


Ringsend WwTP Biomethane Project:
Technical & Commercial Feasibility Report

14th June 2022

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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 authority by DNVGL
- Working on a number of H_2 and CCUS innovation projects

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Contents

Report Briefing

CSL has been contracted by CAW to conduct a desktop study to supplement an existing 'Gas to Grid' proposal. The report will explore various commercially available technologies available by linking site considerations to process design and technology selection. This is supported by concept layout drawings and a tailored financial model providing indicative figures based on previous project work to detail the estimated CAPEX/OPEX included the projected income obtained through various revenue streams. This will also highlight the scope of work expected to completed the project.

Participating Parties

cng services ltd

CELTIC ANGLIAN WATER CAW

Report Structure

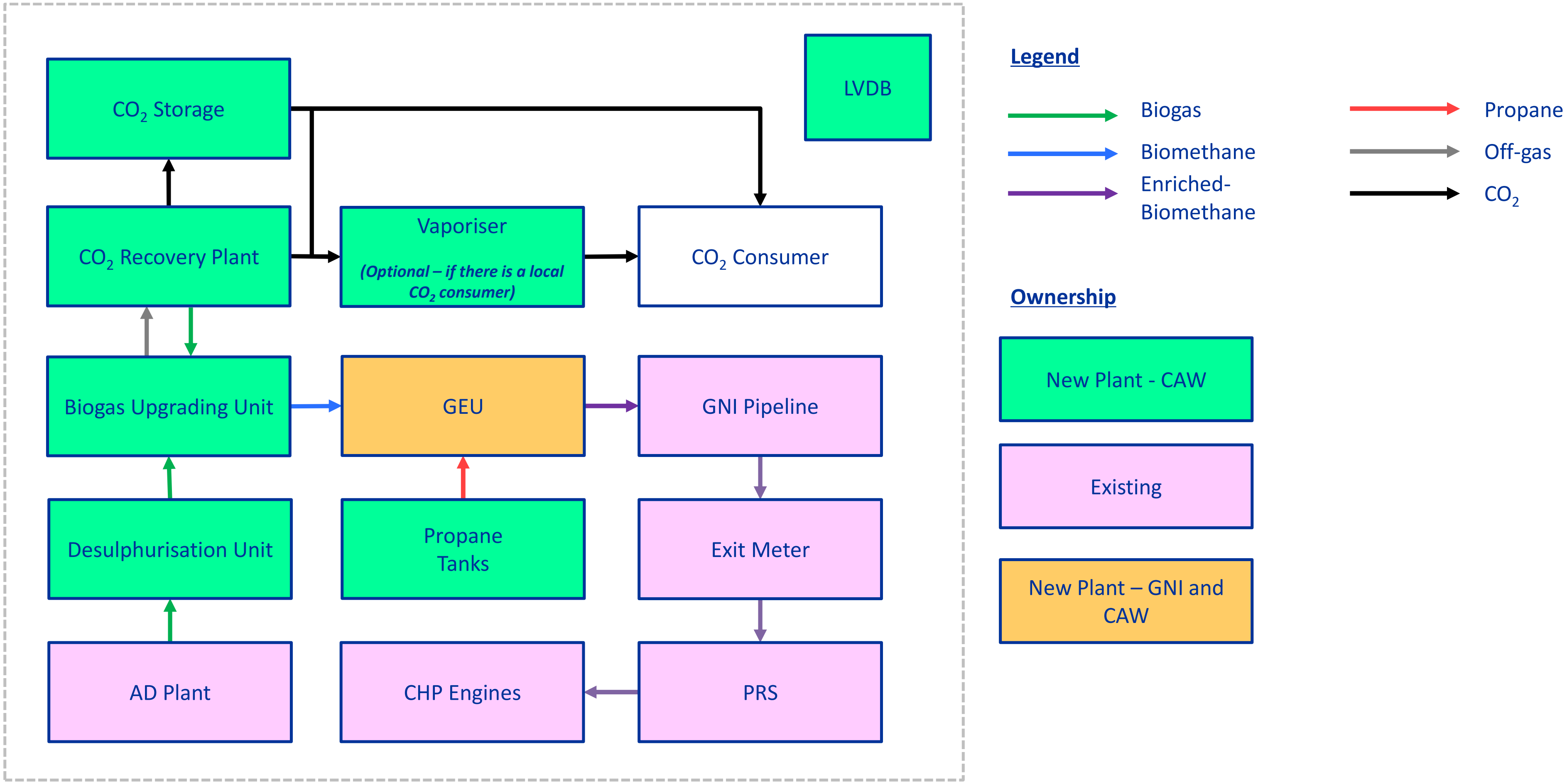
Acronyms

AD	Anaerobic Digestor
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business, Energy and Industrial Strategy
BtG	Biomethane to Grid
BUU	Biogas Upgrading Unit
CSL	CNG Services Ltd
GCV	Gross Calorific Value
GEU	Grid Entry Unit
ICF	Incomplete Combustion Factor
ppmv	Parts per Million Volume
RTFC	Renewable Transport Fuel Certificate
SI	Sooting Index

Project Summary

- Celtic Anglian Water (CAW) have proposed a biomethane option to Irish Water to improve the financial return from the Ringsend site
- The proposal is for CAW to inject biomethane from their biogas production plant into the Gas Networks Ireland (GNI) transportation network
- The site has an estimated maximum hourly biogas flowrate of around 1,100 Nm^3/h and it has been proposed to inject biomethane into a 4 barg grid which is already on the site, which feeds a number of large Industrial & Commercial (I&C) customers
- The biogas gas engines can already operate on natural gas (and can burn Biogas in event upgrading plant not working). The financial performance of the project can be underpinned by the UK Renewable Transport Fuel Scheme with trucks fuelled in GB but can also be supported by new incentive scheme in Ireland
- CO_2 capture and liquefaction could also be an attractive option, generating additional revenue from an otherwise waste product
- The economics are very attractive due to the RTFC potential of around €5.2 million per annum to Ringsend and a CAPEX of around €5.5 million to construct a Biomethane to Grid plant

Scope Summary



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GNI Capacity Study (1)

The detailed capacity study completed by GNI reveals that Injection of biomethane into the gas network can be achieved in two ways:

a) A direct pipeline connection

b) Contracting with a Biomethane Collection and Logistics Service Provider (BCLSP)

The former is deemed the most feasible and economic option. This involves the producer sending gas to the Gas Networks Ireland (GNI) transportation network via a new connection to the GNI Pipeline on site

Direct pipeline connections are designed based on a “minimum connection model” whereby GNI owns the following assets only at the injection point:

a) 1 x Remotely Operated Valve (ROV)

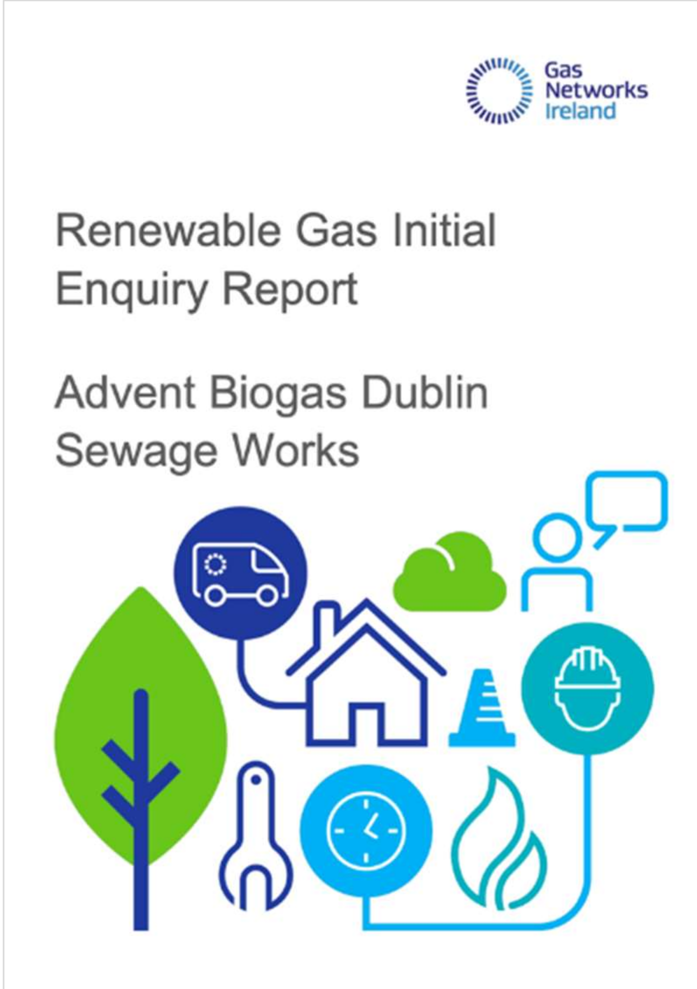
b) 1 x Remote Telemetry Unit (RTU) with associated comms equipment.

c) All pipeline built between the tie-in to the gas network and the connected system point on the clients site (usually the closest flange to the ROV on the clients side)

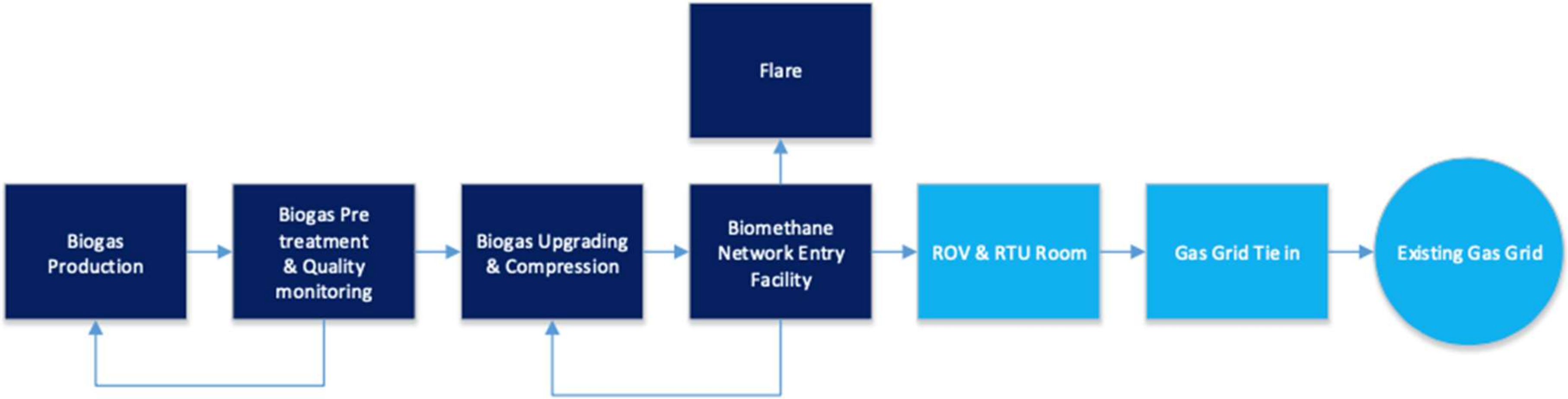
All other equipment at the site will be under the ownership of the producer. This includes any equipment associated with gas analysis, gas compression/pressure reduction and pressure management, gas quality cleansing, conditioning and gas upgrading.

A high level network analysis assessment has been undertaken to determine an indicative maximum and minimum allowable flows to the network. However, this is a high level analysis and more detailed assessments would need to ensure these quantities can be achieved.

Project Detail	Description			
Proposed Facility Name:	Ringsend WwTP Dublin			
Coordinates (GPS Format):	Northing	53.34063	Easting	-6.19616
Estimated Maximum Hourly Flow Rate (MWh):	1,100 Nm³/h (11.5 MWh/h)			
Connection Required Date:	2024			



GNI Capacity Study (2)



GNI Capacity Study (3)

Based on the information submitted by the client a theoretical annual quantity of biomethane production of 82 GWh means that both a distribution and transmission connection may potentially be feasible when compared against option (b) biomethane collection and logistics service provider.

The proposed site is located in a developed part of the network with a number of available connection points close to the site:

a) Connection on to an isolated 4 barg distribution network (Poolbeg) that is already connected to site. This network connects directly to 4 large commercial customers in the vicinity

- Sufficient capacity in the pipeline network to facilitate flows of 1000 m^3/h
- Max winter average peak flow on the distribution network is 2,490 m^3/h with a minimum summer valley flow estimated at 635 m^3/h. Based on this information, a distribution connection into the isolated Poolbeg 4 barg network albeit feasible would likely experience periods of constraint across the year if injecting a continuous flow of 1000 m^3/h

b) Connection to the greater Dublin distribution 4 barg network through the construction of approx. 1.3km pipeline

- The region surrounding the site is extensively built up which could impact the timelines and cost associated with such a connection
- Sufficient capacity in the pipeline network to facilitate flows of 1000 m3/hr. Summer valley flow would be in the region of 2,565 m3/hr. Based on the findings it would appear a distribution tie-in and reinforcement to greater Dublin network would be the most suitable connection option for this project

c) Connection to the nearest transmission 70 barg AGI which is about 650 m from the proposed site

- AGI feeds a number of power gen customers. Power Gen is more susceptible to issues caused by changes in gas quality specification
- Transmission connection assumed to be capable of supporting 1,000 m^3/h injection

Name	DX/TX	Indicative Distance (km)	Indicative Costing (€000)	Indicative Flows Possible (Sm^3/h)
Poolbeg Distribution Network	DX	0.07	91	635
Dublin 4 barg	DX	1.3	171	2,565
Transmission AGI Tie-in	TX	0.65	856	>1,000

Section 1

Biogas Upgrading To Biomethane & Injection into GNI Grid

Biogas Upgrading to Biomethane

The commonly used technologies for upgrading biogas to biomethane are:

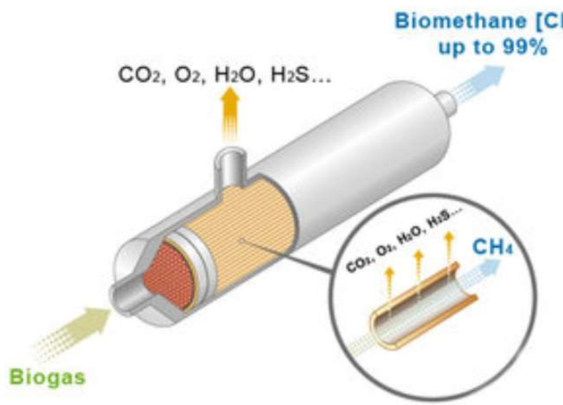
- Water Wash Scrubbing
- Chemical (Amine) Wash Absorption
- Pressure Swing Adsorption
- Membrane Separation

Technology	Quantity (UK)
Water Wash Scrubbing	24
Amine Wash Absorption	5
Pressure Swing Adsorption	5
Membrane Separation	75

Membrane and PSA pre-treat biogas before upgrading to remove:

- H_2S
- VOCs, siloxanes, terpenes
- Ammonia / ammonium carbonate
- Water

- Membrane separation is generally preferred for upgrading biogas to biomethane
- One big advantage is the relatively pure and dry CO_2 vent stream
  - Readily suitable for CO_2 capture either as part of initial design or as retro fit
- Water wash uses air to flush the CO_2 out of the water and so the waste CO_2 is in a N_2 stream and cannot be captured
- Amine technology is very efficient at separating CO_2 but needs heat to regenerate the amine and the trend is for lower temperature operation with no gas burning on site and so no waste heat



Membrane Technology

CO_2 Separation

Technology Type	Notes
Membrane	Commonly used on biomethane processes; multi pass membranes can achieve high CH_4 yield which is suitable for gas injection into grid and vehicle fuel. Can be easily combined with CO_2 liquefaction on day one or by modifying the system. Most (if not all) new Biomethane projects produce Liquid Bio-CO_2 . **A good option for Ringsend**
Water Wash	Not suitable, traps CO_2 within water. The CO_2 is then flushed out of the water using air, which means that the waste CO_2 stream contains N_2 and O_2 and cannot easily be separated.
Amine Scrubbing	Amine is very effective for removing all the CO_2 from biogas. This is the technology that will be used in the major CCUS projects at Teesside and Ellesmere Port. The amine needs high temperature (120°C) to dissociate CO_2 and regenerate solvent for recycling. **A good option for Ringsend**

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Ringsend Biogas Sample Report

- Amine/Chemical wash and Membrane separation are considered the most appropriate technology choice for biogas upgrading at Ringsend
- Depending on the technology chosen and if CO_2 liquefaction is considered as a project deliverable, a dedicated desulfurization unit may be required due to the high H_2S concentration
  - Membrane systems require all H_2S to be removed
  - Amine wash removes H_2S but pre treatment is also preferred
- See Appendix on H_2S removal

SAMPLE DESCRIPTIONS
Celtic Anglian Water, Ringsend WwTw AD Plant

TEST	UNITS	BIOGAS Pre Scrubber
Date Sampled		16/02/2022
Time Sampled		10:30
Hydrogen Sulphide	.ppm	1130
Carbon Dioxide	%mol	41.52
Oxygen	%mol	0.05
Nitrogen	%mol	0.21
Hydrogen	%mol	<0.01
Methane	%mol	58.21
Ethane	.ppm	<1
Ethene	.ppm	<1

Propane	.ppm	<1
Butanes	.ppm	<1
Pentanes	.ppm	<1
C6	.ppm	<1
C7	.ppm	<1
C8	.ppm	<1
C9	.ppm	<1
C10	.ppm	<1
C11	.ppm	<1
C12	.ppm	<1
Hydrocarbon Dewpoint (Calculated)	°C	-135

Process Description – Biomethane to Grid Plant

Gas Conditioning (Pre-treatment)

It is key to consider that the Ringsend biogas has high H_2S. Siloxane concentrations need to be confirmed. It is assumed that either an oxygen generator or ferric dosing system can be implemented to suppress H_2S levels to ~100 ppm, which will be reduced to a network acceptable level by means of activated carbon.

For membrane plants, the pre-treatment process involves the following stages
- A drying process to remove the water
- H_2S/VOC extraction via activated Carbon filters
- Biogas Compression into high pressure membranes

If required, the plant can utilise an internal recycle line to enable repeat biogas processing and achieve the required outlet composition and CH_4 recovery ratio. Generally, the plant is started in recycle mode until operating pressures, temperatures and biomethane quality are compliant

It is recommended that the membrane BUUs should either be supplied by Pentair or Bright Biomethane if it is intended to install an analogous CO_2 recovery plant. Both suppliers specialise in biogas upgrading and CO_2 recovery systems, with installed plants in the UK.

CO_2 Recovery & Storage

The CO_2 rich off-gas from the BUU can be recovered via a liquefaction process. The off-gas is first compressed and dried to remove residual moisture and contaminants. The gas then enters the liquefaction process. Any non-condensable gases such as oxygen, nitrogen and methane are removed via a stripping tower and returned to the BUU inlet. This increases biomethane yield and reduces methane slippage to near 0. The product liquid CO_2 will then be pumped to a storage tank. Each plant should be designed for a maximum throughput analogous to the BUU sizing.

Grid Entry Unit (GEU)

The GEU (GB spec) consists of a 4-compartment kiosk which typically houses the ROV, RTU, plantroom and control room under one roof. In GB, the plant room and control room will be client controlled, whilst the ROV and RTU will be adopted by the network operator.

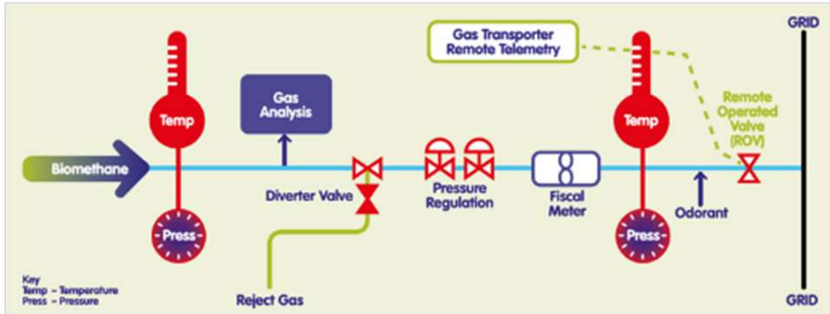
Online instrumentation in the GEU continuously samples biomethane and records results of the analysis using a gas chromatograph. The function of the GEU is supported by a Propane injection system by which the GEU regulates the rates based on a targeted CV target CV received from grid operator (details required from GNI). The ROV will close if the reject system in the GEU fails to operate during a gas quality, pressure or temperature excursion.

Biomethane Export via GEU

Biomethane from the BUU flows towards the GEU. In GB, the GEU consists of a single kiosk comprised of 4 partitions namely: the plant control room (client controlled), plant analysis room (client controlled), Remotely Operable Valve (ROV - Grid adopted asset) Room and Remote Telemetry Unit (RTU - Grid adopted asset). In Ireland, it's believe that GNI will provide and operate all assets related to the GEU.

The function of the GEU is to conduct various gas analyses to ensure exported gas is of GNI spec and meet the criteria defined by the GNI Grid Entry Contract. The GEU is supported by a liquid propane enrichment system to enhanced the CV of biomethane and is then odorised (depending on the grid pressure rating).

The Remote Operated Valve (ROV) is owned and under the control of GNI. The ROV will close if the gas produced from the facility is not compliant with regulations. Non-compliant gas is almost always detected (and then rejected), but the ROV acts as a final, emergency barrier, if required.



Propane Enrichment System

Biomethane is enriched with Liquefied Petroleum Gas (Typically liquid propane) in a process called 'propanation' to increase gas CV specified by GNI.

Note there can be issues with Wobbe, ICF or SI caused by heavy use of propane when pure methane generated. The addition of liquid propane will cool the gas after addition and gas pre-heating is normally required as part of the BUU. The final temperature of the biomethane is required to be within the limits set out in the contract with GNI.

Odorant Injection Systems

In Ireland gas must be odorised to provide the 'characteristic gas smell' people are familiar with. The system needs to be designed in accordance with the principles of any typical odorant facility, and must comply with the IGEM/SR/16 or GNI specific regulation.

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Biomethane Export via GEU

Rhinology Sample Point

This is a point within the export pipe (after the ROV) where monthly and manual gas testing can be undertaken by the transporters. The rhinology (sample) point may or may not be within the site compound but appropriate access will need to be considered and designed in the site plan. The location needs to be selected so that the sample is solely representative of the biomethane and not the natural gas in the pipeline.

Real Time Gas Analysis

The GEU ensures the biomethane is compliant with the requirements of the gas distributor set out in the Network Entry Agreement (NEA). To achieve this, the following functions are considered

- Gas analysis: measuring the constituent components and the calorific value (CV) of the gas etc..
- Flow metering: measuring the quantity of biomethane that is injected for billing purposes
- Pressure control: Regulates pressure prevent over pressurised biomethane entering the grid.
- Temperature measurement: to ensure that the temperature of the gas is kept within specified limits
- Calorific Value functionality: the energy content of the gas being injected into the grid needs to be measured and recorded. The calorific value must match the value stipulated by GNI
- Odorant injection: to give the biomethane the characteristic gas smell
- Communication (telemetry): equipment to send all necessary data to the gas distributor to demonstrate compliance with gas quality standards and regulations

GNI will have a reference document titled Minimal Functional Specification for the GEU. This document will detail the requirements for a safe, efficient and fit for purpose GEU installation. A biomethane producer should ensure that they consult this document from the outset of the project.

