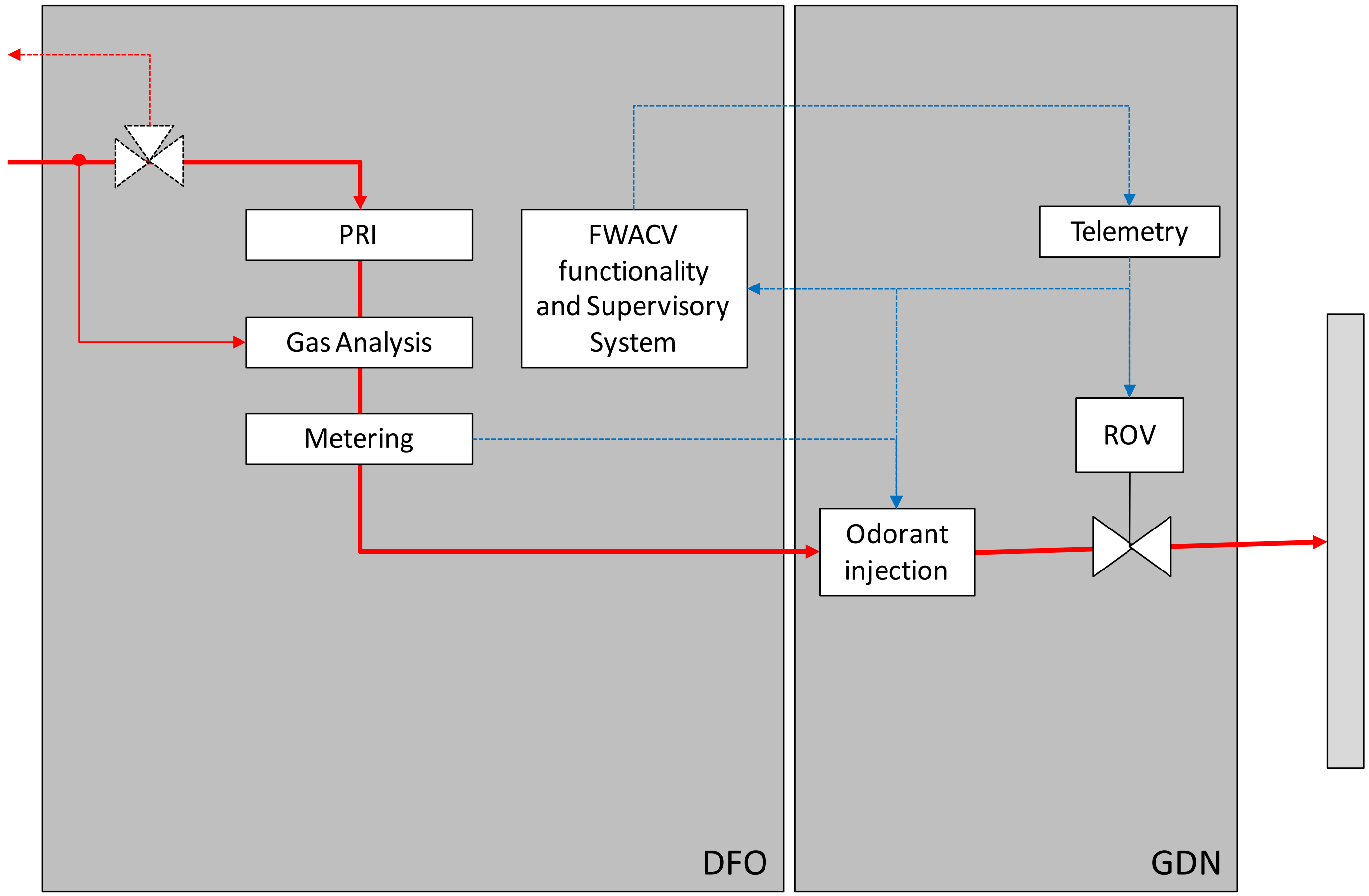


Figure 3: Asset ownership under Model 3A ("Maximum Connection – ROV downstream")

