D6.4 | Guidance for feasibility analysis covering biomethane investment projects - Ireland

Deliverable:	Guidance for feasibility analysis covering biomethane investment projects
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Abbreviations

AD	Anaerobic Digestion
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSTR	Continuously stirred tank reactors
DAFM	Dept for Agriculture, Food and the Marine
DM	Dry Matter
DSCR	Depth Service Coverage Ratio
EBA	European Biogas Association
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
EBIT	Earnings Before Interest and Taxes
ETS	Emission Trading System
FM	Fresh Mass
GGCS	Green Gas Certification Scheme
GHG	Green House Gas
LCA	Life Cycle Analysis
RGFI	Renewable Gas Forum Ireland
RHO	Renewable Heat Obligation

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REGATRACE in a Nutshell

REGATRACE (REnewable GAs TRAde Centre in Europe) aims to create an efficient trade system based on issuing and trading biomethane/renewable gases certificates/Guarantees of Origin (GO) with exclusion of double sale. This objective will be achieved through the following founding pillars:

- European biomethane/renewable gases GO system.
- Set-up of national GO issuing bodies.
- Integration of GO from different renewable gas technologies with electric and hydrogen GO systems.
- Integrated assessment and sustainable feedstock mobilisation strategies and technology synergies
- Support for biomethane market uptake
- Transferability of results beyond the project's countries

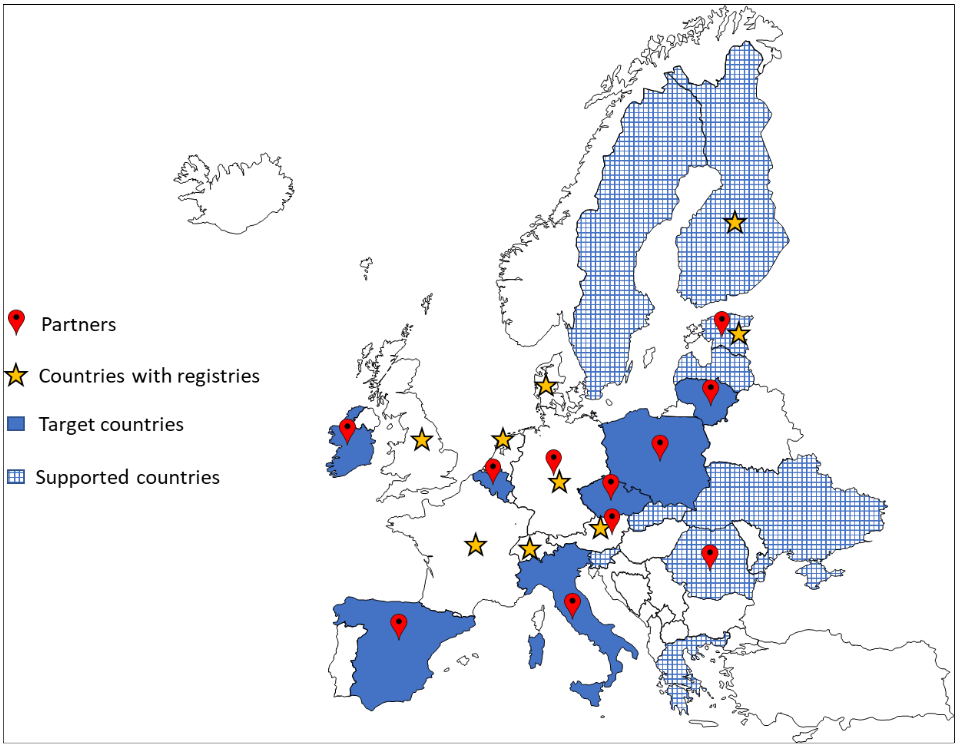

Figure 1: REGATRACE countries and partners

The Purpose of the Guidance

D6.4 Guidance for feasibility analysis covering biomethane investment projects – Ireland, has been produced by the European Biogas Association in collaboration with Renewable Gas Forum Ireland (RGFI) under Work Package 6 of the REGATRACE project. The Guidance provides general assistance for conducting feasibility studies for biomethane investment decisions. It is designed to assist project developers in realising biomethane investment projects based upon the analysis of political, economic, technical, environmental, route to

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market (on or off grid), optimal scale and financial factors influencing the feasibility of biomethane investment projects.

Each participating country is tailoring the generic EU Guidance in view of the specific circumstances prevailing in that country. In Ireland this work is being led by the Renewable Gas Forum Ireland, working collaboratively across all stakeholders, including Government of Ireland and industrial/commercial consumers of gas, many of whom have participated in REGATRACE Workshops. .

1 What is a feasibility study?

The main purpose of a feasibility study is to support/enable:

- taking investment decisions aimed at establishing a new biomethane production facility;
- securing the necessary commercial funding/financing.

A feasibility analysis is used to:

- determine the viability of a project idea and whether it is worth the investment;
- ensure that the project is legally and technically feasible;
- confirm if there is a commercial proposition and if the project should proceed;
- better understand the implied risks.

Generally, the feasibility study precedes technical development, business planning and project implementation.

A feasibility study is not the same as a business plan, which provides a planning function and defines the actions needed to take a business idea into reality.

While it is important to conduct both plans before realising the action, a business plan should only be conducted once the investment project has been deemed viable by a feasibility study.

A well-designed feasibility study should offer:

- a comprehensive review of the background of the project;
- the description of the manufacturing processes;
- the quality and market of the final products;
- details of operations and management;
- estimated future market developments in the circular bio-economy and bio-refinery;
- commercialisation of biogenic CO_2, bio-fertilisers, other bio-actives, bio-stimulants, protein extraction;
- carbon farming, monetising of soil carbon sequestration (carbon credits);
- policy support such as a Renewable Heat Obligation Scheme and capital funding;
- expected financial data, legal requirements, and tax obligations.

Considerations include:

- A full review of national and EU Commission policies and strategies under REPowerEU, EU Green Deal and Farm to Fork, to ensure the project objectives are aligned with them;
- A consideration of the drivers of decarbonisation for example, climate change, food and energy security, sustainable food production, global consumers;
- An understanding of the gas consumer's requirements to comply with Renewable Energy Directive II, III and soon the RED IV;
- IPCC/UNFCCC guidelines for sustainable and regenerative farming.

The perceived objectivity of the feasibility analysis is an essential factor in the credibility of the study for potential project developers, investors and lending institutions.

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2 Where can the Feasibility study be used?

Substantially different pathways can be followed for investing into new biomethane production facilities:

- expansion of existing anaerobic digestion installation with addition of an upgrading facility (potentially also increasing the raw biogas production);
- investment into new, “green field” site consisting of anaerobic digestion, pre-treatment and post treatment technologies, storage facilities and biomethane upgrading;
- investment into grass biorefinery, anaerobic digestion, protein concentrate and fibre extraction, upgrading technology, biogenic CO_2 – interlinked with the two pathways above as appropriate.

