Biomethane Study: Stage 1
Central Injection Hub Financial Model and Reverse Compression for Biomethane Injection Report

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CNG Services Ltd

- CNG Services Limited (CSL) provides consultancy, design and build services to the biomethane industry, all focused on reducing Greenhouse Gas (GHG) emissions
- In the past 10 years our efforts have produced a material impact with an estimated 20 year project life reduction in CO_2 emissions of 17,500,000 tonnes through:
  - Biomethane injection into the gas grid
  - Running trucks on Bio-CNG
  - Acting as developer and design and build contractor for the Highlands CNG Project
- Part owner of CNG Fuels Ltd, a company set up to build a national network of Bio-CNG stations on the high pressure grid
  - National network of CNG Stations
  - 84% saving in GHG compared to diesel
- Part owner of Barrow Shipping Ltd, GB's leading shipper of biomethane and a company that only buys and sells biomethane, no fossil gas
- CSL is an ISO 9001, 14001 and 45001 approved company and has also achieved Achilles certification. CSL is GIRS accredited for design and project management and has been certified as a competent design organisation for high pressure UK onshore natural gas works by DNVGL
- Working on a number of H_2 and CCUS innovation projects

About this report

Report Aim

This report covers stage 1 of three separate stages as part of this overall research project detailed below:

- **Stage 1 Adapting and reviewing the CSL central injection hub model and associated economics to be applicable for the GB regime. Includes comparison with Reverse Compression to create capacity**
- Stage 2 Adapting and reviewing CSL work on sewage biogas conversion of utilisation from electricity generation to biomethane injection
- Stage 3 Report on the mandatory requirements:
    - Including biogas to electricity plants
    - Identifying areas with highest potential for new AD
    - Identifying commercial barriers and opportunities

Participating Parties

Lead Partner	*Participating Partner*	*Project Coordinator*	*Supported By*
NGN	WWU	EIC	ENA

Report Structure

Northern Gas Networks

WALES&WEST UTILITIES

EIC Together we innovate

ena energynetworks association

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Acronyms

AD	Anaerobic Digestor
AGI	Above Ground Installation
BUU	Biogas Upgrading Unit
CBM	Compressed Biomethane
CNG	Compressed Natural Gas
COMAH	Control of Major Accident Hazards
CSL	CNG Services Ltd
CUB	Compressed Upgraded Biogas
DX	Distribution Network
GDN	Gas Distribution Network
GEU	Grid Entry Unit
GGSS	Green Gas Support Scheme
IP	Intermediate Pressure Gas Network
LP	Low Pressure Network
LTS	Local Transmission System
MP	Medium Pressure Network
NGN	Northern Gas Networks
NTS	National Transmission System
O&M	Operation and Maintenance
PRMS	Pressure Regulating and Metering Skid
RHI	Renewable Heat Incentive
TX	Transmission Network
UMOE	UMOE Advanced Composites Type 4 Gas Trailer
WACC	Weighted Average Cost of Capital
WWU	Wales & West Utilities
X-Store	Hexagon / Xperion Type 4 Gas Trailer

Glossary

Biogas	The product gas from the anaerobic digestion process, typically produced from organic waste materials or energy crops (i.e. maize). A typical biogas composition is 60% methane (CH4) and 40% carbon dioxide (CO2).
Biomethane	Biogas that has been cleaned and purified to remove any contaminants and the majority of the CO_2. This results in a composition of <97% methane with a balance of nitrogen, oxygen and CO_2. If biomethane is produced for grid injection purposes, it must meet the specification set by the local grid which may require the addition of propane and odorant.
Bio-CNG	Biomethane that has been injected into the gas grid un-tariffed and transported through the network by means of mass balancing. The biomethane can then be taken out of the grid at a remote point and compressed to 250 barg for use as a vehicle fuel.
Compressed Biomethane (CBM)	Biomethane that has been compressed to >250 barg for use as a vehicle fuel or transportation (when it can be injected directly into the grid without further enrichment). Portsdown Hill and Adapt Biogas at Somerset Farm .
Compressed Upgraded Biogas (CUB)	Biogas that has been upgraded and compressed to >250 barg for transportation however requires enrichment (i.e. the addition of propane and odorant) to meet the grid specification prior to being injected into the gas grid. This is specific to gas being produced/transported to the Vale Green site via Central Hub and also VR Doncaster and the Acorn Bioenergy Sites.
Central Hub	The transmission of gas that occurs without the use of a conventional pipeline. The most common method being via gas trailers. Also referred to as a virtual pipeline.
Mother Station	A CBM filling station that exports gas via trailers to a daughter station. The mother station for this study is located by the biomethane producer to export gas.
Daughter Station	A CBM decanting station that allows the unloading of gas from trailers to be used at the facility. The daughter station for this study is located at the grid connection where the gas will be injected.

Project Brief

Scope

CNG Services Ltd have been commissioned to review and remodel an existing feasibility study which assesses the various biomethane injection types from the Republic of Ireland regime to the GB regime. This study examines the technical feasibility of biomethane injection for a central hub and reverse compression, the financial costs and the environmental benefits when compared to the standard biomethane injection types.

The biomethane connection options projects studied are:

Scheme 1	Direct into 2 bar MP
Scheme 2	Direct into 30-50 bar LTS
Scheme 3	Central Hub i.e. Central Hub for 250-275 bar trailers
Scheme 4	Direct into 2 bar for reverse compression.
Scheme 5	Operates as scheme 3 the Central Hub but has GDN ownership of assets downstream of CBM dispensers.
Scheme 6	Operates as scheme 4 reverse compression with GDN ownership of reverse compression assets.

Note. IP projects based on existing CSL projects cost similar to MP when compared to the rest of the schemes.

The problem

- There is uncertainty in support for biomethane post March 2021 due to the end of the RHI (Renewable heat incentive).
  - Support for Anaerobic Digestion (AD) with CHP projects is weakening. RO (Renewables Obligation) support will start expiring within the next 5 years for the early adopters and under current regulations, FIT (Feed-In Tariffs) supported projects are unable to replace ageing CHP engines without compromising their FIT accreditation.

- The cost of getting biomethane to market caused by GDN MP/IP grid capacity being taken in many areas due to the 110 biomethane projects completed to date.

The Green Gas Support Scheme (GGSS) will replace the Renewable Heat Incentive (RHI) for 4 years as of March 2021.

- Only supports biomethane produced by anaerobic digestion of biomass feedstocks and injected into the gas grid.
- Tier based tariff support scheme for a 15 year period from plants registration

The successes of the RHI and an upcoming increase of the GGSS tier 1 biomethane capacity (tariff p/kWh before diminishing returns) are forecasted to increase biomethane injection around the UK.

- Reverse Compression and Central Hub are available solutions to capacity restricted customers and are reviewed in this report.

Executive Summary

Technical Outputs

Key Financial Trends

- Direct into a 2 bar MP is the best option.
- Next best is the reverse compression for a 2 bar MP (or IP) network.
- This is followed by a HP LTS connection.
- The least attractive scheme is the Central Hub model.

Ownership Models – GDN owned assets with tariff charge

- The GDN ownership works well for Central Hub models due to the high CAPEX costs of a daughter station.
- For reverse compression models, GDN ownership sees a diminishing difference as biogas production increases.
- Smaller (<1000scmh) sites see a bigger difference but will not be as good financially.
- The GDN ownership model works best for small Central Hub models but will lose value as the project size increases.

Environmental Impacts Summary

- Scheme 1, injection into the 2 bar MP grid produces the smallest amount of CO_2 emissions and Scheme 3 a Central Hub, produces the most.
- Reverse compression produces the second smallest amount of CO_2.
- From the study, reverse compression produces more CO_2 the longer it is required to run. However, this should still be less than CO_2 produced from an LTS/HP injection as the hours run will still be much less compared to it.
- A Central Hub has the most environmental impact due to running CBM trailers. Trucks are most commonly diesel (the primary issue) but CO_2 savings can be seen if CNG trucks are employed.

Scenarios Where Key Financial Trends Do Not Apply

1. Capacity Constraint Trends

- If the constraint is less than 10% scheme 1 will remain the most economic model compared to the other schemes.
- Between 10% and 50% constraint the other schemes stack better financially led by the reverse compressor model.
- At 50% constraint or lower the project will not be feasible at all as the financial payback is negative. At this point a reverse compressor is a necessity.

2. Pipeline Limitations

- Pipeline costs for high pressure models, scheme 2 increase significantly more than the other schemes due to high pressure requirements. Its viability is best when the pipeline distance is less than 7km.
- A Central Hub model will be the ideal and most economic scheme if the pipeline distance is significant. This report identifies the Central Hub to be most ideal when the pipeline distance to be 26km for the model site analysed.
- There are also scenarios where a reasonable pipeline connection cannot be made due to the terrain or a trainline. This also leads to the Central Hub being best.

Every biomethane project requires a conceptual/feasibility study but the primary selection criteria identified between a Central Hub scheme (3&5) and pipeline models is how much finance is required for the pipeline.

Introduction

Project Introduction

CNG Services Ltd have been commissioned to review and remodel an existing feasibility study which assesses the various biomethane injection types from the Republic of Ireland regime to the GB regime. The study has a focus on reverse compression as a solution to create capacity for biomethane injection into lower tier networks. The study examines the technical feasibility of such a project, the financial cost and the environmental benefits when compared to standard biomethane injection or transporting biomethane by road to a remote injection point with sufficient capacity.

The GB network is tiered based on the pressure rating, lower pressures being suitable for distribution and high pressure for transmission. Pressures above 7 bar are considered to be high pressure and have separate and more stringent standards to follow.

The GB tiers are separated as follows:

- Low Pressure (LP) - 75 mbar or less
- Medium Pressure (MP) - 2 bar or less to 75 mbar
- Intermediate Pressure (IP) - 7 bar or less to 2 bar
- Local Transmission System (LTS) - 70 bar or less to 10 bar
- National Transmission (NTS) - Approx. 70 to 85 bar

Naturally, biomethane generated from anaerobic digestion (AD) is of low pressure and suitable for the MP network without any additional compression. Businesses operating AD sites want to be producing biomethane all year and if injecting into the MP network at these sites, will run into capacity issues during summer periods of low seasonal demand as there may be insufficient capacity.

Project Outline

This report shall assess the current connection types to find optimal solutions for the GB regime. The study shall examine the technical feasibility, the financial cost and the environmental benefits when compared to each injection type.

The four primary biomethane connection types to be considered are:
Scheme 1 – MP 2-bar grid connection
Scheme 2 – LTS or NTS grid connection
Scheme 3 – Central Hub
Scheme 4 – MP Reverse compression

Previous Work

CSL have previously completed a Feasibility Study which reviewed these options:

- Direct into 4 bar grid
- Direct into 75 bar grid
- Central CBM Decanting Hub (as Portsdown Hill)
- Reverse Compression (as Cadent Doncaster)

The conclusions were that:

- Direct into 4 bar is lowest cost option
- Next best is direct into 75 bar (especially if no propane is required)
- Next best was Reverse Compression (especially attractive for low running hours)
- Least attractive was the Central CBM Decanting Hub

Project Methodology

The existing financial model will be converted to a GB regime but since the existing model was built for two real projects in Ireland, the conversion will be based on a standard ideal biomethane project scenario.

This will be based on real data of existing biomethane sites and projects that have been delivered. Projects that deviate from the ideal scenario are expected to see the same trends since the key mathematical differences between each scheme are based on linear calculations.

A number of simulations will be run on the ideal scenario to obtain the following data:

- The financial costs and payback biomethane producers can see for each scheme
- The environmental benefit or effect of each scheme
- The cost savings of partial GDN ownership of Central Hubs and reverse compression schemes
- The effect of capacity restrictions of low pressure networks and when reverse compression is key
- The effect of pipeline costs on high pressure injections and when this solution is no longer feasible

Note. The analysis in this report considers a singular AD facility to injection point, i.e. central hub.