Measurement	Required By	Instrumentation
Gross Calorific Valve	Ofgem	Ofgem approved GasPT
Relative Density		Calculated from composition
Compressibility		Calculated from composition
Wobbe	GSMR	Calculated from composition
ICF	GSMR	Calculated from composition
SI	GSMR	Calculated from composition
WDP	GSMR	Aluminium Oxide Sensor
Hydrogen Sulphide	GSMR	Sensor with daily cal/check function
Oxygen	GSMR	Sensor with daily cal/check function
Inlet and Outlet Temperature		PT 100 Temperature Transmitter
Inlet and Outlet Pressure		Pressure Transmitter
Flow		Fiscal Meter

Propane Enrichment

- The Gross Calorific Value (GCV) in the GNI gas grid is 39.5 MJ/m^3
- The typical biomethane GCV is 37 MJ/m^3 (98% CH_4 with 2% CO_2/N_2/O_2)
- Propane is hence added to meet the gas quality specification set out by GNI
- Propane likely to be highest operating cost for biomethane project

Propane storage tanks

Propane mixing unit

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Propane Enrichment – Indicative Calculation (1)

Parameter	Value	Unit	Notes
		Key Inputs	
Biogas Flow Rate	1,100	Nm^3/h	
CH_4 Concentration in Biogas	60.0	%	
Target CV	39.50	MJ/Sm^3	FWACV - 0.6 MJ
Minimum Storage Refill Frequency	14.00	days	
		Propane Check	
Propane Requirement	**Check Propane**		< Click to Calculate Propane Requirements
Target CV Error Check	OK		
Wobbe Check	OK		
		Key Outputs	
Biomethane Energy Value (Unpropanated)	36.87	MJ/Sm^3	
Required Propane Addition	38.5	Sm^3/h	
Required Propane Addition	71.67	kg/h	
Biomethane Energy Value (Propanated)	39.50	MJ/m^3	After propane addition
Total Annual Cost of Propane	€ 242,543	EUR/annum	Incl. value recovery from grid injection
Propane Storage	24	tonnes	Maximum tank size below Lower Tier COMAH is 24 tonnes
Propane Storage Refill Frequency	13.95	days	
Total Propane Addition	8,575,105	kWh/annum	
Total Propanated Biomethane	68,173,974	kWh/annum	

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Propane Enrichment – Indicative Calculation (2)

Parameter	Value	Unit
Biogas Composition		
CH_4	58.2	%
CO_2	41.5	%
N_2	0.2	%
O_2	0.1	%
	100.0	%
Biogas Production		
Clean-Up Plant Availability	96.0	%
AD Plant Availability	100	%
Biogas Flow Rate	1,160	Sm^3/h
Biogas Production Per Year	9,636,000	Nm^3/annum
Biogas Production Per Year	62,086,424	kWh/annum
Biogas to Upgrade Per Year	9,250,560	Nm^3/annum
Average Biogas to Upgrading Facility	1,056	Nm^3/h
Average Biogas to Upgrading Facility	1,114	Sm^3/h
Biomethane Production		
Methane Slip	0	%
Methane Gross Calorific Value	37.78	MJ/Sm^3
Assumed CO_2 Content in Biomethane	2.00	%
Removal of Oxygen from Feed Gas	50	%
Biogas GCV	21.99	MJ/Sm^3
Calculated CH_4 in Product Biomethane Stream	648	Sm^3/h
Calculated CO_2 in Product Biomethane Stream	13.29	Sm^3/h
Calculated N_2 in Product Biomethane Stream	2.23	Sm^3/h
Calculated O_2 in Product Biomethane	0.56	Sm^3/h
Biomethane Composition		
CH_4	97.58	%
CO_2	2.00	%
N_2	0.34	%
O_2	0.08	%
Total	100	%
Total Product Biomethane Flow	**664**	Sm^3/h

Biomethane Energy		
Total Product Biomethane Flow	664	Sm^3/h
Biomethane Energy Value	36.87	MJ/Sm^3
Biomethane Energy Flow	24,495	MJ/h
Propane Addition		
FWACV of Area	39.50	MJ/Sm^3
Propane Density	0.51	kg/l
Propane Flow	71.67	kg/h
Propane Flowrate	140.53	l/h
RMM	44.0	g/mol
Energy	91.5	MJ/Sm^3
Vaporisation Load	9	kW
Propane Energy Per Hour	3,524	MJ/h
Total Exported Energy Per Hour	28,019	MJ/h
% Energy Exported from Propane	12.58	%
Propane Value Loss Calculation		
Total Propane Cost	40.60	c/l
Hourly Propane Cost	57.05	EUR/h
Propane Cost (per kWh)	5.83	c/kWh
Propane Sale Price into Grid (as Biomethane)	3.00	c/kWh
Propane Value Loss	2.83	c/kWh
Enriched Biomethane Properties		
Nitrogen Addition	5.07	Sm^3/h
Oxygen Addtion	1.27	Sm^3/h
Enriched Biomethane Properties		
Flow	709	Sm^3/h
CH_4	91.41	%
CO_2	1.87	%
N_2	1.03	%
O_2	0.26	%
Propane	5.43	%
Total	100.00	%
RMM	18.21	g/mol
Wobbe	49.81	MJ/m3
Total Propane kWh per annum (C52 & C55)	8,575,105	kWh/annum

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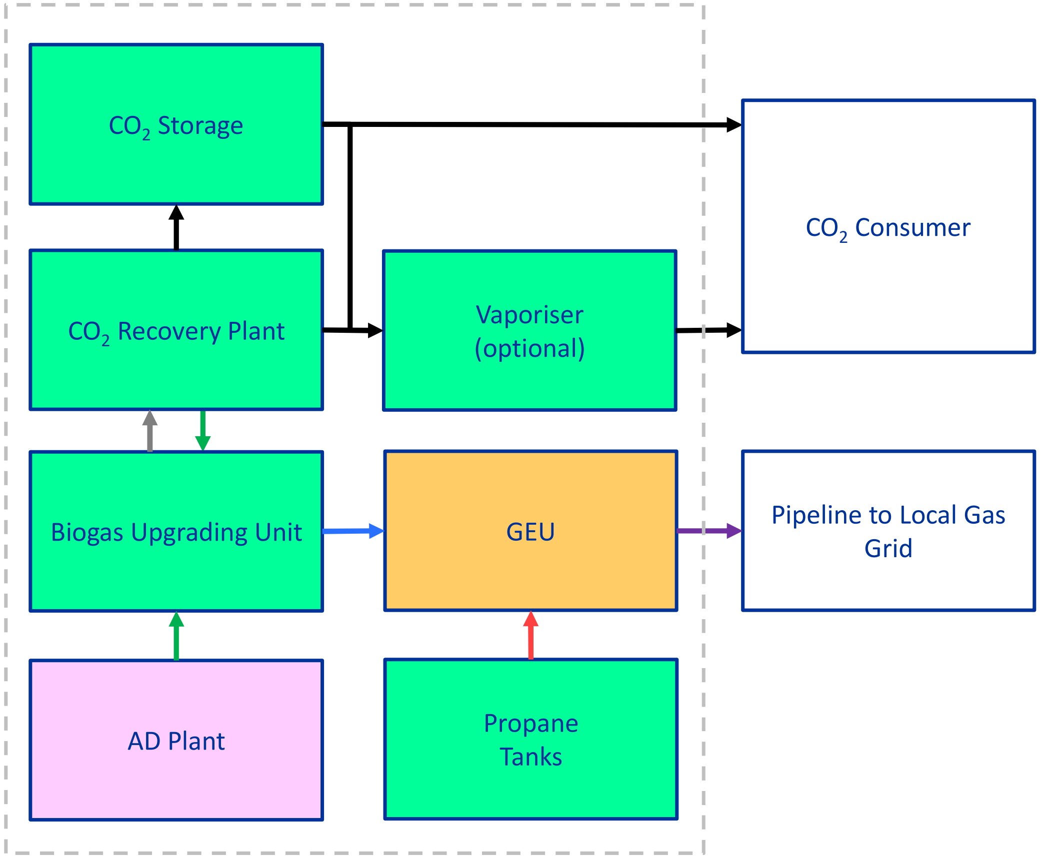
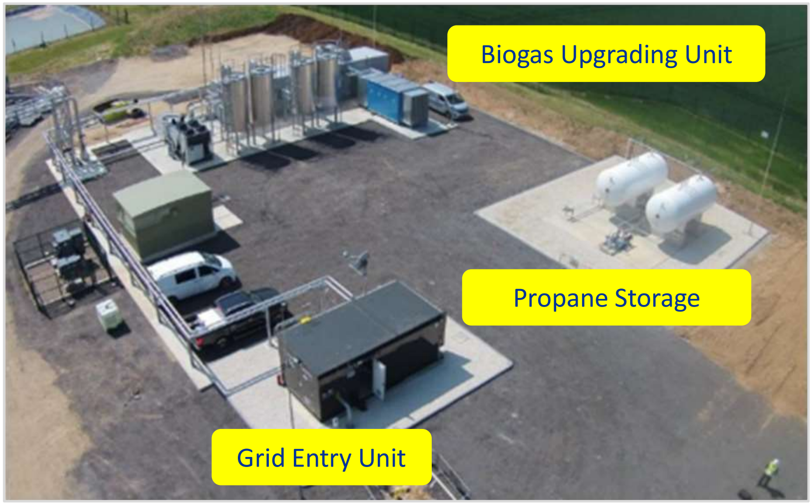
Section 2

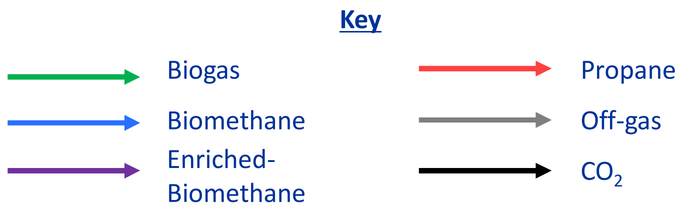
CO_2 Liquefaction

An Introduction to CO_2 Recovery

Biogas Upgrading to Biomethane – Membrane Separation & CO_2 Capture







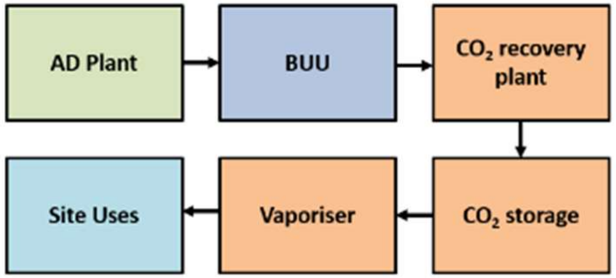
CNG Services – CO_2 Capture Experience

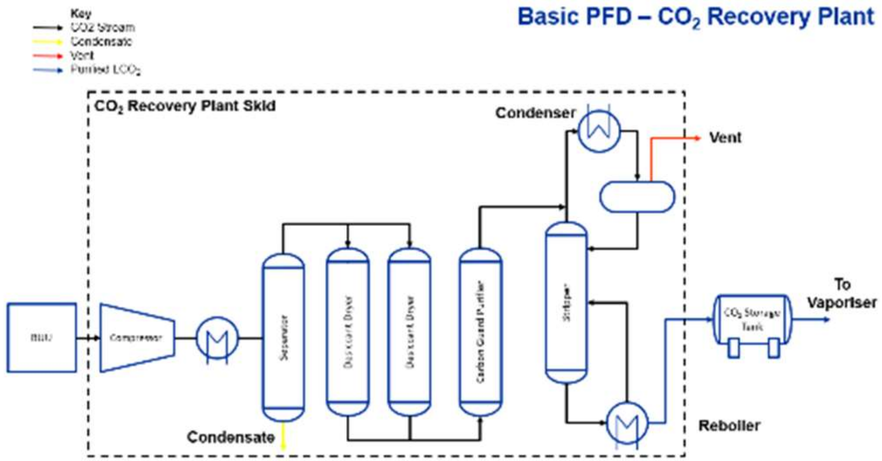
- Pentair systems
  - Right table shows Pentair projects we have worked on, most make Liquid CO_2
  - All use maize as feedstock, CO_2 sold to Air Liquide
  - Typical price £40/tonne (pre todays energy blip)
- TPI systems
  - Poundbury (fitted to DMT BUU)
  - Hampton Bishop (installed by Bright)

Site	Operator	Post Code	Commissioning Date
Bay Farm	Strutt & Parker Farms	IP28 6BS	September 2016
Bromham	Jim Butler	SN15 2DX	June 2016
Ebbsfleet	GW Finn & Sons	CT13 9QL	December 2014
Euston Estate	Biomass 2 Energy	IP24 2QP	May 2015
Fairfields Farm	Qila Energy	CO6 3AQ	March 2016
Isle of Wight	Wight Farm Energy	PO30 3AA	December 2014
Raynham Estates	Aecom	NR21 7LH	June 2015
Tornagrain 2	Qila Energy	IV2 7JQ	October 2017
Vale Green 1	Vale Green Energy	WR10 2PQ	August 2013
Vale Green 2	Vale Green Energy	WR10 2LA	December 2014

Process Description (Upgrading and CO_2 recovery)

1. The off-gas exits the membrane BUU and is directed to the CO_2 liquefaction system
2. The gas is then compressed and passes through an after-cooler before entering the Dehydration System
3. The Dehydration System uses a desiccant dryer and carbon bed to remove residual moisture and contaminants
4. The CO_2 stream then enters a primary/reflux condenser which will liquify the bulk of the CO_2 vapour. The cooling duty will be provided by a refrigeration cycle, which will account for much of electricity demand
5. The condensate is fed to a stripper column which will remove the non-condensable impurities (i.e. N_2 and CH_4) as vapour CO_2 generated from the reboiler ascends the column
6. The CO_2 passes through a final fine filter to remove any remaining impurities
7. The purified liquid CO_2 flows to an insulated storage tank. From the tank, the CO_2 can be transferred to a liquid CO_2 tanker for export from site





Should an LCO_2 Plant be Installed with BUU or Retrofitted?

- CSL have reviewed the benefits of installing a CO_2 plant during initial biomethane facility construction against retrofitting when CCS facilities become available (in 2025/6). The model to the right aims to show the additional income and expenditure that comes with the CO_2 plant's installation. These are listed and explained below:

- Benefits to early CO_2 plant installation

  - **CO_2 Income** – Whilst a valuable commodity, it is expected to increase in value due to higher gas prices going forward. A number of parties interested in purchasing CO_2
  - **Additional CH_4 Capture** – The CH_4 slip through the BUU membranes (estimated at 0.5-1%) will be captured during the CO_2 liquefaction process for grid injection, increasing the biomethane yield
  - **Lump Saving due to No Remobilisation** – Installation the plant during initial works saves money by avoiding future remobilisation

- Costs associated with early CO_2 plant installation:

  - **Additional Electricity Spend** – Electricity is required for the CO_2 liquefaction process – estimated at an additional 0.1 kWh/Nm³ biogas processed
  - **Additional Maintenance Spend** – On top of BUU maintenance
  - **Cost of Accelerated Expenditure** – i.e. of capital financing

- **Modelling the outcome suggests that there are substantial benefits to installing CO_2 capture plant during initial site works instead of waiting for CO_2 sales prices to rise, as long as the plant is big enough and the electricity and accelerated expenditure costs are reasonable**

Parameter	Value	Unit
Biogas and AD Data		
Biogas Composition	58%	%CH_4
Biogas Production Rate	1,100	Nm^3/h
Upgrader Availability	96%	
Biogas Production Rate	1,160	Sm^3/h
AD Operation	100%	
AD Annual Production Hours	8,760	hours
Annual Biogas Production	10,165,451	Sm^3/annum
Biomethane Data		
Biomethane Methane Content	98%	%CH_4
CH_4 Capture	100%	
Biomethane Production	692	Sm^3/h
Annual Biomethane Production	5,819,304	Sm^3/annum
Annual Biomethane Production	59,604,672	kWh/annum

Parameter	Value	Unit
CO_2 Production		
CO_2 Percentage in Biogas	42%	%CO_2
CO_2 Capture Efficiency	90%	-
Potential CO_2 Production	437	Sm^3/h
CO_2 Recovery Plant Availability (Relative to BUU)	100%	-
CO_2 Recovery Plant Operating Hours	8,410	h/annum
Annual CO_2 Production (Volume)	3,671,273	Sm^3/annum
Annual CO_2 Production	6,865	tonnes/annum
Liquid CO_2 Value	€ 94.40	/tonne
Annual CO_2 Income	€ 648,082	/annum

Parameter	Value	Unit
Benefits/Drawbacks of Early CO_2 Plant Installation		
Further CH_4 Captured	0.00	Sm^3/h
Further CH_4 Captured	0	kWh/annum
Biomethane Value	10.1	c/kWh
Annual Income from Additional CH_4 Capture	€ -	EUR/annum
Annual Income from CO_2 Capture	€ 648,082	EUR/annum
Annual Spend on Electricity (0.1kWh per Nm^3/h Biogas extra @ 8 c/kWh)	€ 74,004	EUR/annum
Annual Spend on Maintenance - Marginal Cost on top of BUU (Estimated)	€ 20,000	EUR/annum
Total Saving for Installing Plant Upfront (i.e. no remobilisation etc.)	€ 150,000	EUR
Additional CAPEX for CO_2 Removal (incl. Storage Tanks)	€ 1,740,000	EUR
Cost to Accelerate Expenditure by 2 years	3%	/annum
Total Cost of Accelerated Expenditure	€ 104,400	EUR
Total Time Between Initial Installation (w/o CO_2 Plant) and Remobilisation	2.0	years
Annual Saving due to Early Plant Installation	€ 576,878	EUR/annum
Total Saving (Between Initial Installation and Retrofit)	**€ 1,153,756**	**EUR**

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CO_2 Market Information (UK)

Air Liquide

- Buys food grade from 9 Pentair plants with combined output of 11,800 Nm^3/h of biogas, capable of producing 86,000 t of CO_2/a

Biocarbonics

- Purchases CO_2 from Poundbury and Hampton Bishop
- Sells LCO_2 to 15-20 industrial customers
- Sold to Greenhouses, food and beverage companies

Dry Ice Scotland

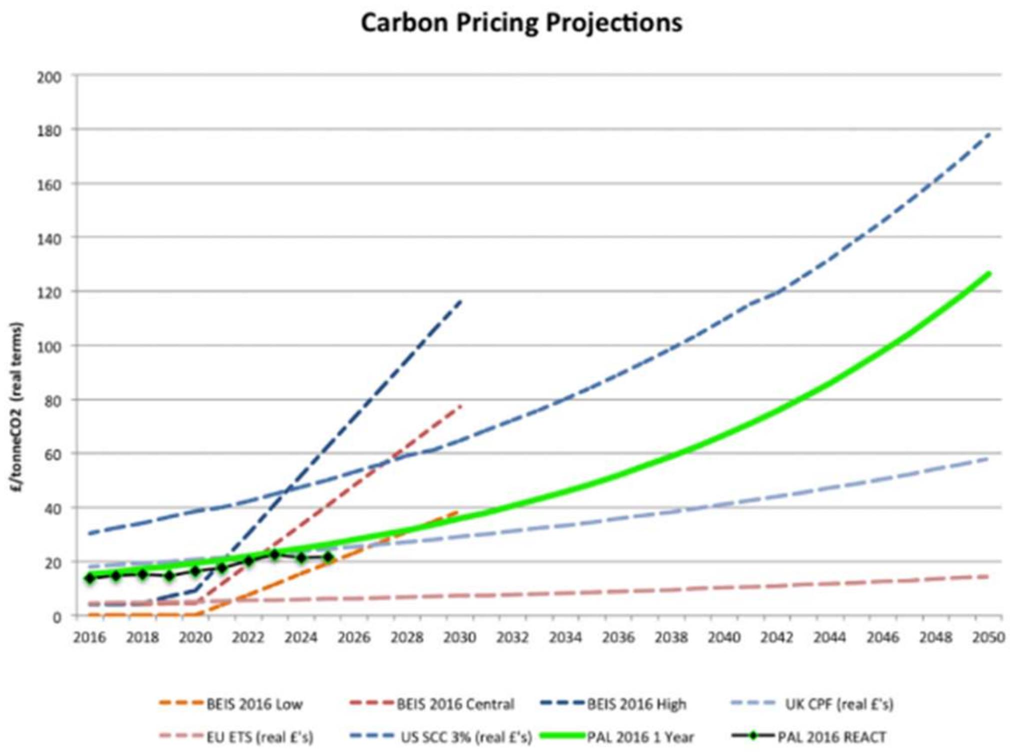
- Purchases CO_2 from latest Pentair plant in Scotland – 8,000 t/y

Pro Gases UK Ltd

- Willing to purchase CO_2 at £80/t

Carbon Capture Clusters

- UK - Teesside, HyNet (Ellesmere Port, North West),
- Norway - Northern Lights (via Saltend, Hull)



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Bio-CO_2 Market Update and Development Pathway (UK)

This is illustrative - whilst this is for UK it is possible that Ireland will follow a similar pathway for Bio-CO_2

This note gives a summary of developments in relation to Bio-CO_2 and sets out a way forward for new Biomethane Plants

1. BEIS are very supporting of Liquid Bio-CO_2 as the UK needs BECCS to get to NetZero and capturing and sequestering Bio-CO_2 from biomethane plants is likely to be lowest cost option for any CO_2 source
2. BEIS also need CO_2 due to high gas prices which have closed CF Fertiliser Ellesmere Port plant
3. EA are developing End of Waste criteria for Bio-CO_2 including Food and Industrial grades and this supports the market
4. To get to market, Bio-CO_2 produced at AD plants must be liquefied and moved by road tanker (approx. 25 tonnes per trip). The road tankers should be fuelled with Bio-CNG fuelled tankers (e.g. CNG Fuels and Grissan)
5. Most Biogas CHP plants expected to transition to Biomethane into the gas grid by 2030 as electricity subsidies end and there are long periods of negative pricing. In addition, generating electricity means no feasible means to capture and sell liquid Bio-CO_2
6. Hynet have indicated possible way to monetise the Bio-CO_2 based on going to Hynet
7. CSL believes Hynet, Equinor Northern Lights in 2024 and Teesside Net Zero (25/26) represent ‘fall back’ options for Bio-CO_2 as the industrial/food grade markets are likely to offer significantly better prices
8. Making e-methanol from Green H_2 and Bio-CO_2 may become an attractive market (for chemicals industry and Maersk container ships)
9. In GB prior to 2020 most Bio-CO_2 was food grade (maize largely) and purchased by Air liquid at around £50/tonne
10. Buyers will now purchase Bio-CO_2 with chemical composition Food Grade but for feedstock including manures, as the ‘reputation’ issue with manures (ie chemically food grade but made from something that customers do not want) seems to be falling away (we recently visited Bio-CO_2 made from chicken muck and horse manure straw going to a brewery)
11. There are a number of existing Biomethane plants installing Liquid Bio-CO_2 (generally using windfall profits from biomethane sales to fund £1.5 million CO_2 CAPEX)
12. New Biomethane projects that CSL are involved in are all installing Liquid Bio-CO_2 from day 1
13. In summary, this sets out case to install the Liquid Bio-CO_2 plant on Day 1
14. CSL believes once you have an approved project, seek contracts for that Bio-CO_2 for 3 years initially which leaves flexibility as the market develops
15. CSL does not believe that the current rate at > £500/tonne is sustainable moving forward as it is driven by the gas commodity price
16. Bio-CO_2 producers can access 1 – 3 years of very high prices in same way the biomethane prices in 21/22 - 23/24 will probably be very high
17. Wholesalers Air Liquide, BioCarbonics, Biogas Sales etc are able to offer £100/tonne today
18. CSL believes the market may settle at around £200/tonne to the end user from 24/25 when new US LNG reduces the European gas price

Section 3

Site Layout

Typical Site General Arrangement

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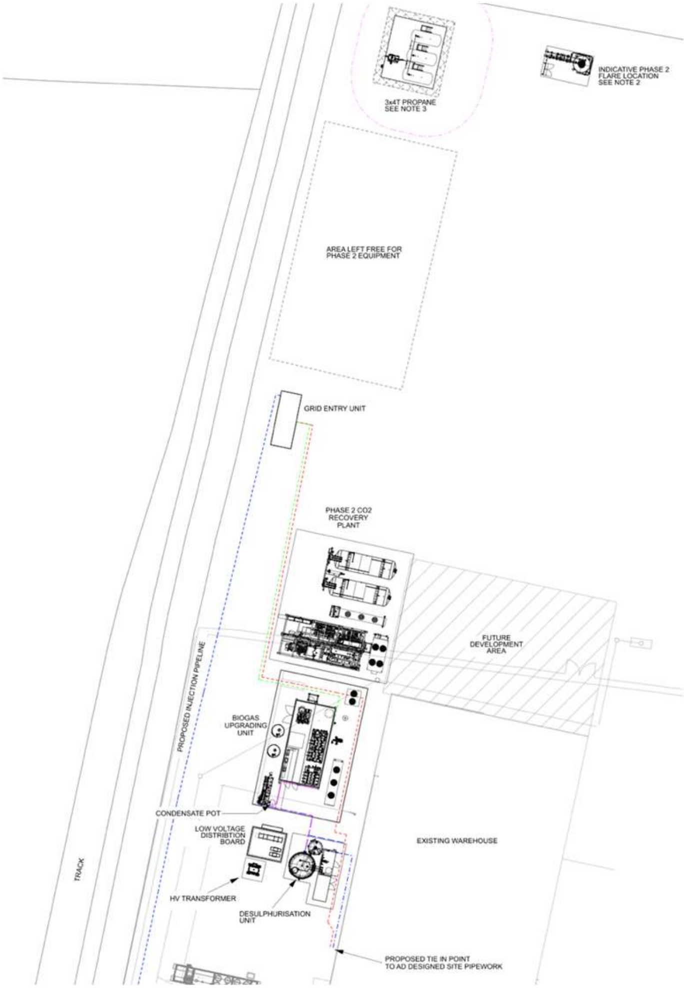
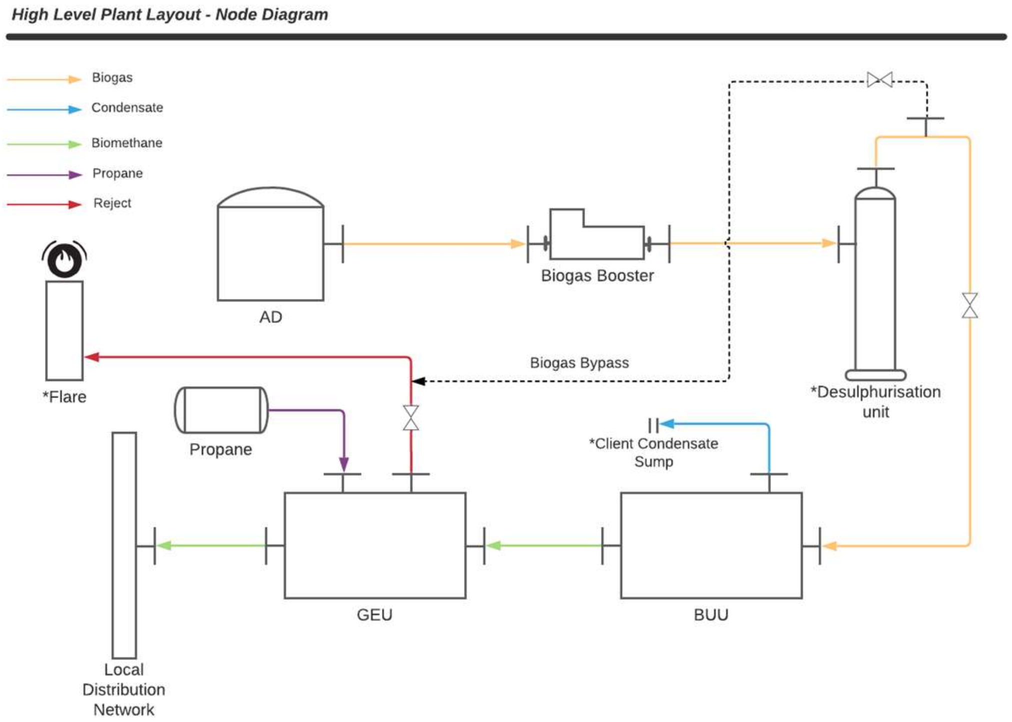
Indicative Layout & PFD