The primary purpose of a feasibility study is to provide reliable and trusted data and information to project developers about the conditions of the project. Subsequently, based upon this analysis the project developers can approach the potential investors and financing institutions.

Feasibility studies also assist the project developers in their communication with the respective authorities, politicians, socio-economic benefits, and impacted local communities, to secure their support for the project. For this purpose, the study must address in detail the potential risks and the expected concerns of the involved parties.

3 Core elements of the feasibility study

The feasibility study comprises technical, market, and commercial feasibility as well as an overall risk assessment.

3.1 Technical feasibility

This part of the feasibility study should answer – for example – the following questions:

- *What feedstocks are available and what are the logistics of using them?*
- *Sustainability of the feedstock under consideration?*
- *What is the most appropriate technology to process the feedstock (yields, material balances, etc.)?*
- *What will be the volumes and characteristics of the main product (biomethane) and the by-products (digestate, biogenic CO_2, etc)?*
- *What are the regulatory standards surrounding the main product, the by-products, and their use?*
- *Assess the commercialisation and monetising of the various by-products, e.g. bio-fertilsers, biogenic CO_2, carbon farming, soil carbon sequestration.*
- *What investments are needed for realising the production?*
- *How will the energy consumption (parasitic load) of the facility be covered (energy balances, etc.)?*
- *What are the technical conditions, grid route and economic assessment for grid connection?*

- *What are the considerations and conditions for the site selection?*
- *Potential impact on local community, public consultation process, information and education, knowledge sharing from recognised trusted sources.*

The above questions can be used both in the case of transforming an existing biogas plant to a biomethane producing facility and in the case of a new, green-field investment.

3.2 Market feasibility

Identifying suitable market conditions is a very important part of a feasibility study when an investment into new biomethane production is proposed. Issues to be considered include whether the main product (biomethane) and the by-products can be commercialised and placed on the market at reasonable market prices or if there is a marketplace for them at all. Available national support schemes are of crucial importance.

Market feasibility should answer – for example – the following questions:

- *What market segments are viable and targeted (transport fuel, heating, thermal demand in industry)?*
- *Who are the potential consumers, size of that market segment and how many of them are there?*
- *Options for route to market, how will biomethane and the by-products be sold?*
- *What are the available support schemes and what are the conditions for participating?*
- *Are there realistic export possibilities?*
- *What are the prices and conditions for external energy supplies?*
- *What are the costs of feedstock supplies, is there competition for feedstock?*

3.3 Commercial Proposition

The commercial proposition assesses the probability of commercial (economic) success. It is mainly focused on studying whether the planned investment can be financed and whether it can generate enough income and profit.

The questions that require answering as part of the commercial proposition of the feasibility study include, for example:

- *What are the potential sales volumes and income streams in different segments?*
- *What is the pricing structure applicable on the various markets?*
- *How far is the feasibility dependent on state aid capital funding and financial support such as the Renewable Heat Obligation Scheme?*
- *Are off take agreements for biomethane available?*
- *What are the sensitivity points for the business in terms of revenues (critical path)?*
- *What are the expected financial indicators of the investment project (IRR, NPV, PI, DSCR)?*
- *What are the options on funding structure, how much own funds/equity are required to realise the investment and start operating?*

- *What are the conditions for attracting and securing suitable funding partners or external finance?*

3.4 Overall risk assessment

The overall risk assessment examines the different ways the project company (the investor) can reduce the risk of embarking on the new venture.

Currently there is no national co-ordination and design authority for the development of renewable gases in Ireland. Having such an authority would greatly reduce risks through providing support for ongoing and continuous improvements to AD biomethane development, market exploitation, new products/innovative technology research, and management support services.

The overall risk assessment should answer the following questions:

- *What are the major risks associated with the operation?*
- *What is the survival outlook for each of the above risks*
- *Benefits from having a national co-ordination and design authority?*
- *How sensitive are the profits?*
- *What are the best ways to minimize these risks?*

The aim is to create a risk assessment map, which deals with the probability of each risk identified and the impact it would have on the project. It should differentiate the risks that can make or break the project from the smaller, more manageable risks.

4 Key factors for successful project development

The political, technical, and financial factors influencing the feasibility of an AD biomethane production facility are addressed across this document. The main issues are summarised here.

Stable, long-term political commitment

Bridging the funding gap between the prevailing natural gas price and the costs of biomethane production is the biggest challenge for every biomethane project. Measures can and should be taken to lower the costs of investment and operation as much as possible, but the business plans must not assume that achieving natural gas parity is only a question of time. Biomethane projects remain dependent on stable, long-term political commitment towards renewable energy deployment and – specifically – towards utilisation of biodegradable feedstock for biogas/biomethane production. The development of a renewable gas industry in **Ireland** depends on the Irish Government declaring policy and legislative support for biomethane. A Renewable Heat Obligation Scheme and capital funding are essential and significant progress has been made in securing the necessary supports from the Government of Ireland, in light of the recent Ukraine crisis and REPowerEU plan

Costs of raw material

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Among the operational costs of sustainable biomethane production the costs of raw material - sustainably produced feedstock supplies have a decisive importance. The project developers must assess the present and future feedstock supply possibilities very carefully and should elaborate alternative plans to handle any disruption. If possible, it is advisable, that the owners of raw materials (for example agricultural feedstock producers, food/beverage industry or waste management companies) are involved in the proposed biomethane projects as shareholders – to secure their long-term interest in backing-up the venture, underpinned by off-take agreement for biomethane.

Flexible technologies

Project developers should never assume that the feedstock supply patterns will remain unchanged over the 15-20-25 years lifetime of the project. It is strongly advisable to install technologies which have the needed flexibility to adjust to changes in feedstock material composition. Under these considerations the design of the facility and the engineering plan facility must have the capacity for adding / changing equipment in the future.

Location

Locations offering guaranteed long-term sustainable feedstock supplies must be preferred. The best locations are those where the feedstock is co-located with infrastructure, and where deep integration to agricultural or industrial activities is possible (for example: co-location of animal slurries/manures, sugar factories, breweries, etc.). In addition, the distance to an existing gas grid must be carefully evaluated for direct grid connection or virtual pipeline i.e., transported to central grid injection facility.
A qualified planning consultant/engineer/ecologist should be consulted to carry out a desk top study, a high-level Appropriate Assessment, advancing to Stage 1 and Stage 2 where necessary, on the proposed site locations for the AD biomethane plant.

Biodegradable Materials

Biodegradable materials offer good opportunities for biomethane facilities, but experience shows that the gate fees paid by bio degradable material owners tend to decrease and even disappear with the increasing number of biomethane plants in the region.