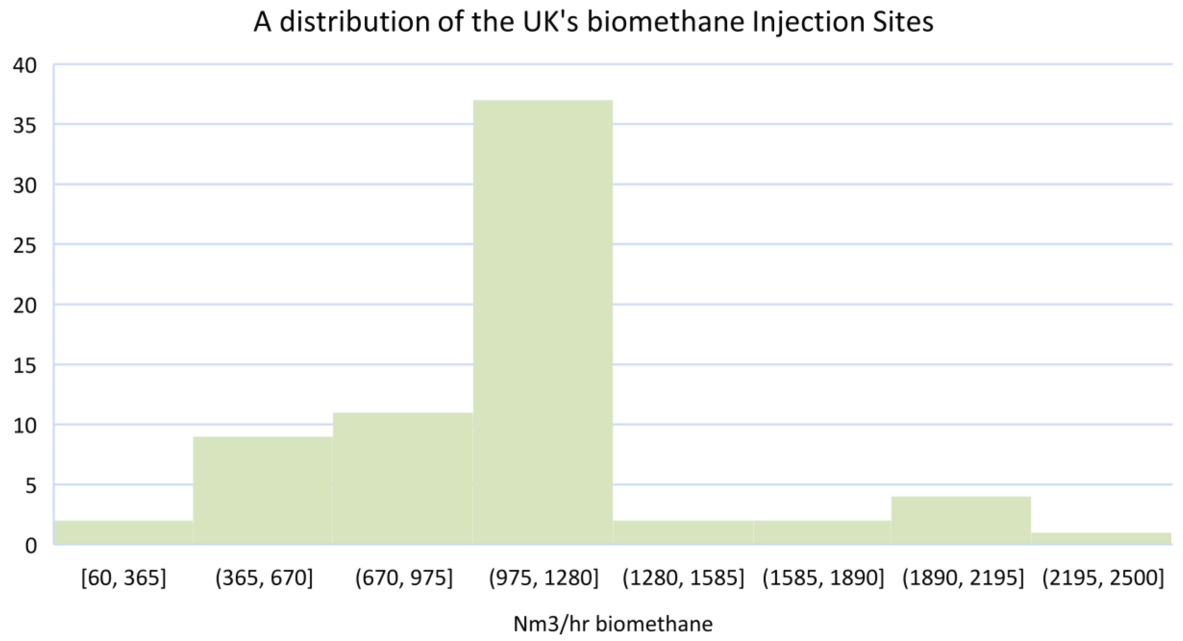
Model Site [1]

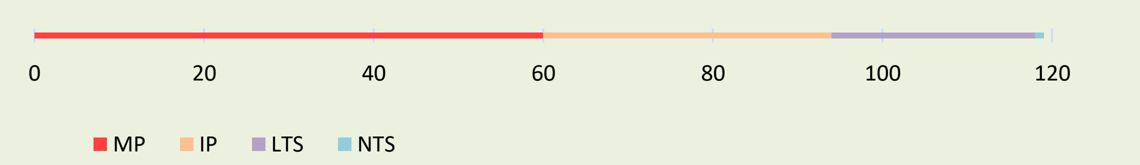
There are 3 main input parameters for a biomethane site that affect the technical and financial suitability of a project. The first is how much biomethane is produced that is to be injected which ultimately decides how much money the producer will make. The second is the network capacity which decides how much of the produced biomethane can be injected and affects lower pressure networks such as the MP grid. The third is the distance of the biomethane site to a connection point which can limit availability of cheaper injection costs. If an accessible connection point is too far away consideration needs to be given to a Central Hub as pipelines and associated costs can be very expensive. The model considers these as the primary input parameters for the site and are modelled as follows.

Injection Flowrate

The injection flowrate is based on statistical data of operational biomethane sites injecting gas into the grid as shown in the chart to the right. The sample size considers 68 sites from a recorded operational total in the UK of 97 sites. Currently there are 121 sites in the UK, injection flowrate confirmation for the sites missing from the sample were not available as of writing this report.

The proposed injection flowrate is 1000scmh as the base model for analysis and was selected based on the statistics shown to the right. Larger flowrates generate more revenue and minimise the payback difference between each scheme. This leads to lower flowrates to be suitable to assess financial difference. After running the model at 1000scmh, sufficient difference was seen between the schemes to make a deduction without the need to re-run and analyse a simulation at a reduced flowrate. For validation simulations were checked at higher and lower flowrates to assess the hypothesis of flowrate to payback difference trend. With enough biomethane injected the financial difference between each scheme becomes minimal and difficult to compare, and at the scope studied the difference between the schemes are large enough to understand the difference between each scheme which can seen in the graph in the conclusion.





Basic Statistics

Mean	1024.99	*Min Value*	60	*IQR*	122.25
Standard Deviation	415.91	*Lower Quartile*	900	*Skewness*	1.20
Modal Value	1000	*Median Value*	1000	*Kurtosis*	2.77
Max Value	2500	*Upper Quartile*	1022.25		

Model Site	Proposed injection flowrate
Ideal Site (AGI/Injection point)	1000 scmh (average estimate)

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Model Site [2]

Network Capacity

The network capacity is how much gas can fit into the network at any point in time. Network capacity is normally only an issue with low tier pressure networks such as the MP grid. A typical gas network consists of a high winter demand and low summer demand. The ability of a gas network to accept biomethane relies on sufficient consumer demand downstream of the injection point. The demand is normally lowest at night times, and during the summer period when heating load is not applied

The capacity loss is how much biomethane cannot get into the network as a result of local capacity issues. This is zero for all schemes other than scheme 1 injection into the MP grid, where distribution capacity is restricted due to local area constraints.

For the standard ideal model a 97% network capacity was selected. This is a good value as a starting point and should prove that scheme 1, MP grid injection is the most economic model. The 3% loss allows for some error room in winter to summer demand drop. Following this base case a number of runs will be simulated to determine:

- Capacity constraint at which scheme 1 remains the cheapest
- Capacity constraint at which scheme 1 is no longer feasible

This analysis will output an operating band showing when reverse compression is suitable when injecting into the MP grid.

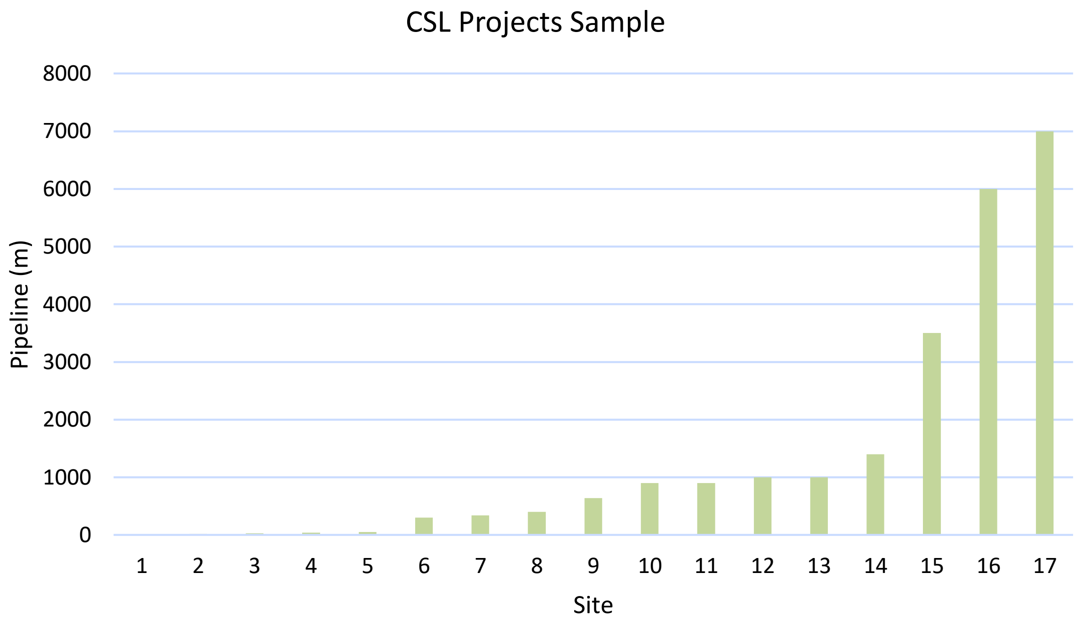
Model Site	Network Capacity	Connection Distance
Ideal Site (AGI/Injection point)	97%	1km Pipeline

Whilst constraints may not currently be an issue for some GDNs, BEIS want to fund larger projects using new AD sites. Efficient prospective sites will be where the waste is located so the actual possible biomethane injection sites are minimised due to the location of AD plants who will then be compete for capacity as the industry develops.

Network Distance to Biomethane Site

CNG Services Ltd has completed a number of high and low pressure biomethane to grid connections and typically accessibility to a connection point drives how biomethane will be injected. A sample of the projects CSL has completed show pipeline connections range from 70m to 7km so there is too much of a difference to do accurate statistical analysis. For the ideal site a 1km pipeline was agreed.

Pipeline costs can be a significant portion biomethane projects at increasing distances so a financial analysis of pipeline distance with biomethane injected will be carried out.



Biomethane Connection Types Overview

There are four main connection options for biomethane projects which are:

Scheme 1	Direct into 2 bar (distribution connection pipeline)
Scheme 2	Direct into 50 bar LTS (transmission connection pipeline)
Scheme 3	Central Hub i.e. CBM by road (transmission connection)
Scheme 4	Direct into 2 bar for reverse compression

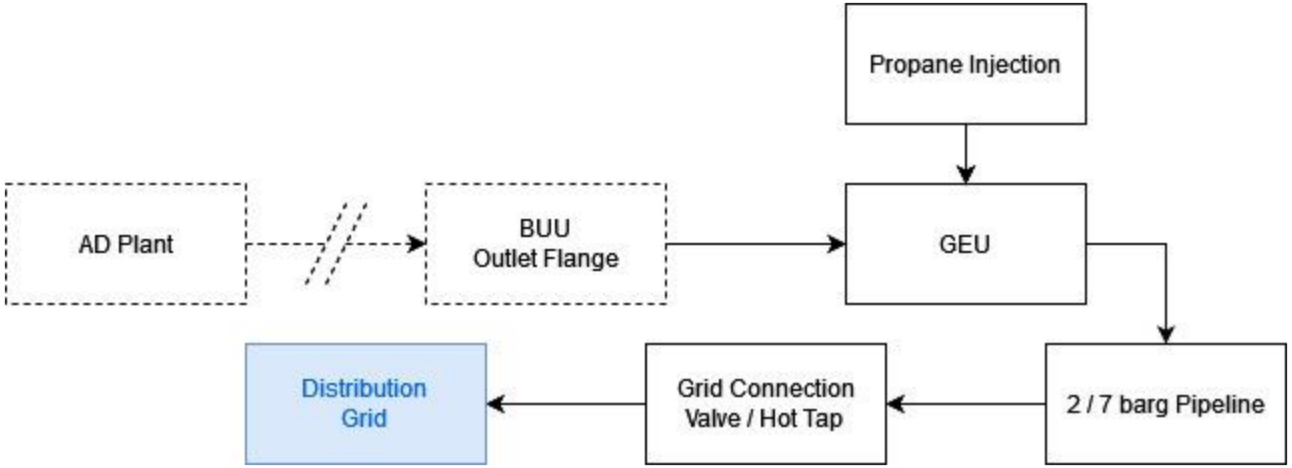
There are two additional options that consider a different split of funding between the GDN and the AD site owner/operator, these are schemes 5 and 6. The additional options provide alternative schemes which require less upfront CAPEX that is recouped through an OPEX tariff fee.

- Schemes 5 operate as scheme 3 the Central Hub but has GDN ownership of assets as summarised in the table to the right
- Scheme 6 operates as scheme 4 reverse compression with GDN ownership of assets

The following pages provides further operational detail of each of the schemes.