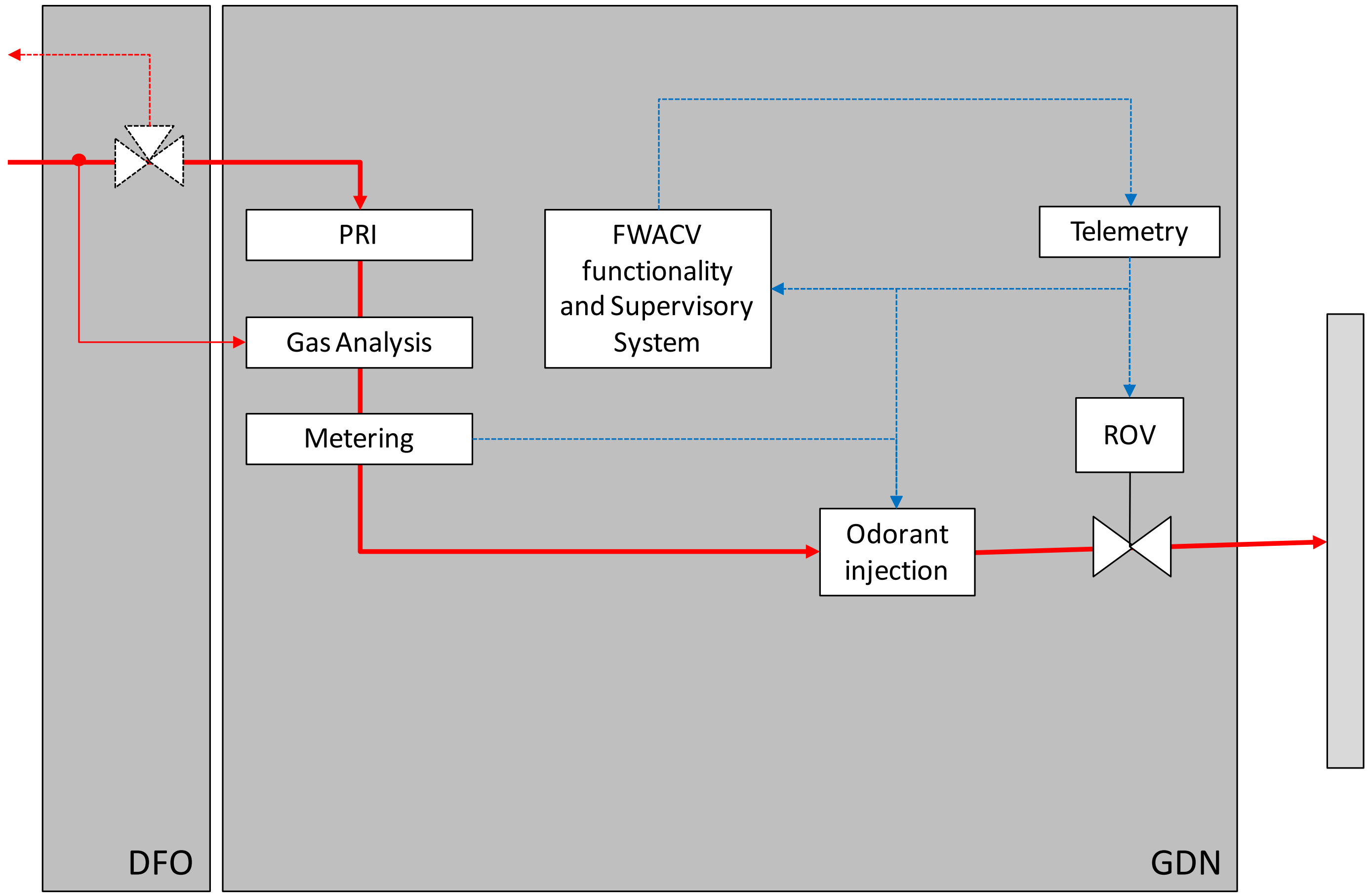
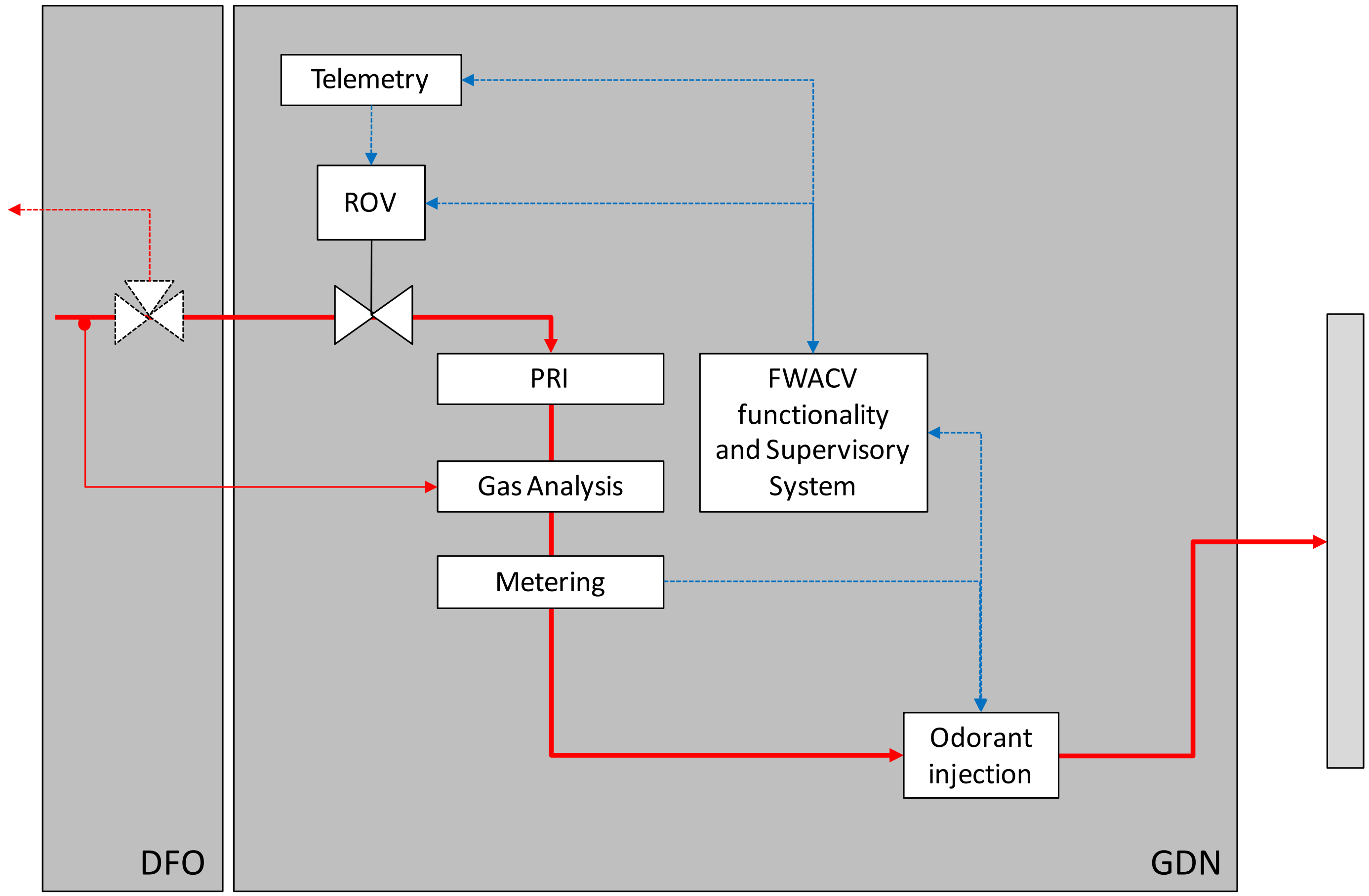


Figure 4: Asset ownership under Model 3B ("Maximum Connection – ROV upstream")



Appendix a
Data Files and File Structure

INTRODUCTION

HPMIS is an Oracle database located at a central server and forms the basis by which many of the Gas Transporter obligations under the Gas (Calculation of Thermal Energy) Regulations can be managed. Data is imported as CSV files with a fixed data structure that must be adhered to if data is to be located correctly into the database.

The following Table lists the file naming and format for the daily average CV file to be returned from the BtG facility.

Because it has not been established whether additional files need to be returned from the BtG facility, I have limited the Appendix to the "EOD" file. Should additional files need to be added then this can be done in a further revision. An alternative would be to agree a (single) dedicated file format for BtG facilities that satisfies Ofgem in terms of Gas Transporter's obligations and develop a suitable script for HPMIS to transfer data. Obviously this would have cost implications for the GDNs.

Details of the checksum at the end of the file will need to be supplied once the principles have been agreed, however it is probably not appropriate to include it at this stage.

The existing approved instruments are multi-stream and have between 3 and 5 gas streams: Stream 1 (calibration gas); Stream 2 (Gas Examiners' test gas) and Streams 3-5 (gas for analysis). For single-stream instruments that have neither calibration nor GE test gases, the extension ".ST3" is recommended for consistency.

HPMIS file name: Hsite.AByymmdd.Y0n.		
This file contains the results of the end of day averaging process and is generated at the end of the Gas Day (currently 06:00, although it is recommended that this is configurable). The stream number is indicated by "n".		
Line	Structure	Example

HPMIS file name: Hsite.AByymmdd.Y0n.		
This file contains the results of the end of day averaging process and is generated at the end of the Gas Day (currently 06:00, although it is recommended that this is configurable). The stream number is indicated by "n".		
Line	Structure	Example
1:	Header comprising the Instrument number and location description followed by the name and version number of the software generating the data. (Under current arrangements the software that performs the averaging process is approved by Ofgem, so software name and version number must be included.)	"Instrument1234 at location: EODAVE v3.7"
2:	Time and date of the last record used in the file that contains individual CV data.	"06:02-20/01/2012"
3:	Stream number	3
4:	Blank (intentional)	-
5:	Indication if the average CV is valid (Y,N, or X)	Y
6:	Number of records used in the averaging process.	98
7:	Average CV (rounded to 1 dp using the normal rules of rounding).	38.5
8:	Blank? (Average RD)	0.6324
9:	Blank? (Number of records used in tracker averaging)	-
10:	Blank? (Tracker CV)	-
11:	Blank? (Tracker RD)	-
12:	Blank? (attribution flag)	-
13:	Blank (intentional)	-