Proven and Reliable Technology

Mature and efficient anaerobic digestion and biogas upgrading technologies are available from several technology suppliers. There is strong competition among these companies which puts developers/promoters in a good negotiating position. The selection of proven and reliable technology reduces the risk of future operational difficulties. Developers/promoters can focus too much on the purchase price and not consider other important elements, like the performance guarantees and operational and maintenance support services offered by the supplier(s). These should be negotiated as part of the initial package and where possible consider clustering of AD plants in negotiating Capex and Operation & Management contracts.

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Biomethane purchase agreements / Renewable Heat Obligation Scheme

Long-term biomethane purchase agreements (BPAs) must be secured from the start to underpin the project, and socialise the funding gap, in lieu of financial supports/incentives, such as a Renewable Heat Obligation (RHO) Scheme. From this viewpoint regions with developed CNG-LNG fuelled transportation are especially attractive. Long-term supply agreements with companies distributing gas for heating/thermal demand can also serve as a solid base for an investment decision.

An RHO scheme in Ireland is progressing to design phase on structure and administration of the scheme, and will give a strong signal to the markets and provide investor certainty and confidence due to the obligation it places on shippers / suppliers, backed up by strong consumer demand in the manufacturing and processing sector to decarbonise the thermal demand.

Bio- fertiliser

The potential use of digestate as a bio-fertiliser is a key issue for any successful biomethane project. Digestate, a biofertilizer is zero carbon and can be produced in compliance with fertiliser product regulation and a revenue source to the biomethane plant. The residue is usually separated into a solid and a liquid fraction. The solid fraction can be used as organic fertiliser with a market value. Further processing may be required. Such treatment of the of digestate may trigger extra investment and operational cost.

Liquefaction of Biomethane

The liquefaction of biomethane is an interesting alternative, however the market would need to mature further, and markets develop.

Biogenic CO_2

The appetite and market development for Biogenic CO2 is advancing, as an alternative source to fossil produced CO2. A white paper has been produced and the EU Commission is giving serious consideration to recognising the benefits of biogenic CO for use in food production, drinks and beverages industries, other uses in building materials etc are also possible.

Also, a strong possibility of biogenic CO2 being recognised under Taxonomy as a recognised activity and product can be certified.

Local Stakeholder Engagement

It is essential to engage at an early stage of the project and have good communication with local stakeholders. Understanding and addressing their valid environmental or social concerns in advance, such as how odour and traffic will be dealt with, is essential. In addition, communicating the economic and environmental benefits of the biomethane plant is relevant such as: sustainable job creation; rural, circular, bioeconomy / biorefinery support; displacement of chemical fertiliser; biodegradable material treatment etc.

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5 CASE B – converting an electricity generating AD plant to biomethane producer

This Guidance is focusing on the feasibility of a "green-field" biomethane investment project. Nevertheless, biomethane investment may take place in an existing biogas plant, which has been generating electricity in local CHP, but the Feed-in-Tariff / Feed-In-Premium (FIT/FIP) period is due or has expired and producing electricity in not economic anymore.

A feasibility study in this case is also necessary to determine the expected economics and provide the basis for securing the financing / bank credit to cover the additional investment costs.

Regards to adding an upgrading unit to the existing AD unit, the technical project should address – among others – the following questions:

- which revamping measures are necessary to extend the lifetime of the AD unit?
- is it possible to increase the biogas production capacity?
- if yes, which additional investments are needed in the AD unit (e.g., for receiving the additional substrates, adding pre-treatment/mixing, pumping capacity, etc.)?
- is the existing biogas desulphurisation solution acceptable for the upgrading unit or new desulphurisation unit must be installed?
- is there sufficient space available for installing the upgrading unit (space limitation may influence the selection of the upgrading technology)?
- which part of the electricity generation equipment (CHP) will remain in operation to supply electricity to both the AD and upgrading units?
- what are the technical conditions for connection to the natural gas grid, distance and feasibility for connection to distribution or Transmission pipe network. at location (pressure, etc.)?

The feasibility study for the conversion project may apply the series of practical data generated during the operation of the AD unit, such as actual substrate costs, biogas yields, biogas quality, energy consumption, digestate quality and placement, achieved full-load operating hours etc. This is very important as banks are usually concerned about the so called "biological risk", i.e. the risk of proper functioning of the biological system in the digesters. Mitigation measures include Scada systems, monitoring probes and early detection.

The financing of the conversion project is substantially different from the green field AD + upgrading project, while in this case the owner/investor is not expected to provide fresh financial funds, the exiting assets should be sufficient.

Having a Renewable Heat Obligation scheme (REDII - Article 23) would be a key factor and improve the commercial proposition for conversion from electricity generation. Capital grant funding and bank credit can also be applied.

Conversion considerations include:

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- replacing the estimated biogas production related data with actual, practical data from past operation,
- depreciation of certain components and need to upgrade equipment of the AD unit
- additional investments needed for the AD unit,
- the remaining lifetime of the AD unit.

6 Technical Feasibility

6.1 Biogas feedstock and biogas production forecast

It is essential to secure feedstock supplies and to elaborate reliable and prudent forecasts for them. The volume, quality, and costs of either processed or agri crops feedstock, determine the engineering and the biogas producing capacity of the AD plant and substantially influence the feasibility of the project.

6.2 Basic considerations

When selecting the raw materials for biogas production several factors must be taken into consideration, such as:

- regulatory – sustainability.
- technical;
- by-products potential;
- competitiveness and efficiencies
- economic.

6.2.1 Regulatory aspects

a) **Food and feed crops**

Food and feed crops are defined in the RED II, III and under review in RED IV, while currently as follows:

"Food and feed crops" means starch-rich crops, sugar crops or oil crops produced on agricultural land as a main crop excluding residues, waste or ligno-cellulosic material and intermediate crops, such as catch crops and cover crops, provided that the use of such intermediate crops does not trigger demand for additional land.

Article 26 of the RED II contains specific rules for biomass fuels (including biogas) produced from food and feed crops. At the time of writing, with the ongoing institutional debate on the Renewable Energy Directive revision, the co-legislators position haven not heavily impacted the text of Art. 26 of food and feed crops utilisation. With higher GHG emissions savings thresholds

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to comply with in the Heating and electricity sector, the market for substrate with better GHG emissions performances will further develop.

In relation to growing sustainable forage for AD biomethane production in **Ireland**, the KPMG/Devenish/GNI Sustainable feedstock report, 2021 concludes that multi-species swards are an approved feedstock, that complies with RED II and III when used in co-digestion with animal slurries at 60/40 or 50/50 (sustainability criteria post 2026) ratio of feedstock to slurries.

b) Animal by-products

Animal by-products (ABPs) are materials of animal origin not fit for human consumption. ABPs include among others:

- Animal feed - e.g., based on fishmeal and processed animal protein,
- Animal slurries/manures - organic fertilisers and soil improvers
- Technical products - e.g., commercial food waste, by products from food and drinks processing plants,

EU and national rules regulate the movement, processing, and disposal of ABPs. ABPs are categorised according to their risk using the basic principles in Regulation (EC) 1069/2009[1] and Commission Regulation 142/2011[2]. These regulations also contain the rules for processing ABPs in anaerobic digesters of the biogas plant, with limitations and rules applied to regulate and approve ABPs, such as animal slurry, used in AD plants.