Scheme	Description	Comments
1	2 barg Grid	A typical biomethane connection into a local distribution network.
2	50 bar LTS Connection	As scheme 1 but the site connects into a nearby high-pressure transmission pipeline. The site will need on-site or remote compression.
3	Central Hub	The produced biomethane is processed on site and then compressed to 250 bar for transport via CBM trailer. When arriving at the injection site, the biomethane is decanted to transmission grid pressure and injected into the grid following final analysis and metering.
4	Reverse Compression	As scheme 1. To free up capacity in the 2 barg grid, compression is carried out at or near a local AGI to recompress gas from 2 barg grid into a higher-pressure tiered network to create appropriate capacity for biomethane injection.
5	Central Hub (GDN Ownership Model)	As scheme 3 but with GDN funding of the associated assets *i.e. all capital costs downstream of CBM dispensers*
6	Reverse Compression (GDN Ownership Model)	As scheme 4 but with GDN funding of the associated assets *i.e. all capital costs involved with the reverse compression works*

Scheme 1 – Distribution Connection (2 bar MP)



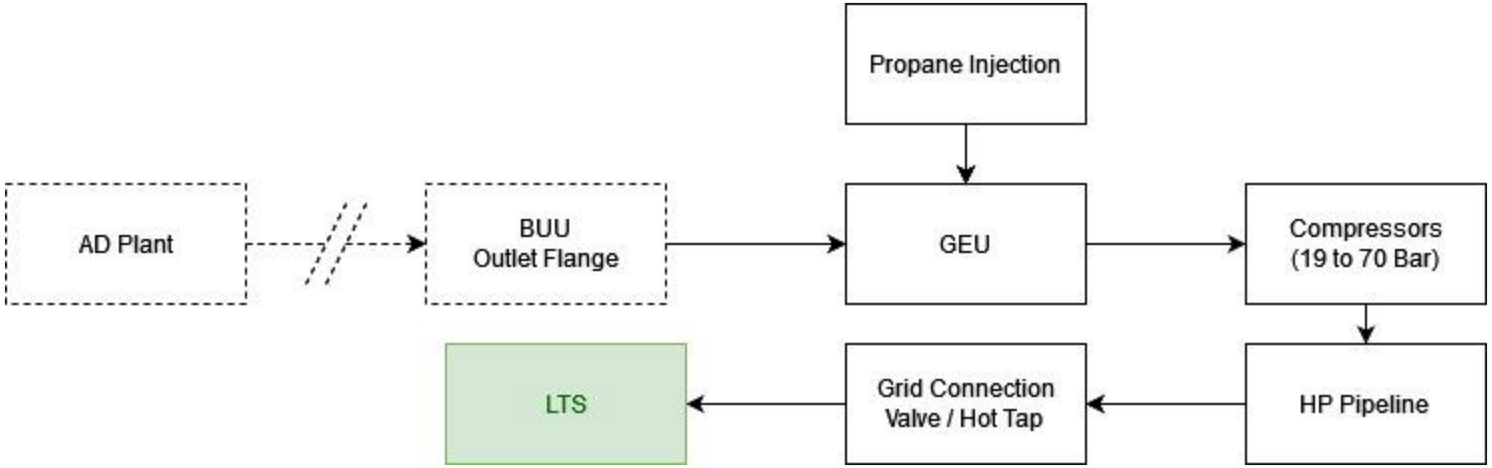
Basic Operational Process

1. Biogas flows from the AD and is treated in the Biogas Upgrading Unit (BUU), removing contaminants and CO_2.
2. The upgraded biogas from the outlet of the BUU is fed through the Grid Entry Unit (GEU) which enriches, odorises, meters and analyses the gas. This GEU is situated at the same site as the BUU and ensures that biomethane produced is within grid specifications
3. The resultant biomethane is fed through a Medium Pressure (75mbarg to 2 barg) or Intermediate Pressure (2 barg to 7 barg) pipeline, taking gas from the AD site to the proposed connection point on the GDN network
4. Gas is then injected into the grid at the connection provided there is capacity in the distribution grid

Note.

IP projects based on existing CSL projects have a similar overall cost to MP when compared to the rest of the schemes. Therefore analysis for scheme 1 will only consider MP.

Scheme 2 – Transmission Connection (LTS)



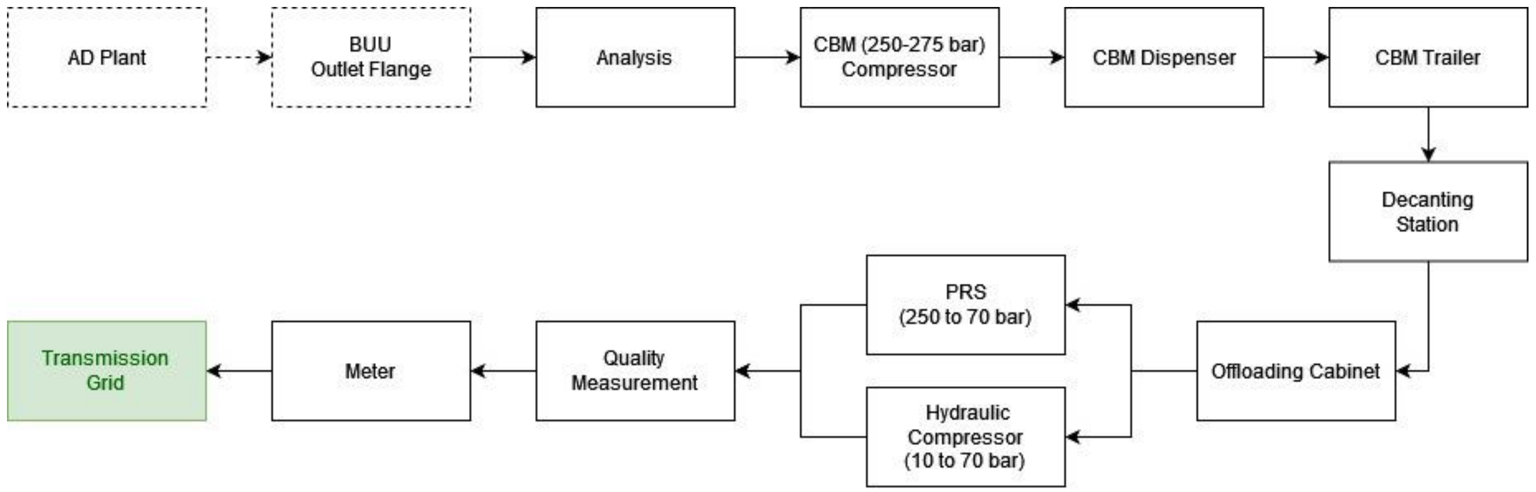
Basic Operational Process

1. Biogas flows from the AD and is treated in the Biogas Upgrading Unit (BUU), removing contaminants and CO_2.
2. The upgraded biogas from the outlet of the BUU is fed through the Grid Entry Unit (GEU) which enriches (*LTS only*), odorises (*LTS only*), meters and analyses the gas. This GEU is situated at the same site as the BUU and ensures that biomethane produced is within grid specifications
3. The biomethane is then compressed (either at the AD site or at a remote compression compound) up to the pressure of the transmission grid
4. NTS ONLY - No propane or odorant is added into the gas stream at the GEU
5. Downstream of the compressors, the metered biomethane is fed through an HP pipeline from the AD site to the transmission grid connection point. This pipeline can be quite short if the compression process is carried out at a remote compression compound
6. The connection into the grid requires an operable valve connection. This can be carried out using an existing tee/valve assembly or a hot tap procedure. The use of an existing tee/valve is preferred.
7. In GB there is one NTS Injection Project, Somerset Farm (75 barg) and around 20 projects involving injection into the LTS (19 – 70 bar)

Note.

For Scheme 2, the model will consider the LTS at 50 bar as it the more common biomethane connection type of the two. A similar flowchart and operational process applies to the NTS which can go up to an 85 bar requirement for a biomethane connection. The key and leading costs of the two types of connections can be considered the same so any trend or difference seen in scheme 2 with respect to the other schemes will also apply to an NTS biomethane connection.

Scheme 3 – Central Hub (For Transmission)



Basic Operational Process

1. Biogas flows from the AD and is treated in the Biogas Upgrading Unit (BUU), removing contaminants and CO_2.
2. Upgraded biogas quality is measured to ensure it is within specification prior to compression
3. Upgraded biogas is compressed up to 250 - 275 barg using a Compressor
4. Biomethane is dispensed into trailers using dispensers
5. The trailers transport the gas to a decanting site
6. At the decanting station, biomethane is decanted from the trailer through an offloading cabinet
7. Biomethane is decanted down to grid pressure through a pressure reduction system (PRS)
8. When the trailer pressure reaches the grid pressure, a hydraulic compressor can take over to deplete the trailer down to [20] barg. This is not necessarily done as it can be more expensive to do this than leaving residual gas in the trailer.
9. Gas is then measured, metered, [odorised and enriched] prior to injection into the grid via an existing valve or a new connection point

Note.

Whilst a Central Hub can inject into any grid connection the smallest amount of losses are incurred when injecting into the LTS. For an NTS connection loss is incurred from odorant injection. For lower pressure tiers such as MP or IP there is a loss of energy that has been used to compress the biomethane to 250 bar. Modifications downstream of offloading cabinets may be required if an MP/IP connection is chosen. For the central hub model the Central Hub will offload and inject biomethane into a 50 bar LTS as the above flowchart.

Scheme 3 - CNG Trailers

UMOE CBM Trailer

Hexagon-Xperion CNG Trailers at Fordoun

Trailers comprise of a skeletal framework upon which a container holding high-spec gas cylinders is installed. For high-volume transportation, 'Type 4' cylinders are used, which are filament-wound composite cylinders wrapped around a plastic former. The composite is generally either glass or carbon fibre.

Two options have been used on previous CSL projects

Option 1:

- Manufacturer – Hexagon/Xperion/Wystrach – Type 4 – 45ft (X-store)
- Cylinder Material - Carbon Fibre
- Total Capacity – 9.6-10 tonnes
- Transported Capacity (assuming 20barg residual) – 8.9 tonnes
- Transported CBM Volume (assuming 20barg residual) – 10,500 Sm^3
- Price estimate – Approx. £500,000 per trailer

Option 2:

- Manufacturer – UMOE Advanced Composites - Type 4 – 40ft (UMOE)
- Cylinder Material - Glass Fibre
- Total Capacity – 6.5-6.9 tonnes
- Transported Capacity (assuming 20barg residual) – 6 tonnes
- Transported CBM Volume (assuming 20barg residual) – 7,100 Sm^3
- Price estimate – Approx. £200,000 per trailer

Scheme 3 - Gas Compression (Mother Station / Biomethane Site)

Overview & Basic Operation

Compressor during installation

Compressors and Vent-Stacks - Fordoun

Compressor Overview – To maximise transportation efficiency, gas needs to be compressed up to 275-300barg. Generally, this is achieved using reciprocating compressors. A duty/standby configuration is a good engineering practise, allowing for active and preventative maintenance to occur whilst ensuring that operation is not affected.