Site General Arrangement

As per request, CSL have superimposed a typical G2G plant onto the potential construction areas as guided by CAW. The following slides present 2 possible configurations (subject to further design considerations). Both options have considered additional construction area for contingency use, supports ease of access for maintenance and construction activities

Design points to consider:

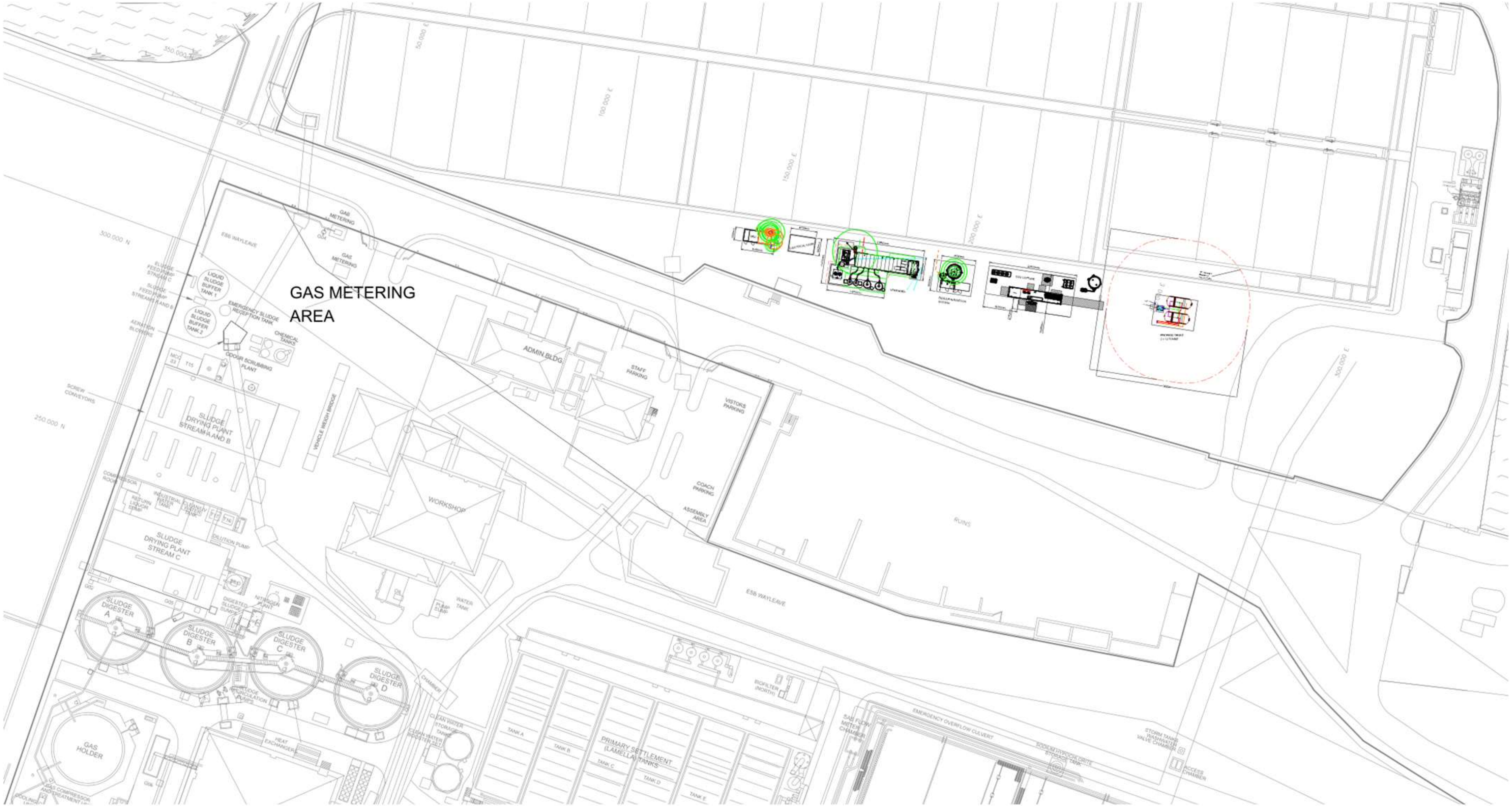
Developing the G2G plant adjacent to the storm tanks (configuration 1) will present some design challenges

- Biogas delivery pipework to G2G compound (Pipe bridge or below ground)
- Reject pipework back to site (assuming no flare)
- Pipework supporting desulfurization system (e.g. digestate, hot water)
- Condensate discharge from BUU to sump location
- Site electrical/comms integration with Low Voltage Distribution Kiosk
- Excavation work across the road may be required to complete grid connection/biomethane connection to GEU from BUU
- Layout for indicative purposes – final arrangement can be optimised with more design details

Configuration 2

- 'MLPS flow meter chamber' appear to run below the intended construction area. This could create issues relating to planning permission
- GEU and propane tanks located near metering kiosk to reduce brugge pipework (propane line) and export pipeline length. Easement area of adopted assets minimised
- Layout for indicative purposes – final arrangement can be optimised with more design details

Configuration 1 – Site Overview



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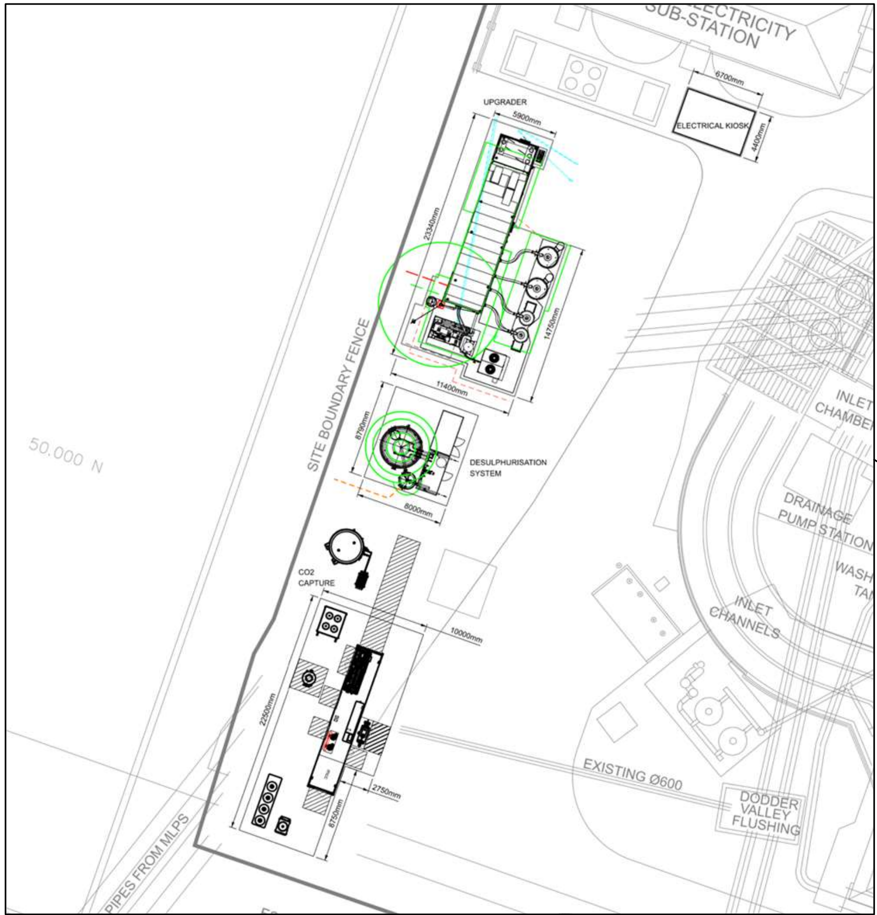
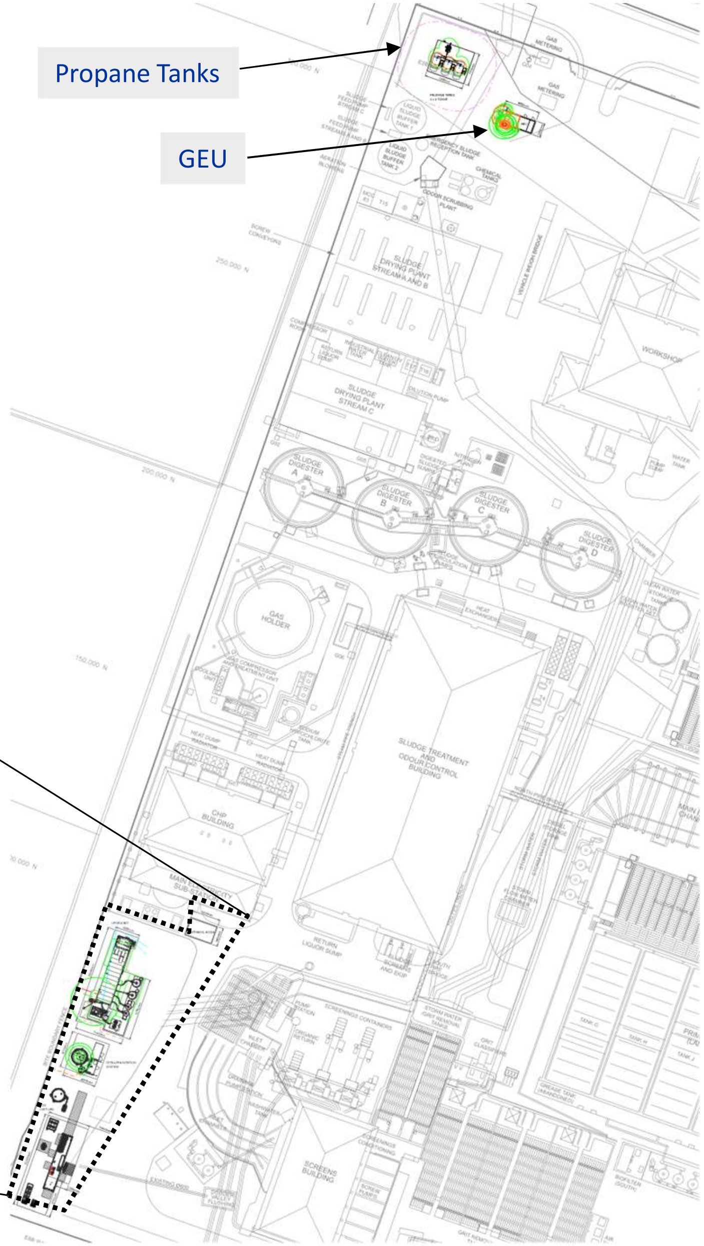
Configuration 1 – G2G Compound

Configuration 2 - Site Overview





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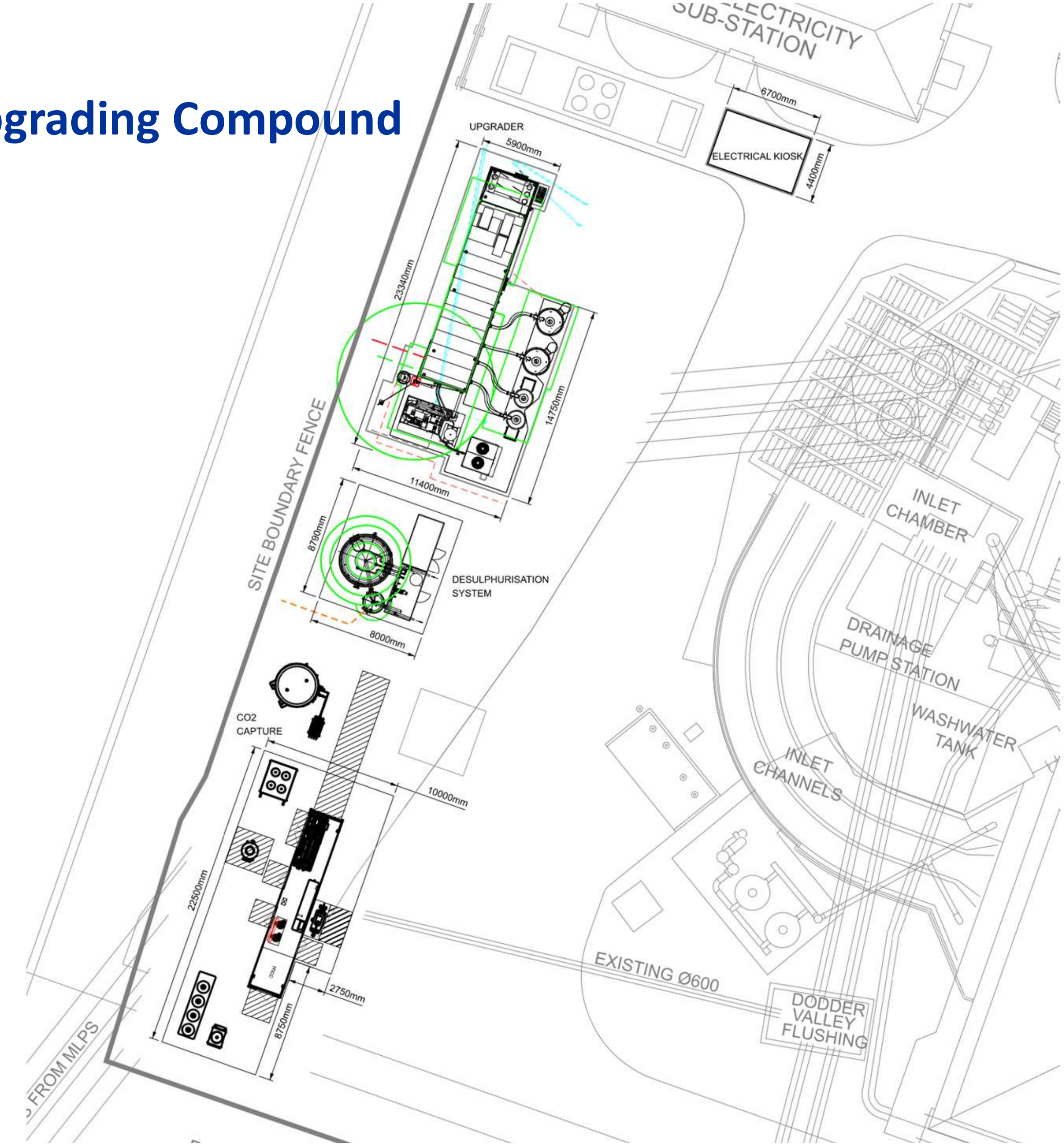
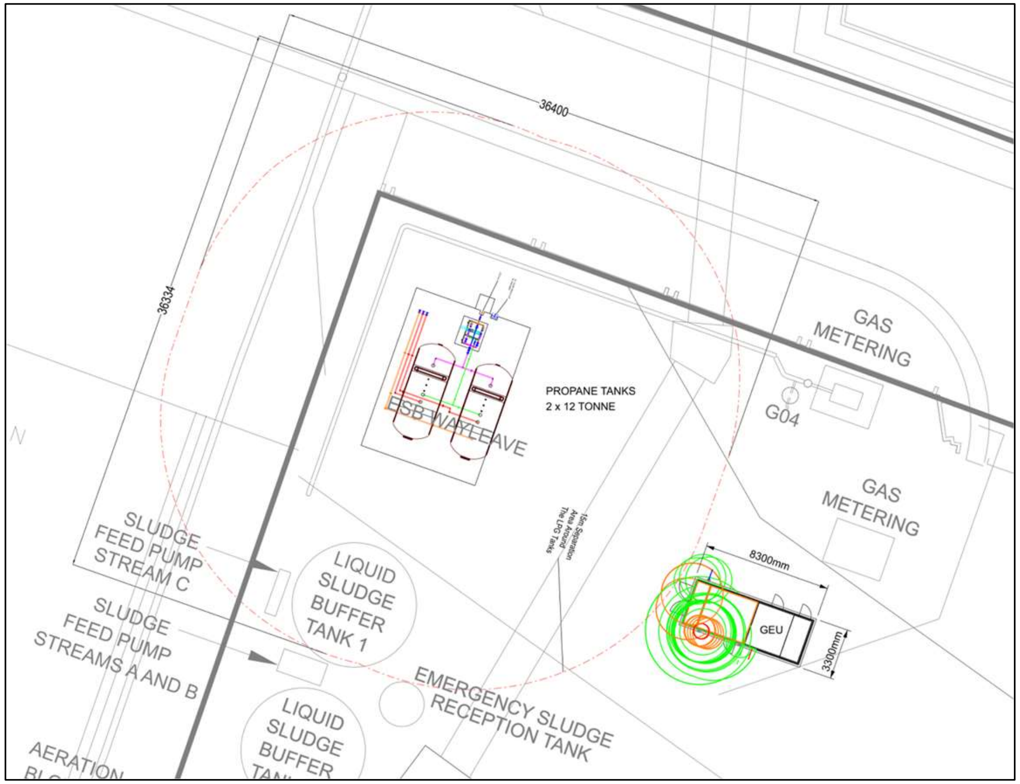
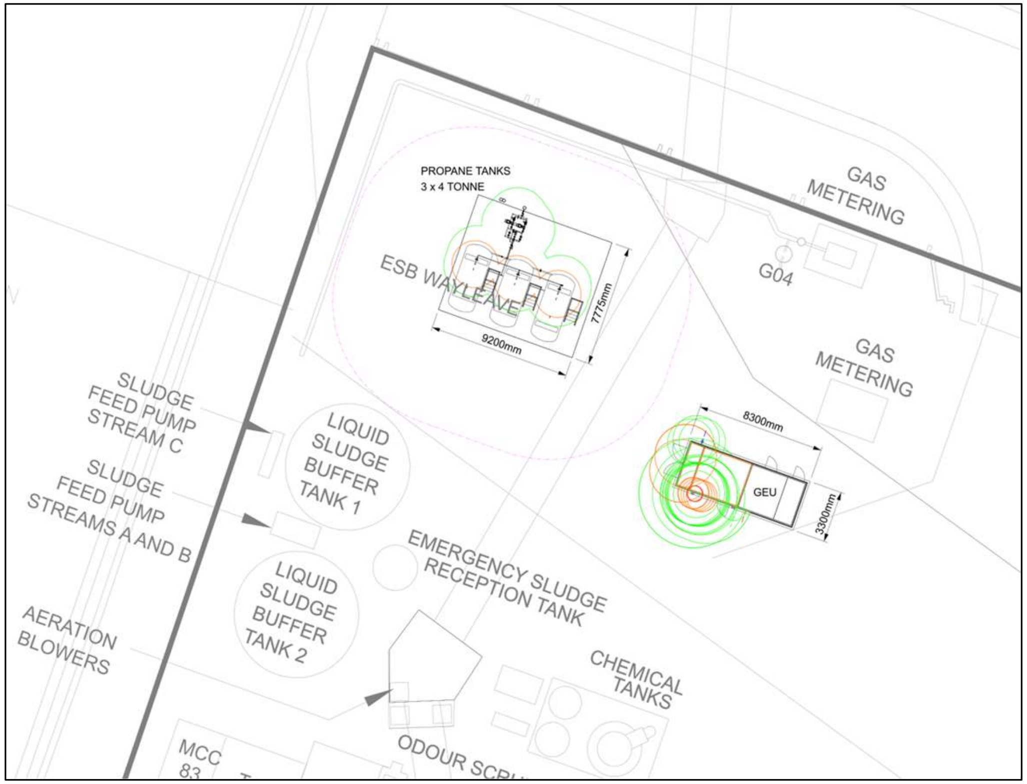
Configuration 2 – Gas Upgrading Compound



Configuration 2 – Propane Tanks

LHS configuration uses 24t storage. The exclusion zone can be reduced by reducing onsite storage capacity; RHS configuration is an example of 12t storage





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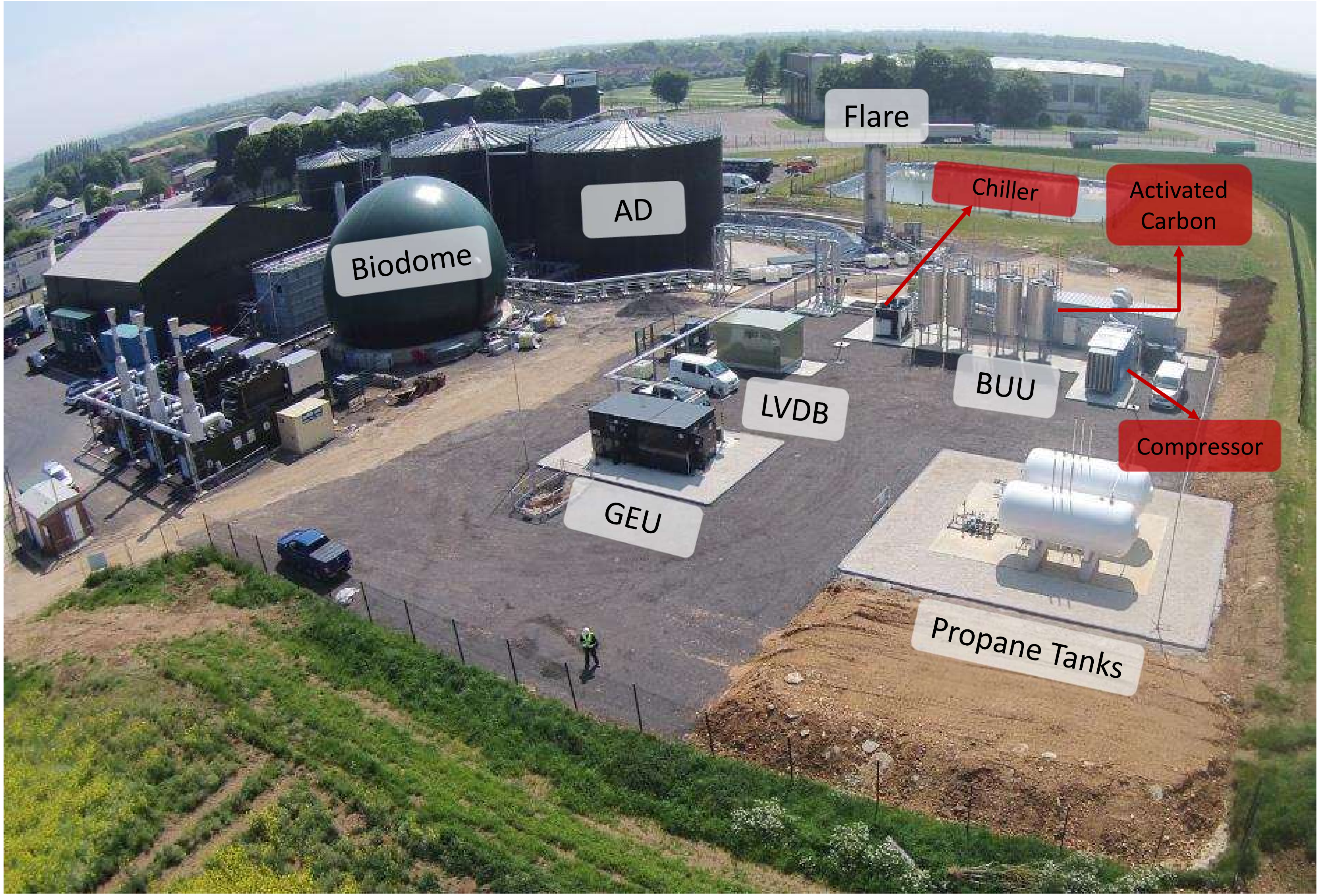