In **Ireland**, Regulation (EC) 1069/2009 has been transposed to domestic legislation - EU (Animal By-Products) Regulations 2014 (SI No 187 of 2014). The Department of Food, Agriculture, and the Marine (DAFM) is the national regulating entity, and a licence is required to operate an AD plant. In **Ireland**, pasteurisation is the standard minimum requirement to mitigate the risks associated.

The Renewable Gas Forum Ireland works closely with the DAFM officials and inspectors in supporting AD developers during the planning and licencing process.

c) Feedstock accepted for “advanced fuel” production.

RED II contains specified targets for the share of “advanced fuels” in the total fuel consumption in transport. In case the transport fuel use of biomethane is targeted, focusing on this list of Annex IX Part A is much desirable.

Some of these are not relevant to the Irish situation:

- Algae
- Biomass fractions of: MMW (not separated) industrial waste (not fit for use in food or feed) W&R from forestry.
- Biowaste from Private Households

[1] *REGULATION (EC) No 1069/2009 of the European Parliament and of the Council of 21 October 2009*

[2] *COMMISSION REGULATION (EU) No 142/2011 of 25 February 2011 implementing Regulation (EC) No 1069/2009 of the European Parliament and of the Council laying down health rules as regards animal by-products and derived products not intended for human consumption and implementing Council Directive 97/78/EC as regards certain samples and items exempt from veterinary checks at the border under that Directive*

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- Straw
- Animal manure and sewage sludge
- Pome and empty palm fruit branches
- Tall oil pitch
- Crude glycerine
- Bagasse, grape marcs and wine lees. Nut shells, husks, cobs cleaned of corn kernels
- Other non-food cellulosic material
- Other ligno-cellulosic material except saw logs and veneer logs

Annex IX is currently under revision and an updated draft version will be soon published by the European Commission services; the draft delegated act will be then submitted to the scrutiny of co-legislators.

d) Sustainability requirements

Sustainability requirements (detailed in Article 29 of the RED II) must be taken into consideration. In Ireland, the Green Gas Certification Scheme has a number of measures and monitors the sustainability of biomethane production in compliance with RED II criteria.

Among the sustainability related requirements the data on greenhouse gas emission intensity is the most important. According to Article 29. para 10. of RED II the greenhouse gas emission savings from the use of biofuels, bioliquids and biomass fuels shall be:

- at least 65 % for biofuels, biogas consumed in the transport sector, and bio-liquids produced in installations starting operation from 1 January 2021.
- at least 70 % for electricity, heating and cooling production from biomass fuels used in installations starting operation from 1 January 2021 until 31 December 2025, and 80 % for installations starting operation from 1 January 2026.

The GHG emission savings are to be demonstrated in comparison with the relevant fossil fuel comparators. RED II imposes different GHG emission reduction thresholds depending on the field of application. For example:

- for biomass fuels used as transport fuels the fossil fuel comparator shall be 94 g CO_2eq/MJ,
- for biomass fuels used for the production of electricity the fossil fuel comparator shall be 183 g CO_2eq/MJ electricity,
- for biomass fuels used for the production of useful heat, as well as for the production of heating and/or cooling, the fossil fuel comparator shall be 80 g CO_2eq/MJ heat.

Annex VI of RED II contains the “Rules for calculating the greenhouse gas impact of biomass fuels and their fossil fuel comparators”. In the Annex default values are also provided for some biogas feedstock/substrates (manure, multispecies swards, triticale, biodegradable material). In the absence of default values, the GHG emission is to be calculated, using the methodology detailed in Annex VI. The preference is to use actual figures to provide more robust and reliable data/information on GoO for gas consumers and national accounting. Sustainability criteria has proposed 40% animal slurries with 60% agri feedstock, substrate of grass silage/mixed species pasture.

When planning a proposed AD biomethane project, the GHG emission caused by the production process at every stage and transportation of feedstock (processed in the AD unit) must be considered. See BIOSURF (BIOmethane as SUstainablle and Renewable Fuel) Deliverable 5.3. Calculation of GHG emissions caused by biomethane (in the whole Life Cycle) [3]
.

The GGCS for Ireland already factors the logistics of feedstock and other key measures of the AD biomethane process into Life Cycle Analysis (LCA) in full compliance with RED II sustainability criteria.

6.2.2 Technical aspects

The AD equipment must be engineered and dimensioned (sized) in accordance with the volume and estimated quality of the feedstock input – also considering potential seasonal changes in composition and quality. The optimum scale of AD biomethane plant in **Ireland** is 20 GWh, based on the findings of the *RGFI/KPMG Integrated Business Case for Biomethane Production in Ireland*, 2019.

The characteristics of the feedstock determines the technology of the anaerobic digestion unit. For example:

- certain feedstocks require pre-treatment before entering the digester, such as cutting (chop sizing), thermal treatment, etc. Such requirements are especially important for animal by-products and ability to ensure thorough pasteurisation of the digestate;
- the equipment used to feed, i.e. forwarding the materials into the digesters must correspond to the characteristics of the feedstock ;
- the mixing equipment is to be designed to suit the characteristics of the feedstocks;
- the size (necessary volume) of the digesters must provide for sufficient retention time for complete degradation;
- the covered storage tanks for the digestate must be sized to ensure sufficient capacity for the closed season for spreading fertilisers.

Under normal anaerobic digestion process, the volume and composition of substrate input mix determines the volume and composition of digestate. The placement of digestate is one of the most important challenges in an AD/biomethane investment.

6.2.3 Economic aspects

When selecting the feedstocks for biogas/biomethane production, special attention is to be given to the possibility of processing different biodegradable materials and other materials of zero or low market value (for example: manure, animal slurry, and food processing industries, food and beverage waste etc.).

[3] *http://www.biosurf.eu/en_GB/downloads-and-deliverables/deliverables/*

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Utilising organic biodegradable materials has pros and cons. On the positive side, the supply costs may be lower, the GHG emission reduction effect higher and, in some cases, "gate-fee" type income can be realised. On the negative side, the volume of these biodegradable materials is usually relatively low, their composition fluctuates with time and season, and requires additional treatment facilities. The feasibility study must address realistically both the positive and negative impacts. Commercial waste feedstock is a finite resource, with existing facilities already competing for the same commercial waste in Ireland. The experience in the UK is that commercial waste is commanding a fee for supply to an AD plant.

During the preparation to the AD feasibility study the volume, quality and biogas potential of these organic waste streams must be thoroughly checked. The waste materials have no standard quality, and it is quite difficult to take representative samples for laboratory analysis. For these reasons, the biogas yields forecasts must be treated with reservation.