Basic Operation

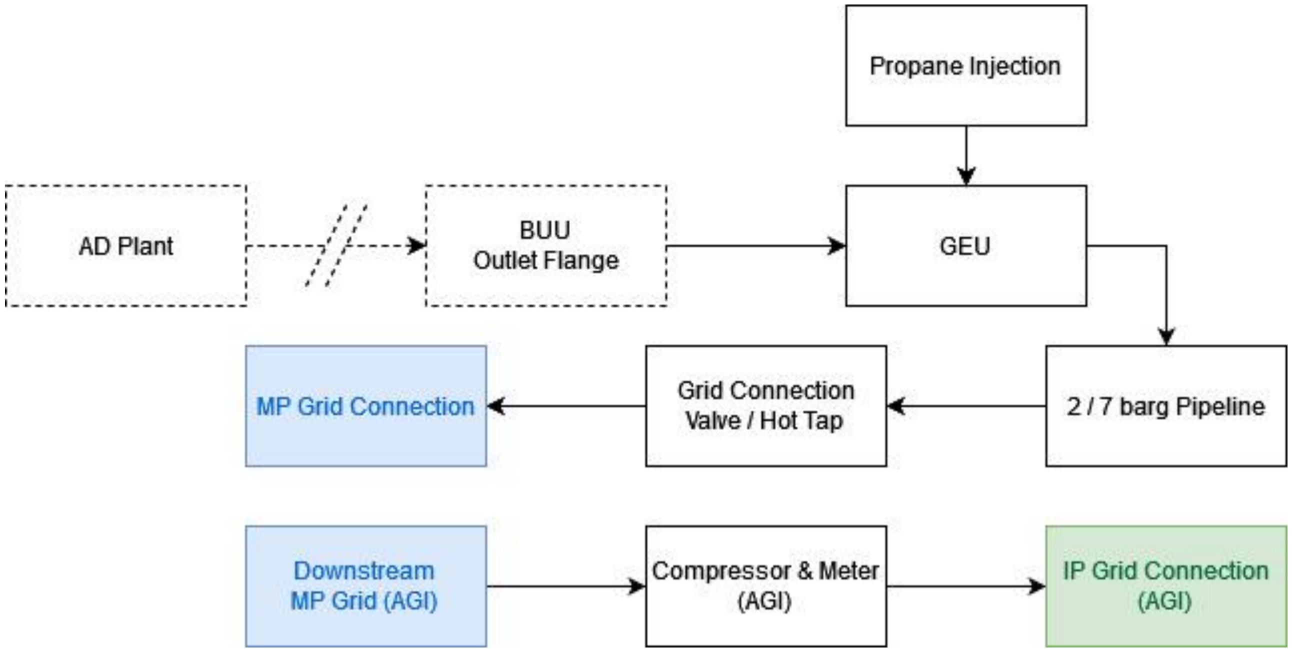
- Gas is filtered and the pressure is regulated.
- Gas is subject to 'multistage compression' to achieve the desired pressure output
- Gas is cooled after each stage using a water circuit connected to a fan-cooled skid
- Gas is filtered at the outlet and is then chilled using a heat exchanger
  - *Hydraulic Compressors* allow compression at a large range of inlet pressures and can be used at the daughter station to help offload a CBM trailer into CBM storage

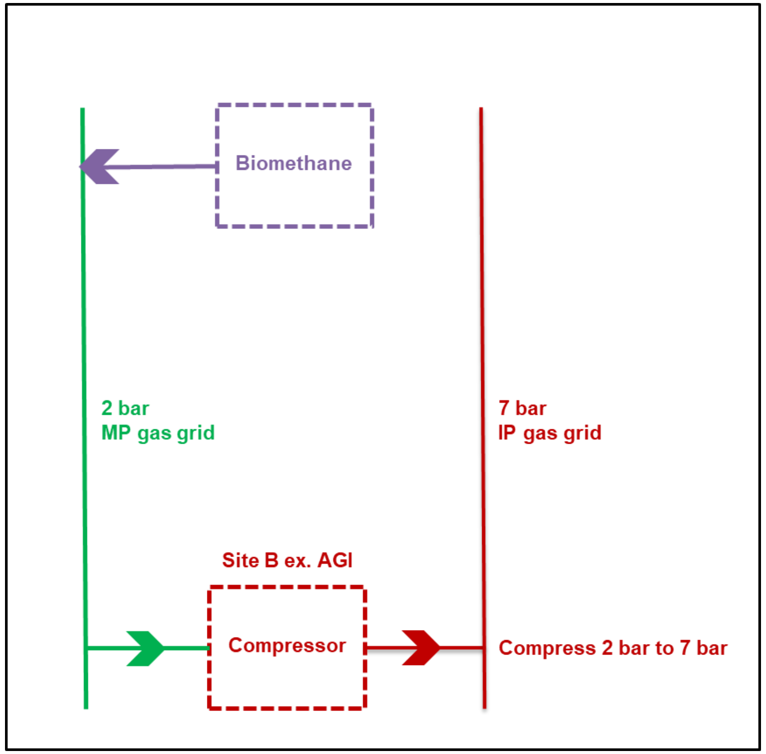
Suppliers – CSL have most experience with SAFE CBM Compressors

Key Consideration – There are a couple of technical reasons to install compressors that have a higher design outlet pressure than 250barg:

- If filling vehicles from storage cylinders, a higher maximum pressure in the storage cylinders means that fewer 'top-ups' are required.
- It can increase the logistical and transportation efficiency if transporting large volumes of gas:
  - The maximum limit of gas allowed on a trailer is often quoted to be '250barg at 15^oC'
  - Gas heats up when compressed into trailers; temperature can increase to 50^oC+ depending on flowrates, even if chilled on compressor outlet
  - A trailer filled to 250barg at 40^oC carries a lower gas inventory than one filled to 250barg at 15^oC
  - If filled to 250barg at 40^oC, when the gas cools back down to 15^oC (or lower depending on ambient conditions), the pressure will decrease, meaning that there is a lower gas transportation efficiency than desired.
  - Filling to 270barg+ at higher temperatures will mean a higher settled pressure at 15^oC

Scheme 4 – Reverse Compression





Basic Operational Process

1. As per Scheme 1, biomethane is injected into an MP or IP grid
2. At an appropriate location (could be an Above Ground Installation), gas is compressed from the 2/7 barg grid into a higher pressure grid to create appropriate capacity for biomethane injection into the lower tier grid
3. To be clear, this compression occurs between two GDN owned and operated gas grids
4. Gas flow can be metered to provide useful information for the GDN

Note.

Reverse compression works by connecting a low pressure grid to a high pressure grid. For scheme 4 reverse compression will occur between the MP to the IP grid at an AGI installation.

Reverse Flow Design Concept

Design Principle

Reverse Compression has been studied briefly by the gas networks in GB. During warm summer nights gas demand can fall close to zero. A biomethane site will ideally inject gas at the same rate throughout the year so encounters capacity issues during the summer and will be unable to export gas.

The same capacity constraint applies if there is a large industrial gas consumer on the same network as the biomethane project. When the factory takes gas, there is capacity. At weekends/bank holidays/summer shutdowns there is no capacity.

The operating principle underpinning Reverse Compression is that during the summer the gas network will be able to reduce the regulator set points at the AGIs that feed the localised network a biomethane site is connected to. This will give a compressor a pressure band to operate in and ensure that the compressor is not moving gas from low pressure to high pressure networks for the regulators on an AGI to then flow the gas back from high to low pressure.

For example, the MP distribution networks in GB are at a nominal 2 barg and as such the maximum operating pressure that the AGI regulators will be set at is 1.9 bar. If this is reduced to 1.2 bar during times of low network capacity (i.e. summer) it will give the compressor a band to operate in from 1.2 bar to 1.9 bar. The pressure cannot rise above 1.9 bar as the compressor will be switched on to move gas out of the network. If the pressure falls and approaches 1.2 bar then compressor will turn off. If the network pressure falls even further below 1.2 bar then the AGI regulators will start to open and move gas from the high pressure network to low pressure. Maintaining 1.2 bar for summer demand will be acceptable in terms of gas security of supply.

Scheme 4 - Compressor Options

Compressor Types

For such an application, two types of compressors are considered: reciprocating and screw.

In both cases, it is quite important to begin with the boundary limits of the application, especially the capacity required, inlet conditions of the gas (composition, pressure, temperature) and discharge pressure, as these are the determining factors which define the range of compressor products available in the market which can be considered for the application.

Even with a single manufacturer, differences in the capacity or pressure can change the design which the manufacturer has available to satisfy the requirements of the application. This also means that changes in the application design parameters may have fundamental impact on the available features of the compressor or the system.

Vane compressors are widely used for gathering raw digester gas and feeding it to the process plant. However, while vane compressors are simple, robust and tolerant of the dirty digester gas, they are not available with design pressures high enough for grid entry. They also have application limitations on pressure ratio. As such, they are not considered here.

Another typically discussed option in the design of reverse compression sites are the National Grid Gas NTS Centrifugal compressors. These do not fit the scope of reverse compression design.

- Driven by gas generator and power turbine or electric drive
- Typically 50 MW, flow of >100,000 scmh
- 40 to 70 bar (low compression ratio)

Reverse compression compressors will be screw or reciprocating depending on inlet and outlet pressure.

Maintenance and Operational Requirements

The compressor module and associated safety equipment will be installed in its own secure enclose. It is anticipated that the Compressor will be maintained by the manufacturer's nominated servicing agent. For the project being considered a reciprocating compressor would be best and will require maintenance time.

Weekly inspections are required for gas and oil leaks during the running season and lubricating oil needs to be topped up. Due to the nature of reverse compression the duty cycle is expected to be low and the maintenance will be considerably less than if it was continuously running.

Reciprocating compressors can require downtimes of weeks to repair or replace seals, valves, bearings, and pistons but as the duty cycle can be spread over a number of years maintenance will be considerably less.

Maintenance of the mechanical parts, maintenance of the compressor monitoring, and safety devices installed within the compressor enclosure will need to be carried out either to be undertaken by the GDN employees or a third-party subcontractor.

In addition to the maintenance specific to the compressors, there will be an additional maintenance requirement on items added to the site to enable compression to take place. This will include statutory safety requirements and include:

- Pressurized systems inspections and validation
- Filter checks and replacement
- Safety protection system testing
- Instrument calibration and testing
- Valve maintenance and testing
- Electrical system maintenance and testing

Reverse Compression - Projects

Great Britain

2012 – NGN and NG feasibility concept demonstration at Skipton

2013 – Euston Biomethane project. Cadent supportive but there was minimal benefit as the IP had limited capacity

2013 to 2017 – Reverse compression projects that didn't go ahead:

- Crewe – Cadent
- Wessex Water Avonmouth – WWU
- Cuadrilla Preston New Road (LTS to LTS) - Cadent
- GWE Biogas - NGN
- Gravel Pit - NGN
- Lake District Biogas – NGN
- A B Agri Sherburn – NGN
- Wight Farm IOW - SGN
- Igas Bletchingley onshore gas field – SGN
- Grindley Farm – Cadent
- Camp Farm Snitterfield – Cadent
- Dagenham – Cadent
- Chatteris – Cadent
- West Fen Farm – Cadent

2013 to 2017 – 4 completed quasi reverse compression projects at 50% compressor operation:

- Euston
- Methwold
- Bay Farm
- Bonby

March 2022 - Cadent are installing a 5000 scmh, 7 bar to 37 bar capable compressor

- Optinet – WWU & Cadent

France

CNG Services have used Safegas to supply compressors to many of their biomethane jobs. Safegas have also supplied 8 compressors for reverse compression projects in the north of France tabled below.

The locations include:

- Noyal-Pontivy
- Pougauges
- Manchemore
- Craon
- Laon
- Mercin-et-Vaux
- Mareuil-lex-Meaux
- Bourges

Parameter	Site 1	Site 2	Site 3	Site 4	Site 5	Site 6	Site 7	Site 8
Suction pressure (barG)	3,9	4	7,5	4	8	7	8	4
Discharge pressure (barG)	55	67,7	60	67,7	67,7	67,7	67,7	67,7
Capacity (Nm3/h)	540	1,450 x2	820	1,000	1,500	1,000	3,000	1,500
Suction Temp. (°C)	15	15	15	15	15	15	15	15
EM power (kW)	110	250 x2	110	200	250	200	450	315

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Schemes 5 & 6 – GDN Ownership Models

Scheme 5 (Central Hub)

Scheme 5 operates in the same manner as Scheme 3 – gas is created at an AD site, and transported to an injection point via a Central Hub, where it is decanted and injected. However, the CAPEX and O&M costs of haulage, dispensing and injection into the network is priced as a service the GDN sells to a biomethane developer. Some of the heavy upfront cost of a project is alleviated and paid back over time through the tariff charge.

Scheme 6 (Reverse Compression)

Scheme 6 operates just as Scheme 4 – gas is injected into an MP or IP grid and capacity is created within that grid using a reverse compression system. The CAPEX and O&M costs of the reverse compression site are borne by the GDN. Similar to Scheme 5, the 'reverse compression' capital and operating costs are sold to the biomethane developer as a service.