Section 4

CAPEX, OPEX & Monetisation

Monetisation & Support Schemes

Primary Equipment List

BtG Equipment

- **Pre-Treatment System** – Typically consisting of a Biogas Cooler, Blower and up to 4 Activated Carbon Vessels (2 x H_2S removal, 2 x VOC removal). These shall be specified according to biogas analysis. To reduce H_2S levels from the AD, a ferric chloride dosing/oxygen injection system can be implemented
- **Membrane BUU** – Sized for the maximum biogas flowrate. Minimum turndown usually 50%. Membrane system is recommended for CO_2 capture
- **CO_2 Liquefaction Plants** – Bolt-on to membrane BUU. Sized based on biogas flowrate
- **Liquid CO_2 Storage Tanks** – Typically sized for 72h storage capacity
- **Grid Entry Unit** – Sized based on maximum biomethane throughput. RTU housed in GEU kiosk
- **Propane Tank(s)** – Mounded. Often sized for 2 weeks of storage capacity
- **Biomethane Flare** – Propanated biomethane should not be recycled back through the BUU
- **Export Pipeline** – Designed based on injection flowrate and pressure etc.
- **ROV** – Normally installed in compartment of GEU kiosk, although can be remote subject to location of site relative to grid

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Biomethane to Grid Plant – Process Considerations

Parameter	Significance	Example
Maximum Biogas Production	Pre-Treatment/BUU sizing and overall CAPEX	1,100 Nm^3/h
Average Biogas Production	Annual OPEX and revenue	1,100 Nm^3/h
Maximum Biomethane Production	Connection agreement and GEU/export pipeline design	700 Sm^3/h
Average Biomethane Production	Propane consumption and revenue	700 Sm^3/h
Export Pressure Tier	4 bar is best option	GNI (4 barg)
Gas Composition		
Methane (CH_4)	Ties into biomethane production and hence potential revenue	58%
Carbon Dioxide (CO_2)	Influences CO_2 production rate and hence design, CAPEX, OPEX and revenue associated with the CO_2 recovery plant	42%
Hydrogen Sulphide (H_2S)	Dictates pre-treatment requirements and OPEX (i.e. vessel size, frequency of replacement etc.)	140 mg/m^3
Volatile Organic Compounds (VOCs)	Dictates pre-treatment requirements and OPEX (i.e. vessel size, frequency of replacement etc.)	10 mg/m^3

Primary Biomethane Plant process considerations used in the financial modelling

Biogas and Biomethane Production

Parameter	Value	Unit
Biogas and AD Data		
Biogas Composition (%CH_4)	58%	-
Biogas Production Rate	1,100	Nm^3/h
Biogas Production Rate	1,160	Sm^3/h
AD Operation	100%	-
Upgrader Availability	96%	-
AD Annual Production Hours	8,760	h/annum
Annual Biogas Production	10,165,451	Sm^3/annum
Biomethane Data		
Biomethane Methane Content	98%	%CH_4
Gross Calorific Value - Biomethane	36.873	MJ/m^3
Density of Biomethane	0.709	kg/m^3
Gross Calorific Value - Biomethane (Mass)	52.007	MJ/kg
1kWh of Energy	3.6	MJ
kWh Energy in 1 kg of CBM	14.447	kWh/kg
CH_4 Capture	100%	-
Biomethane Production	692	Sm^3/h
Annual Biomethane Production	5,819,304	Sm^3/annum
Annual Biomethane Production	4,125,886	kg/annum
Annual Biomethane Production	59,604,672	kWh/annum

Key Points and Worked Example

- As per the conditions stated on the previous slide, an average annual biogas flowrate of 1,100 Nm^3/h with a methane concentration of 58% equates to a biogas production of ~62,000,000 kWh/annum
- When implemented with CO_2 recovery, a near 100% methane capture rate can be considered. BUU suppliers can guarantee an availability up to 97% of the year subject to their recommended inspection and maintenance regime
- Based on the above, an annual biomethane production of ~60,000,000 kWh/annum could be achieved. Note: Biomethane production is often stated in terms of Gross Calorific Value (GCV). The wholesale gas value is also measured in terms of GCV although RTFCs are sometimes measured in terms of Net Calorific Value (NCV). For the purpose of these calculations, all figures are reported in terms of GCV unless otherwise stated

CO_2 Production

Parameter	Value	Unit
Biogas and AD Data Summary		
Biogas Composition (%CH_4)	58%	-
Biogas Production Rate	1,100	Nm^3/h
Biogas Production Rate	1,160	Sm^3/h
Annual Biogas Production	9,636,000	Sm^3/annum
CO_2 Production		
Biogas Composition (%CO_2)	42%	-
CO_2 Capture Efficiency	90%	-
CO_2 Recovery Plant Availability (Relative to BUU)	100%	
CO_2 Recovery Plant Operating Hours	8,410	h/annum
CO_2 Density	1.87	kg/Sm^3
CO_2 Production Rate	437	Sm^3/h
Annual CO_2 Production (Volume)	3,671,273	Sm^3/annum
Annual CO_2 Production (Mass)	6,865,280	kg/annum
Annual CO_2 Production (Mass)	6,865	t/annum
CO_2 Storage		
Daily CO_2 Production (Mass)	11.43	t/day
Total Storage Required	3	Days
Total Storage Capacity Required	40	t
CO_2 Value		
Carbon Price	€ 94.40	EUR/tonne
Value of CO_2 Captured	**€ 648,082**	**EUR/annum**

- Direct CO_2 capture from the biogas upgrader is an increasingly popular concept, with rising CO_2 prices and pressure to reduce carbon emissions
- CO_2 captured from an AD could potentially be sold as either as an industrial gas or for food/drink subject to meeting EIGA requirements, albeit the perception surrounding the origin of the CO_2 (particular for waste feedstocks) may restrict certain customer bases.
- A preliminary value of £80 per tonne has been shown, with a capture efficiency of 90% based on supplier recommendations. Current CO_2 sales prices from AD capture are over £100/tonne, although prior to current shortages, prices were around £60/tonne
- Capture efficiency is stated as 90% as a small portion of the CO_2 is lost to the biomethane export, with the rest being lost to regenerate the carbon vessel in the plant every 12 hours

TG2

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Biomethane to Grid Plant CAPEX Overview

Factor	Quantity		CAPEX
Main Plant Items			
Biogas Upgrading Unit [1,100 Nm^3/h]	x1	€	3,262,500
Grid Entry Unit	x1	€	590,000
CO_2 Recovery and Liquefaction Plant [1,000 kg/h]	x1		Incl.
CarboScan Analyser	x1	€	354,000
CO_2 Storage Tanks [50t Horizontal]	x1	€	106,200
Air Compressors	x2	€	17,700
Propane Tank	x1		N/A
Sub-Total for Plant and Equipment		**€**	**4,330,400**
Civil Engineering Works			
Civils - Design	-		Incl.
Civils - Plant Bases	-		Incl.
Civils - Concrete, Tarmac, Ground Works, Ducting	-		Incl.
Lightning Protection	-		Incl.
Sub-Total for Civil Engineering Works		**£**	**200,000**
Electrical, Instrumentation & Control Works			
Incoming Distribution Board & Supply from Transformer	-	€	70,800
Power Supply Cables	-	€	88,500
Control Integration	-	€	23,600
Signal Cables	-	€	5,900
Earthing	-		Incl.
Gas Detection System	-	€	17,700
Internet Connection	-	€	11,800
Sub-Total for Electrical Works		**€**	**218,300**

Site Mechanical Works			
Interconnecting Pipework	-	€	177,000
Sub-Total for Mechanical Works		**€**	**177,000**
Pipeline Connection to Gas Network			
Design and Project Management	-	€	40,000
Pipeline Cost	-	€	50,000
Sub-Total for Pipeline Connection		**€**	**90,000**
Other Costs			
Design and Project Management	-	€	180,000
Principal Contractor Works	-	€	50,000
Travel/Subsistence/Expenses	-	€	30,000
Sub-Total for Other Costs		**€**	**260,000**
EPC Fees			
EPC Fee incl. Insurance - 10% of Total		**€**	**527,570**
Total Contract Cost		**€**	**5,803,270**

The above figures are for a 1,100 Nm^3/h biogas upgrade and grid injection plant. Civils are not included as they are typically installed by the AD civils contractor. The pipeline cost implemented is a placeholder value (assuming the Poolbeg Distribution Network) – the actual cost is subject to further assessment. The EPC fee covers the cost of insurance, contingency and the EPC cost of the project.

Note – pipeline to Greater Dublin Distribution Network (4 bar) is 1.3 km from site and could cost around €500,000

NB: The overall cost is ultimately dependent on the size of the plant. Higher flows will mean the BUU requires a larger compressor/more membranes, a large CO_2 recovery plant, larger cables, large diameter pipework/export pipeline etc.

Slide 42

TG2 desulphurisation cost not included?
Taha Giurani, 15/06/2022

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OPEX Overview (1)

OPEX		
Description	**Value**	**Unit**
General		
Maintenance Charge (BUU)	0.60	c/Sm^3
Propane		
Propane as a Proportion of Energy Export	10%	-
Average Propane Value Loss	1.80	c/kWh Propane
Annual Biomethane Export to Grid (excl. Propane)	5,895,961	Sm^3/annum
Annual Biomethane Energy Export to Grid	60,018,593	kWh/annum
Total Propane Export	6,001,859	kWh Propane
Propane Value Loss	**€ 108,033**	**EUR/annum**
BUU OPEX		
Power Consumption		
Electricity Consumption	0.28	kWh/Nm^3
Power Factor	0.8	-
Annual Electricity Consumption	**2,698,080**	**kWh/annum**
Activated Carbon		
Assumed H_2S Concentration	140.0	mg/Nm^3
Assumed VOC Concentration	10.0	mg/Nm^3
Total H_2S Removal	1,349	kg/annum
Total VOC Removal	96	kg/annum
Activated Carbon Absorptivity	200	kg/t
Activated Carbon Unit Cost	€ 4	EUR/kg
Total Carbon Consumption	7.23	t/annum
Carbon Consumption Cost	€ 28,908	EUR/annum
Carbon Vessels Installed	2	-
Carbon Vessel Size	5	m^3
Replacement Frequency	0.69	Years
Carbon Vessel Rental (x2)	€ 14,400	EUR/annum
Exchange Fees (i.e. Delivery, Handling)	€ 1,301	EUR/annum
Annual Activated Carbon Cost	**€ 44,609**	**EUR/annum**

OPEX Breakdown – Part 1:

- A maintenance charge is considered to account for general wear and tear attributed to the plant running hours

- Approximately 10% of all energy exported by the grid will be from propane addition, to meet the entry requirements. An average propane value loss is considered as the difference between the cost of propane and wholesale gas value (received when injected into the grid)

- The primary power consumers in the BtG process are the BUU and CO_2 plant. Suppliers suggest a power consumption of around 0.28 kWh/Nm^3 of Biogas throughput for the biogas upgrading process and 0.08 kWh/Nm^3 for the CO_2 plant

- Pre-treatment requirements are typically dependent on flow rate and biogas composition. To meet network entry requirements and avoid damage to the downstream plant, H_2S and VOCs need to be removed prior to the BUU. The values are shown in the table assuming bulk H_2S suppression is performed by means of ferric addition by the AD operator prior to transmission to the BtG plant. H_2S is then reduced from 100 ppm to <1 ppm by means of activated carbon removal

TG1

Slide 43

TG1 Project scope assumes a desulphurisation unit will be installed, no need for ferric dosing. CAPEX

Taha Giurani, 15/06/2022

OPEX Overview (2)

CO_2 Plant OPEX		
Electricity Consumption	0.08	kWh/Nm^3
Average Power Demand	88.0	kW
Annual Electricity Consumption	**770,880**	**kWh/annum**
Fixed OPEX		
BUU Maintenance Package	€ 114,188	EUR/annum
CO_2 Plant Maintenance Package	Incl.	EUR/annum
GEU Maintenance Package	€ 60,000	EUR/annum
Electrical Capacity Charge	€ -	EUR/annum
Site Operator	€ 87,685	EUR/annum
Business Rates	€ -	EUR/annum
Insurance	€ -	EUR/annum
Fuel Management	€ -	EUR/annum
Sub-Total Fixed Maintenance	**€ 261,873**	**EUR/annum**
Variable Maintenance		
BUU and CO_2 Plant	€ 34,916	EUR/annum
Sub-Total Variable Maintenance	**€ 34,916**	**£/annum**
Totals		
Total OPEX (Excl. Electricity)	€ 448,686	EUR/annum
Contingency	10%	-
Total OPEX (Excl. Electricity)	**€ 493,554**	**EUR/annum**

OPEX Breakdown – Part 2:

- To guarantee plant availability as per supplier recommendations, fixed service and maintenance contracts will need to be in place. For the BUU and CO_2 plant (the primary process equipment), this typically around 3.5% of the total CAPEX value of the plant
- A contingency has been allowed to cover items not detailed in the table
- For a 1,100 Nm^3/h Biogas to Grid plant incl. CO_2 recovery, the total OPEX excluding electricity consumption is estimated to be around €400,000 per annum
- The total estimated plant electricity consumption is around 3,500,000 kWh/annum. The cost impact of which will be dependent on the means of electricity supply (i.e. via the grid or gas engines) and the current retail prices for electricity/gas

Electricity Generation

CHP Data		
CHP Efficiency (NCV to Electricity)	43%	
CHP Availability	95%	
Annual Electricity Generation	22,760,327	kWh/annum
Effective Generation	2,735	kWe
Support Tarriff	N/A	
Support Tarriff Value	€ -	EUR/MWh
Basic Electricity Value	€ 70.00	EUR/MWh
Electricity Embedded Benefits Value	€ -	EUR/MWh
Annual Income from Support Tarriff	€ -	EUR/annum
Annual Income from Electricity Generation	€ 1,593,223	EUR/annum
Total Annual Income from CHP	**€ 1,593,223**	**EUR/annum**
Gas Engine Data		
Gas Engine Efficiency (NCV to Electricity)	43%	
Gas Engine Availability	95%	
Estimated Biomethane to Grid Site Load	416	kWe
Estimated Gas Engine Requirement	3151	kWe
Annual Gas Engine Generation	26,220,614	kWh/annum
Natural Gas Energy Input	60,978,173	kWh/annum
Total Natural Gas Input	6,452,717	Sm^3/annum
Natural Gas Retail Value	€ 42.00	EUR/MWh
Total Cost of Gas Import	**€ 2,561,083**	**EUR/annum**

- It is assumed that the current CHPs use all 1,100 Nm^3/h of the biogas proposed for upgrade for electrical generation and heat supply to the plant. Considering a 43% electrical efficiency (based on the NCV of the Biogas), this equates to a net generation of around 2.5 MWe
- If the electricity is exported to the grid, it will receive the wholesale electricity value, and avoid the need for electrical import (which includes retail charges – estimated as around 7 c/kWh)
- For the purposes of this model, it is assumed that the site is a net importer of electricity (i.e. all electricity generated from the 1,100 Nm^3/h of biogas is used by the site)
- Considering the electrical load of the BtG plant, a total natural gas import for 3 MWe of generation would be needed to replace the biogas, which is considered a cheaper solution than importing electricity from the grid. During periods of maintenance/downtime, the site will still draw electricity from the grid
- It will be a major benefit if the site can have a direct wire link to the Covanta EfW plant next door (next slide) to avoid network charges
- If there is a direct wire to EfW Plant, there will be no waste heat on site which means chemical wash not so attractive
- Gas import cost indicative of long term price not 2022/23 price

Proximity to Covanta EfW plant

(if Ringsend wanted to buy electricity from a Direct Wire to this facility)

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Revenue Streams – RTFC and Renewable Heat Subsidy (TBC)

Parameter	Value	Unit
Biogas and AD Data Summary		
Biogas Composition (%CH_4)	58%	-
Biogas Production Rate	1,100	Nm^3/h
Biogas Production Rate	1,160	Sm^3/h
Annual Biogas Production	9,636,000	Sm^3/annum
Annual Biogas Production	55,907,362	kWh/annum
Biomethane Data (for RTFC) Summary		
Biomethane Methane Content	98%	%CH_4
CH_4 Capture	100%	
Biomethane Production	692	Sm^3/h
Annual Biomethane Production	5,819,304	Sm^3/annum
Annual Biomethane Production	4,125,886	kg/annum
Annual Biomethane Production (NCV)	53,672,603	kWh/annum
Annual Biomethane Production (GCV)	59,604,672	kWh/annum
RTFC Data		
% of Biomethane Produced from Waste	100%	
Number of RTFO Certs per kg of Biomethane from Waste	3.80	
Value of 1 RTFC	47.20	c/RTFC
Total Value of 1 kg Biomethane	179.36	c/kg
Value of 1 kWh of Biomethane (Based on GCV)	12.42	c/kWh
RTFC Income		
% of RTFC to Biomethane Producer	75%	
RTFC Value Share (based on GCV)	9.31	c/kWh
Gas Commodity Value (based on GCV)	3.54	c/kWh
Total Gas Commodity Income	€ 2,110,005	EUR/annum
Total RTFC Income to Producer	€ 4,997,772	EUR/annum
Total Income	**€ 7,107,778**	**EUR/annum**

- The primary income sources for biomethane export to the grid will be the wholesale value of gas entering the grid, and either a renewable heat subsidy (subject to completion of the ongoing review), or a Renewable Transport Fuel Obligation (RTFO) via the sale of the gas for use as a vehicle fuel

- It is expected that a tariff resulting from the renewable heat obligation consultation will be worth around 8-10 c/kWh, under a tiered system. For initial modelling a Tier 1 value of 6 c/kWh has been assumed. Based on the export of 60,000,000 kWh per annum of biomethane, this is worth around £3.6 million per annum

- Renewable Transport Fuel Certificates (RTFCs) are awarded by the UK DfT for use of biomethane as a vehicle fuel. This is available to ROI Biomethane producers. There is no cap on the volume of biomethane exported for RTFC. The RTFC option is displayed as a possible case to be compared to ROI subsidy regime

- This transaction can be performed via the gas grid. This is only economically viable for biomethane produced from waste as it received double certificates (3.8 certificates per kg of fuel)

- Currently, the traded RTFC value is around 40 p/RTFC (~48 c/RTFC). The Gas Shipper and CNG Station Operator will take a cut of the final RTFC value, estimated to be around 25-30% of the total value. If biomethane is used/distributed by the biomethane producer, 100% of the RTFC value will be retained

Biomethane to Grid Project – Proposed Scheme Overview

Parameter	Scheme 1	Scheme 2	Unit
Details of Scheme			
Scheme	Gas to Grid	Gas to Grid	-
Support Tariff	RTFC	RH	-
Tier 1 Cap	Unlimited	60,000,000	kWh
Green Gas Scheme After Tier 1	N/A	RH	-
Tier 2 Cap	Unlimited	100,000,000	kWh
Green Gas Scheme After Tier 2	N/A	RH	-
Annual Production			
Annual Biogas Production	9,636,000	9,636,000	Sm^3/annum
Annual Biomethane Production	5,819,304	5,819,304	Sm^3/annum
Annual Biomethane Production	4,125,886	4,125,886	kg/annum
Annual Biomethane Production (NCV)	53,672,603	53,672,603	kWh/annum
Annual Biomethane Production (GCV)	59,604,672	59,604,672	kWh/annum
External Heating Deduction	0	0	kWh/annum
CHP Biogas Input Capacity	0	0	Nm^3/h
Biomethane to Site Heating	0	0	kWh/annum
Energy Export to Grid	59,604,672	59,604,672	kWh/annum
Electricity Import	1,384,163	1,384,163	kWh/annum
Natural Gas Import	67,920,371	67,920,371	kWh/annum
CO_2 Production	6,865	6,865	t/annum

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Commodity Cost Projections – Example

Cost Projections					
Year	Gas (Wholesale)	Gas (Retail)	Electricity (Wholesale)	Electricity (Retail)	LCO_2 (Wholesale)
	Total Market Report & BEIS High Scenario (2019)				Assumed
2023	6.39	7.21	19.89	27.3	81.90
2024	4.99	5.81	15.21	22.2	93.60
2025	3.11	3.93	8.54	15.56	105.30
2026	3.15	3.97	8.19	15.80	117.00
2027	3.19	4.01	8.31	15.33	128.70
2028	3.23	4.05	7.96	14.98	140.40
2029	3.27	4.09	7.96	14.98	140.40
2030	3.31	4.13	7.61	14.86	140.40
2031	3.35	4.17	7.49	14.86	140.40
2032	3.39	4.21	7.61	14.86	140.40
2033	3.43	4.25	7.84	14.86	140.40
	c/kWh	c/kWh	c/kWh	c/kWh	EUR/tonne

Recent inflation has impacted the economics of a biomethane to grid project. In the short term, the cost of any gas/electricity imports and exports have risen immensely. Subject to the resolution of contributing factors (e.g. COVID-19, Russian invasion of Ukraine etc), figures are expected to fall in the medium term. Such considerations should be taken into account in terms of forecasting potential OPEX/revenues. The above values consider Total Energy's daily market report for period 2023-2024 and the BEIS 2019 Energy and Emissions Projects (high) forecast for 2025 onwards, assuming the market will settle

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Example Cashflow Results from the Biomethane to Grid Scheme

Biomethane to Grid - Renewable Heat Tariff w/ CO_2 Recovery

Year	Gas Commodity Sale Income	Renewable Heat Income	CO_2 Income	BtG Plant OPEX (Excl. Electricity)	Natural Gas Import (Gas Engines)	Electricity Import	Net Cashflow
2022	€ -	€ -	€ -	€ -	€ -	€ -	€ -
2023	€ 3,808,189	€ 3,576,280	€ 562,266	-€ 493,554	-€ 4,895,754	-€ 377,337	€ **2,180,092**
2024	€ 2,975,148	€ 3,576,280	€ 642,590	-€ 493,554	-€ 3,946,491	-€ 307,699	€ **2,446,274**
2025	€ 1,856,492	€ 3,576,280	€ 722,914	-€ 493,554	-€ 2,671,767	-€ 215,390	€ **2,774,976**
2026	€ 1,880,293	€ 3,576,280	€ 803,238	-€ 493,554	-€ 2,698,889	-€ 218,629	€ **2,848,740**
2027	€ 1,904,095	€ 3,576,280	€ 883,562	-€ 493,554	-€ 2,726,011	-€ 212,151	€ **2,932,221**
2028	€ 1,927,896	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,753,133	-€ 207,292	€ **3,014,083**
2029	€ 1,951,697	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,780,254	-€ 207,292	€ **3,010,762**
2030	€ 1,975,498	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,807,376	-€ 205,673	€ **3,009,061**
2031	€ 1,999,299	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,834,498	-€ 205,673	€ **3,005,740**
2032	€ 2,023,101	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,861,620	-€ 205,673	€ **3,002,420**
2033	€ 2,046,902	€ 3,576,280	€ 963,885	-€ 493,554	-€ 2,888,741	-€ 205,673	€ **2,999,099**

The above cashflows represent the net difference between the proposed BtG scheme and a business as usual case. The scheme considers the parameters displayed on the previous slides, whereby 1,100 Nm^3/h of biogas is upgraded for biomethane export to grid, diverted from current CHP generation. All biomethane exports receive a Renewable Heat tariff equivalent to 6 c/kWh. 'Natural Gas Import' accounts for the replacement of the biogas CHPs with natural gas import for use in gas engines. It is considered that electricity is purchased at its retail value to operate the site when the gas engines are not available (5% downtime assumed). Commodity values are based on the table in the previous slide.

The results suggest biomethane to grid export with CO_2 capture would be highly lucrative.

Initial analysis shows the scheme offers a potential annual revenue increase of €3,000,000 vs the business as usual case.