The costs of feedstock are the most important single component in the total cost of biomethane production and the reliability of related data is a pre-condition of an acceptable feasibility study (and later of a successful project). To this end RGFI regularly consult with Teagasc on the cost of producing sustainable feedstock, and ongoing collaboration and coordination of the Integrated business case for AD biomethane production potential and capacity building in **Ireland**.

6.3 Biogas production forecast

Note that REGATRACE has provided an Example of cash flow calculations related to the feasibility of AD biomethane project and investment. They have not been included in this document as the numbers applied in **The Example** are imaginary and do not take account of the rapidly changing face of biomethane production and so cannot be used as a reference. The related tables have been included to illustrate the kind of information used. The Example cash flow calculation can be found in the general Guidance on European level: *REGATRACE D6.4 Guidance for feasibility analysis _ Europe*.

The feedstock supply forecast must be reliable both in relation to volumes and biogas potential. (The specific biomethane yield is expressed in Nm^3 methane generated from 1 kg organic matter).

The data for the biomethane gas yields can be taken from several sources:

a) for usual feedstock substrates, the biogas/biomethane yield data can be found in the literature. For example, the independent German institution KTBL (Kuratorium für Technik und Bauwesen in der Landwirtschaft) publishes recommendations ("Richtwerte") for planning biogas and biomethane yields from different feedstock substrates.[4]
b) laboratory analysis of representative samples,
c) data received from other biogas plants processing the same materials,

[4] *Gasausbeute in landwirtschaftlichen Biogasanlagen Heft 107 Jahr 2015 3. Auflage www.ktbl.de;*

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d) data provided by specialised companies offering AD technology, consultancy, biotechnological service, etc.

Table 1: Biogas production forecast

Feedstock	Volume	DM	oDM	Biogas	Biogas	Biomethane	Biomethane
	to/year	%	%	Nm^3/to oDM	Nm^3/year	%	Nm^3/year
Cattle slurry	14,000						
Sustainable forage	21,000						
Total/average	35,000						

where:
DM – dry matter content
oDM – organic dry matter share in total DM
Nm^3 – The volume of any gaseous material at temperature: 0 °C, and pressure: 1.01325 barA.

The specific costs of individual feedstock [substrates] per unit of produced biomethane is a good indicator for identifying both the economically most attractive and most problematic feedstock This indicator also assists in addressing the economic impact when one or more feedstock [substrates] must be replaced.

Table 2: Biogas Feedstock cost forecast

Feedstock	Volume	Methane	Feedstock cost	Feedstock cost	Feedstock cost
	to/year	Nm^3/to FM	EUR/to	EUR/m^3 CH_4	EUR/year
Cattle slurry	15,590				
Sustainable forage	19,144				
Total/average					

where:
FM – fresh mass

Important questions to be answered in the feasibility study are the following:

a) are the applied biogas/biomethane yields realistic?
b) are long-term supply agreements possible?
c) what are the risks of one or more feedstocks becoming unavailable?
d) will alternative feedstock sources be available in case of disruptions with originally foreseen supplies?
e) has the deterioration of quality and loss of biogas/biomethane potential with storage time been considered?
f) Is the necessary C:N ratio in the feedstock supply mix secured?

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6.4 Comments on Feedstock

A detailed description of the sustainable feedstock foreseen for processing is essential to presentation of a reliable and trustworthy feasibility study.

a) Agri crop feedstock (multispecies/grass) silage

Assuming best farm practice and land management methods and cross compliance regulations are applied, the use of dedicated Agri crops as feedstock, such as multispecies sward pasture, can be sustainable, for biomethane production.

In **Ireland**, Based on Teagasc surveys the current grass yields for the non-dairy sector is 6-7tnDM/ha/yr. Teasgasc launched Grass 10 with a target of achieving 10tnDM/ha/year grass utilised – equating to c.12-13tnDM/ha/yr (assuming livestock consume and convert over 70% of this to meat and milk protein). In its Grass10 Report, Teagasc noted that the "701 grassland farmers that participated in the 42 Grass 10 courses in 2019/20 increased grass production by 1.8 tonnes DM/ha, proving that it is possible to increase grass yield simply through proven land management techniques.

This evidence is further supported by research by Devenish at Dowth Farm, a Global Lighthouse Farm, which showed that utilising Multispecies swards (MSS) rather than mono crop ryegrass can increase the yields from 10tn/DM/ha/yr to 12-13tn/DM/ha/yr in addition to reducing the fertiliser requirement by approximately 58%. Such increased yields can be achieved primarily by (1) correcting soil nutrition deficiencies; (2) installing or upgrading grazing infrastructure on the farm and (3) sowing MSS.

In practice, long-term sustainable feedstock supply agreements must be concluded between the biomethane plant and the farmers to ensure stability and sustainability for both parties. The farmers gain secured diverse income at fixed price, while the biomethane plant receives guaranteed sustainable feedstock supplies at fixed price. Mitigating and excluding the fluctuation of agri forage crop prices is beneficial for both parties in the long run.

The following factors must be taken into consideration in such supply agreements:

- the fixed price of sustainable agri feedstock paid by the AD biomethane plant to the farmers must be linked to the quality, preferably to the biomethane potential of the supplied material
- for a replacement crop the same principle is to be applied: for example, if the biomethane potential of the crop is 10% less, than its price should reflect this.

b) Animal slurries

Animal husbandry results in the by-production of animal slurries that can be used as raw material for biomethane production. However, only slurries generated from indoor housing can be obtained for energetic purposes. The main part of animal manures from sheep, goats, horses, gooses, and ducks is not usable for energy applications due to the high proportion of free-range systems for these animals. In Ireland, big quantities of animal slurries from indoor housing originate from cattle and pig farming, less from poultry farming. Manure from

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chicken/poultry can be co digested in biomethane plants with recommended limited amounts of c. 5% due to high ammonia content.

Animal slurry contains a liquid and a solid fraction. It consists of water with solid matter and urine of animals, including possibly also small amounts of litter. "Manure" is a mixture of excrements of domestic animals which includes materials of animal bedding such as straw or wood chips. The biomethane potential of animal slurries (both solid and liquid) depends partially on the food quality (fresh/liquid fodder, dried fodder). The yields for bio methane depend on the type of slurry / manure, the animal species, and the age of the animal slurry (outgassing).

Animal slurry can be used for the commercial energy production on and near farms, without transportation over long distances. The material is easy to ferment, and the fermentation residue (digestate) can be applied as organic fertilizer. Significant advantages of the fermentation residues compared to untreated animal slurry are the reduced odour emissions, the homogenization of the digestate which makes it more readily spreadable and absorbed into the soil, increased proportion of inorganic nitrogen which better satisfies the nutritional needs of plants, fewer pathogens and weed seeds.

c) Biodegradable organic material

The European Animal By-Product Regulation (ABP) 1069/2009 controls the use, recycling and disposal of animal by-products which are declared unsuitable for human consumption. The ABP Regulation stipulates the categories of ABP and in which conditions they are allowed to be treated in biomethane plants. The Department of Agriculture, Food and The Marine has a key role to play in approving the type of AD plant according to the feedstock being used in the plant and site location with appropriate controls in place.