HPMIS file name: Hsite.AByymmdd.Y0n.		
This file contains the results of the end of day averaging process and is generated at the end of the Gas Day (currently 06:00, although it is recommended that this is configurable). The stream number is indicated by "n".		
Line	Structure	Example
14:	Blank? (Total number of non-zero flow records in the file containing data for averaging)	-
15:	Blank? (24hr integrated flow)	-
16:	Blank? (24 hr integrated energy)	-
17:	Blank? (Sample gas minimum pressure and temperature)	-
18:	Blank? (Calibration gas pressure at end and temperature at calibration)	-
19:	Blank? (test gas end pressure and minimum temperature)	-
20:	Blank? (the two carrier gas cylinder pressures at end)	-
21:	Name of file containing the data that was averaged.	C:\DATA\DATA0101.ST3
22:	Configuration parameters for the for the averaging software: end of day time, loss of record time (hrs), stream sequence, FWACV flag, streams with a flow computer and the no flow time (hrs)	"06:00",8,"3","Y","3",0
23:	File terminator: @ plus 6 character checksum.	@XXXXXX

Appendix 4: ENA Capacity Position Paper

Capacity for distributed gas entry

Gas Act obligation
Gas Act section 9 obliges transporters to develop an economic and efficient system.
Standard Special Condition D12 3b requires the DN to offer the maximum flow rate that is ava
from time to time.

Current method of capacity analysis
The DNs will analyse capacity using the following principles.

Analyse available capacity on day of minimum demand using network analysis models assum
appropriate proportion of peak day flow for that network and pressure tier. We would use moc
the period up to the end of the next Forecast Year 1. A check will be performed to ensure that
capacity is not reliant on a few large loads. Relying on large loads is not a tenable strategy as
can be no guarantee that the demand will always match the supply for example due to short t
long term plant shutdowns.

- Where there is sufficient capacity the available capacity will be offered
- Where there is insufficient capacity to meet the entrant's request, the entrant may ask
to consider other measures to provide the requested capacity. The entrant would ne
pay for the feasibility study to determine what options are available and any measur
taken to provide capacity which would be chargeable to the connecting party

Methods of providing increased network capacity
Networks can provide increased entry capacity by the following methods which may not be av
in all circumstances.

- Changing current network dynamics
- Linking two networks
- Within network compression

<u>Changing current network dynamics</u>
This allows the distributed gas injection to be the "lead" and to back out the gas from the NTS.
are cost implications for on going analysis, control centres and operations. This solution may
detrimentally affect pressures at times of high demand.

<u>Linking two networks</u>
In this case two adjacent networks could be linked to provide a larger network to take the avai
gas. Each case would need to be examined on a case by case basis and there is likely to be

<u>Within network compression</u>
This might be possible in the future if the within-network compression IFI project produces pos
results. A compressor would be installed to pump gas up to a higher pressure level at times o
demand on the network to which the distributed gas source is connected.

Changes in available entry capacity after the connection is made
If the exit demand on the local network to which the entrant is connected reduces at some po
the future then in some cases the entrant may not be able to inject gas. If it is possible to rein
the network to allow the entrant to continue to inject gas then either

- The entrant pays for the reinforcement
- The reinforcement is treated as general reinforcement

<u>Entrant pays for the reinforcement</u>
In this case the entrant takes on an open ended liability to pay for reinforcement for the life of t
plant. This would be inconsistent with the approach taken for Exit demands where a gradual ir
in demand leads to general reinforcement. If this approach is adopted it seems likely that the r
of distributed gas schemes implemented will reduce as only those where there is plenty of cap
will be viable. This solution is likely to become complex if two or more entrants share inject ga
the same network.

The reinforcement is treated as general reinforcement
This seems to be the only realistic option. This would be consistent with the treatment of exit.

Proposal
Following the successful connection of a distributed gas connection any future reinforcement of the Network to provide the contracted capacity should be treated as general reinforcement and included within the DN's RAV.

General reinforcement to support entry would be defined as reinforcement caused by changes in exit demand that means that there is no longer sufficient entry capacity available to enable gas entrants to continue to inject gas at the rate agreed at the time of connection and for which there was sufficient entry capacity at the time of connection over the DN'sTs planning horizon (up to the end of Forecast Year 1).

Appendix 5: Accuracy Of CV Determination Systems For Calculation Of FWACV

ACCURACY OF CV DETERMINATION SYSTEMS FOR CALCULATION OF FWACV

1 INTRODUCTION

Energy billing of domestic gas consumers is generally based on the actual volume of gas consumed, converted to a volume at reference conditions of temperature and pressure. The resultant *quantity*[1] of gas is then converted to energy by multiplying it by a calorific value (CV) that is *representative* of that received by consumers in a given charging area. Generally, the billing CV applied by gas suppliers is the average of daily values provided by National Grid for each charging area, or Local Distribution Zone (LDZ), over the billing period of the consumer. The conversion of actual volume to volume at reference conditions and the determination of daily charging area CVs is governed by the Gas (Calculation of Thermal Energy) Regulations 1996 and Amendment 1997 ("the Regulations").

Volume conversion is performed by gas suppliers by use of national fixed factors that account for variation of temperature and pressure of gas in the meter. These factors are provided in the Regulations and are based on principles and methods originally used by British Gas Corporation prior to privatisation of the UK gas industry.

Daily charging area CVs are calculated by National Grid from determinations of daily CVs for all relevant inputs to, and relevant outputs from, a particular charging area. The methodology for calculating daily charging area calorific values is prescribed in the Regulations and permits either use of "lowest source" or "flow weighted average" approaches. Flow Weighted Average Calorific Value (FWACV) has been the method of choice by the then Transco, and now the four Gas Distribution Networks, since the amendment to the Regulations in 1997 which permitted its use.

FWACV is calculated from daily CVs calculated for individual relevant inputs to and outputs from a particular charging zone, which in turn are based on individual determinations of CV made by gas transporters using instruments that have been approved by Ofgem. The location and manner of determination of CV is formally prescribed through Letters of Direction from Ofgem to the gas transporter. The Letter of Direction requires the use of instruments that are approved by Ofgem and this approval is formally given by Ofgem to the gas transporter through the use of a Letter of Approval. Currently two types of instrument are approved by Ofgem: a combustion calorimeter manufactured by Cutler Hammer and two variants of the gas chromatograph manufactured by Daniels Industries Ltd ("the Danalyzer").

There is no agreed specification for the required performance of instruments for determination of CV, although custom and practice has led to the use of certain criteria for initial and regular performance evaluation of gas chromatographic systems:

a) Error in CV determined by the instrument when presented with gases of different composition.

b) Repeatability of the composition determined by the instrument when presented with gas of constant composition.

The criterion for acceptable error in CV is generally for error to be no more than +/- 0.1 MJ/m^3. Initially this criterion was applied for four hypothetical test compositions agreed with Ofgem. However, with increased PC power, use of Monte Carlo (MC) methods has been used to determine error for a large (typically tens of thousands) set of hypothetical compositions. This approach has been taken to align performance evaluation with some of the more advanced concepts of error and uncertainty in use by the natural gas metrology community.

The criterion of Maximum Permissible Error of +/- 0.1 MJ/m^3 is historical and dictated by Danalyzer performance, rather than any notion of fairness to or impact on the domestic consumer for whom the CV determination is principally directed. As a result, in 2006 Ofgem requested a view on the impact of this criterion on the domestic consumer and in 2006 a National Grid report[2] set out a methodology for assessing and quantifying its impact.