Scheme	Tariff	Tariff Description	Calculated Tariff
5	8% WACC 10 Year Payback period	This is tariff the GDN charge customer for collection, transport and injection of gas.	0.84 p/kWh
6	8% WACC 10 Year Payback period	This is tariff the GDN charge customer for operating and maintaining reverse compression compressor.	0.21 p/kWh

The tariff calculation for each scheme is detailed in the appendix.

Scheme	Description
1	2 bar Grid
2	LTS Connection
3	Central Hub
4	Reverse Compression
5	Central Hub (GDN Ownership Model)
6	Reverse Compression (GDN Ownership Model)

Asset Ownership

Minimum Connection Model – Schemes 1 to 4

For the assets ownership and costs the minimum connection model is employed for schemes 1 to 4.

- The biomethane producer pays for everything including the connection to the grid.
- The biomethane producer will own everything up to the minimum connection, which will be adopted after completion.

- The minimum connection includes the GDN grid connection and minimal pipework ending at an emergency control valve (ECV). This can include a remote operable valve (ROV), independent CP and isolation joints (IJ). This is designed, managed, constructed, approved and appraised to the GDNs private standards. The cost of the minimum connection is paid for (in most cases) by the producer and provided the GDN is satisfied, they will adopt the assets taking over ownership.

Note.
Whilst GDNs can and sometimes do provide equipment for use in the minimum connection, biomethane producers should not assume such equipment/assistance will be provided.

Schemes 5 & 6

For scheme 5 (Central Hub), the GDN will pay for and own all capital equipment downstream of CBM dispensers , highlighted yellow in the below table.

For scheme 6 (reverse compression), the GDN will pay for and own all capital equipment associated with reverse compression, highlighted yellow in the below table.

These costs will be recouped by the GDN over a 10 year period with a tariff charge.

Scheme	1	2	3	4	5	6
Biogas Production Site						
- **Consents, PM and Equipment**	X	X	X	X	X	X
- **Connection to Grid**	X	X	X	X	X	X
- **Service Connections**	X	X	X	X	X	X
- **Mechanical, E&I and Civils Install**	X	X	X	X	X	X
CBM Compression Station			X		X	
Reverse Compression Station				X		O
CBM Daughter Station			X		O	
CBM Daughter Grid Connection			X		O	
CBM Trailers			X		O	

Given the upfront capital cost, biomethane producers will normally pay for this through finance.
This report assumes this to be over a 15 year period with a 9% interest rate.

Economic Model

To carry out this study a comprehensive spreadsheet model was built on excel. The spreadsheet takes key inputs and variables of a biomethane project to produce a financial summary with comparison of the schemes being considered.

Key input variables used in the model as shown in the table below are as follows:

1. Biogas flowrate input
2. Scaling factor for AD CAPEX – allows the model to scale to different AD sizes.
3. Compression inputs – gives choice of generic or actual compression costs.
4. Compression fee calculator – Compression fee calculation based on the chosen payback period and WACC.
5. GDN ownership passthrough charges – the tariff the GDN charge customers to collect, transport and inject gas or operate and maintain the assets for schemes 5 and 6.
6. Connection costs – Pipeline costs and distances.
7. Connection Policy - If selected then the GDN owned assets associated with connection to the network are scaled by the stated scaling factor.
8. Energy prices
9. Capacity Issues - How much biomethane cannot get into the network as a result of local capacity issues. Zero for all schemes other than scheme 1 where distribution capacity is restricted due to local area constraints.
10. Reverse compressor size and runtime
11. Propane addition and target CV
12. Haulage parameters including trailer type, quantity and average round trip.
13. Emissions variables – CO2 calculation parameters

Sheet	Description	Comments
1	Summary	Provides description for each sheet and scheme.
2	Input Variables	Interface for all user input and variables.
3	Results	Quick basic summary of each scheme.
4	Financials	Detailed summary of each scheme
5	CAPEX	Project installation and construction costs.
6	OPEX	Electrical & heating, maintenance and OPEX costs.
7	Biomethane & Gas Flows	Biomethane Income and fossil gas import.
8	Propane Flow	Propane calculations to reach target grid CV.
9	Haulage	Trailer haulage calculations and OPEX
10	Compressors	Compressor calculations
11	Compression Fee	Calculates the pass-through charge if the GT owned the Reverse Compressor Station.
12	CO2 Emissions	Calculates CO2 emissions for each scheme

Sheet guideline for the model spreadsheet

Biomethane Flows and Income

Biomethane Flows

The biomethane table below shows the analysis of taking biogas production from the AD, upgrading and adding propane to provide biomethane for export. Scheme 1 is constrained by 3% giving less biomethane for export compared to the other schemes.

Description	Scheme 1	Schemes 2 to 6	Unit
Analysis of energy flow to gas grid			
Biogas flow from AD	1,589	1,589	Nm3/hr
Biogas flow to BUU	1,676	1,676	Sm3/hr
Methane % in the biogas	55%	55%	%
Methane Higher Heating Value	37.74	37.74	MJ/Sm3
Biomethane Purity Post Upgrading	97%	97%	%
Biomethane Produced (Hourly)			
Biomethane Flow (Sm3/hr)	950.47	950.47	Sm3/hr
Biomethane Flow (Nm3/hr)	900.92	900.92	Nm3/hr
Biomethane energy value (MJ/Sm3)	36.61	36.61	MJ/Sm3
Biomethane energy value (MJ/h)	34794.59	34794.59	MJ/h
Biomethane energy value (MWh/h)	9.67	9.67	MWh/h
Plant Availability			
AD plant availability	95.0%	95.0%	%
Clean-Up Plant availability	97.5%	97.5%	%
Total Availability	93%	93%	%
Biomethane to Grid (Flows)			
Biomethane Flow (Sm3/hr)	950	950	Sm3/hr
Propane Flow (Sm3/hr)	49.53	49.53	Sm3/hr
Total Gas Flow (Sm3/hr)	1000	1000	Sm3/hr
Total Gas Flow (Nm3/hr)	947.8672986	947.8672986	Nm3/hr
Biomethane to Grid (Energy)			
Annual Biomethane Production (Methane)	78.42266587	78.42266587	GWh
Annual Biomethane Production (Propane)	6.20	6.20	GWh
Annual Biomethane Production (Total)	84.61845022	84.61845022	GWh
Less Constraint / Capacity Issues	3%	0%	%
Annual Biomethane Production (Methane)	76.07	78.42	GWh
Annual Biomethane Production (Propane)	6.01	6.20	GWh
Annual Biomethane Production (Total)	82.08	84.62	GWh

Biomethane Income

The model is based on a sales price of gas at 1.67 p/kWh and pre 2021 updated RHI. At typical flowrates the income of basic gas alone in not enough to support AD projects and require government support (RHI/GGSS) or external funding. RHI (and GGSS) tariff is tiered with diminishing returns. The most recent RHI tariffs are: 4.95p/kWh for the first 40GWh, 2.92p/kwh for the next 40GWh and then 2.25p/kWh for the rest of the injected biomethane.

Gas sales and green premium for the project for an export biomethane flow rate of 1000 scmh is approx. £ 4.4 - 4.6 million per annum. This value is pre inclusion of CAPEX and OPEX and is not the profits incurred for each project.

Description	Scheme 1	Scheme 2	Scheme 3 & 5	Scheme 4 & 6	Unit
Value of biomethane export					
Gas basic sales value	1.67	1.67	1.67	1.67	p/kWh
RHI Tier 1 biomethane /yr	40,000,000	40,000,000	40,000,000	40,000,000	kWh/yr
RHI Tier 1 premium	4.95	4.95	4.95	4.95	p/kWh
RHI Tier 2 biomethane /yr	36,069,986	38,422,666	38,422,666	38,422,666	kWh/yr
RHI Tier 2 premium	2.92	2.92	2.92	2.92	p/kWh
RHI Tier 3 biomethane /yr	0	0	0	0	kWh/yr
RHI Tier 3 premium	2.25	2.25	2.25	2.25	p/kWh
Annual Income - basic (incl Propane)	1,367,451	1,409,743	1,409,743	1,409,743	£/yr
Annual Income - basic (excl Propane)	1,267,326	1,306,522	1,306,522	1,306,522	£/yr
Annual Income - green premium	3,033,244	3,101,942	3,101,942	3,101,942	£/yr
Annual Income - total (incl Propane)	**4,400,695**	**4,511,685**	**4,511,685**	**4,511,685**	£/yr
Annual Income - total (excl Propane)	**4,300,570**	**4,408,463**	**4,408,463**	**4,408,463**	£/yr

Scheme	Description
1	2 bar Grid
2	LTS Connection
3	Central Hub
4	Reverse Compression
5	Central Hub (GDN Ownership Model)
6	Reverse Compression (GDN Ownership Model)

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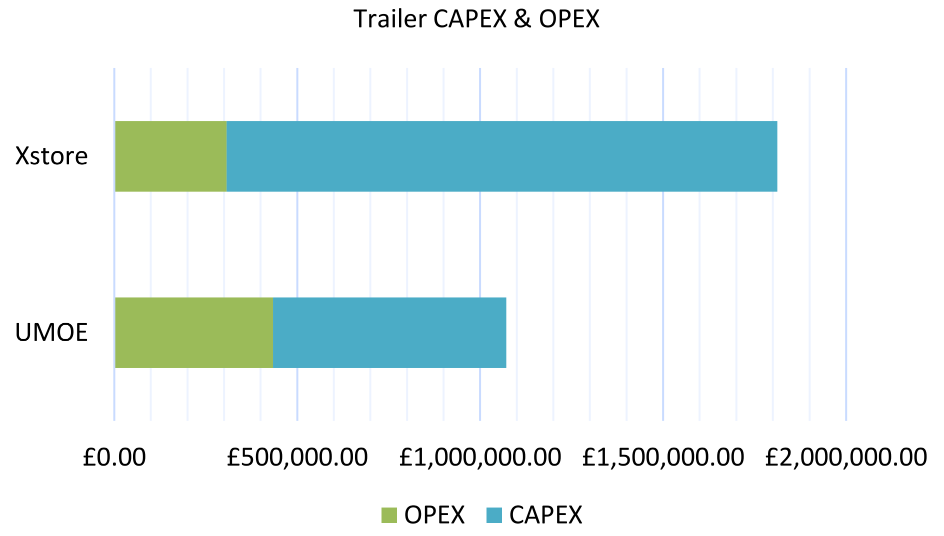
Scheme 3 - Central Hub Trailer Selection

Trailer Model and Quantity

Two trailer types were assessed for the Central Hub study, UMOE and X-Store. Running the model through multiple simulations have shown UMOE to be the cheaper option as it allows the central hub model to reach financial payback quicker by 8 months; even though the X-Store model has a cheaper OPEX as indicated in the chart below. A full breakdown of the CAPEX and OPEX is shown on the following page.

- A 3 trailer model has been selected assuming an individual off-grid Central Hub model. At any point in time each trailer has a separate role, 1 trailer is injecting, 1 trailer is collecting and 1 trailer is in transport reserve.

- This is a suitable number of trailers for the selected 50km (30 mile) round trip distance between the mother and daughter station. Each trailer is not in commission for 46 days of the year giving enough time for maintenance and any other variables such as holidays.