In **Ireland**, AD plants approved by DAFM may handle ABP and non-ABP materials. However, the quantities may be restricted in plants that are not (fully) pasteurising feedstocks. Such restriction will be detailed in the conditions attached to the AD biomethane plants permit and approval.

Other (than animal excrements) organic biodegradable materials are defined under the Waste Framework Directive[5] : "bio-waste" means biodegradable garden and parklands material, food and kitchen waste from households, restaurants, caterers and retail premises and comparable waste from food processing plants.

Although efforts have been made to reduce the amount of biomaterial from households in some member states, there is still a considerable amount of biomaterial derived from food, feed and beverage production and consumption that cannot be avoided. One of the best options for dealing with these organic material streams is processing them in biomethane plants producing energy and organic fertiliser.

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[5] *Directive (EU) 2018/851 of the European Parliament and of the Council of 30 May 2018 amending Directive 2008/98/EC on waste (Text with EEA relevance)*

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Certain bio-material streams, mainly from beverage and food processing, have a competing application, they can be also used as fodder (or component to fodder). If these materials (for example: spent grains from ethanol production, rape-seed press cake from biodiesel production, sugar-beet press cake etc.) find place on the animal feed market, the income there is substantially higher than the value generated through anaerobic digestion.

The landfilling of biodegradable organic material from households is banned. The bulk of the separately collected biomaterial from households is currently still treated in composting plants. Due to further regulations and developments in the biomethane sector, an increasing amount of bio- material from this category can be expected for use in anaerobic digestion.

The term "residue" comprises very different types of biodegradable materials. All of them have in common that they are by-products and were originally not intended to produce bioenergy. Besides municipal and agro-industrial bio-degradable materials and animal slurries, this biomass category also includes crop residues (mainly straw), residues from landscape maintenance and conservation, incl. pruning material and catch crops.

The EU's revised legislation on waste sets clear targets for reduction of waste and establishes the long-term path for waste management and recycling. Key elements of the revised waste package include:

- a common EU target for recycling 65% of municipal waste by 2030.
- a binding landfill target to reduce landfill to maximum of 10% of municipal waste by 2030.
- a ban on landfilling of separately collected waste.
- promotion of economic instruments to discourage landfilling.

The new waste legislation is clearly promoting the source separated collection of bio-degradable materials and treats anaerobic digestion as the preferred method of utilisation in the bioeconomy and recycling. The recycling targets combined with strict limitations on landfilling create serious challenges in those countries, regions and communities which still landfill the bulk of their municipal waste. Ireland will be expected to continue to take strong measures towards source separated collection and recycling. Processing the organic material for biomethane production as the target product will be increasingly attractive, while in this way clean fuel can be provided for the local fleets of buses, waste collecting, and street cleaning machinery and other vehicles used by municipalities.

d) Crop residues

Crop residues are parts of the crop that are not harvested during standard agricultural operations. Significant amounts of agricultural residues remain on the field after harvest. The utilisation of these residues (also called by-products from agriculture) depends on several factors: types of crops, crop rotation, crop mix, agricultural practices, harvesting technics. Straws from cereal, maize and rapeseed production are the main crop residues, there are considerable differences in Europe regarding cultivated area, types of crops and yields due to climate and soil conditions, accessibility, and farm practices.

Other primary residues that can supply bio-degradable materials for bioenergy include cuttings from parklands or other recreational areas, and abandoned grasslands. Management of abandoned areas through cutting can be beneficial for biodiversity.

e) Catch crops (cover crops/second crops)

Catch crops are cultivated on the same piece of arable land before or after the main crops. These crops are mostly used to bridge the time in between main crop cultivations when the area would otherwise just consist of delicate fallow land. In this context catch crops/cover crops help to prevent water and wind erosion, nutrient leakage, and the consequent soil deterioration. Table 3. lists some of the plants which can be cultivated as catch crops/cover crops.

Table 3: List of potential catch crops/cover crops

Winter barley	Hordeum vulgare
Winter triticale	Triticum x Secale
Winter oat	Avena sativa
Sunflower green	Helianthus annuus
Rye green	Secale cereal
Mustard green	Sinapis alba
Summer barley	Hordeum vulgare
Summer oats	Secale cereal
Summer triticale	Triticum x Secale
Oilseed radish	Raphanus salivus
Phacelia	Phacelia tanacetifolia

Cover crops are listed in Annex IX. Part A. of RED II under raw materials which can be used for producing “advanced biofuels”.

6.5 Anaerobic digestion

This section describes the aspects of the anaerobic digestion (AD) process to be included in the feasibility study to inform financial decisions and to also assist the project developer in formulating enquiries to technology suppliers, to go through the phases and specification of the technology.

There is a big variety of biomethane anaerobic digestion/ fermentation technologies on the market offered by specialised technology engineering companies, some of them having a proven track record with reference lists and confirmed performance, others at the early stage of development and practical application experiences.

The technological solutions differ from each other in the following key elements:

a) Pre-treatment of feedstocks
b) Fermentation

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c) Number of fermentation stages
d) Digestion temperature
e) Digester configuration
f) Mixing equipment (agitators)
g) Desulphurisation
h) Biomethane storage

6.5.1 Pre-treatment of feedstocks

Regulations may require pre-treatment or post-treatment which is very much dependent on the type of feedstock. This may include pasteurisation and cutting the feedstock to a maximum particle size (12 mm in **Ireland**). Feedstock of vegetable origin may require ultra-wave treatment, thermodynamic (heat and pressure) treatment, bio-extruders, etc. Most of these technical approaches have appeared recently and need to be proven both in practical and economic terms.

6.5.2 Fermentation

Digested material from another AD plant is required to initiate the stock of microbes in a new AD biomethane plant.

Most agricultural biomethane plants apply wet fermentation, which means that the dry matter content of the fermentation mass is in the range of 6 – 15%. This offers the best environment to the microorganisms "working" in the system.

The wet AD process is applied to liquid waste streams that are conveyable by pumping. The wet AD process can take place in reactors of two main configurations, continuously stirred tank reactors (CSTR) and plug flow reactors. The theory of the CSTR is that, through continuous mixing, the composition of the contents of the reactor in any given location in the tank is the same as in any other location in the tank. The theory of plug flow, on the other hand, is that the makeup of the contents at the head of the digester is different from that of the material leaving the digester as the material flows through the digester like a plug through a pipe and does not mix with the material that has entered before or after it.

6.5.3 Stages in the fermentation process

The AD biomethane plants operating on a wet fermentation basis differ from each other regarding the number of process stages. There are plants, where the fermentation is realised in a single stage (that means that all substrates enter a single digester, and the fermentation residue is taken out of this digester). Depending on the volume of feedstock there might be more than one digester running parallel to each other in one-stage fermentation systems.