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Example Cashflow Results from the Biomethane to Grid Scheme

Biomethane to Grid - RTFC Scheme w/ CO_2 Recovery

Year	Gas Commodity Sale Income	RTFC Income	CO_2 Income	BtG Plant OPEX (Excl. Electricity)	Natural Gas Import (Gas Engines)	Electricity Import	Net Cashflow
2022	€ -	€ -	€ -	€ -	€ -	€ -	€ -
2023	€ 3,808,189	€ 4,703,511	€ 562,266	-€ 493,554	-€ 4,895,754	-€ 377,337	€ **3,307,322**
2024	€ 2,975,148	€ 4,703,511	€ 642,590	-€ 493,554	-€ 3,946,491	-€ 307,699	€ **3,573,504**
2025	€ 1,856,492	€ 4,703,511	€ 722,914	-€ 493,554	-€ 2,671,767	-€ 215,390	€ **3,902,206**
2026	€ 1,880,293	€ 4,703,511	€ 803,238	-€ 493,554	-€ 2,698,889	-€ 218,629	€ **3,975,970**
2027	€ 1,904,095	€ 4,703,511	€ 883,562	-€ 493,554	-€ 2,726,011	-€ 212,151	€ **4,059,451**
2028	€ 1,927,896	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,753,133	-€ 207,292	€ **4,141,313**
2029	€ 1,951,697	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,780,254	-€ 207,292	€ **4,137,992**
2030	€ 1,975,498	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,807,376	-€ 205,673	€ **4,136,291**
2031	€ 1,999,299	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,834,498	-€ 205,673	€ **4,132,970**
2032	€ 2,023,101	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,861,620	-€ 205,673	€ **4,129,650**
2033	€ 2,046,902	€ 4,703,511	€ 963,885	-€ 493,554	-€ 2,888,741	-€ 205,673	€ **4,126,329**

Section 5

Conclusions

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Conclusions (1)

- Based on the economic model and capacity study, biomethane injection into the GNI network is both a feasible and profitable project. The economic gains from the project can be further heighted by considering the projected value of CO_2 in both the short and long term.
  - The capacity study shows 2 feasible options for direct gas injection to the GNI network. Connection to the isolated 4barg Poolbeg distribution network or greater Dublin distribution network
  - Either option is a good fit for the site. If the site plans expects to inject 100% of its gas, the greater Dublin distribution network is recommended as there is likely to be no constraint periods across the year if injecting a continuous flow of 1000 m^3/h
  - The fact that the engines can operate on biogas is a significant advantage in the event that the biomethane plant is down

- With respect to the technology choice; CSL would recommend the installation of either a membrane separation plant (preferred) or an amine wash facility. This is subject to further discussion to develop a better understanding of the site operational requirements in addition to CAPEX and OPEX costs associated to each.

- If the gas engines on site operate on natural gas but this is only for Dunkelflaute type conditions (no wind in NW Europe and so very high electricity prices and need for gas generation) with a direct wire to the Covanta plant then membrane will be the best option due to absence of waste heat from the gas engines

- The Bio-CO_2 from the plant should be attractive in the Dublin area as at present such CO_2 is imported from UK and fossil derived

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Conclusions (2)

- The proposed areas for site development has raised some concerns. Area 1 appears feasible however CSL requests an opportunity to further discuss the layout to refine and optimise configurations A & B. Immediate concerns for area 1 relate to the proximity to nearby admin buildings, G2G plant located at the site entrance (possible impact to traffic within the area for deliveries etc) and the need to better understand how the client would like to develop the mechanical integration of pipework (Biogas pipework from AD to G2G plant)
  - Areas 2 and 3 are not ideal; the proposed areas are too small for development. While specific components can be built within these areas, this would significantly impact the mechanical and electrical integration costs
  - Areas 2 and 3 appear difficult to maintain good level of access for maintenance and commissioning activities

- Monetisation via UK RTFC is very attractive and shown as a case for comparison with the new Irish incentive scheme. Whilst CAW/Irish Water ma not want to go down the RTFC route, private developers in Ireland using waste feedstock will see this as attractive , particularly if risk underpinned by a lower value to reliable subsidy scheme in Ireland

- Further work
  - Likely ROI Biomethane Support scheme
  - H_2S removal
  - Direct wire to Covanta
  - Bio-CO_2 sale options
  - Technology selection and tender to suppliers

Appendix – A1

Supporting Slides

UK Biogas Upgrading Suppliers

Water Wash

GREENLANE RENEWABLES™

MALMBERG

Chemical Absorption

Ammongas

WÄRTSILÄ

Membrane

EnviTec Biogas

HoST BIO-ENERGY INSTALLATIONS

dmt Environmental Technology

Air Liquide

ClarkeEnergy® A KOHLER COMPANY Engineer - Install - Maintain

PENTAIR

PSA

CARBOTECH

Appendix – A2

CO_2 Removal Technologies

i) Absorption -Water Wash

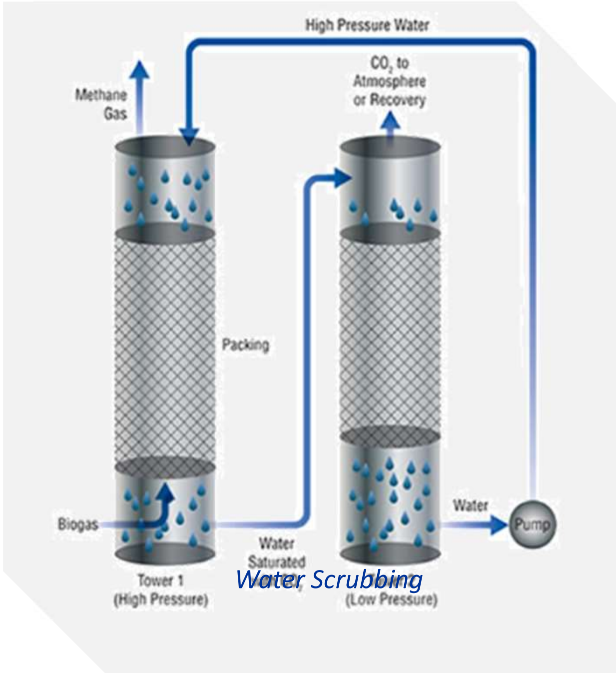
Absorption techniques exploit the difference in selective affinity of the components of interest with respect to the solvent used. Several different technologies have been developed based on different liquid absorption medias in which the CO_2 is dissolved and the CH_4 is not. The temperatures and pressures utilized for controlling the absorption and desorption (stripping) process are subject to which media is used

In water scrubbing, CO_2 is removed by a water wash process. The process uses a pressurised water (6-8bar) within the first column to preferentially react soluble contaminants such as CO_2, H_2S generating a clean methane stream. Often, the process water is recirculated in the biogas upgrading plant, which requires the desorption of the CO_2 from the process water. This is achieved by passing the contaminated water through an air stripper at ambient pressure and temperature. In many cases, post treatment of the stripper air and water is needed to fulfil environmental legislation due to trace contaminates (assuming no pre-treatment plant is installed – to handle VOC's/H_2S. It is important to note that non-regenerative water wash is a technique commonly used by WWTP due to the large quantities of water available in addition to WW treatment capacity.

For optimal operation, a base is often supplement to the process to maintain peak efficiency due to the oxidation of H_2S in the biogas. A antifoam agent may also be needed to improve mass transfer in the absorption column and increase the separation between carbon dioxide and methane. Growth of microorganisms in the scrubber is a commonly reported issue. This can be reduced by operating at a lower temperature and may be further minimized by the addition of biocides or treatment of the fresh water to the upgrading plant to minimize the amount of nutrients in the process water.

Advantages
- Suitable for ammonia-containing gas streams
- Suitable for high flowrate systems
- Multi-contaminant gas treatment (VOC,CO_2,H_2S)
- Capable of large flow rates
- High quality biomethane

Disadvantages
- Pipe fouling
- Contaminated liquid stream needing further treatment
- High CAPEX as well as consumption of water and/or chemicals
- Large footprint
- Entrained N_2 making CO_2 recovery difficult)



Water Scrubbing

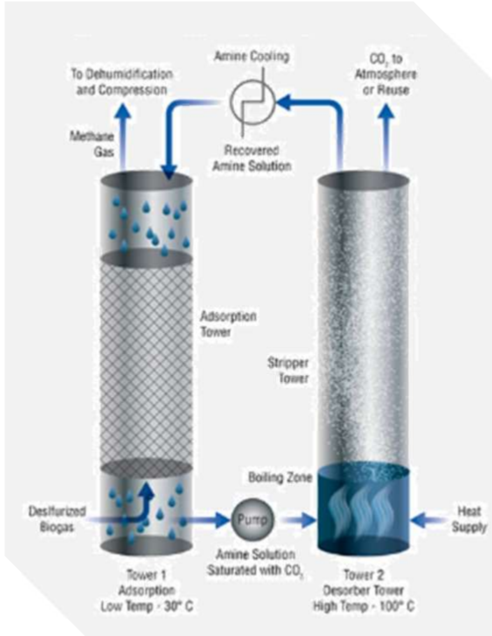
ii) Absorption - Amine Wash

The process of amine scrubbing use a reagent with high CO_2 affinity which chemically binds thereby removing it from the gas stream. This is most commonly performed using a water solution of amines such as MDEA (methyldiethanolamine). Amine scrubbing system uses a two-step approach to upgrading biogas. The first step is an adsorption process followed by stripping column to regenerate the solvent.

The inlet raw biogas enters the absorber from the bottom and is set in contact with the amine solution. The CO_2 content of the biogas reacts with the amine and is transferred to the solution. The methane fraction of the biogas passes through the reactor untouched by the solvent due to the preferential binding property for CO_2. The spent amine solution is then passed to the stripping column where the CO_2 is desorbed by a regeneration process which heats the solvent to boiling point (steam injection); the CO_2 in the stripping tower disassociates from the solvent and is discharged. The regenerated amine solvent is condensed and recycled.

Amine scrubbers are effective for multipollutant control, allowing simultaneous cleaning of both CO_2 and H_2S without the need for pre-treatment. With high concentrations of H_2S, the spent solvent will be a complex containing both CO_2 and H_2S. Once dissociated, the resultant flue gas can be passed through a boiling system to effectively remove the H_2S to generate a pure CO_2 stream making this an effective technology for CO_2 liquefaction and storage. . Its important to note that while this system is effective for H_2S removal, there may be more cost effective options such as desulfurization scrubber which can achieve up to 95% reduction rates.

Systems operates at low operating pressures (100-200mbar). This low-pressure design leads to improved operational savings compared to typical high pressure design such as water scrubbers.

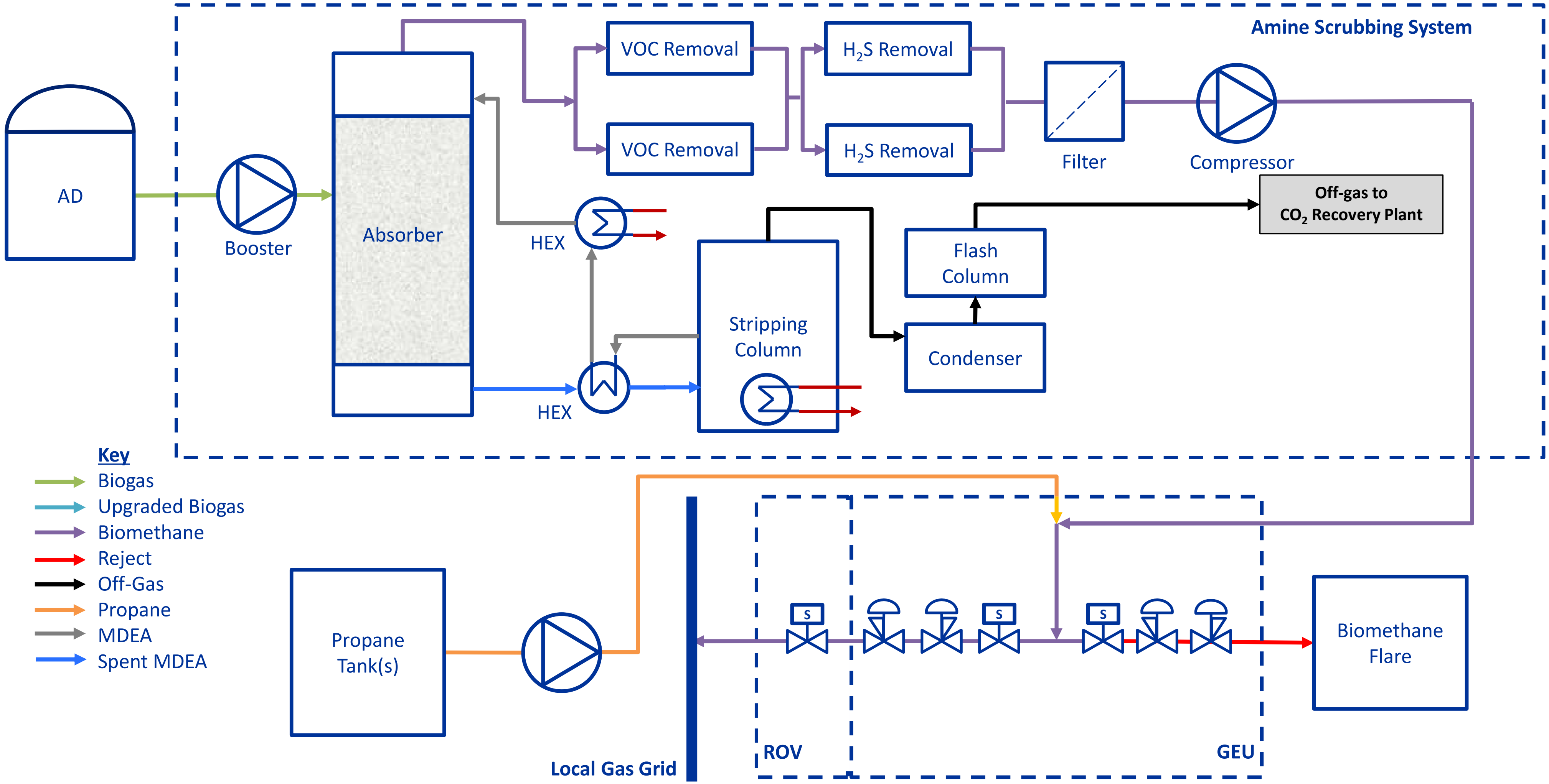


Advantages
- Suitable for ammonia-containing gas streams
- Suitable for high flowrate systems
- High methane purity
- Low methane Slip
- Pure CO_2 stream can be obtained
- Multipollutant control (NH_3, VOCs, H_2S and siloxanes)

Disadvantages
- Energy Intensive (Regeneration process)
- Pre-treatment maybe required
- Difficulties in handling solvent including solvent loss
- Salt precipitation, foaming and poisoning of amine
- Exhaust gas treatment maybe required (if not precleaned)
- Amine technology does not offer appreciable removal of O_2 or N2
- Not suitable for low flow rate systems

Ammongas Amine Solution

High Level Process Flow Diagram – Gas to Grid Plant with Amine Wash



Amine Plant – Preliminary GA

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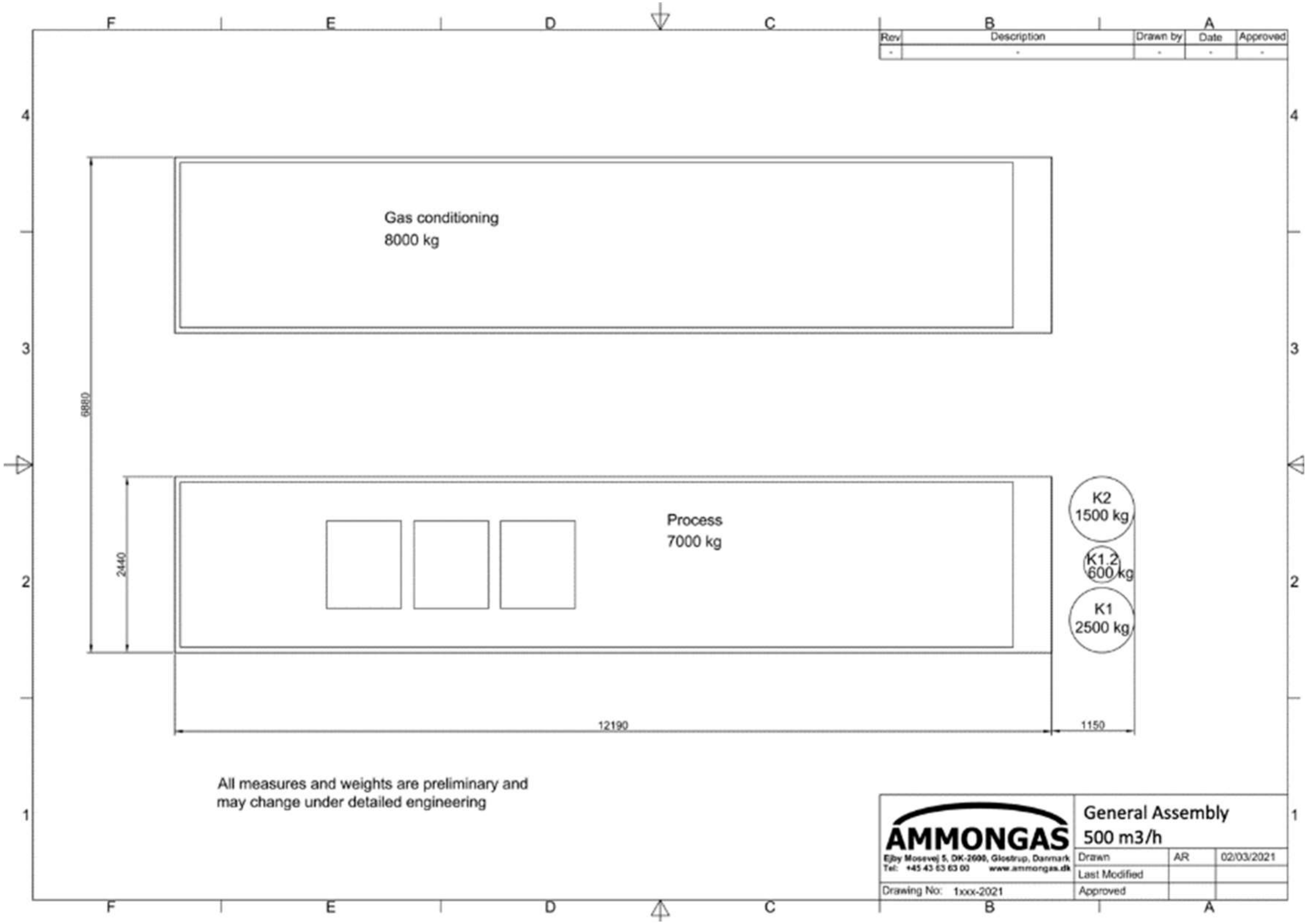

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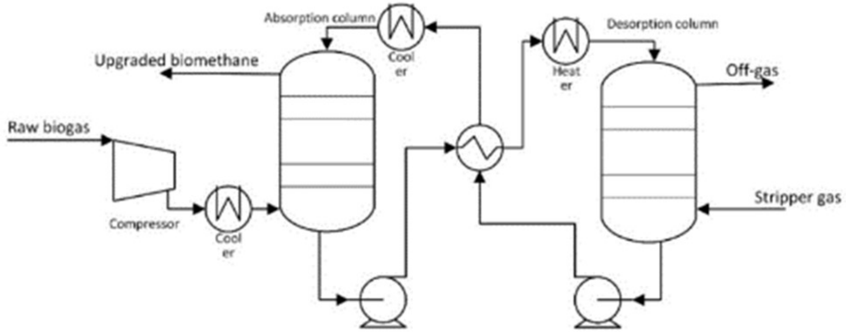
iii) Absorption (Organic Wash)

The process resembles that of a water wash or amine scrubber and operates under a similar principal (High solubility for CO_2 in the organic solvent – However, here the difference in solubility is much greater allowing for small diameter vessels to be used).

Biogas is compressed to 7-8 bar and then cooled before being fed to the bottom of an absorption column. Here, CO_2 is absorbed to the liquid phase using an organic solvent such as 'Genosorb' which is a mixture of mixture of dimethyl ethers and polyethylene glycol. The spent solvent is then flashed where some of the CO_2 and CH_4 is desorbed and then further on to the desorption column where the rest of the solvent is regenerated by adding heat. The heat needed is supplied from waste heat within the process. This makes the energy consumption similar to that of a water scrubber (requiring electricity for mainly the compressor, the cooler and the feed pump).

The corroding effect seen with amine scrubber is not present with 'Genosorb' scrubbing as the solvent is designed to be anti-corrosive. This allows for non stainless-steel piping reducing CAPEX costs. The foaming issue seen in amine scrubbers can also be ignored for the same reasons.

Most other impurities such as H_2S, NH_3 and VOCs are dissolved in the organic solvent and recovered in the stripping column using air. Therefore, post treatment of the air for mostly may be depending on legislation. The use of air generated a complex flue gas stream, making CO_2 recovery difficult.



Organic Scrubber

Advantages

- Avoids corrosion and foaming issues
- Suitable for high flowrate systems
- High methane purity
- Low methane Slip
- Multipollutant control (NH_3, VOCs, H_2S and siloxanes)

Disadvantages

- Difficulties in handling solvent including solvent loss
- Exhaust gas treatment maybe required (if not precleaned)
- Amine technology does not offer appreciable removal of O2 or N2
- Not suitable for low flow rate systems
- Difficult to capture CO_2 (air entrainment)
- Gas leaves partially saturated, will require drying
- Not applicable for biogas containing high O_2/N_2

iv) Adsorption

In the adsorption process, specific molecules are adsorbed to the surface of the zeolites (molecular sieves) at high pressures and then released at low pressures when the material is saturated. There are two types of adsorption operations: physical, where the pollutant molecules are held in place in the pores by weak physical forces or chemical, in which much stronger chemical bonding forces are also present.

In both applications, the solid will become saturated and is then be discarded, sent back to the manufacturer to be cleaned out, or regenerated in situ. The regeneration process can be achieved using heat or pressure to reverse the adsorption process and volatilize the absorbed compounds. Direct steam injection is the most widely used method of providing heat for regeneration.

Dissociating the pollutant from the surface can be achieved with either of the following operating methods:

- Pressure Swing Adsorption (PSA)
- Temperature Swing Adsorption (TSA)
- Electric Swing Adsorption (ESA)

The most used adsorption technique is PSA. PSA plant uses a multistage process operating on 4 different phases; adsorption, de-pressuring, regeneration and pressure build up. The heart of the process is an adsorptive media, which separates gas molecules based on their molecular weight. CO_2/N_2/O_2 preferentially adsorb onto the media surface because of the molecular size variance compared to methane, allowing methane to permeate through.

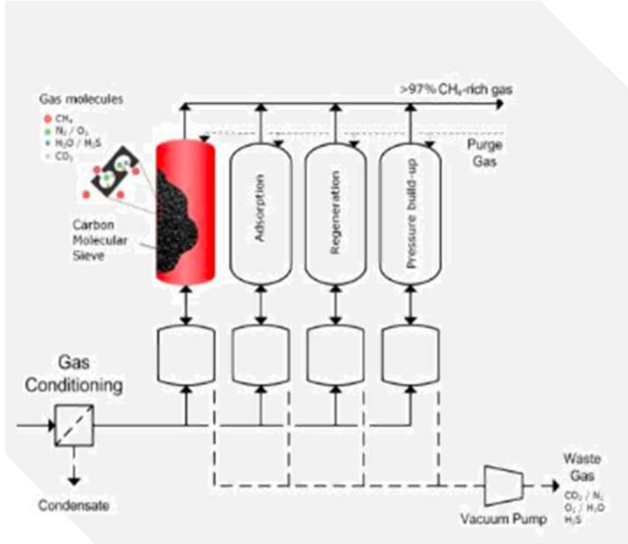
When a vessel becomes saturated, it is regenerated by reducing the pressure. At lower pressure, compounds are desorbed from the media in a separate off gas stream. This is a low quality gas stream that contains a mixture of adsorbed compound including CO_2, H_2S, and trace methane. Each vessel alternates its mode of operation from service, depressurization, regeneration and finally repressurisation before it returns to service mode to allow for a continuous operation.