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[1] Because the volume of a gas increases and decreases with increasing temperature and pressure, respectively, it does not define a quantity of gas. Instead actual volume is converted to a volume the gas would have occupied, had it been at reference conditions of temperature and pressure. The volume at reference conditions can be considered a quantity. The UK gas industry has adopted ISO reference conditions of 15^{o}C and 1.01325 bar.

[2] "Accuracy of CV determination systems for calculation of FWACV". National Grid Measurement and Process Report MPR071. October 2006.

In late 2011 Ofgem instigated the setting up of the EMIB Review Panel[3] under the stewardship of the Joint Office of Gas Transporters with the aim of addressing the outstanding technical and commercial barriers thought to the injection of biomethane into gas distribution and transportation systems. One such barrier is the cost associated with CV determination devices (CVDDs) and the question of the appropriate level of accuracy of CVDDs and in particular those associated with biomethane injection (the flows of which inevitably represent a relatively small fraction of the energy flowing into a charging area, even under the most optimistic of future scenarios).

The work carried out in 2006 and reported in MPR071 has therefore been updated to address the issue of small flows of biomethane (or any other gas, for that matter) into charging areas and the impact of different levels of CV determination accuracy on the consumer. This report describes both the original work published in 2006 and the recent work carried out for EMIB.

2 METHODOLOGY FOR ASSESSMENT OF IMPACT OF CVDD INSTRUMENT ACCURACY

The approach taken in assessing impact is based on the principles and recommendations developed by the Marcogaz Energy Measurement Working Group[4]. Essentially the process sets out the bias and uncertainty in bias for all component parts that together make up the determined quantity of energy. Bias is defined here as the mean of a distribution of errors of a series of determinations.

Biases for each component part are combined by arithmetic addition, whereas uncertainties in biases are combined by addition in quadrature.

2.1 DOMESTIC METER

Assuming that the domestic gas meter is unbiased and complies with the in-service requirements of BS EN1359 (MPE 3%) the bias is estimated to be zero with a standard uncertainty of 1.5%.

2.2 CONVERSION TO VOLUME AT REFERENCE CONDITIONS

A number of components make up the conversion factor employed to convert actual volume to volume at reference conditions and are described in turn below.

Atmospheric pressure. The correction factor in the Regulations assumes an atmospheric pressure of 1013.25 mbar. For the UK[5] mean monthly atmospheric pressure from 1987 to 1996 was estimated to be described by a distribution with mean 1015.20 mbar and a standard deviation of 24.43mbar, so the bias in atmospheric pressure is taken to be -1.85 mbar, with a standard uncertainty in bias of 24.43 mbar.

Meter pressure. The correction factor in the Regulations assumes meter pressure regulator is set at a pressure of 21 mbarg. IGE/GM/8 Part 1 specifies an accuracy of 7.5% (preferred) or 10% (limit) of set gauge pressure for domestic meter regulators with an inlet gauge pressure of between 21 and 100 mbar. Bias in meter gauge pressure is therefore taken to be zero, with a standard uncertainty in meter pressure of 1.05 mbar ((0.1 x 21)/2). The divisor 2 is based on an assumption that the accuracy requirements of IGE/GM/8 Part 1 can be interpreted as an expanded uncertainty corresponding to a probability of around 95%.

Altitude. The correction factor in the Regulations is based on a nominal altitude of 66m above sea level. In practice the correction factor is based on the use of an altitude adjustment to pressure of -8.114 mbar. This value is derived from Table in Part 1 the Regulations (height above sea level band >65.0, ≤67.5m), which in turn is derived from an altitude of 67.5m in the formula that was in use by British Gas prior to the Regulations coming into force:

pressure deduction = altitude in metres * 0.120208

The value 0.120208 is the altitude correction factor. For the UK[5] mean altitude was estimated to be described by a distribution with mean 67.16 m and a standard deviation of 54.55 m, so the bias in altitude is taken to be +0.34 m, with a standard uncertainty in bias of 54.55 m.

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3 Ofgem Review Group on Energy Market Issues for Biomethane Projects

4 "Guidance note on energy determination: implementation of certain principles presented in relevant standards." Marcogaz, October 2006.

5 L.M.Wallis. "Examination of environmental factors affecting gas metering accuracy". BG Technology Report R2278 April 1998.

The value of altitude correction factor (0.120208 mbar/m) was in use by British Gas prior to the Regulations coming into force. This value is assumed to have zero bias and a standard uncertainty of 0.0012 mbar/m (1%).

Temperature. The correction factor in the Regulations assumes a gas temperature of 12.2 °C. For the UK[5] mean monthly atmospheric pressure from 1987 to 1996 was estimated to be described by a distribution with mean 11.9 °C, with a half-range of 11.2 °C, so the bias in gas temperature is taken to be +0.3 °C, with a standard uncertainty in bias of 5.6 °C (11.2/2).

Zb/Z. The correction factor in the Regulations assumes that non-ideality of the gas can be ignored, i.e. Zb/Z = 1. Actual values of Zb/Z were estimated for the UK based on gas composition data for 2005 at a pressure of 1028.125 mbar and 11.9 °C (i.e. the conditions of temperature, pressure and altitude above) and from this the bias in Zb/Z was estimated to be 0.000184 with a standard uncertainty of 0.0000049.

Truncation and rounding. The correction factor in the Regulations is a combination of three factors a temperature factor, a pressure factor and a Z factor:

$$\frac{T_b}{T}\frac{P}{P_b}\frac{Z_b}{Z}$$

In the Regulations the correction factor employs a value for the temperature factor $\frac{T_b}{T}$ of 1.0098 instead of the exact value. In addition the final value is truncated to 1.02264.

Combining all of the above components results in a bias in conversion factor of -0.318% and a standard uncertainty in bias of 3.1497%.

2.3 CONVERSION TO ENERGY

Components making up the conversion to energy are as follows:

Actual CV. Although the billing CV is used for consumer billing, a consumer may actually receive gas of CV up to 1 MJ/m3 lower than that used for billing. The billing CV may therefore be in error (from an individual consumer's perspective) by up to 1 MJ/m3. The bias in actual CV is therefore assumed to be zero with a standard uncertainty in bias of 0.5 MJ/m3 (1.0/2).

Billing CV. Bias in billing CV and its uncertainty are governed by bias and uncertainty associated with the FWACV, which is in turn dependent upon: variation in daily CV of all sources of gas into the charging area, the bias and uncertainty in bias in the CVDD at the relevant inputs and outputs to the charging area, and the bias and uncertainty in bias in the daily volume measurement equipment at the relevant inputs and outputs to the charging area. Bias and uncertainty in bias in billing CV were estimated for North West LDZ daily volumes and daily CV seen in 2005, using combinations of accuracy for CVDD and daily volume measurement system. The details and methodology are given in Section 3. The billing CV is actually the average of the daily CVs calculated for the billing period, so over a typical 91 day billing period the uncertainty in the average billing would be the uncertainty of the daily CVs divided by $\sqrt{91}$ if the daily CVs were uncorrelated. However for this exercise daily CVs assumed to be perfectly correlated. This probably over-estimates the uncertainty, but errors in CV are likely to be related strongly to composition, so if similar gases are seen throughout the charging period then errors are likely to be similar

Truncation of the billing CV. The Regulations require the average billing CV to be truncated to 1 dp. Assuming that over time the digit of the 2nd decimal place of the billing CV is equally distributed between 0 and 9 suggests that truncation results in a bias of -0.05 MJ/m^3 with standard uncertainty in bias of $0.5/\sqrt{3} = 0.29$.