In the two-stage solutions the feedstocks are fed-in into the first stage digester (often called main digester) and the fermentation mass is thereafter forwarded to the second stage digester (often called post-digester). The advantage of such digester configuration is that higher level of biodegradation of organic material (i.e., higher specific biogas yield) can be achieved.

Research has concluded that the remaining biogas potential in the fermentation residue of one-stage fermentation plants can be nearly two times higher than in the two-stage processes. *

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In a 3-stage system the first stage is operated at low pH value and is destined for the hydrolysis step in the biological process chain. It is to be considered whether the additional investment- and operational costs are justified for typical agricultural feedstocks.

6.5.4 Fermentation temperature

Biomethane plants operated with agricultural feedstocks apply different fermentation temperatures:

- Most of the units are operated at the so called "mesophilic" temperature range, which is 38 +/- 3 °C - the biological system is most stable at this temperature.
- Operating the fermentation at "thermophilic" temperature (54 +/- 2 °C) is more efficient but also more demanding (for example the regulation of the temperature in the digesters must be more precise and reliable);

It is undesirable to combine a mesophilic stage with a thermophilic stage as totally different microbes live and "work" at different temperatures. However, a reserve capacity could be established at low cost and with no risk by setting up for mesophilic fermentation conditions but installing digester heating system and insulation, which would enable to run the plant at thermophilic temperature range in the future.

6.5.5 Digester configuration

Digesters are placed either horizontally or vertically. Horizontal digesters might have a rectangular or a cylinder form, while all vertical digesters are cylinders.

The digester configuration, the feed-in systems and the mixing equipment are essential parts of proprietary anaerobic digestion fermentation technologies and – as such – are determined by the selected technology partner.

**The Fachagentur Nachwachsende Rohstoffe e.V. (FNR) has carried out a Biogas Measure Program under the appointment of the German Ministry for Nutrition and Agriculture. They have analysed the data from 61 biogas plants and concluded that the remaining biogas potential in the fermentation residue of one-stage fermentation plants can be nearly two times higher than in the two-stage processes. In the FNR study the average remaining biogas potential was 9,5 Nm^3 CH_4/to in one-stage plants as compared to the average of 4,9 Nm^3 CH_4/to in the two-stage plants.*

6.5.6 Digester dimensions

A key design parameter for any digester system is the overall organic matter loading rate. For any given project, no two digester suppliers will provide a system of the same size. Loading rates are commonly expressed as the average number of days of retention time and/or the quantity of organic matter introduced to a given tank volume per day.

Under "organic load" we understand the quantity of organic dry matter (oDM) loaded into the unit volume of the digester daily expressed in kg oDM/m^3/day.

The hydraulic retention time (HRT) indicates the number of days substrates remain in the digester(s) on average.

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Table 4: Digester volume estimation

Organic dry matter (oDM) input	t/year	14,000
Average organic dry matter (oDM) input	kg/day	39,696
Allowed organic load (for planning purposes)	kg oDM/day/m^3 digester	39.70
Digester volume recommended based on organic load	m^3	25,736
Input volume	m^3/day	37.90
Average hydraulic retention time (HRT)	days	32
Digester volume recommended based on HRT	m^3	28,953
Recommended digester volume, min.	m^3	25,736

In Ireland, RGFI estimates an optimum size plant of 20 GWh at 35,000/t pa, 40% animal slurry and 60% agri-feedstock.

Table 5: Digester dimension indicators

Digester volume	28,953	m^3
HRT (average)	32	days
Organic load (average)	39.696	M^3/ day
Biogas production	6,927	m^3/m^3/day

Showing these indicators in the feasibility study will strengthen the confidence that the anaerobic digestion facility has been designed with due diligence and whether or not the fermentation system will have reserve capacity.

6.5.7 Mixing technique (agitators)

The proper mixing of the fermentation mass is an important pre-condition for efficient biodegradation. There are 3 principal ways of solving this task:

- mechanical agitators,
- circulation of the fermentation mass by means of an outside pump,
- injection of biogas (mixing with the biogas bubbles moving upwards).

6.5.8 Desulphurisation of biogas

The most common and cost-effective solution for the desulphurisation of the biogas produced is the biological way when aerobic microbes convert hydrogen sulphide (H_2S) into elementary sulphur in the presence of oxygen. Biological desulphurisation can be carried out either in the biogas area on top of the digesters or in separate desulphurisation columns. The latter is a more efficient solution, which also causes limited dilution of the biogas with nitrogen (and oxygen) but requires additional investment costs. The biological desulphurisation solution can be extended by adding active-coal filters.

Different biogas upgrading technologies have different requirements with regards to the sulphur content of the raw biogas. For example, biomethane quality standards and natural gas

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grid requirements put strict limits on the oxygen content of biomethane. These requirements must be thoroughly considered at connecting the anaerobic digestion installation with the biogas upgrading facility. No decision can be taken on desulphurisation within the AD unit without knowing the specifics of the subsequent technological step.

6.6 Upgrading of biogas

The specific features of the technologies used to upgrade the biogas should be taken into consideration when elaborating the material and energy balances in the feasibility study.

Upgrading of biogas to biomethane means

- purification (removing components like water, hydrogen sulphide, ammonia, oxygen, nitrogen, carbon monoxide, halogenated hydrocarbons, siloxanes and particles)
  plus
- separation of biogenic carbon dioxide from methane.

Currently, biogas upgrading to biomethane is performed via water scrubbing, chemical scrubbing, physical scrubbing, pressure swing adsorption, and membrane separation. Recent advances have been made in the field of biochemical biogas upgrading using microbial-based systems and in cryogenic upgrading. The cryogenic technology offers additional benefits, such as production of liquified biomethane (for transport fuel use) and the simultaneous production of high purity, food-grade biogenic carbon dioxide. *

When selecting the upgrading technology several factors must be looked at, among them:

- expected composition of biogas (for example hydrogen sulphide, ammonia, oxygen, nitrogen content),
- the technical quality requirements – CEN-EN 16723,
- the natural gas grid technical requirements (for example pressure, oxygen content),
- the intended use (for example intermediary biomethane storage is needed if refuelling stations are supplied directly),
- parasitic load the energy consumption (electricity and thermal) and the available energy sources,
- national regulations on limiting the methane emissions with the CO_2 stream,
- market options and requirements for selling the co-produced biogenic CO_2

**A comprehensive and up-to-date review of biogas upgrading technologies is provided in the Research review paper „Biogas upgrading and utilization: Status and perspectives" by Irini Angelidakia et al. in Biotechnology Advances.[6] www.elsevier.com/locate/biotechadv*

6.7 Storage of biogas

The biomethane plants must have a buffer biogas storage capacity, while

- there are interruptions in the operation of the upgrading (and the CHP unit, if installed),
- the volume of biogas production or biomethane upgrading is fluctuating in time.