General Information	Value	Unit
GBP/EUR	1.17	-
CNG Annual Volume	7,712,061	Sm3/a
CNG Density at 1bara and 15C	0.709	kg/Sm3
CNG Mass Transported	5,471,018	kg/a
CNG delivered per trip	5,724	kg
Trailer trips per annum	319	-
Trips per annum	956	-
Average Round Trip between Mother and Daughter Station	30	miles
Truck MPG	8.0	-
Gallons of Diesel	3.75	gal/trip
Litres of Diesel	17	L/trip

Trailer Capacity	Value	Unit
Trailer Type	UMOE	-
Water Capacity of Trailer	30,600	L
Working Pressure	250	bar
Residual Pressure	50	bar
Gas Temperature in Trailer (filling)	15	*C
Gas Temperature in Trailer (emptying)	15	*C
CBM Density (250 bar)	229.21	kg/m3
CBM Density (50 bar)	42.14	kg/m3
Loaded CBM Mass	7,014	kg
Residual CBM Mass	1,289	kg
Transported CBM Mass (not including residual mass)	5,724	kg
Transported CBM Volume (not including residual mass)	8,069	Sm3

Central Hub Trailer CAPEX & OPEX

Operating Cost	Value	Unit
Number of trailers	3	-
VOSA inspection	£102	/annum
Annual MOT	£510	/annum
6 weekly inspections	£2,975	/annum
Cylinder inspection etc annually	£1,488	/annum
Major test after 5 years , annual charge	£1,870	/annum
Additional (tyres etc)	£2,338	/annum
Ground storage inspections	£0	/annum
Trailer Insurance	£4,250	/annum
Sub Total for CNG Maintenance	**£40,596**	**/annum**
Haulage Cost	**Value**	**Unit**
Driver Wages	£255	/trip
Management Services	£26	/trip
Ops Licence	£10	/trip
Insurance	£20	/trip
Fuel at £0.94 per litre	£16	/trip
Tractor Rental	£85	/trip
Total Cost	£412	/trip
Sub Total for CNG Haulage Cost	**£393,580**	**/annum**
Total Operating Cost	**£434,176**	**/annum**

Capital Cost		
CNG Trailer Cost	£195,500	
Total CNG Trailer Cost	£586,500	
Skeletal Trailer for Type 4 (1 off)	£17,000	
Skeletal Trailers for Type 4	£51,000	
Total CNG Trailer CAPEX	**£637,500**	

OPEX

There are a number of required maintenance actions to be carried out for safe and legal trailer operation. The first table show on the top left indicates the cost of each of these actions. The trailers are not expected to be used for ground storage and will transport to inject gas as it is being produced.

The second table Haulage Cost, shows the individual cost of transporting a trailer per trip. This includes the personnel cost, tractor cost and diesel fuel. The total OPEX is the combination of the maintenance cost and the haulage operating cost.

NOTE.

- A liberal price has been given to the cost of diesel and a diesel tractor has been selected as it is currently the norm. It is worth noting that at this given cost there is further savings to be found by using CNG tractors of approximately £5400 per year with a 6 year CAPEX payback period. Even further savings can be seen at a less generous diesel fuel cost.

CAPEX

3 trailers have been selected so the total CNG trailer CAPEX cost is 3 times the individual UMOE trailer cost added to the cost of 3 skeletal trailers. The skeletal trailer is just the bottom of the trailer, base chassis and wheels. The CNG trailer cost, in this case UMOE is simply the storage equipment in a box that fits onto the skeletal trailer.

CAPEX – Installation and Construction

CAPEX

The CAPEX detailed covers the CAPEX investment of all the schemes. These are fixed costs based on the CSL database from similar projects in GB. All the schemes include costs for biogas production; costs for other equipment and third-party sites are different depending on the scheme as itemised in the table below. The CAPEX costs associated with the production can be scaled as desired.

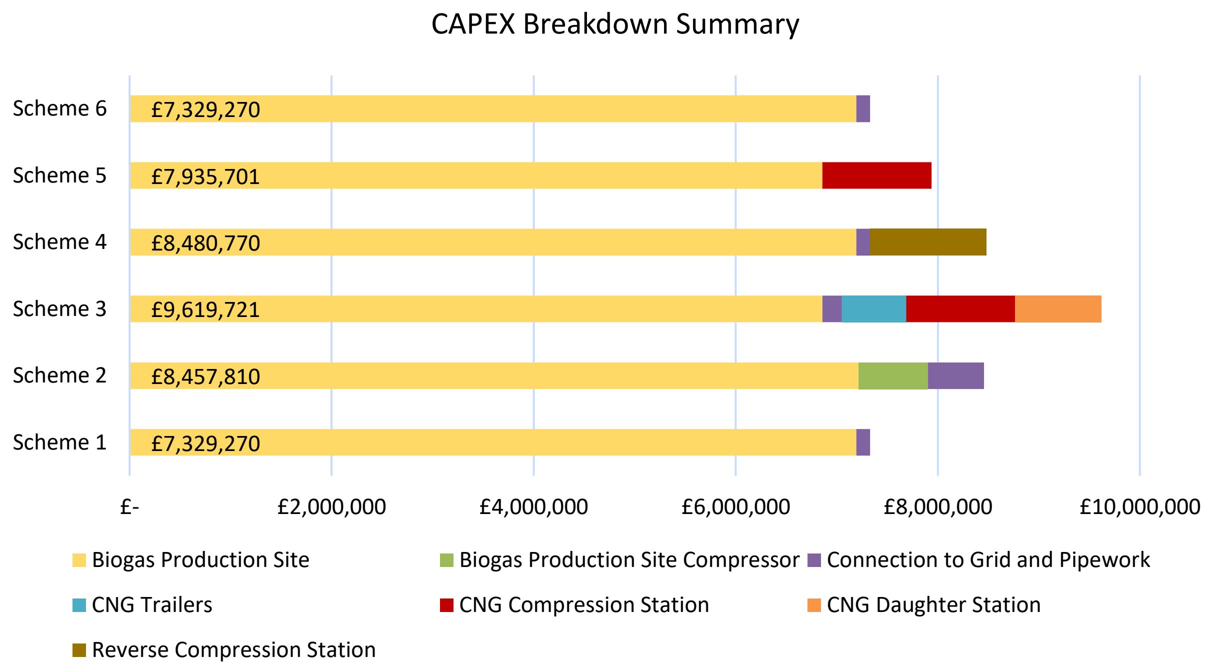
Scheme	1	2	3	4	5	6
Biogas Production Site						
- Consents, PM and Equipment	X	X	X	X	X	X
- Connection to Grid	X	X	X	X	X	X
- Service Connections	X	X	X	X	X	X
- Mechanical, E&I and Civils Install	X	X	X	X	X	X
CBM Compression Station			X		X	
Reverse Compression Station				X		
CBM Daughter Station			X			
CBM Daughter Grid Connection			X			
CBM Trailers			X			

Scheme	Description
1	2 bar Grid
2	LTS Connection
3	Central Hub
4	Reverse Compression
5	Central Hub (GDN Ownership Model)
6	Reverse Compression (GDN Ownership Model)

CAPEX Breakdown

A summary of the CAPEX breakdown is shown in chart format below. Some observations include:

- The biogas production site accounts for majority of the CAPEX which is due to the AD plant and biogas upgrading unit.
- Grid connection costs for scheme 2 are significant. This is due to the high-pressure pipeline cost required for the TX connection.
- Scheme 1 is the cheapest due to it being a 2-bar connection.
- The reverse compression schemes (4&6) are cheaper than the Central Hub schemes respectively (3&5).



OPEX – Electrical and Maintenance

OPEX

As with the CAPEX costs for each scheme different OPEX costs are required depending on the scheme. These include electrical and heating loads, maintenance, and operational costs. The OPEX costs associated with the production can be scaled as desired.

Note that scheme 5 and 6 only have OPEX costs pertaining to the biogas production site as in these schemes the costs are accounted for in the GDN service charge as per the structure of the schemes. The cost is added per kWh of biomethane injected.

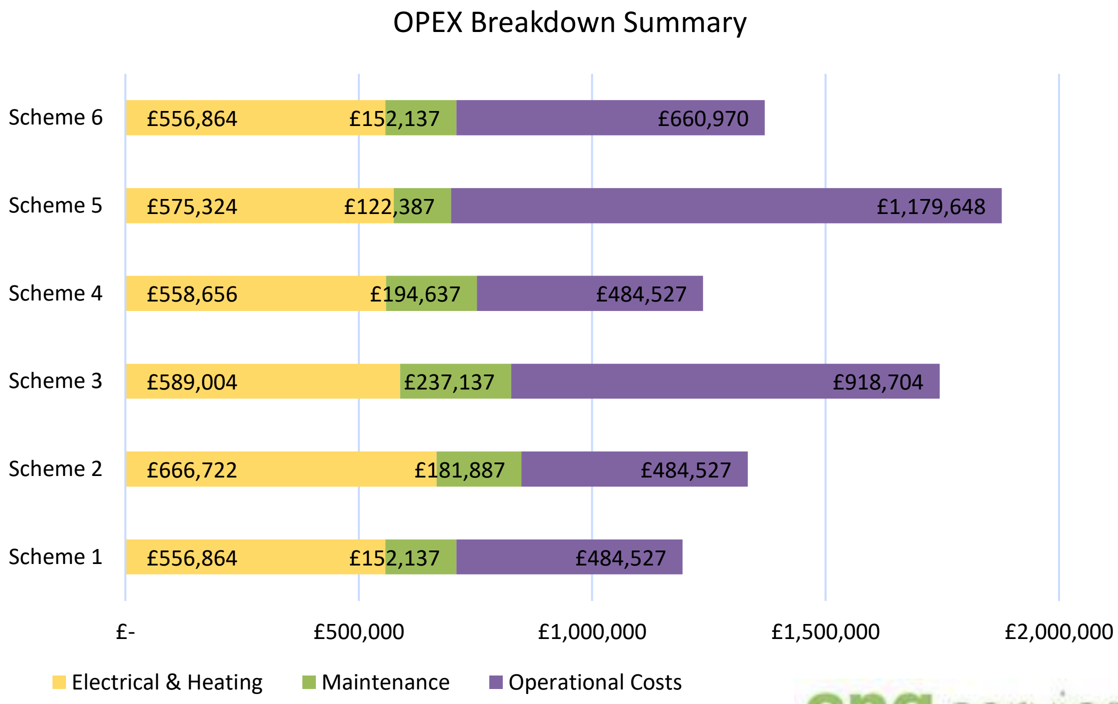
Scheme	1	2	3	4	5	6
Biogas Production Site – Electrical	X	X	X	X	X	X
CBM Compression Station – Electrical			X		X	
Reverse Compression Station – Electrical				X		
CBM Daughter Station – Electrical			X			
Biogas Production Site – Maintenance	X	X	X	X	X	X
CBM Compression Station – Maintenance			X		X	
Reverse Compression Station – Maintenance				X		
CBM Daughter Station - Maintenance			X			

Scheme	Description
1	2 bar Grid
2	LTS Connection
3	Central Hub
4	Reverse Compression
5	Central Hub (GDN Ownership Model)
6	Reverse Compression (GDN Ownership Model)

OPEX Breakdown

A summary of the OPEX breakdown is shown in chart format in the figure below. Some observations include:

- Scheme 1 is the cheapest to run due to the absence of compressor load.
- Central Hubs Scheme 3 have the highest OPEX which is due to the cost of haulage.
- Scheme 4, reverse compression is cheaper than Scheme 2 in terms of OPEX and is expected since the reverse compressors run for smaller periods of time.
- The GDN ownership schemes are more expensive than their counterparts due to the tariff charge which is where the CAPEX difference is recouped.



Model Results

Financial Summary

All CAPEX costs for each scheme have been financed with an interest rate of 9% over a period of 15 years. This results in annual CAPEX finance costs which when coupled with the annual OPEX costs can be subtracted from the Income to give a total Annual Profit and a payback period for the CAPEX outlay.

The most lucrative scheme is the simple MP 2bar connection (scheme 1). This is to be expected as it is the scheme with the lowest CAPEX outlay, lowest ongoing OPEX and minimal capacity constraint. This is followed by the reverse compression scheme followed shortly by an LTS connection. Cost savings are seen in the GDN ownership models for their respective schemes.

It can be seen from this simulation that if the model is based on the average live project that has gone ahead, each scheme is profitable with relatively close payback period to each other. Naturally this will deviate as available distribution capacity decreases or the distance to a connection increases particularly so for the LTS connection.