Combining all of the above components results in a bias in energy conversion of -0.126% and a standard uncertainty in bias of 1.2679%.

3 BIAS AND UNCERTAINTY IN BIAS IN BILLING CV

Billing CV is the average of each daily FWACV calculated over the billing period. Bias in billing CV will depend upon how the bias in FWACV varies over that time and for simplicity this is assumed to be constant across the billing period. In the absence of a capped FWACV, bias in FWACV is assumed to be zero and hence bias in billing CV is assumed to be zero. This assumption is valid so long as the measurements of daily calorific values and daily volumes are unbiased, i.e., they show a distribution of errors that are centred about zero. Uncertainty in error in billing calorific value will depend on the uncertainty in daily FWACV values and how strongly the daily FWACV values are correlated. If the FWACV values were uncorrelated, the uncertainty in bias in billing calorific value would be smaller than that of the FWACV by a factor of √91 for a 13-week (91day) billing period. Clearly some components of FWACV are strongly correlated (e.g., Danalyzer performance over a billing period is relatively constant) and so the most conservative estimate of uncertainty in bias in billing CV is to assume it is that of the daily FWACV.

The bias and uncertainty in bias of the daily FWACV was calculated using a Microsoft Excel spreadsheet model of a sample charging area using data for National Grid's North West LDZ. For each days data (daily volumes and daily average CVs for each offtake) uncertainty in bias in FWACV was estimated from the analytical solution of the uncertainty budget.

4 BIAS AND UNCERTAINTY IN BIAS IN LDZ ENERGY

The model described in Section 3 also permits the uncertainty in bias in LDZ energy to be estimated.

5 RESULTS

5.1 BIAS AND UNCERTAINTY IN BIAS IN FWACV

Bias and uncertainty in bias in FWACV was estimated for different combinations of NTS offtake metering and CV measurement accuracy, the extremes in which correspond to the situation like that prevalent today (accuracy of CVDD 0.1 MJ/m^3; accuracy of offtake metering around 4%) and an idealised "highest accuracy" situation (accuracy of CVDD 0.1 MJ/m^3; accuracy of offtake metering around 1%). The resulting standard uncertainties in bias in FWACV are shown in Table 1 below, expressed as relative %:

Table 1: Standard uncertainty in bias in FWACV, u(bias(FWACV), relative %

a(E(Vd))	a(E(CV))			
	0.05 MJ/m^3 (0.125%)	0.10 MJ/m^3 (0.25%)	0.20 MJ/m^3 (0.5%)	0.50 MJ/m^3 (1.25%)
1%	0.0373	0.0746	0.1491	0.3727
2%	0.0373	0.0746	0.1491	0.3727
3%	0.0373	0.0746	0.1491	0.3727
4%	0.0374	0.0746	0.1491	0.3728
5%	0.0375	0.0746	0.1491	0.3728
Note: a(Vd) and a(CV) are the assumed uncertainties in daily volume and a(CV) respectively, expressed as half-range values (uniform distribution).				

The values in Table 1 are those used as estimates of uncertainty in bias in billing CV (see 2.3).

5.2 IMPACT ON DOMESTIC CONSUMERS

The output from the domestic energy uncertainty calculations set out in Section 2 is a mean and standard deviation for the distribution of possible errors in energy estimated for the domestic consumer. The distribution arises from combination of the distributions associated with sources of uncertainty or distributions of error.

Table 2 shows the calculation of uncertainty in bias in consumer billing for a typical LDZ, where uncertainty in bias in NTS offtake metering and CV determination are around ±4% and ±0.1 MJ/m^3 respectively.

Table 2: Calculation of uncertainty in bias in consumer billing for a typical LDZ

	Units	Property, P	meanP	bias(P)	bias(P)/P	u(bias(P))	u(bias(P)/P)	variance	% total variance
1. Actual billing period volume	**m3**	**100.00**	**100.00**	**0.00**	**0.000%**		**1.5000%**	**0.0225%**	**16.33%**
atmospheric pressure	mbar	1013.25	1015.20			24.43			
meter pressure	mbarg	21.00	21.00			1.05			
altitude	m	67.50	67.16			54.55			
altitude correction factor	mbar/m	-0.12	-0.12			-0.0012			
Pressure (combined)	mbar	1026.14	1028.13	-1.9909	-0.194%	25.31	2.4619%	0.0606%	43.99%
Temperature	K	285.35	285.05	0.3000	0.105%	5.60	1.9646%	0.0386%	28.01%
Zb/Z	-	1.0000	1.000184	0.0002	0.018%	0.0000049	0.0005%	0.0000%	0.000002%
Fixed factor		1.022654755	1.025905981						
Truncation of T factor and rounding		1.022640000	1.025905981	-0.0033	-0.318%				
2. Volume conversion		**1.022640000**	**1.025905981**		**-0.318%**		**3.1497%**	**0.0992%**	**72.00%**
CV variation	MJ/m3:E	39.50	39.50	0	0.000%	0.5	1.2658%	0.0160%	11.63%
area FWACV	MJ/m3:E	39.50	39.50	0	0.000%		0.0746%	0.0001%	0.04%
truncation of area CV	MJ/m3:E	39.50	39.55	-0.05	-0.126%	0.032	0.0810%	0.0001%	0.05%
3. Energy conversion	**MJ/m3:E**	**39.50**	**39.55**	**-0.050**	**-0.126%**		**1.2680%**	**0.0161%**	**11.67%**
4. Overall	**MJ**	**4039.43**	**4057.46**	**-18.03**	**-0.445%**		**3.7119%**	**0.1378%**	**100.00%**

Overall:

Bias in domestic consumers' bills	-0.445%	
Standard uncertainty in bias in domestic consumers' bills	3.712%	
Expanded uncertainty in bias in domestic consumers' bills	7.4239%	assuming k=2

For a typical LDZ the bias in domestic energy metering is therefore estimated to be:

-0.445% ±7.42%

Assuming an average domestic gas bill of £1,000 pa or £2.74 per day this corresponds to a bias in the daily energy bill of:

-£0.01 ±£0.20

Note that the above expanded uncertainty corresponds to 95% of all daily energy estimates and not 95% of consumers.

The above estimate assumes that the standard uncertainty in bias in FWACV is 0.0746% (see Table 1). Table 3 below shows the impact of varying the uncertainty in bias in NTS offtake metering and CV determination. In all cases bias in domestic billing is unaffected and uncertainty in bias is insensitive to accuracy of NTS offtake metering and relatively insensitive to CV determination.