Advantages

- High Biomethane purity (96-98%)
- PSA is the only gas upgrading technology that can separate oxygen and nitrogen from methane
- Economical in a wide range of flow rates
- Small footprint – no large towers

Disadvantages

- 2-4% methane slip
- Pre-treatment required (H_2S poisoning of media)
- Complex waste gas stream (Expensive CO_2 recovery process)
- Exhaust gas cleaning recommended or obligatory depending on the country emission requirements



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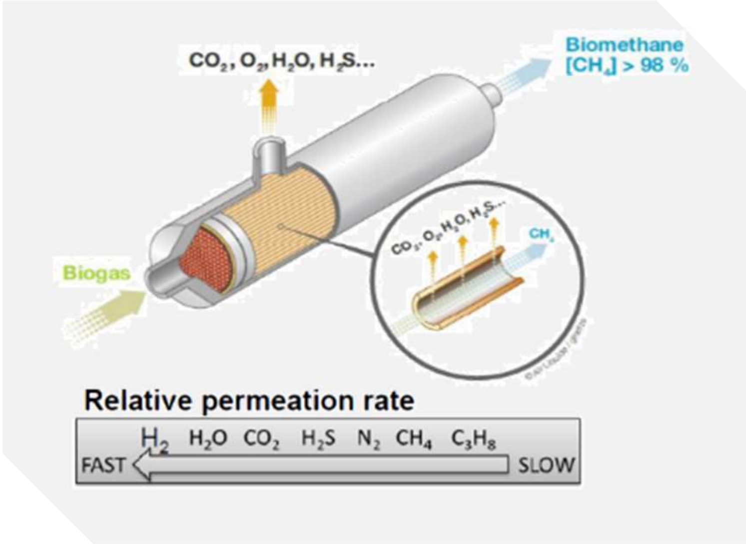
v) Membrane Separation

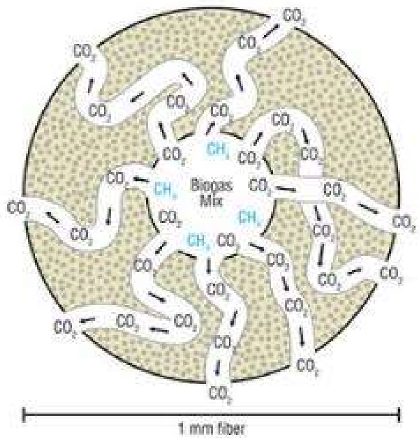
This technology consist of a single or multistage semipermeable membrane to separate CO_2 from the bulk gas stream by establishing a partial pressure gradient across a semipermeable glass/rubber surface that constitutes the membrane. By design, the membrane allows gas molecules to pass preferentially, resulting in a more concentrated pollutant stream on one side of the membrane due to the atomic differences in molecular weight of each component (and thereby the permeation rate). While, single-stage separation units exist, depending on the gas composition and volume of gas involved, and multistage separation is required.

Membranes can also be used for simultaneous removal of other impurities. Although, for plant operators to benefit from the additional revenue stream sourced from liquefied CO_2 and to further extend membrane lifetime, other impurities contained within biogas (e.g. H2S, VOC's) are treated upstream of the upgrading process. As part of the process design, suppliers will integrate activated carbon vessels which absorb both H_2S and VOC's with high efficiency.



Example Configurations Available

- Two stage with CO2 liquefaction → Pentair, Springhill Nurseries
- Two stage with RTO device to burn off 2% CH_4 in off-gas → Air Liquide, Future Biogas
- Three stage with CO2 liquefaction → Bright Biomethane, Pentair
- Three stage with <0.5% CH4 vented → DMT, Methapower, Envitec, MT-Energie, TPI (Clarke Energy), Air Liquide



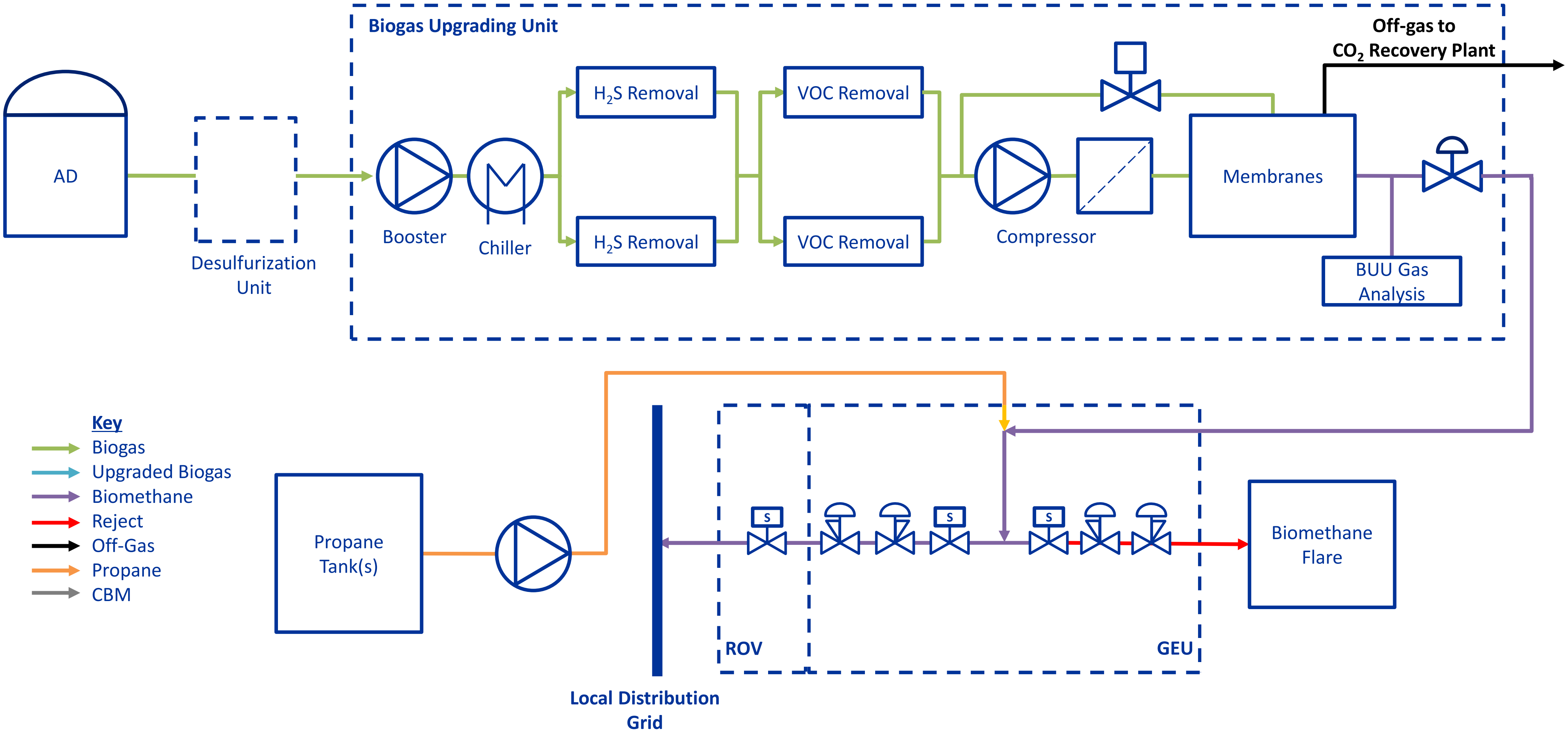
Advantages

- Compact Design – Small footprint with no large towers
- Modular Design – Can be integrated with existing BUU sites
- Low maintenance, few consumables used
- Food grade liquid CO_2 produced (Pentair)
- Low methane slip and high biomethane purity/yield
- Competitive rates – More than 6 suppliers in the market
- Configurable to recover all CO_2% and 0% methane slip
- Easy to manipulate operation
- Membrane lifetime up to 10 years if well maintained

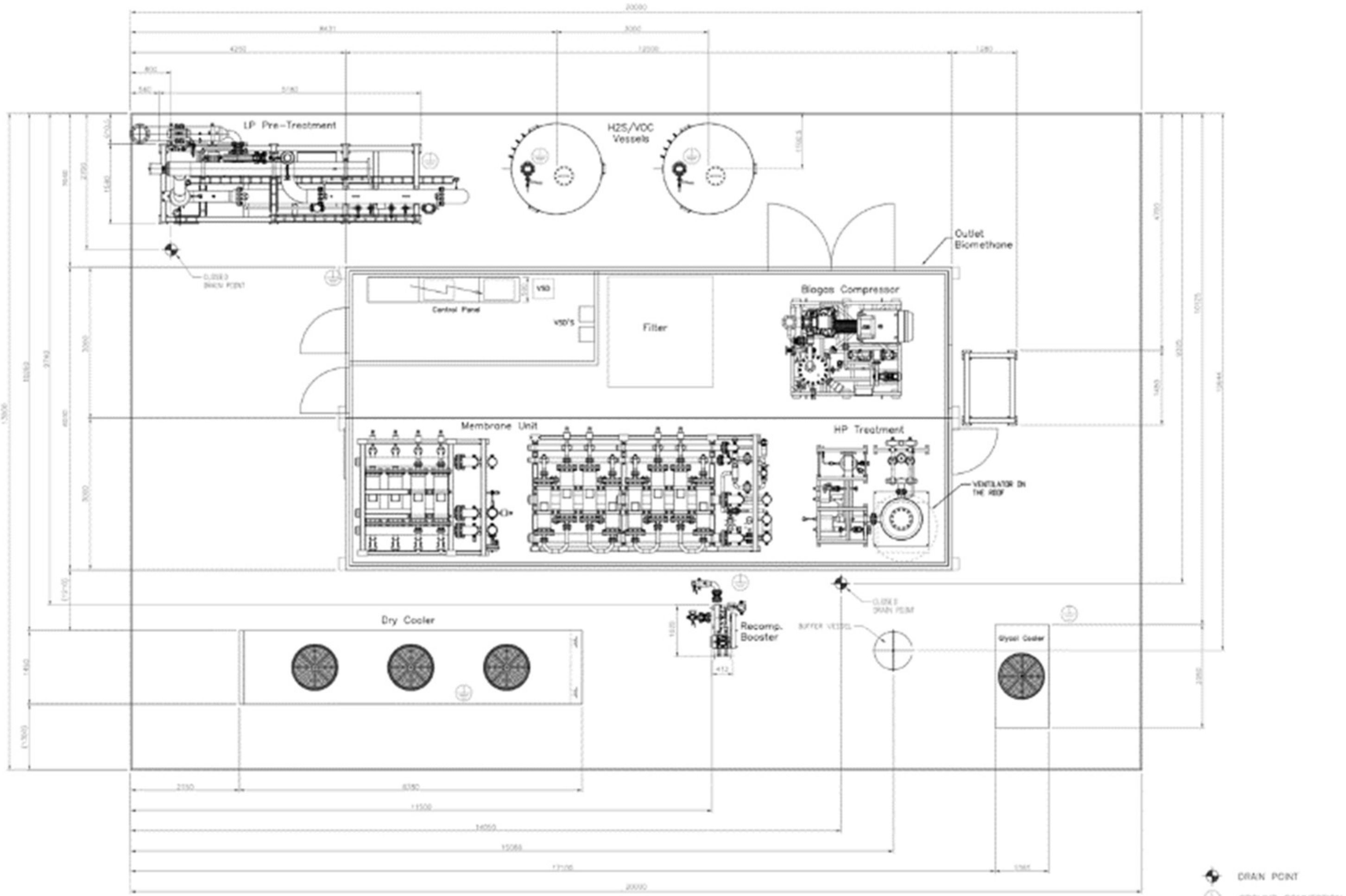
Disadvantages

- Requires dry gas
- High electrical demand (compression for membranes)
- If purified CO_2 stream is desired, dedicated H2S/VOC removal units required (Higher CAPEX)
- Flow rate limited for one system

High Level Process Flow Diagram – Gas to Grid Plant with Membrane Separation



Membrane Plant – Indicative GA (Pentair)



PRELIMINARY

Appendix – A3

Membrane Upgrading Process Description

Membrane Upgrading Plant (Bright Biomethane)

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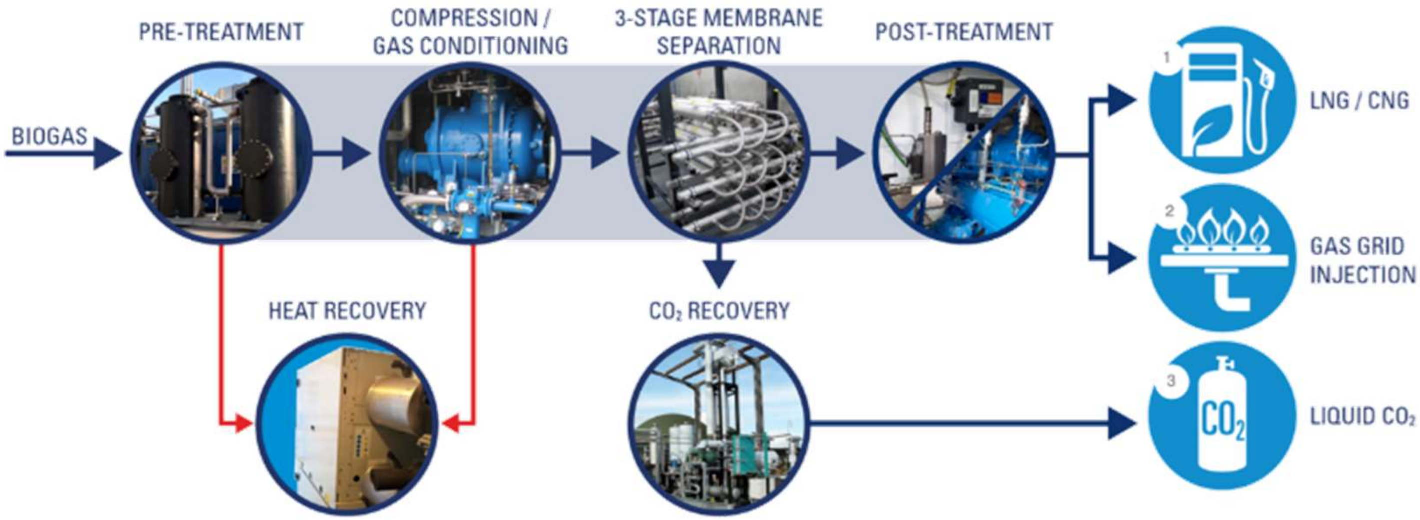

Pre-treatment Of Biogas

This will involve a drying process as well as hydrogen sulphide (H_2S) and VOC removal to prevent membrane poisoning. H_2S among other contaminants are removed from the biogas using a active carbon filter vessel. The biogas is analysed between each filter to determine the H_2S/VOC breakthrough point to aid with plant predictive maintenance. Water is removed by cooling the biogas to approximately 5°C (dew point) with a chiller.

Compression & Heat Recovery

After pre-treatment of the biogas, the biogas is compressed to the necessary pressure for upgrading by membranes. To optimise the process, heat is recovered in various stages; heat from biogas drying, heat from gas compression and cooling the gas after the compressor may be recovered using a heat recovery system.

Separation By 3 Stage Membrane Arrangement

CH_4 is separated by means of an imposed pressure difference over the membrane to obtain two purified gas streams, namely biomethane and CO_2. The membrane modules in the system are arranged in 3 stages. The permeate gas from the different stages is recirculated to improve process efficiency and lowest methane loss .

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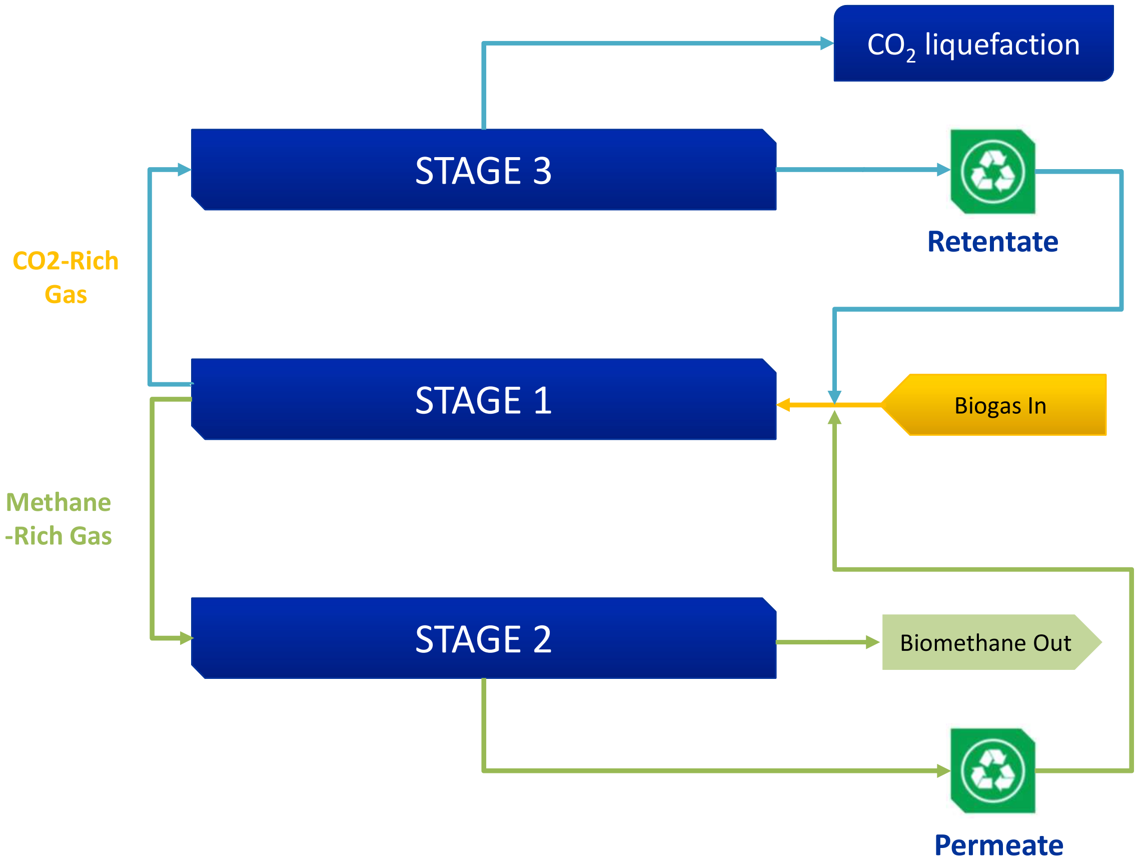
Process Flow Diagram (Bright Biomethane)



The permeate of stage 2 and retentate of stage 3 are recycled to achieve a recovery rate above 98%. The 3rd stage is an optional unit used to recover any methane slip and thereafter process the captured CO_2 towards the liquefaction plant

3-stage membrane separation

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Appendix – A4

H_2S Removal Technology

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H_2S in Biogas Background Summary

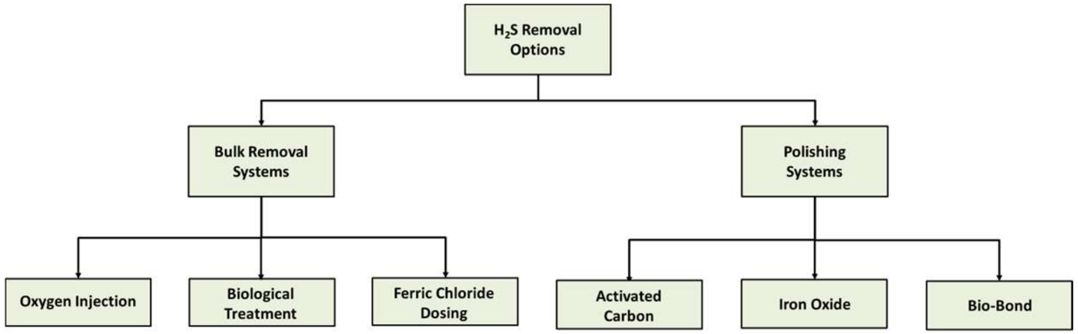
- Hydrogen sulphide (H_2S) is always present in biogas, although concentrations vary with the feedstock. The concentration of hydrogen sulphide in the gas is a function of the digester feed substrate and inorganic sulphate content. Wastes which are high in proteins containing sulphur-based amino acids (methionine and cysteine) can significantly influence biogas hydrogen sulphide levels

- The inorganic sulphate present in the feedstock of the digestion process will also be reduced by sulphate reducing bacteria in the digester and end up contributing to the sulphide level in the biogas.

- The hydrogen sulphide contained in biogas causes odours, corrosiveness, and sulphur emissions when the gas is burned.

- If the gas is to be used in internal combustion engines, membranes, turbines, compressors or fuel cells, the removal of hydrogen sulphide from the biogas may be required to protect the equipment.

- For grid injection or use in a truck fuel, all H_2S has to be removed



Ferric Chloride Dosing

- Ferric Chloride dosing is an option for H_2S suppression into digesters
- It can be added into the digester sludge in order to prevent the formation of H_2S gas
- Ferric Chloride is commonly used to reduce bulk H_2S levels in biogas from 10,000 to 2,500 ppm down to 50-100 ppm
- This is not low enough for grid injection, running through biomethane upgraders, GEUs however is a good pre-treatment option that is both relatively cheap and easy to carry out, in combination with a polishing step
- The process involves the following reaction which produces elemental sulphur

$$2FeCl_3 + H_2S \rightarrow 2FeCl_2 + S + 2HCl$$

Figure: Example dosing tank and dosing pump arrangement

Figure: Ferric chloride storage IBC

Biological Treatment

- Biological treatment is another commonly used method for desulphurisation
- Used to treat high H_2S loads down to the 100ppm range (and sometimes lower) however an activated carbon polishing system in series is usually required to reduce the H_2S to <10ppm
- CSO are a supplier that make these systems (such a system has been installed by GWE biogas)
- Benefits include relatively low footprint, low OPEX
- Higher CAPEX that ferric dosing system
- Good for treating large quantities of H_2S >1000ppm
- Significant savings on OPEX can be made using such systems if activated carbon beds are experiencing high H_2S loads
- No chemicals are required, sits in a stand alone solution

Figure: CSO scrubbing system

CSO Group
AD & Pollution Solutions

Oxygen & Air Injection

- Oxygen can be injected, either directly into anaerobic digesters or downstream
- This reacts with the H_2S, producing either elemental sulphur or sulphates depending on oxygen concentration
- A low, controlled concentration allows for the production of elemental sulphur (as a solid) – otherwise, sulphates are produced (which tend to dissolve into the water/condensate present)
- When injected directly into digesters, just enough oxygen is injected to partially oxidise H_2S into the elemental sulphur **without inhibiting the methanogenesis process**
- An O_2 generator can be installed to prevent N_2 being added into the biogas

Figure: example O2 generation system

Figure: small scale O2 generator

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Adsorption (Activated Carbon, Bio-Bond, Iron Oxide)

- Adsorptive desulphurisation systems remove nearly all hydrogen sulphide from the gas stream and ensure in a duty-standby configuration a continuous operation
- Remove H_2S down to <5ppm typically
- Require carbon adsorbent change outs
- Can be used in conjunction with biological treatment, oxygen injection or ferric dosing as a polishing step
- Only option for ensuring that biogas will meet inlet specification for upgraders
- Sizing depends on ppm of H_2S in biogas
- Can have significant OPEX (adsorbent switch outs) with higher H_2S levels – **not recommended for bulk H_2S removal**

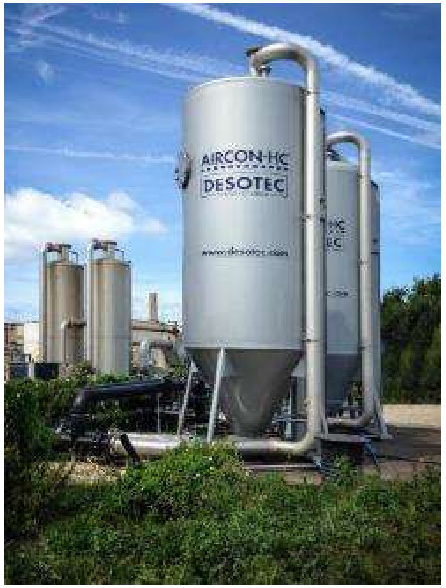

Figure: activated carbon scrubbing tanks

Appendix – A5

Propane Injection

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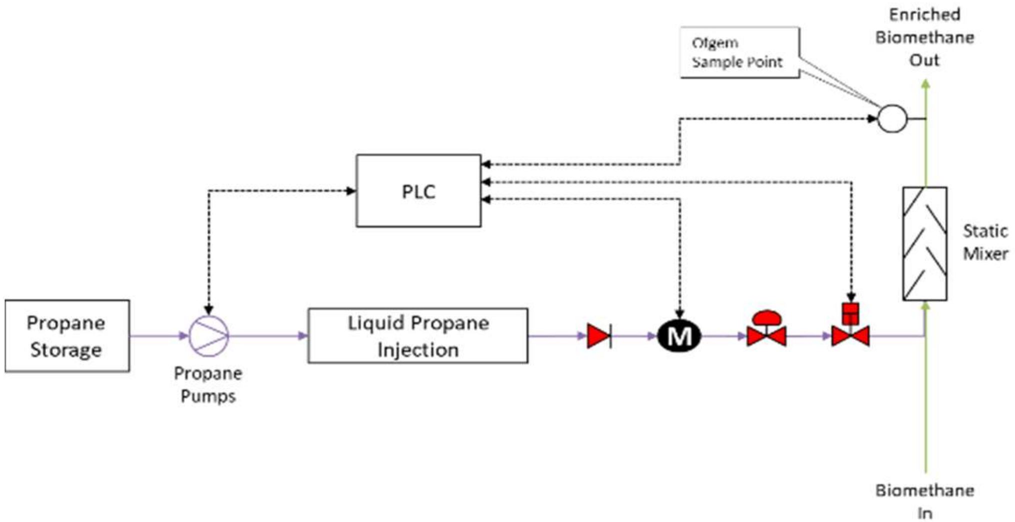
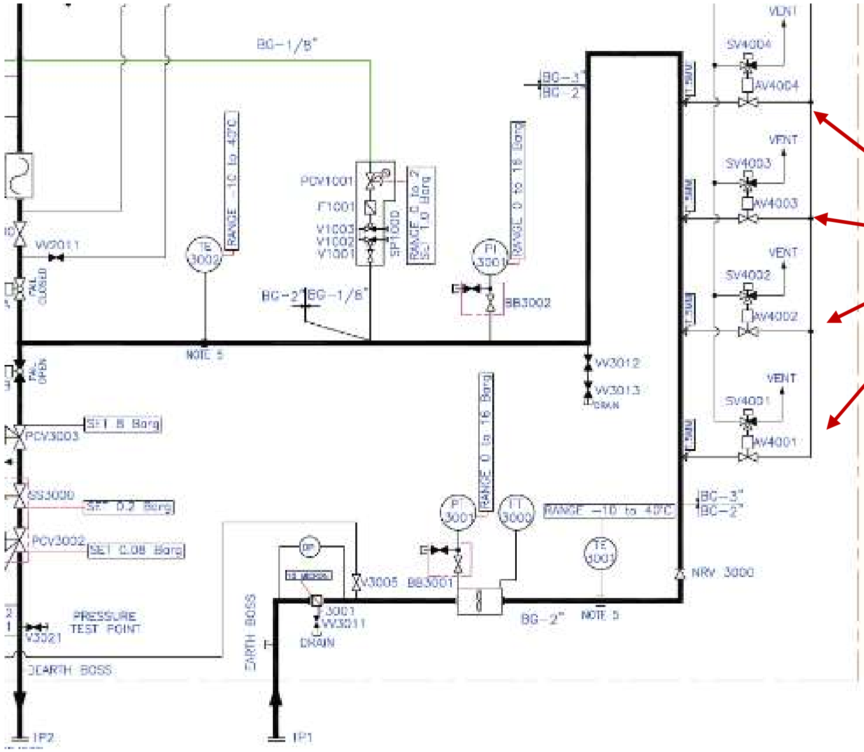
Options for Propane Injection

- Vaporiser – this uses heat to vaporise the propane prior to injection and blending in biomethane stream. Heat can be sourced from:
  - Either from CHP or compressors
  - Electric/NG heater (penalised on RHI)
  - Hot water
- Liquid injection system - uses the heat in the incoming gas stream to vaporise the propane after injection into the biomethane stream



Electric vaporisation system

Injection Points



Propane Injection within GEU

Propane Injection within GEU using biomethane latent heat for vaporisation

Propane Storage – Above Ground or Buried?