GDN Ownership Models

The compression fee required for GDN ownership models were tested for different sized compressors. Minimal to no impact on the compression fee was observed if the size of the compressor and running hours were modified in the range of up to 1400 scmh. This means the compression fee will remain consistent regardless of the compressor size within a suitable range.

- The GDN charge for Central Hub service is 0.84 p/kWh
- The GDN charge for reverse compression service is 0.21 p/kWh

The GDN ownership works well for Central Hub models due to the high CAPEX costs of a daughter station. For reverse compression models GDN ownership sees a diminishing difference as biogas production increases. Smaller (<1000scmh) sites see a bigger difference but will not be as good financially. The GDN ownership model works best for small Central Hub models but will lose value as the project size increases.

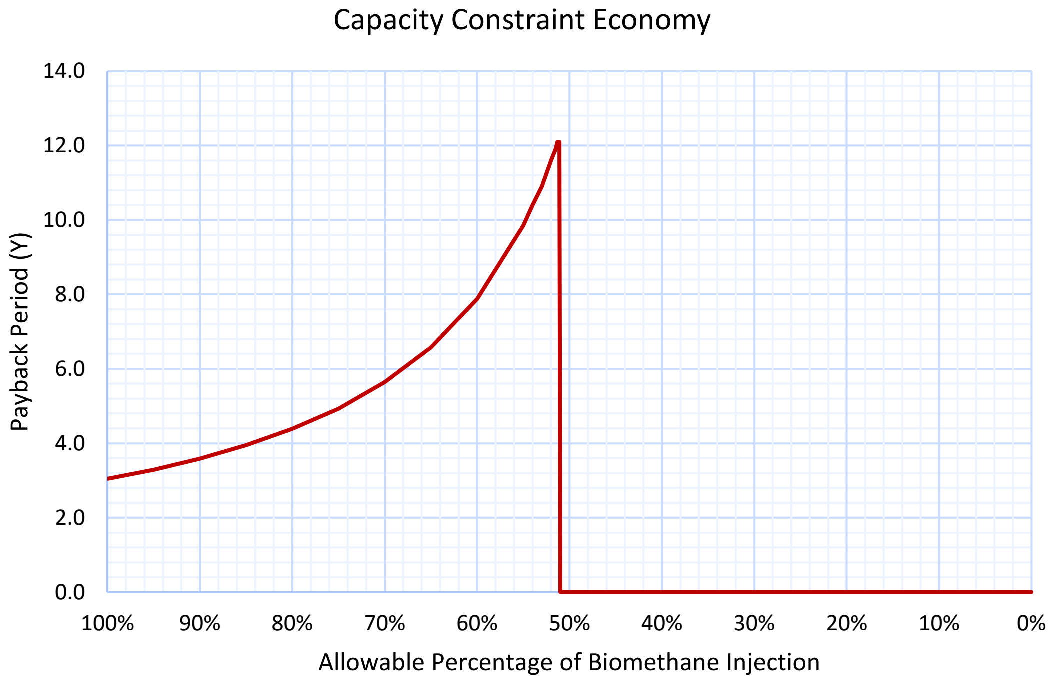
Summary	MP 2bar	LTS/NTS	Central Hub	MP Reverse Compression	Central Hub (GDN Ownership model)	MP Reverse Compression (GDN Ownership model)
Income	£4,400,695	£4,511,685	£4,511,685	£4,511,685	£4,511,685	£4,511,685
Operating Costs	£1,193,528	£1,333,136	£1,744,844	£1,237,820	£1,877,359	£1,369,970
Operating Profit (excl. Capital Finance)	£3,207,167	£3,178,550	£2,766,841	£3,273,865	£2,634,326	£3,141,715
Capital Costs	£7,329,270	£8,457,810	£9,619,721	£8,480,770	£7,935,701	£7,329,270
Capital Cost - Annual Finance	£909,261	£1,049,267	£1,193,412	£1,052,115	£984,494	£909,261
Total Annual Profit (taking Capex Finance & Opex into account)	£2,297,906	£2,129,283	£1,573,429	£2,221,750	£1,649,832	£2,232,454
Payback Period	**3.2**	**4.0**	**6.1**	**3.8**	**4.8**	**3.3**

Further Analysis

Capacity Constraint

Scheme 1, an MP connection will typically remain the cheapest model. The deciding factor where this is not the case for this scheme depends on the volume of biomethane constrained per annum.

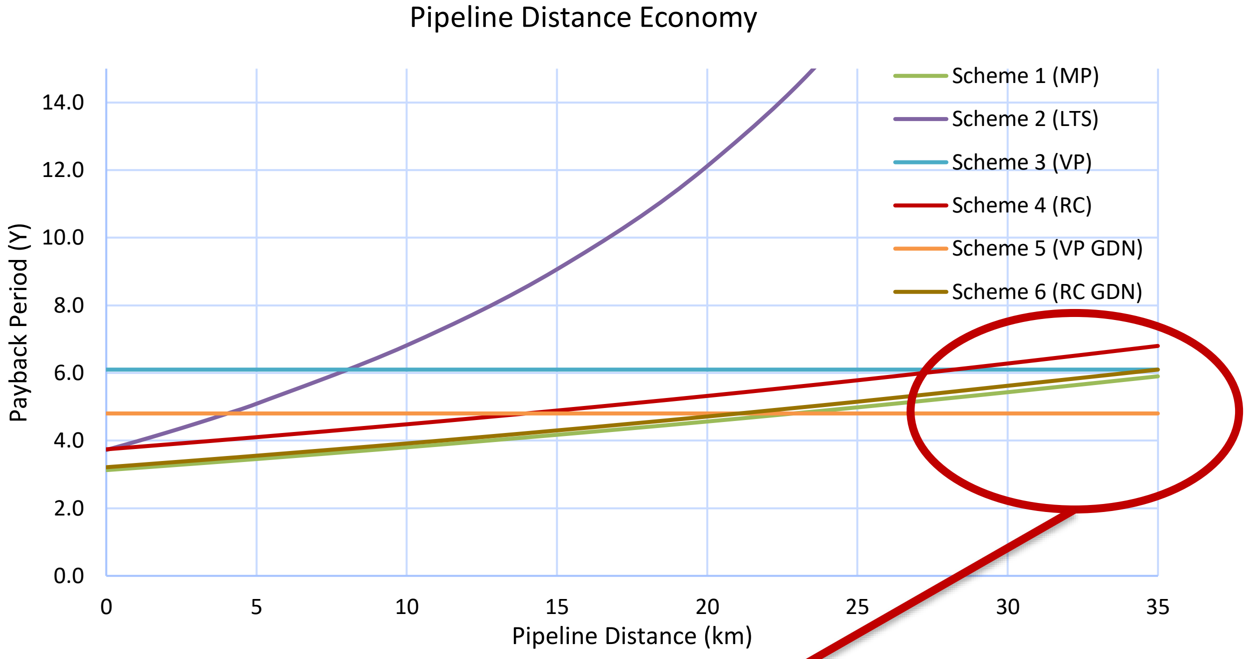
- If the constraint is less than 10% it will remain the most economic model compared to the other schemes.
- Between 10% and 50% constraint the other schemes stack better financially
- At 50% constraint or lower the project will not be feasible at all as the financial payback is negative.



Pipeline Connection

A number of sensitivities were run to determine the pipeline economy as shown in the below chart. The shown analysis is based on a 1000scmh plant but the similar results were seen in separate runs.

- Pipeline costs for TX models, scheme 2 increase significantly more than the other schemes due to high pressure requirement. Its viability is best when the pipeline distance is less than 7km.
- At approx. 35km the Central Hub becomes more economic compared to scheme 1, MP connection. For reverse compression this distance is approx. 26km.
- The cost of trailer road trips is significantly less compared to pipeline costs



The Central Hub model will be the most economic if the required pipeline distance is long enough.

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Environmental Impacts

The main areas of emission for the biomethane projects are the heating and electrical requirements for biogas production and compression. Scheme 3 has an additional CNG haulage requirement from diesel emissions for the haulage of CBM trailers as required in Central Hub schemes. Scheme 1 does not require a compressor resulting in a smaller CO2 emission.

The carbon intensity used for the electricity grid is 110 gCO2e/kWh set at the time of reading. The carbon intensity of diesel used was 2680 gCO2e/ litre. No electrical loads for AD tanks were used in the calculation as they would be the same across all schemes. Scheme 3 (Central Hub) was used as a baseline to compare the CO2 emissions as it will always produce the most CO2 due to haulage and higher compression requirements.

Scheme 1 injection into MP produces the smallest amount of CO2 emissions and Scheme 3 Central Hub, produces the most. From the study reverse compression produces more CO2 the longer it is required to run. This should still be less than CO2 produced from an LTS injection as the hours run will still be less compared to it.

As the electricity grid is decarbonised the CO2 impact of compressor running hours will fall significantly. In addition, the use of CBM to fuel trucks would remove the majority of emissions associated with haulage.

Parameter	MP 2bar	LTS	Central Hub	MP Reverse Compression	Unit
Biogas Production Electrical Requirement	4,864,956	5,859,145	4,864,956	4,864,956	kWh/annum
Biogas Production Heating Requirement	1,890,783	1,890,783	1,890,783	1,890,783	kWh/annum
CNG Compression Site Electrical Requirement	0	0	1,809,887	0	kWh/annum
CNG Daughter Site Electrical Requirement	0	0	87,600	0	kWh/annum
CNG Daughter Site Heating Requirement	0	0	392,113	0	kWh/annum
Reverse Compression Site Electrical Requirement	0	0	0	175,764	kWh/annum
CNG Haulage Diesel Requirement	0	0	15,964	0	L/annum
Propane Injected	6,195,784	6,195,784	6,195,784	6,195,784	kWh/annum
Carbon Intensity of Electricity Grid	110	110	110	110	gCO2e/kWh
Carbon Intensity of Gas Grid	140	140	140	140	gCO2e/kWh
Diesel Calorific Value	37	37	37	37	MJ/L
Diesel Well to Tank	73	73	73	73	gCO2eq/MJ diesel
Diesel CO2 Combustion Emissions	2,680	2,680	2,680	2,680	gCO2/l
Propane Emission Factor	229	229	229	229	gCO2/kWh
Total CO2e Emissions	**2,220,548**	**2,329,909**	**2,526,950**	**2,239,882**	kgCO2e/annum
Percentage Emissions Saving (wrt Scheme 3 – Central Hub)	**12.13%**	**7.80%**	**0.00%**	**11.36%**	

Challenges – Technical, Commercial & Regulatory [1]

Central Hub

Security of Supply

- The transportation of gas by road is relatively reliable, but there could be possible issues (i.e. closed roads, poor weather) that could lead to delayed deliveries, and therefore a lack of gas supply.
- Although reliable, in a case that the offloading and pressure reduction site trips (due to high pressure, low temperature or other reasons), the gas supply would again be removed. This is considered unacceptable unless there are reliable backup energy sources for the gas flow.

Satellite sites

- If multiple biomethane sites will use a single daughter station to inject into the grid this needs to be designed and considered in early for future proofing to prevent overload or excessive gas storage onsite which may push the allowable COMAH tier.

Planning consent

- In rural areas planning consent for gas trailer stations can be an issue.

Hazardous Substances Consent and Lower Tier

- No major problems are expected in receiving consent provided the design is done competently with someone who has prior experience.

Excessive Distance

- It is more expensive and difficult to employ trailer drivers who would be required to rest mid journey if the Central Hub distance is excessive.

Land Space

- Mother and daughter stations require land space that may be too expensive or not be available at all to the biomethane producer.

Indicative land space required for a Central Hub offloading facility

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Challenges – Technical, Commercial & Regulatory [2]

Pipeline Connection – Reverse Compression

Security of Supply

- Biomethane exporters are reliant on a green premium per injection such as the RHI and need to pay capital costs through finance making capacity concerns a critical issue. If they don't inject biomethane they do not receive RHI whilst still having costs to pay. Concerns around capacity needs to be addressed early during feasibility/conceptual design for pipeline projects. Reverse compression however is one of the solutions to this issue.