Table 3: Expanded* uncertainty in bias in domestic consumer energy billing

a(E(Vd))	a(E(CV)), MJ/m^3			
	0.05	0.10	0.20	0.50
1%	7.4228	7.4239	7.4284	7.4597
2%	7.4228	7.4239	7.4284	7.4597
3%	7.4228	7.4239	7.4284	7.4597
4%	7.4228	7.4239	7.4284	7.4597
5%	7.4228	7.4239	7.4284	7.4597
*Assuming a coverage factor k=2, corresponding to a probability of around 95%				

5.3 BIAS AND UNCERTAINTY IN BIAS IN LDZ ENERGY

Table 4 shows the expanded uncertainty in LDZ energy for the same combinations of uncertainty in NTS offtake metering and CV determination employed in 5.2 above.

For a typical LDZ the bias in LDZ energy is estimated to be:

0% ±2.04%

The bias in LDZ energy resulting from the LDZ model is zero because the model assumes that daily volumes and daily CVs are unbiased.

Expanded uncertainty in bias is relatively insensitive to CV determination and dominated by the accuracy of NTS offtake metering. Typically uncertainty in LDZ energy is around one-half of the offtake metering accuracy and this arises because errors in NTS volumes and CV measurements are assumed to be uncorrelated. For errors in volume this assumption is probably justified, but some correlation between errors in CV measurement might be expected because all Danalyzers employ the same composition of calibration gas and typically show similar response curves for the main component (i.e. methane tends to show a relatively large non-zero intercept in its response). However, the degree of correlation was estimated using performance evaluation data for each Danalyzer associated with the NTS offtakes into the LDZ. Little correlation was actually observed (only one off-diagonal term in the correlation matrix was greater than 0.5). The assumption of uncorrelated errors is therefore justifiable.

Table 4: Expanded* uncertainty in bias in LDZ energy

a(E(Vd))	a(E(CV)), MJ/m^3			
	0.05	0.10	0.20	0.50
1%	0.5146	0.5306	0.5902	0.9028
2%	1.0212	1.0294	1.1612	1.2622
3%	1.5296	1.5350	1.5566	1.7000
4%	2.0384	2.0424	2.0586	2.1690
5%	2.5472	2.5506	2.5636	2.6530
*Assuming a coverage factor k=2, corresponding to a probability of around 95%				

5.4 IMPACT OF BIOMETHANE INJECTION

The estimates of bias and uncertainty in bias in in Tables 3 and 4 do not consider a future scenario in which injection of relatively small quantities of renewable gases into charging areas. Clearly the impact on consumer billing of injection of low flows of biomethane will be insignificant, since wholesale relaxation of CV determination accuracy to ±0.5 MJ/m^3 has little impact (see Table 3). However the impact on accuracy of LDZ energy determination was assessed by reducing the CV determination accuracy at one of two NTS offtakes whilst retaining the current 0.5 MJ/m^3 accuracy at all other offtakes. Under these scenarios the expanded uncertainty in bias in LDZ energy increased from ±2.0424% to:

±2.0555%, for an NTS offtake with mean daily volume of 3.09 million m^3 (14.8% of LDZ volume)

±2.1266%, for an NTS offtake with mean daily volume of 8.24 million m^3 (39.4% of LDZ volume)

In both cases, daily volume at all offtakes is assumed to be ±4%.

The measurement of CV with an accuracy of ±0.5 MJ/m^3 is judged to be achievable by relatively low-cost devices and the measurement of biomethane volume with an accuracy of ±4% is readily achievable if compliant with the general principles of IGE/GM/8, for instance.

6 DISCUSSION

6.1 DOMESTIC METERING

The bias in domestic metering (-0.445%) is relatively small and negative i.e. the energy bill is under-estimated. The sources of bias are: pressure assumptions in the conversion factor (44% of total bias); truncation of billing CV (28%); temperature assumptions in the conversion factor (24%); and gas ideality assumptions in the fixed factor (4%).

The uncertainty in bias (7.42%) and the principal sources are: pressure assumptions in the conversion factor (44% of total variance); temperature assumptions in the conversion factor (28%); domestic meter accuracy (16%); and CV variation (12%). Accuracy of billing CV contributes very little to the overall accuracy of domestic billing (0.04% of variance).

Uncertainty in bias in domestic consumer energy billing leads to cross subsidy from consumers whose bills are over-estimated to those whose bills are under-estimated. The dominant source of this cross-subsidy is associated with conversion of the actual volume of gas metered at consumers' premises in accordance with the fixed factors specified in the Regulations and in particular the assumptions about pressure and temperature of gas metered in domestic premises.

This cross-subsidy could in principle be reduced by direct pressure and temperature correction at the meter or through adoption of LDZ-specific fixed factors. Technically, the greatest reduction would be through volume conversion at the domestic meter, but this would require investment in new metering technology for the domestic meter population. This might be regarded as an unjustifiable expense in its own rights, but it should be noted that installation of smart metering is planned for the UK economically anyway, so the marginal cost of volume conversion is what requires economic test and not the full cost of new meters. Both volume conversion and LDZ-specific fixed factors would require modification of consumer billing systems (not without significant cost) and both would of course require amendment to the Gas (Calculation of Thermal Energy) Regulations.

6.2 ACCURACY IN BILLING CV

Energy conversion contributes around 12% of the variance in bias in domestic billing and hence cross-subsidy between consumers. The dominant source of this variance is not the accuracy of CV determination itself, but the variation in the gas actually received by different consumers within a given charging area. Reducing this source of uncertainty could be achieved by CV determination at the domestic meter, transmission to a smart meter of an estimated daily CV from a central location, or reduction in the size of charging area. Similar arguments to that for domestic metering above apply, i.e. marginal cost of CV determination at the meter (using inferential methods, such as speed of sound determination) or facilities for receipt of a transmitted daily CV and the need for billing system and regulatory changes.

The only other means of reducing uncertainty in billing CV is through adoption of higher accuracy standards for CV determination or volume metering at entry to charging areas. Although it may be possible to achieve better accuracy with modern CV determination instrumentation, the overall impact on consumer billing would be insignificant.

There is in fact some merit in relaxing accuracy standards for CV determination or volume metering at entry to charging areas if this could open up lower capex/opex options for CV measurement instrumentation, such as micro-gc or inferential devices. This approach would be especially applicable for low volume flows such as inter-LDZ flows, small NTS offtakes and injection of biomethane and other non-conventional sources of gas. As might be expected, the impact of such slight changes in accuracy of FWACV on the domestic consumer energy bill is also slight. Use of lower accuracy CV determination devices, e.g. a(E(CV)) of ±0.5 MJ/m^3, for daily volume flows of up to around 2.5 million m^3 would have an almost imperceptible impact on accuracy of FWACV and on accuracy of consumer energy billing.

A key assumption in this study was that for flows into the charging area the CV and flow measurements were unbiased, i.e., the distribution of errors was centred at zero. In practice individual instruments will demonstrate some bias and for gas chromatographs will reflect how well the composition of the calibration standard employed matches the distribution of compositions of gases that might be presented to individual instruments. An additional criterion for CV determination instrumentation is therefore recommended, based on the mean error in CV for the gases likely to be (or actually) presented to the instrument. (The MPE is based any possible gas composition within the approval range of the instrument.)

6.3 LDZ ENERGY

For a typical LDZ, where uncertainty in bias in NTS offtake metering and CV determination are around ±4% and ±0.1 MJ/m^3 respectively, determined LDZ energy is expended to be zero and expanded uncertainty in bias estimated to be ±2.04%. Biomethane flows employing CVDDs with an accuracy of ±0.5 MJ/m^3 are not expected to have a material impact.