Propane tanks can be installed above-ground on a concrete plinth or below-ground. There are positives and negatives to both options, there is also a mounded option which is a hybrid approach:

Storage Arrangements

Three possible options for propane storage

- Above ground – simplest installation
- Buried or mounded – halves separation zone required
- Part buried and part mounded

24 tonnes storage max

- If above 24t, this need COMAH regulations and planning permission and a water deluge system
- 2x12 tonne more readily available but single tank can be used (larger separation zone)
- The Liquefied Petroleum Gas Association publication Code of Practice No.1 (Pt 1) covers siting of LPG storage tanks above ground and Code of Practice 1 (Pt 4) covers siting of mounded or buried LPG storage tank

Above-Ground Advantages

- Cheaper than buried (less civils cost and lower propane cost)
- More standard installation (90% of sites)
- Easier maintenance/inspection
- Easier civils works

Above-Ground Disadvantages

- Visually not as appealing – could cause planning issues
- Technically less safe than when buried in a fire event

Buried Positives

- Small visual footprint
- May be the 'ALARP' safety option when considering COMAH

Buried Disadvantages

- More expensive installation and maintenance
  - Higher 'fixed' propane price
  - Higher civils costs
- Technical issues if ground conditions not appropriate (sinking etc.)
- Limited for 4T or less (per tank)

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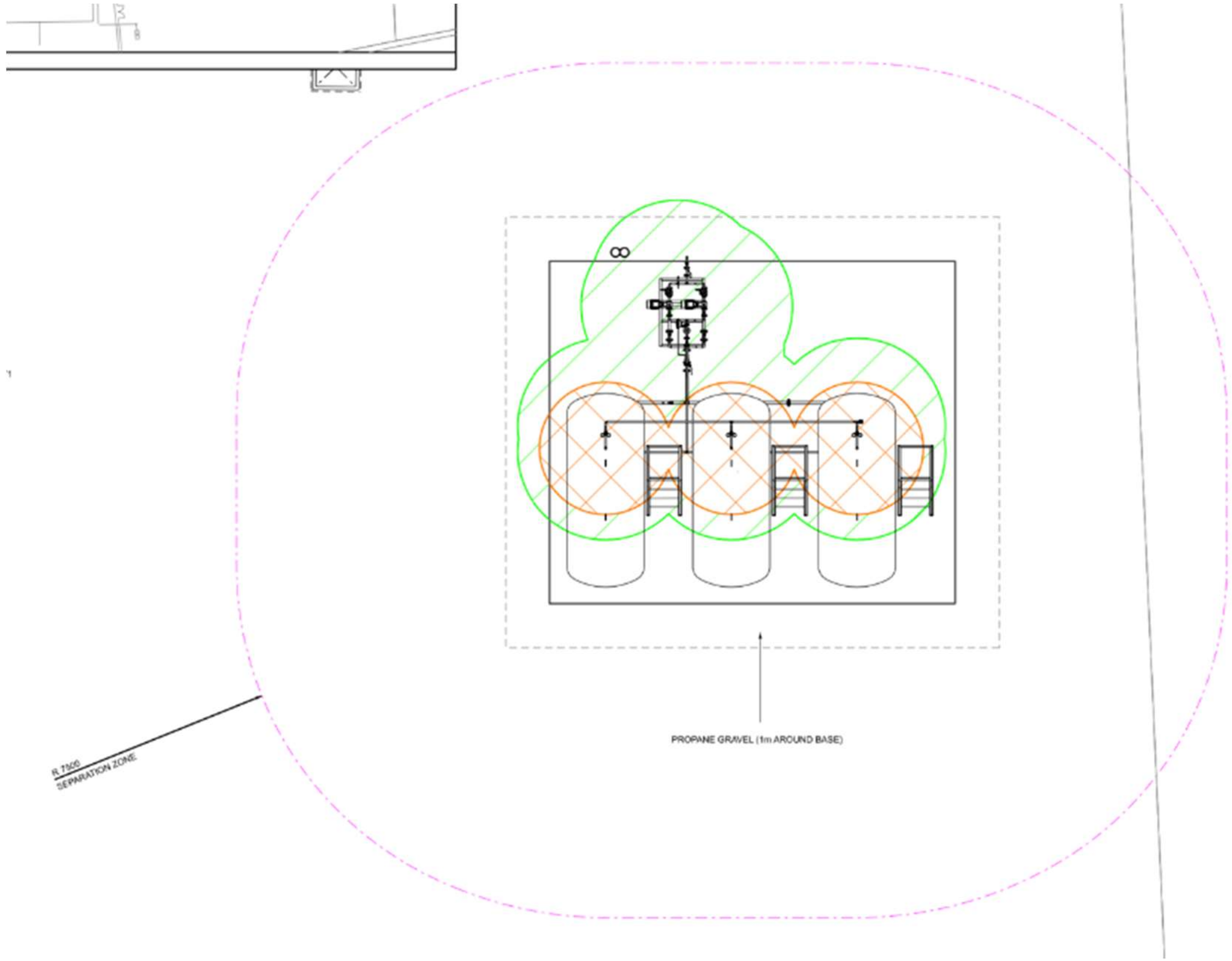
Above Ground Propane Storage – Separation Distances

Above Ground Propane Storage

- LPG COP1 Part 1 stipulates the separation distances which should be employed around above ground propane storage vessels
- For above ground installations, a separation zone applies around the vessel outline
- Multiple tanks can be installed in an arrangement although a maximum number in a group applies depending on the size of the tank
- Tanks must be separated by 1 meter (<4 tonnes) or 1.5m (>4 tonnes)
- Gas dispersion/fire walls can be employed on two sides of an arrangement which will half the separation zone around the tank. The distance is measure from the edge of the tank to the boundary around the edge of the wall

LPG Capacity (Tonnes)	LPG Capacity of a Group (Tonnes)	Distance from Boundary (m)	Distance from Boundary w/ Fire Wall (m)	Distance Between Vessels (m)
0.05 to 0.25	0.8	2.5	0.3	1
>0.25 to 1.1	3.5	3	1.5	1
>1.1 to 4	12.5	7.5	4	1
>4 to 60	200	15	7.5	1.5
>60 to 150	260	22.5	11	¼ Sum of Diameter of adjacent vessels
>150	1,000	30	15	As above


R 7500
SEPARATION ZONE
PROPANE GRAVEL (1m AROUND BASE)

Buried/Mounded Propane Storage – Separation Distances

Buried/Mounded Propane Storage

- LPG COP1 Part 4 stipulates the separation distances which should be employed around buried/mounded propane storage vessels
- Burying a vessel halves the separation distance around the tank relative to an above ground arrangement, which is centred around the valve assembly on the roof of the tank
- A separation zone does apply around the vessel outline, although this is severely reduced versus above ground vessels
- For buried arrangements, only a single tank should typically be installed >4 tonnes of storage capacity

Vessel LPG Nominal Capacity Tonnes	Group Total Nominal LPG Capacity Tonnes	Distance from Buildings, Boundary, Property Line or Fixed Source of Ignition.			Distance between Vessels
		To vessel surface	To valve assembly		
			Without gas dispersion wall	With gas dispersion wall	
Column References					
A	B	C	D	E	F
0,05 to 1,1	3,3	1	3	1,5	1
>1,1 to 4	24,9	3	7,5	4	1
>4 to 60	200	3	7,5	4	See 2.3.1.7
>60 to 150	460	3	11	6	See 2.3.1.7
>150	1 000	3	15	8	See 2.3.1.7

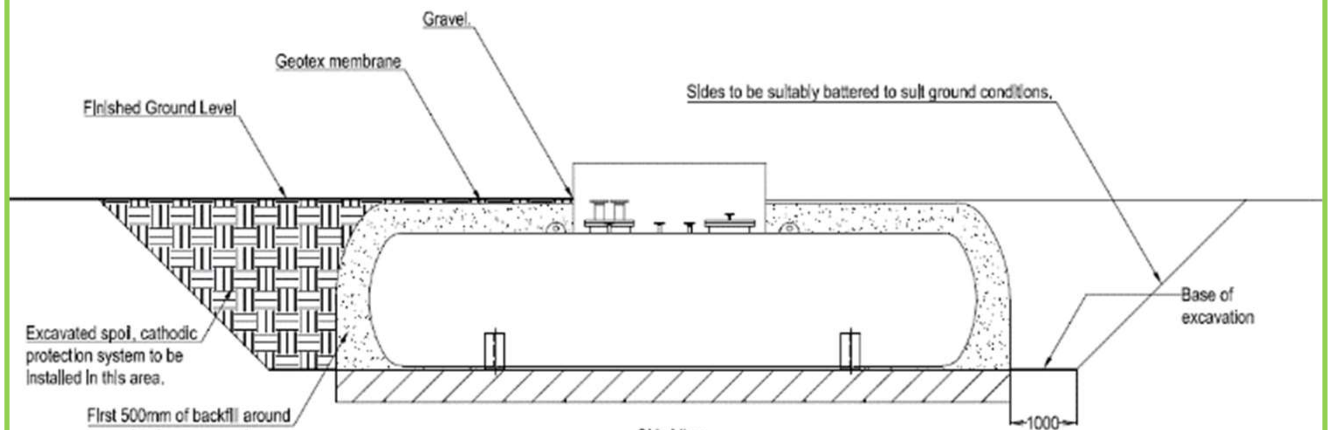
Above-Ground Propane Storage
Northwick – 2 x 12 tonne tanks

Above-Ground Propane Storage
6 x 2 tonne tanks

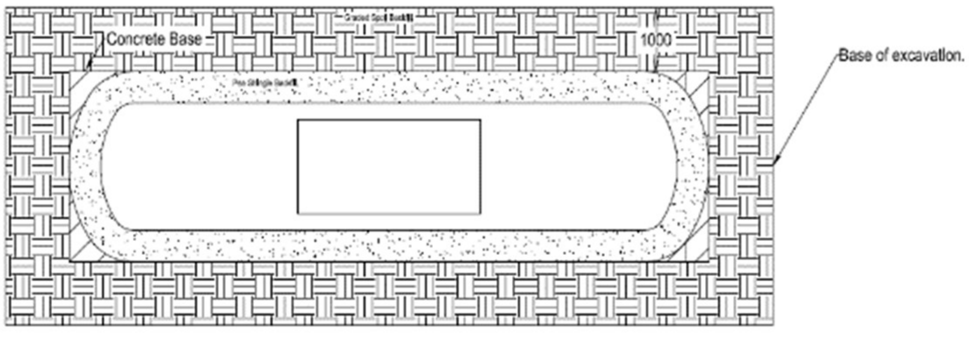
Mounded Propane Storage
Cumbernauld - 1 x 12 tonnes

Buried Propane Storage

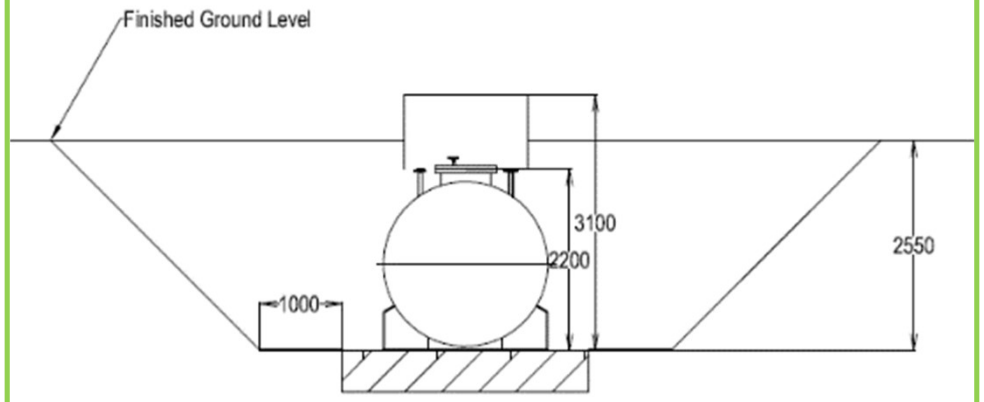
Civils for Below Ground Propane



Side View.



Top View.



End View.

Appendix – A6

CO_2 Liquefaction Process & Supporting Information

CO_2 Liquefaction Process (Evonik)

A bolt on solution can be used to create an extra source of revenue for the plant owner with CO2 liquefaction. An additional benefit with this system is 0% methane slip is achieved, since the methane that is recovered during this process is recycled back to the BUU.

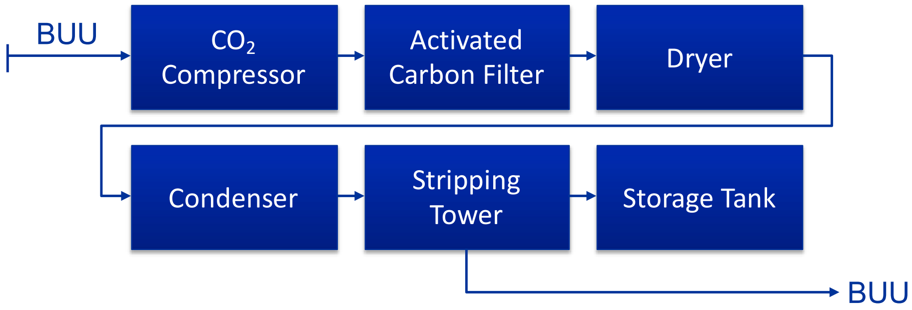
Process Overview:

1. Compression
The carbon dioxide is compressed to 18-19 Barg.

2. Cleaning
The process of CO_2 liquefaction starts with a purification stage, using activated carbon filter (similar to those used within the BUU), which will absorb the remaining H_2S/VOC components. With trace amounts of impurities, the carbon can be regenerated through steam washing.

3. Dryer
A Tower Dryer ensures full and proper regeneration while using an extremely low quantity of CO_2. The Dryer is delivered filled with appropriate adsorbing material. In order to save regeneration gas, the heating is performed by air, while the cooling uses a small portion of dried CO_2 from the outlet of dryer or from non-condensable gas discharge. An atmospheric dew point of minus 60 deg C or lower is continuously maintained in the CO_2 gas.

4. Condenser
The purified gas is sent to the condenser. Traces of non-condensable gases still contained in the CO_2 gas remain gaseous when the CO_2 is liquified. Any entrained non-condensables such as oxygen, methane and nitrogen are effectively removed in the stripping tower. These non-condensable gases are used for the regeneration process for the dryer; the pure liquid CO_2 flows to the insulated storage tanks. From the tank the CO_2 can be taken off to the CO_2 evaporator and then to storage.



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Pentair – Options Overview

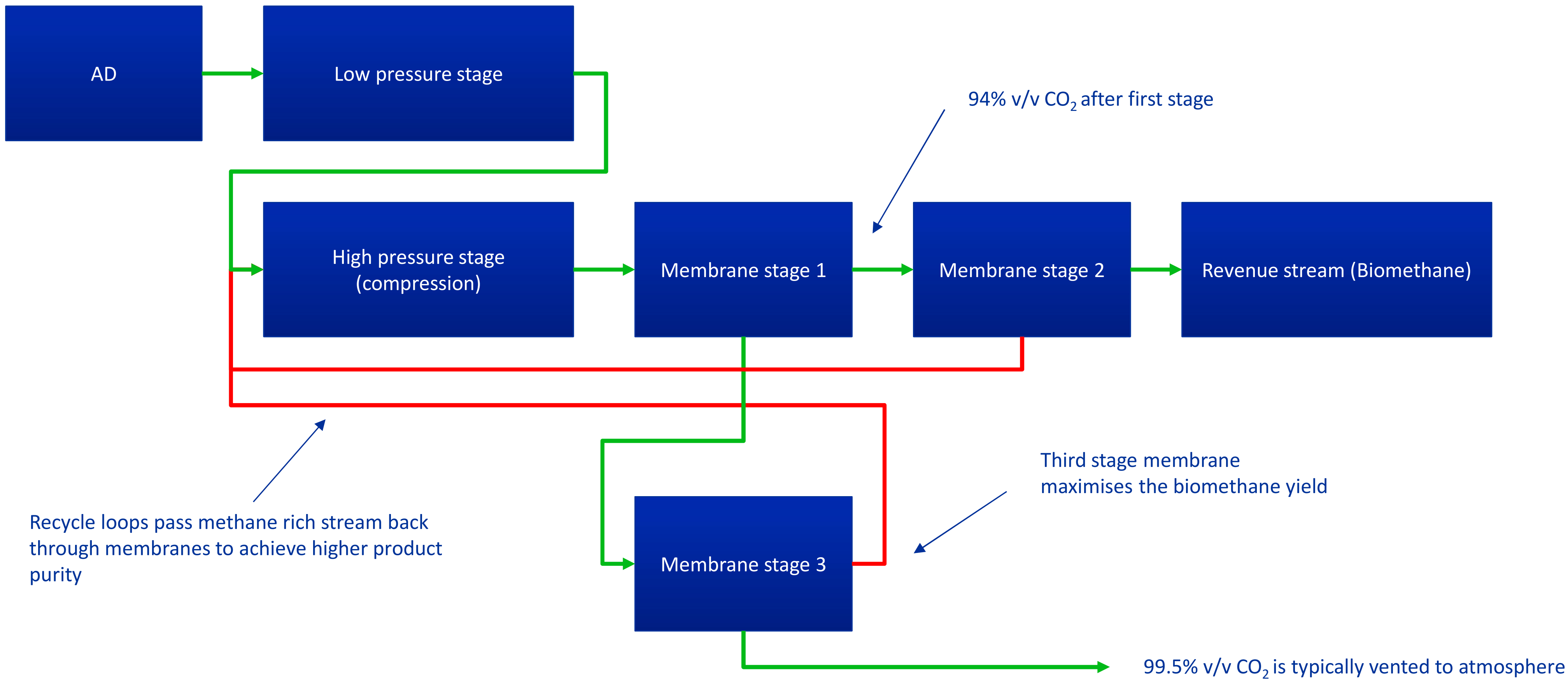
System	Pre-treatment	Compression	Membranes	CO_2 Production	Note
BioBasic	Yes	Yes	2	Vented	
BioPlus	Yes	Yes	3	Vented	Increased yield
BioComplete	Yes	Yes	2	Liquefaction + storage	Food grade CO_2
Bolt-On	No	No	N/A	Liquefaction + storage	For addition to existing biomethane processes

Pentair Gas Upgrading Systems

Pentair have multiple systems for the upgrading of biogas to biomethane. The most basic system uses a 2 stage membrane system to achieve biomethane suitable for grid injection. A 3 stage membrane system can be purchased to achieve maximum biomethane yield as less CH_4 is sent to the waste CO_2 stream. The BioComplete package swaps the third stage membrane for a CO_2 liquefaction plant while still achieving optimal biomethane yield and adding a food grade CO_2 stream that can generate additional revenue. This CO_2 liquefaction plant can be bolted onto the back end of an existing upgrading plant.