Pipeline Variables

- Variables such as a trainline can make a pipeline connection impossible.
- The terrain can increase pipeline costs significantly and increase construction times.

Regulation & Design

- In terms of the design, construction and management of a pipeline based project in the UK, the available standards, GDN IGEM etc. are thorough and not normally an issue provided the designers and contractors are competent.

Connection into Ageing Assets

- For a biomethane project some available existing offtake connections are ageing assets and CSL has previously faced issues with passing valves requiring live gas maintenance. Consideration needs to be taken if delays from this will incur a greater cost as compared to a hot tap connection.

Stranded Assets

- Most compressors are moveable assets but long distance pipeline will normally be left in the ground redundant with nitrogen, if projects fall through.

Conclusion

To conclude the financial model, all scheme models are financially viable provided sufficient biomethane is injected into the grid due to the financial difference being minimised as shown in the graph to the right. Finance support schemes available for biomethane injection typically run for 15 years so there is financial safety for biomethane injections above 57 GWh.

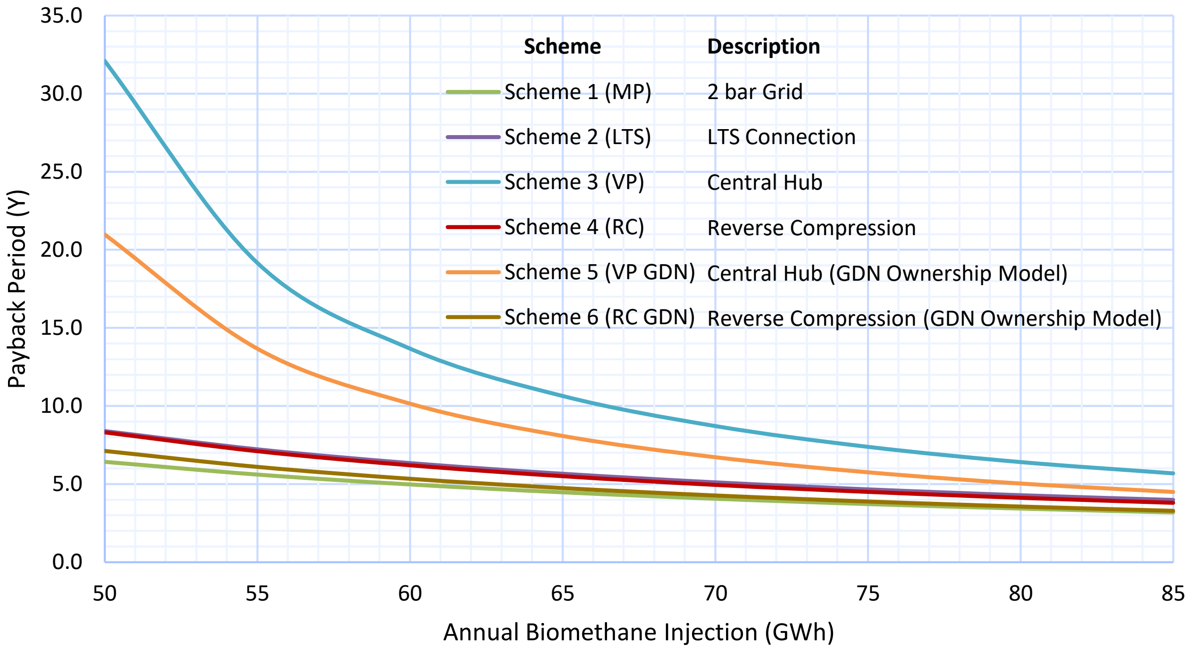
However, certain scenarios exist where schemes start to lose viability and as such, reverse compression allows biomethane producers to avoid these and allows the supply of biomethane all year round. If a low pressure MP grid was previously inaccessible or limited due to capacity restrictions the inclusion of a reverse compressor station allows this injection an take place all year round and is financially better than the alternative schemes.

Key trends that were output from the model are as follows:

- Direct into a 2 bar MP is the best option.
- Next best is the reverse compression for a 2 bar MP network.
- This is followed by a HP LTS connection.
- The least attractive scheme is the Central Hub model.

Capacity constraints of when a 2 bar MP injection is no longer the best option is as follows:

- If the constraint is less than 10% it will remain the most economic model compared to the other schemes.
- Between 10% and 50% constraint the other schemes stack better financially led by the reverse compressor model.
- At 50% constraint or lower the project will not be feasible at all as the financial payback is negative. At this point a reverse compressor is a necessity.



Pipeline Factor

- A Central Hub model will be the ideal and most economic scheme if the pipeline distance is significant. This report identifies this distance to be 26km for the model site analysed.
- There are also scenarios where a reasonable pipeline connection cannot be made due to the terrain or a trainline. This also leads to the Central Hub being ideal.

Every project requires a conceptual/feasibility study but the primary selection identified between a Central Hub and pipeline model is how much finance is required for the pipeline.

Appendix A – RHI (Non-Domestic Biomethane Injection)

Post 2021 RHI – Impact on Capacity

1. BEIS want larger projects and so tariffs are up to 60 GWh/annum for Tier 1.
2. Biomethane projects need to make >50% of biogas from waste, the location of the AD has to be where the waste is
    - This reduces the number of sites and means that grid capacity is critical
3. Gas Networks are not designed for smaller distributed sources such as biomethane:
    - Limited metering or knowledge of real flows at sites that feed the IP and MP pipelines (and any metering designed for peak so may not be accurate at low flow)
    - No concept of a summer "1 in 20" – so the network analysis models still use winter peak which only gives theoretical issues at grid extremities
    - Some 'guaranteed' pressures for I&C customers and new housing prevent lowering of pressure to accept injection of biomethane
4. BEIS plan to only intend support to new biomethane plants injecting into the gas grid via anaerobic digestion.
5. New requirements for AD plants will be more strict and GHG emissions targets and calculations will be more stringent.

Capacity is a key issue facing the biomethane industry. Approx. 30% of potentially good biomethane projects (that have feedstock) have not gone ahead because there is no way to get gas into the grid. Many have gone CHP.

Eligible Sizes	Date of accreditation	Tier	Tariff Rate 2021/22 (p/kWh)
All capacities	before 1 January 2015	N/A	8.73
First 40,000 MWh		Tier 1	8.73
Next 40,000 MWh	before 1 July 2015	Tier 2	5.12
remaining MWh		Tier 3	3.96
First 40,000 MWh		Tier 1	8.31
Next 40,000 MWh	between 1 July and 30 September 2015	Tier 2	4.87
remaining MWh		Tier 3	3.76
First 40,000 MWh		Tier 1	7.49
Next 40,000 MWh	between 1 October and 31 December 2015	Tier 2	4.39
remaining MWh		Tier 3	3.39
First 40,000 MWh		Tier 1	6.73
Next 40,000 MWh	between 1 January 31 March 2016	Tier 2	3.96
remaining MWh		Tier 3	3.05
First 40,000 MWh		Tier 1	5.82
Next 40,000 MWh	between 1 April 2016 and 30 June 2016	Tier 2	3.42
remaining MWh		Tier 3	2.63
First 40,000 MWh		Tier 1	4.95
Next 40,000 MWh	between 1 July and 30 September 2016	Tier 2	2.91
remaining MWh		Tier 3	2.24
First 40,000 MWh		Tier 1	4.70
Next 40,000 MWh	between 1 October and 31 December 2016	Tier 2	2.78
remaining MWh		Tier 3	2.13
First 40,000 MWh		Tier 1	4.24
Next 40,000 MWh	between 1 January and 31 March 2017	Tier 2	2.49
remaining MWh		Tier 3	1.91
First 40,000 MWh		Tier 1	3.82
Next 40,000 MWh	between 1 April and 31 June 2017	Tier 2	2.25
remaining MWh		Tier 3	1.72
First 40,000 MWh		Tier 1	3.43
Next 40,000 MWh	between 1 July 2017 and 21 May 2018	Tier 2	2.03
remaining MWh		Tier 3	1.55
First 40,000 MWh		Tier 1	5.82
Next 40,000 MWh	between 22 May and 31 December 2018	Tier 2	3.42
remaining MWh		Tier 3	2.63
First 40,000 MWh		Tier 1	4.95
Next 40,000 MWh	on or after 1 January 2019	Tier 2	2.92
remaining MWh		Tier 3	2.25

Appendix B – Biogas Trailer Viability for Central Hub

The economic viability of biogas transportation does not compare to biomethane as seen in the table to the right. The reasoning is summarised as follows:

- Methane has a molecular mass of 16 and Carbon Dioxide has a molecular mass of 44.
- For a biogas mix of 55% CH4 and 43% CO2, methane accounts for 31% of the kg weight and CO2 67% of the weight (the remaining % are O2 and N2 etc).
- A biogas trailer will need to transport all of the biogas whereas a biomethane trailer will only need to transport 31% of this.
  - 67% loss is incurred due to transporting CO2 for biogas
- The biogas trailer transports slightly less gas than the biomethane trailer but the above point is what causes the big difference.

Parameter	Biomethane	Biogas	Unit
Biogas Composition (%CH4)	55%	55%	
Biogas Production Rate	**500**	**500**	**Nm3/h**
Biogas Production Rate	527	527	Sm3/h
AD Operation	100%	100%	
AD Annual Production Hours	8,760	8,760	hours
Methane Higher Calorific Value	37.78	37.78	MJ/Sm3
Biogas HCV	20.78	20.78	MJ/Sm3
Biogas HCV	5.77	5.77	kWh/Sm3
Annual Biogas Production	4,620,659	4,620,659	Sm3/annum
Annual Biogas Production	26,670,189	26,670,189	kWh/annum
Biogas Density (Standard Conditions)	1.203	1.203	kg/Sm3
Annual Biogas Production	5,559,737	5,559,737	kg.annum
Biogas/Compressed Upgraded Biogas delivered / tanker	6,200	4,692	kg/trip
Trips by tanker	**288**	**1,185**	**trip/annum**
Trips by tanker	0.8	3.2	trip/day
Cost per return trip (25 miles)	200	200	£/trip
Number of tankers	**1**	**3**	**Tanker(s)**
Trips per tanker per day	0.8	1.1	trips/d/tanker
CH4 Capture	99%	99%	
BUU Availability	97%	97%	
Biomethane Methane Content	97%	97%	%CH4
Energy in 1m^3 of Biomethane (97% CH4, 2% CO2, 0.8% N2, 0.2% O2)	36.647	36.647	MJ/m3
Density of Biomethane (97% CH4, 2% CO2, 0.8% N2, 0.2%)	0.709	0.709	Kg/m3
Energy in 1 kg of Biomethane	51.688	51.688	MJ/Kg
1kWh of Energy	3.6	3.6	MJ
kWh Energy in 1 kg of CBM	14.358	14.358	kWh/kg
Biomethane Production	296	296	Sm3/h
Annual Biomethane Production	2,515,949	2,515,949	Sm3/annum
Annual Biomethane Production	1,783,808	1,783,808	kg/annum
Annual Biomethane Production	25,611,383	25,611,383	kWh/annum

Appendix C – Satellite AD plants

Cluster Model Considerations – Commercial & Technical

- For a cluster of satellite AD sites, there would be a claim for RHI (and assumed GGSS) at the biomethane entry point as per any other project.
- RHI (and assumed GGSS) is paid on the total energy input into the grid after deducting the external heating load and any propane, as this displaces the equivalent fossil gas energy.
- Therefore the energy flows at each facility need to be monitored and measured which include; electricity, heat, feedstock and kWh of biogas produced.
- This means biomethane injected into a central hub will require separate trailers for each AD site and monitoring at the central hub facility.
- If biogas upgrading only takes place at the injection point, each AD satellite will require separate pipelines to the biogas upgrader.
- Whilst more complex, cluster models can be feasible and economic.
    - Cost savings can be found for a cluster model using AD satellites provided competent design, management and sensible contracts (for separate entities) is employed.