7 CONCLUSIONS

1) For a typical LDZ, where uncertainty in bias in NTS offtake metering and CV determination are around ±4% and ±0.1 MJ/m3 respectively, the bias in domestic energy metering is estimated to be: -0.445% ±7.42%. The dominant sources of bias and uncertainty in bias are associated with fixed factors for conversion of actual domestic metered volume to reference temperature and pressure.
2) For a typical LDZ, the bias in LDZ energy is estimated to be: 0% ±2.04%. The bias in LDZ energy resulting from the LDZ model is zero because the model assumes that daily volumes and daily CVs are unbiased.
3) Current custom and practice is for CV determination equipment to meet a requirement that (absolute) error in CV should not exceed 0.10 MJ/m^3. This requirement results in insignificant impact on domestic energy metering.
4) Some relaxation in Maximum Permissible Error (MPE) in CV determination may be appropriate, particularly in low volume applications, such as biomethane injection, for which the anticipated daily volumes are so low as to make CV determination accuracy insignificant in respect of impact on the domestic consumer. The appropriate MPE should be decided by consideration of other regulatory issues (such as monitoring of compliance with the GS(M)R if shared duty is being practiced), or normal

commercial factors for sale of energy. However, daily flows of up to 2.5 million m^3 could be measured with devices having an MPE of 0.5 MJ/m^3 with no material impact on accuracy of FWACV and hence domestic consumer energy billing.

5) In addition to MPE, a formal performance specification for CV determination devices should include a maximum bias shown by CV determination devices with gases that the instrument (or family of instruments) is likely to see.

Appendix 6: Specification Of Water Dew Temperature Of Biomethane Injected Into Gas Distribution Systems

SPECIFICATION OF WATER DEW TEMPERATURE OF BIOMETHANE INJECTED INTO GAS DISTRIBUTION SYSTEMS

1 INTRODUCTION

Gas Distribution Networks typically make no distinction in the gas quality specification for gas entering their Local Transmission Systems (LTS) or their Gas Distribution Systems (GDS). For water dewpoint, a typical Network Entry Agreement requires water dewpoint to be no more than -10^{o}C at 85 barg. Gas with this water dew temperature is extremely dry and corresponds to a water content of around 57 ppm (molar)[1] and is difficult to achieve when drying biomethane at conditions typically employed in its production (typical biogas clean-up to remove CO_2 and main contaminants is carried out at a pressure of around 10 barg).

Measurement risk assessment to assess the monitoring requirements for biomethane entry into a below 7 bar GDS has highlighted that the risk posed by concentrations of water greater than 57 ppm (molar) may not be sufficient to warrant such a strict specification. This report provides information on historical water dewpoint specifications and offers an approach to deciding a more appropriate requirement.

2 HISTORICAL SPECIFICATIONS

Originally the normal water dew temperature specification employed by the then British Gas Corporation was -10 ^{o}C at 1000 psig (68.95 barg). A pressure of 1000 psig was employed because that the line pressure at which gas typically entered its National Transmission System (NTS) and water dew temperature was determined for compliance purposes by measurement with a chilled mirror instrument.

Following metrication of the UK gas industry, the water dew temperature specification employed by the British Gas Corporation changed slightly by the adoption of -10 ^{o}C at a pressure of 69 barg.

After some parts of the NTS were reinforced to permit its pressure to be increased to 85 barg, Transco (the monopoly gas transporter following privatisation of the British Gas Corporation) changed the water dew temperature requirement in their Ten Year Statement to -10 ^{o}C at 85 bar. Note that the ten year statement does not specify gauge pressure and so the assumption is that the water dew temperature requirement should be assessed at 85 bar absolute pressure.

The determination of water dew temperature for compliance purposes by measurement is now relatively rare for gases entering the NTS. National Grid typically employs equipment that measures the concentration of water and converts this measurement into a water dew temperature at the desired pressure using GasVLE and the LRS equation of state. The pressure typically employed by National Grid for these calculations is 69 barg.

Table 1 summarises the concentrations of water that correspond to these three historical water dew temperature specifications. Also included is the water content corresponding to -10 ^{o}C at 85 barg, because of the ambiguity over National Grid's current Ten Year Statement.

Table 1: Historical water dew temperature specifications

Water dew temperature	water concentration ppm (molar)
-10^{o}C at 1000 psig	63.45
-10^{o}C at 69 barg	63.42
-10^{o}C at 85 bar	57.89
-10^{o}C at 85 barg	57.65

[1] Calculated using GasVLE using a typical natural gas composition and the LRS equation of state.

The water dew temperatures were carried out with GasVLE and the LRS equation of state for a natural gas with the dry gas composition shown in Table 2.

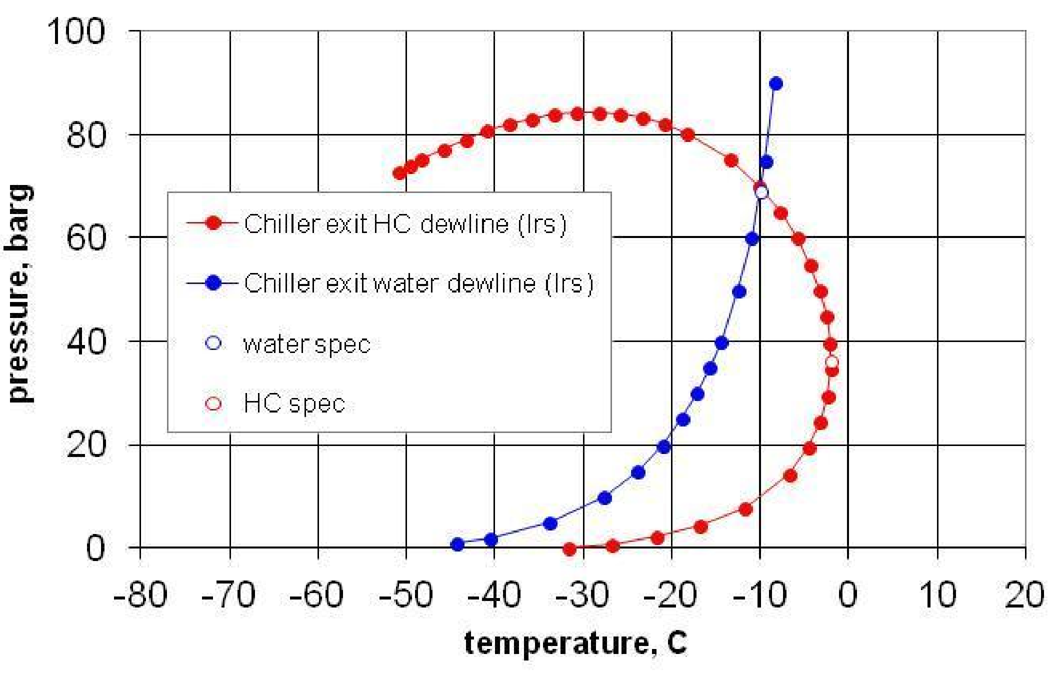
Table 2: Composition of natural gas employed for water dew temperature calculations (mol%)

methane	88.790
ethane	5.820
propane	1.865
i-butane	0.162
n-butane	0.339
neo-pentane	0.002
i-pentane	0.052
n-pentane	0.057
n-hexane	0.042
nitrogen	1.055
carbon dioxide	2.255

Historically, most natural gas entering the NTS was treated by chilling at line pressure so as to meet the hydrocarbon dew temperature requirement, i.e. the cricondentherm temperature should be no greater than -2 ^{o}C. In order to achieve such a hydrocarbon dew temperature, typically the gas at 1000 psi has to be chilled to around -10 ^{o}C. As a result, the gas exiting the chiller typically had a dew temperature of around -10 ^{o}C at 1000 psi.