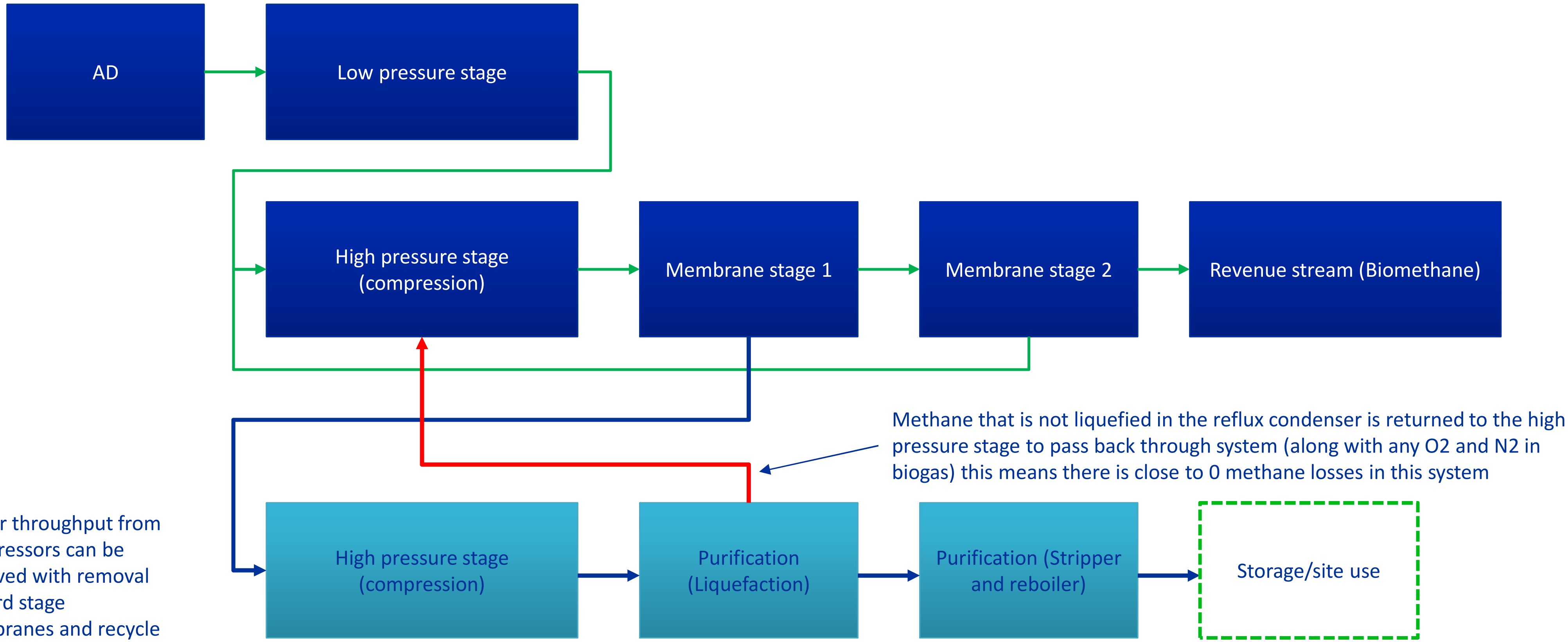
Outlet CO_2 Recovery **) Depending on inlet conditions*			
Capacity gas outlet	780	Kg/h	*)
Temperature	-24	°C	
CO_2 purity	> 99,9	% v/v	
CO_2 specification**)	According to EIGA***)		
Storage conditions	17.5 bar(g) @ -24°C)		
Methane slippage	**≤ 0,0**	% CH_4	****)

Pentair Haffmans BioPlus



Basic biomethane plant (equivalent to 3 stage membrane design from Evonik) used by Bright, DMT, Pentair

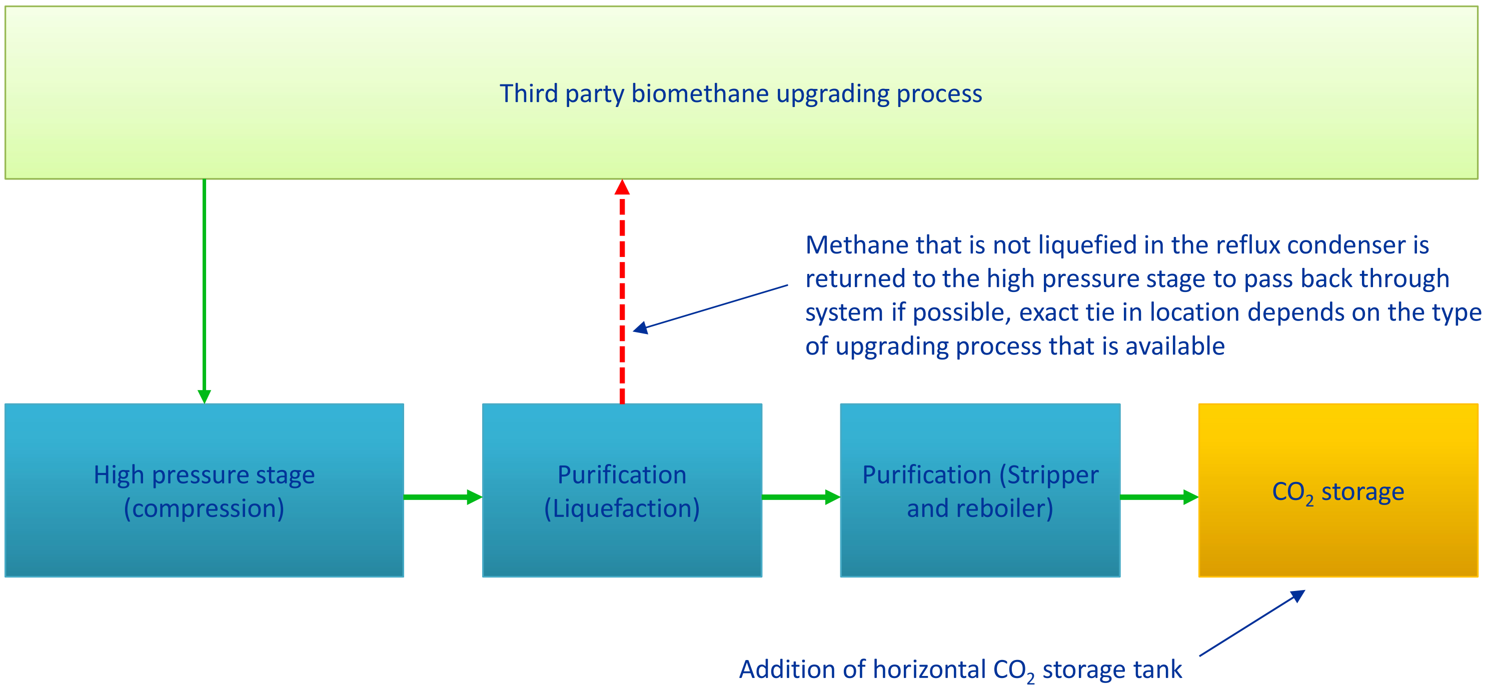
Pentair Haffmans *BioComplete*



Higher throughput from compressors can be achieved with removal of third stage membranes and recycle

Pentair Haffmans *Bolt-On* (CO_2 System Only)

CO_2 taken from existing biomethane site to provide a new source of income – biogas upgrading and compression is therefore not required – can be bolted on to membrane processes or



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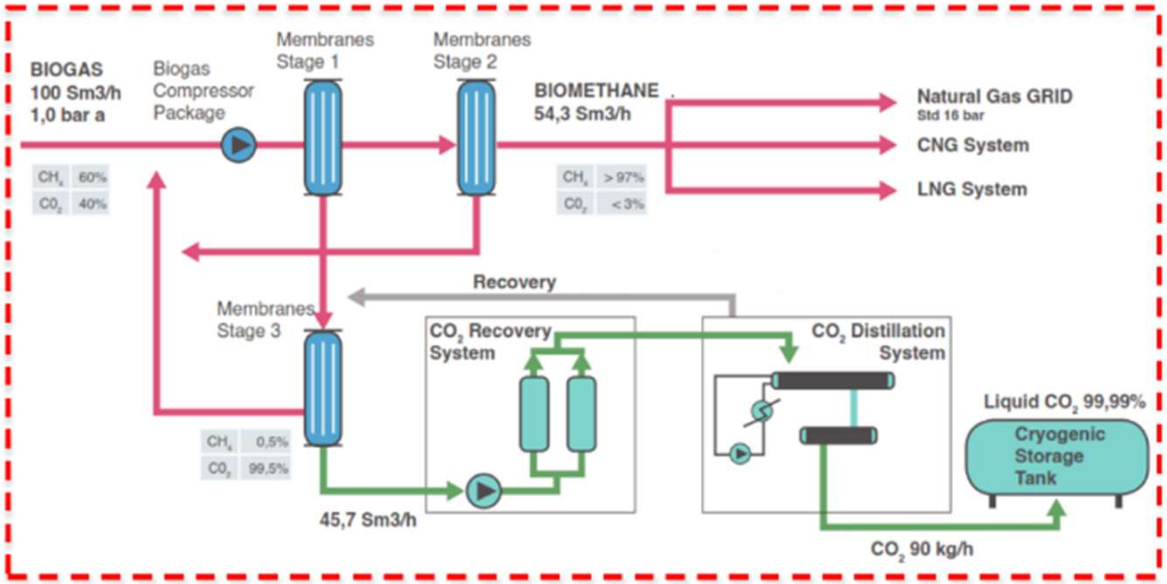
TPI CO_2 Liquefaction Technology

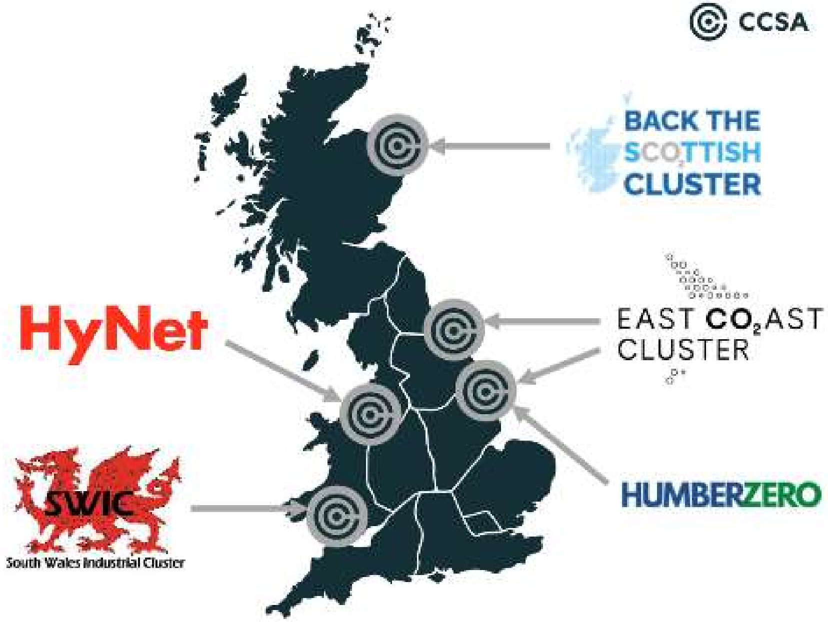
- Waste CO_2 stream from biogas production sent to a CO_2 compression package (two stage reciprocating oil-free compressor)
- Gas exiting compression system meets a cooler and high pressure pre cooler before entering the dehydration system (this drops water out to prevent overloading the dessicant dryer)
- A primary liquid reflux condenser then liquefies the remainder of the CO_2
- A stripping tower is used to remove impurities by flowing impure condensate counter current against the pure vapor being regenerated in the reboiler
- The CO_2 then goes to a fine filter to remove any more impurities including odorant and fine particles
- It is then liquefied before being sent to a storage tank

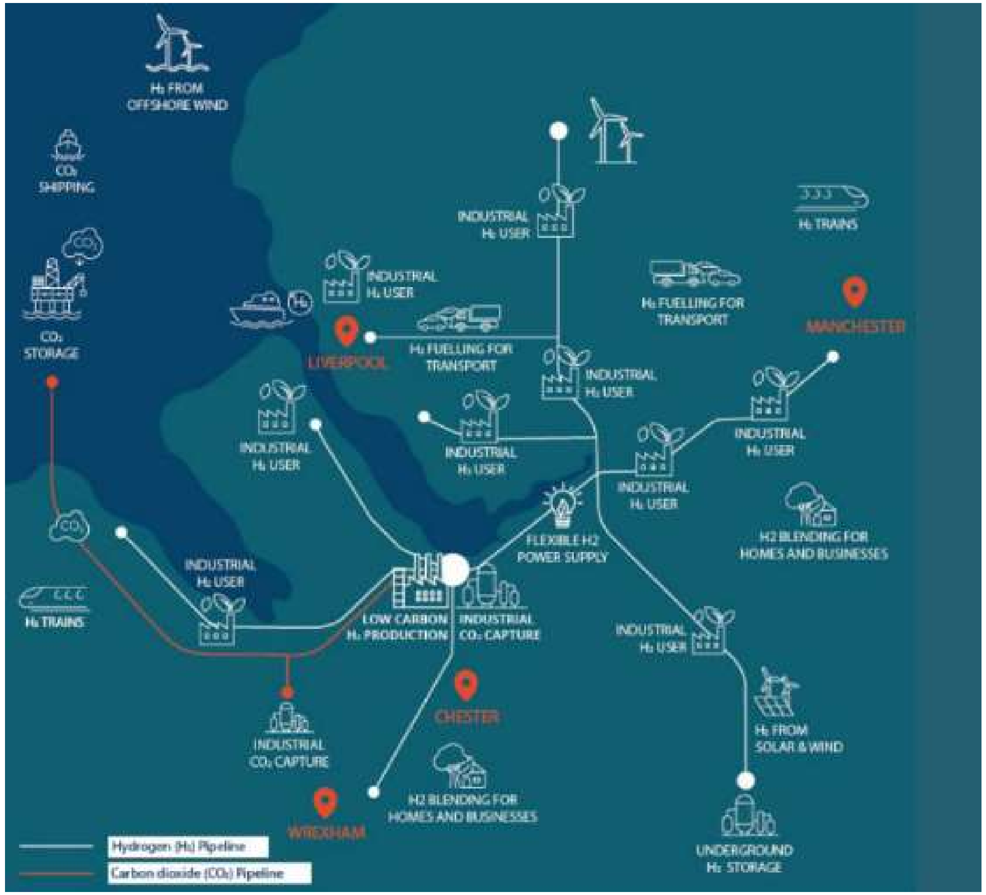


HyNet CCS

Key Points:

- HyNet North West is the UK's leading industrial decarbonisation project
- HyNet will produce, store and distribute low carbon hydrogen as well as sequester CO_2 in spent/depleted oil wells
- Liquid Bio-CO_2 delivered in tankers from the Biomethane plant to the CCUS facility
- Target 2025 (may be 2024 for Future Biogas Northern Lights)
- Advantage of the CO_2 sequestration is that it removes CO_2 from the atmosphere which is CO_2 negative



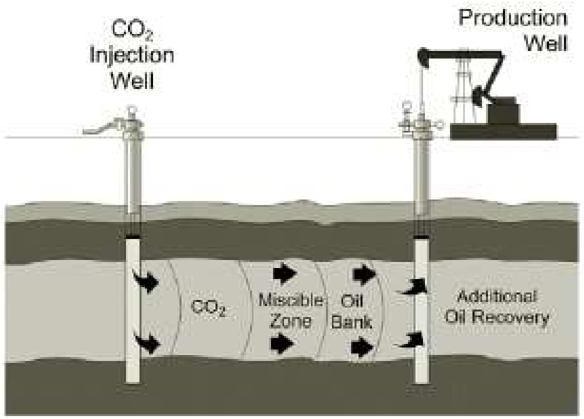


Utilisation of CO_2

- **Carbon-neutral fuel**
  - Carbon-neutral fuel can be synthesised by using the captured CO_2 from the atmosphere as the main hydrocarbon source. The fuel is then combusted and CO_2, as the byproduct of the combustion process, is released back into the air. In this process, there is no net carbon dioxide released or removed from the atmosphere, hence the name carbon-neutral fuel
  - Methanol - SMR (Steam methane Reformation)

- **Chemical synthesis**
  - As a highly desirable C1 (one-carbon) chemical feedstock, CO_2 captured can be converted to a diverse range of products
  - Used to make such as polycarbonates, acetic acid, urea and PVC

- **Enhanced oil/gas recovery**
  - Captured CO_2 is injected into depleted oil fields with the goal to increase the amount of oil to be extracted by the wells. This method is proven to increase oil output by 5-40%.
  - Carbon Sequestration with Enhanced Gas Recovery is a process in which CO_2 is injected deep in the gas reservoir and as a result additional methane is extracted



- **Carbon mineralisation**
  - Carbon dioxide from sources such as flue gas are reacted with minerals such as magnesium oxide and calcium oxide to form stable solid carbonates.
  - The carbonates produced can be used for construction, consumer products

- **Biofuel from microalgae**
  - Microalgae is fed with a source of carbon dioxide. Microalgae is then allowed to proliferate. The algae is then harvested and the biomass obtained is then converted to biofuel.

Appendix – A7

RTFC

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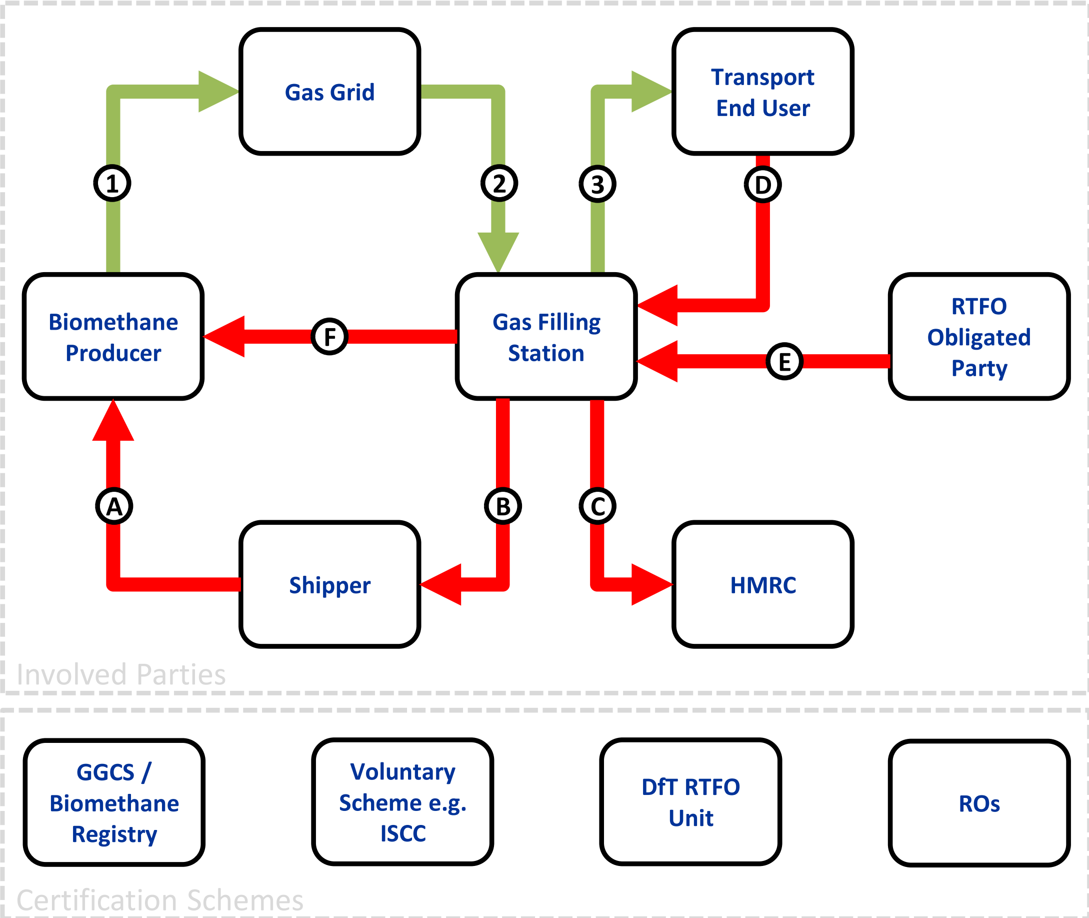
RTFC Explanation in Terms of Gas and Cash Flows

Gas Flows:

Biomethane and fossil gas are chemically identical and therefore the buying and selling of renewable gas is evidenced by certificates. The gas certificates are traded separately from the physical molecules to enable biomethane to move efficiently from the producer to end user. This process is known as mass balancing.

1. Biomethane can be injected into the gas grid anywhere (in Europe) under the mass balance rules, as long as there is a continuous working gas grid between the entry point and the exit point, and the flow of gas is in the relevant direction. The producer must have a contract with a gas shipper to do this
2. Gas is withdrawn from grid by the fuel supplier (station operator) who can then evidence the origin of the gas
3. Gas is dispensed to a vehicle



Money Flows:

A. The biomethane producer is paid by the shipper for the commodity value of the gas injected into the grid

B. The fuel supplier pays the shipper for the "brown" gas purchased from the grid

C. The fuel supplier pays fuel duty to HMRC

D. The fuel user (haulier) pays the fuel supplier for the gas it has purchased to refuel their vehicle. (They do not necessarily pay any more for purchasing biomethane rather than fossil gas in this transaction)

E. The Obligated Party pays the fuel supplier for the RTFCs generated by the use of biomethane as a vehicle fuel

F. The fuel supplier pays the biomethane producer for the "green value" of the gas, using the income from the Obliged Party

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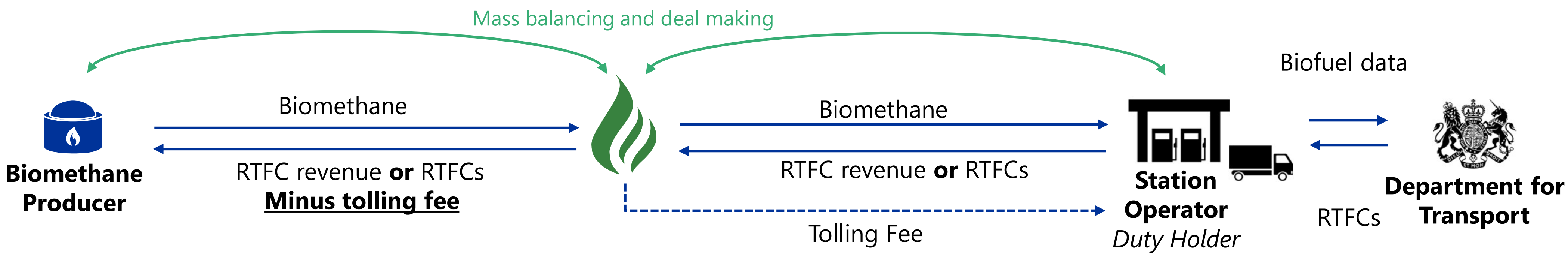
Biomethane Sale via a 3rd Party CNG Station

- Should the biomethane producer sell their gas via a 3rd party CNG Station, they will require an ISCC certified gas shipper to manage the mass balance from injection to offtake
- In return, the shipper will retain a portion of the RTFC value. It is assumed the producer will retain approximately 75% of the total value
- If the biomethane producer uses the gas at the point of production in their own vehicles, they will be able to claim 100% of the value when selling the certificates since they will be managing the flow and distribution of the gas



Appendix – A8

CNG Services

Our Services & Expertise

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Our Services

CNG Services Limited (CSL) provides design, consultancy and construction services in relation to the injection of biomethane into the gas grid and virtual pipelines.

- With in-depth knowledge of the regulatory requirements and technologies of biomethane production, we can ensure a smooth transition from drawing board to commissioning in all project stages. Our Services Include:
  - Supports the development of new anaerobic digester
  - Gas clean-up design
  - Project management
  - Enrichment to gas grid specification
  - Plant commissioning including testing, first flow, and performance testing
  - Injection to the gas grid (gas quality monitoring, connection pipeline)
  - Negotiations with gas grid operators (Network Entry Agreement)
  - Support in relation to gas price negotiations with gas suppliers
  - Advice on relative economics and CO_2 performance of all utilisation options
  - Offer a full connection design and construction service at any network pressure
  - Support for introduction of Bio-CNG vehicles

- 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

- CNG Services have been involved in 83 Biomethane projects as an EPC contractor or consultant. These projects have been commissioned across a variety of different sites using different feedstocks including sewage sludge, agricultural waste and food waste

- Generally, the type of feedstock has dictated the upgrade technology used, with water wash plants commonly used to upgrade sewage derived biogas. It is now considered that membrane and chemical wash plants are now good options

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CSL EPC Projects: 2015-20

Name	Description	Date	Contract Size (£)
Euston States	7km pipeline, electricity supply, compression plant, LTS connection	Jun-15	£ 1,600,000
RAF Leeming	3km pipeline, GEU, propane, integration (NGN)	Jun-15	£ 1,300,000
Raynham Estate	GEU, propane, export compressor, plant integration	Jun-15	£ 1,600,000
NGD Pipeline (Raynham Estate)	1.5 km 19 bar Hexel One (plastic pipeline) and LTS connection	Jun-15	£ 1,300,000
Peacehill Farm, Scotland - Envitec	Engineering and commercial support, export pipeline	Jun-15	£ 250,000
Forty Foot Road, Teesside - Air liquide	GEU, propane, integration and export pipeline	Dec-15	£ 1,700,000
Shanks, Cumbernauld, Scotland - Air Liquide	GEU, propane, integration and export pipeline	Dec-15	£ 1,200,000
High Wood Farm, Brinklow - Brinklow Biogas	GEU, propane, integration, export compressor, LTS connection pipeline	Dec-15	£ 1,500,000
Aspatria, Cumbria - Lake District Biogas	CO2 removal plant, GEU, propane, integration, export pipeline	Dec-15	£ 2,500,000
North Moor Farm, Scunthorpe - Rockscape Energy	GEU, propane, integration, export pipeline	Dec-15	£ 1,300,000
Fairfields Biogas, Colchester	BUU, GEU, propane, integration, compression, LTS connection	Feb-16	£ 3,300,000
Leyland LTS CNG Station - CNG Fuels Ltd	LTS connection, compressors, CNG storage	Mar-16	£ 1,700,000
Roundhill Sewage Works - STW	CO2 removal plant, GEU, propane, pipeline	Dec-16	£ 4,000,000

Name	Description	Date	Contract Size (£)
Stoke Bardolph – STW	GEU, propane, integration and export pipeline	Dec-16	£ 1,700,000
Derby and Strongford Sewage Works – STW	GEU, propane, integration and export pipeline	Mar-17	£ 2,000,000
Bay Farm - Strutt and Parker Biogas	GEU, pipeline, compression	Mar-17	£ 1,800,000
ReFood - Dagenham	Connection to IP, design integration	Dec -17	£ 500,000
Northwick - Air Liquide	Installation of BUU, GEU, propane, export connection to IP	2017	£ 1,200,000
Hemswell - Air Liquide	Installation of BUU, GEU, propane, export connection to IP	2018	£ 1,600,000
Bonby - Air Liquide	Installation of BUU, GEU, propane, plus 7 km private pipeline and remote compression compound to LTS	Dec-18	£ 2,500,000
Kemsley - DS Smith	Plant integration and gas export pipeline	Dec-18	£ 300,000
Distillery Project, Fordoun CNG Station - Air Liquide	NTS connection, private pipeline, compression	2019	£ 3,500,000
Distillery Project, Glenmorangie - Air Liquide	CNG offloading station, PRS, storage	2019	£ 500,000
Distillery Project, Diageo (Dalwhinnie, Clynelish, Roseisle)	CNG offloading station, PRS, storage	2019	£ 2,000,000
Ledbury – Heineken	Conversion of Bulmers cider factory to gas	2019	£ 500,000
Barnes Farm, Spaldington, Park Farm, Somerset Farm	Installation of BUU, GEU, propane, export connection to LTS/MP	2019/2020	£ 7,000,000