Figure 1 illustrates the correspondence between hydrocarbon and water dew lines and shows how a chilling natural gas to -10^{o}C results in a gas with a cricondentherm of -2^{o}C. Figure 2 was constructed using a GasVLE model of chilling of a "water and hydrocarbon wet" natural gas.

Figure 1: Dew Lines of treated natural gas



3 APPROPRIATE WATER DEW TEMPERATURE SPECIFICATIONS

The purpose of a dew temperature specification is to ensure that liquid cannot form if gas is cooled. Liquid water formation can lead to corrosion issues with metallic pipe and significant liquid formation can lead to plugging and cause operational problems. Gas can be cooled by sensible heat loss through the pipe to its surroundings and also through Joule-Thomson cooling at pressure reduction stations.

Assuming that sensible heat loss is unlikely to result in gas temperature below 0^oC, a hydrocarbon liquid cannot form at any pressure if the cricondentherm is set at -2 ^oC through specification. Joule-Thomson cooling can cause the temperature to fall below 0^oC, and preheating is typically employed at NTS offtakes to ensure gas temperature does not fall to less than 0^oC.

It is believed that because chiller temperatures of -10 ^oC at 1000 psi were typically employed to meet hydrocarbon dew temperature requirements, NTS entry specifications were set to that typically observed and not what is required to provide an adequate margin to prevent liquid water corrosion.

For gas entry at distribution pressures, the water content can be relaxed somewhat and still provide an adequate degree of protection from liquid water formation.

One further factor must also be considered. For the purpose of consumer billing natural gas is assumed to be perfectly dry (i.e. water-free) when its calorific value is calculated. As increasing water content decreases its calorific value and hence the consumer of such gas will have been billed for energy not received.

Section 12(2) of the Gas Act 1996 (“the Act”) gives a discretion to Ofgem to determine the quantity of water vapour in gas supplied to consumers. Under the Wet Gas Administration Scheme (discontinued by Ofgem in 2003) Ofgem classified gas as being “wet” if the dew point is -26 ^oC or greater, otherwise it is considered to be dry. Gas containing water vapour with a dew point of -26 ^oC causes a billing error of around 0.06%.

In order to explore possible dew temperature specifications, Table 3 shows a number of water content and dew temperatures that can be examined for their impact with respect to the above two considerations, i.e. consumer billing and liquid water formation.

Table 3: Water dew points and concentrations for four alternative specifications

Dew temperature, ^oC Pressure	-10 16 barg	-10 10 barg	-10 7 barg	-26 1 atm	-2 7 barg	-10 2 barg
water content, ppm (molar)	187.60	280.18	378.66	564.82	692.72	979.50
Water dew T (1 atm), ^oC	-36.48	-32.77	-29.91	-26.00	-23.96	-20.41
Water dew T (7 barg), ^oC	-18.67	-13.80	-10.00	-4.76	-2.00	+2.84
Water dew T (10 barg), ^oC	-15.04	-10.00	-6.07	-0.64	+2022	+7.24
Water dew T (16 barg), ^oC	-10.00	-4.71	-0.59	+5.11	+8.12	+13.41

Notes:

1. Water dew temperature at 1 atm calculated using Sonntag equation so as to correspond with Ofgem "wet gas" criterion. All other dew temperatures calculated with the LRS equation of state

2. Dry gas composition 98 mol% CH_4, 2 mol% CO_2

The specifications, in order of increasing water content, correspond to the following water dew temperature specifications:

a) -10^oC at 16 barg
b) -10^oC at 10 barg
c) -10^oC at 7 barg
d) -26^oC at 1 atmosphere
e) -2^oC at 7 barg
f) -10^oC at 2 barg

4 DISCUSSION

A specification of -10 ^oC at the maximum pressure likely to be encountered in a Gas Distribution system is an obvious alternative specification value to the current one. This maximum pressure could be specified either explicitly (e.g. 2 barg, 7 barg and, in view of potential increase in scope of IGE/TD/3, 10 barg and 16 barg) or implicitly (i.e. "-10 ^oC at the maximum pressure of the distribution system into which the biomethane is injected").

However, an implicit pressure would mean different specifications for different biomethane entry points and could be construed as not being even-handed. In addition, changes in the system pressure could have impacts on the producer in the future. An appropriate compromise might be to employ an explicit pressure for injection into below 7 bar pressure systems (arguably the majority of biomethane injection projects) and an implicit pressure for injection into above 7 bar systems.

Of the options outlined in Table 3:

a) A specification of -2^oC at 7 barg or -10^oC at 2 barg gives a higher water content than that corresponding to Ofgem's "wet gas" criterion and would clearly be perceived to disadvantage some consumers.

b) A specification of -26^oC at 1 atmosphere would be "just dry" according to Ofgem's criterion and would provide a safety margin of around 4.8 ^oC from gas at a temperature of 0 ^oC for gas at 7 barg to prevent liquid formation. However, there would be little margin for additional water ingress to cause consumer billing issues. Moreover, at 10 barg the margin would be just 0.7 ^oC, so injection into systems above 7 barg (or re-compression back into a higher pressure tier) would need to ensure that there was sufficient dilution to provide adequate safety margin to prevent liquid water formation.

c) A specification of -10 ^oC at either 7 barg, 10 barg or 16 barg might therefore be appropriate, giving safety margins of 10 ^oC to prevent liquid water formation. In addition the specifications would result in dew temperatures around 4^oC, 7 ^oC and 10 ^oC lower, respectively, than Ofgem's "wet gas" criterion.

d) A specification of -10 ^oC at 16 barg is equivalent to -36.48 at 1 atmosphere and this might be only just attainable with drying systems typically employed in biogas treatment. A specification of -10 ^oC at 10 barg is equivalent to -4.71 ^oC at 16 barg, which still provides a reasonable safety margin to prevent liquid water formation should gas be injected into (or recompressed back into) a future 7-16 barg distribution system.

e) Calculated water dew temperatures are sensitive to the equation of state, so the equation of state to be used should accompany the specification. A simpler specification would be to simply state a maximum water content, such as 280 ppm (molar) for a future above 7 barg distribution system, or 390 ppm (molar) for a below 7 barg distribution system.

5 CONCLUSIONS

1. Typical NTS water dew temperature specifications are more stringent than required for gas distribution systems.
2. A more appropriate specification would be to require:
    a. water dew temperature to be no greater than -10 ^oC at 7 barg for injection into below 7 barg distribution systems, or

b. water dew temperature to be no greater than -10 °C at the maximum anticipated pressure for injection onto an above 7 barg (7-16 barg) distribution system

An equation of state to be used in calculating the water dew temperature should accompany any specification. The current equation employed by NG NTS, and in the calculations report here, is the LRS equation of state and is recommended.