Biogas can be stored in the gas domes [membranes] installed on top of the digesters. The other solution is the installation of stand-alone ¾ spheres. Both solutions are of equal technical value, the choice is mainly dependent on the configuration and production capacity of the digesters, and whether the AD biomethane plant is on or off grid. Additional storage is most likely to be required if the biomethane plant is off grid

The necessary minimum size of biogas storage capacity is to be determined considering the coupling with the upgrading unit. Installing big biomethane storage capacity provides important operational flexibility but results in additional capital and operational costs.

6.8 Minimizing gas leakages

Due to the economic, safety and environmental significance of methane losses, biomethane plants need to be designed in detail, planned, built, and operated to minimise methane losses. There are several technical and organisational measures that can be taken to reduce the emissions from biomethane plants. Technical mitigation measures are real interventions on the plant, e.g., the installation of higher specification components and are mostly in connected with costs. Organisational measures describe the action sequences during plant operation. A non-exhaustive list of mitigation measures is listed below.

Technical mitigation measures:

- Gas-tight membrane covering the tanks, e.g., storing or mixing tanks;
- Installing an exhaust gas treatment;
- Correct dimensioning of biogas pipes;
- Regular planned replacement of aged membranes and seals;
- Regular maintenance of pressure valves and pumps.

Organizational mitigation measures:

- Perform leakage tests before operation and instalment of monitoring system for regular leak detection during operational phase.
- Emission measurements after the renewal of plant components
- Gas holder filling level preferably at 50%
- Regular maintenance of valves
- Adjustment of feedstock substrate feeding regime before planned maintenance.
- Sufficient aeration during post-treatment
- Analysis of residual gas potential in the digestate.

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6.9 Material balances

Feasibility studies for AD biomethane plant investment projects must contain the estimated material balances of the processes foreseen. The respective technical data, specifications and information should be obtained from the technology providers. Only preliminary opinions can be formulated but no decisions should be made based on general data and information from literature.

In the case of converting an existing biogas plant to biomethane production the material balance of the anaerobic digestion unit will be composed from actual operational data.

The Tables below indicate how the material balances can be provided in the feasibility study.

	Volume	DM	oDM	Biogas	Biogas	Methane	Methane
	to/year	%	%	Nm³/to oDM	Nm³/year	%	Nm³/year
Cattle slurry	14,000	6	5	19.75	276,500	60	165,900
Sustainable forage	21,000	32	28	135.65	2,848,800	60	1,709280
Total/average	38,000	19	16.5	62.81	3,125,300	60	1,875,180

Where the operation of local CHP is foreseen, the biogas balance could look like as given in Table 6.

Table 6: Biogas balance

	Nm³/year	Nm³/hour
Gross biogas production	3,125,300	364
Biogas loss (0,5%)	15,626	1.82
Biogas to CHP	0	0
Biogas for upgrading	3,109,674	362
Biogas methane content	60%	60%
Gross methane production	1,865,804	217

The DM (dry material) and oDM (organic dry material) balances are less important from economic point of view but they provide information on the level of conversion of organic material to biomethane and on the expected DM content of the digestate coming out of the digesters. (Table 7.)

Table 7: DM and oDM balances

	DM input	oDM input	oDM input
	to/year	to/year	%
Cattle slurry	14000	13,860	5
Sustainable forage	21000	20,160	28
Total	**35,000**	**34,020**	
Converted to biogas		3,125,300	
Remaining in digestate		28,577	

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Fermentation residue (digestate)		**84%**	

In anaerobic digestion facilities of this size the digestate bio fertiliser is usually separated into two fractions: the solid part can be transported for longer distances and marketed as bio-fertiliser, while liquid fraction can be spread on cultivated land.

Table 8. indicates the material balance of digestate separation.

Table 8: Seperation of digestate

Total volume	28,577 tn/year
Assumed density	32kg/m^3
DM	60%
Liquid fraction DM	6%
Liquid fraction volume	1,306,636 m^3/year
Solid fraction DM	55%
Solid fraction weight	15,717 tn/year

The material balance of the upgrading unit must include the methane loss factor. This has double importance: on one side this reduces the volume of biomethane produced, on the other hand any methane emitted to the atmosphere has a negative effect of the GHG emission intensity of producing biomethane. The methane loss factor is very much dependent on the selected upgrading technology and of its efficiency (for example of the number of stages in PSA or membrane separation).

Table 9. indicate the material balance of the upgrading stage.

Table 9: Material balance of upgrading

	Nm^3/year	Nm^3/hour
Biogas for upgrading	3,125,300	363
Gross methane production	1,865,804	217
Methane loss in upgrading (1%)	18,658	2.16
Net methane production	1,847,146	215
Carbon dioxide stream	1,093,855	127

6.10 Energy supplies

Both the anaerobic digestion and upgrading units consume electrical and thermal energy.

The level of energy consumption related to the biomethane production depends on:

- the volumes and composition of feedstocks,
- the selection of technology (for example mesophilic or thermophilic digestion, membrane, chemical absorption, or any other upgrading technology),
- the energy demand of the necessary technology equipment,
- the energy consumption of digestate bio fertiliser processing (for example drying).

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Correspondingly, the feasibility study can address the issue of energy supplies only based on data available from the basic engineering of the AD and upgrading units, most technology providers will have reasonably accurate data and information on the energy load required by their equipment.

The principal decision to be taken at an early stage is to cover the energy consumption of the installation fully or mainly from own sources or to import electricity and source(s) of thermal energy. RGFI would recommend where feasible to maximise the use of renewable energy sources for the parasitic load.

The straightforward solution for energy self-supply is to install a CHP (combined heat and power) unit to generate electricity and heat, an assessment on use of BioLPG for boilers producing heat in the form of hot water.

Pros for autonomous energy generation and supply:

- the full volume of produced biomethane is qualified as renewable methane (while no fossil energy was consumed in the production processes),
- the regulations of applicable national financial support schemes may prohibit the consumption of fossil energy sources,
- self-supply protects from potential disruption of supplies from external sources,
- self-supply protects from potential future price increases for external sources (electricity, natural gas) and provides a stable basis for the cost projection of energy supply.

Cons for autonomous energy generation and supply:

- electricity and thermal energy produced by the local CHP may be more expensive than the imports from external sources – this is very much dependent on the price mechanisms valid on the domestic energy markets and access to grid infrastructure,
- for the security of operations, the connection to the electricity grid (as a back-up) is needed in any case.
- maintaining the process temperature in the digesters at times when the CHP is not in operation may require access to back up or outside thermal energy source anyway.

Note: full independence from external energy sources cannot and should not be considered: the most sensitive part of the machinery and equipment must be operated, the process temperature in the digesters should be maintained also at times of disruption of the local CHP operation (for example for maintenance, etc,).

The easiest way of securing a back-up electricity supply is to establish a connection to the electricity grid with entitlement to take electricity any time. Alternatively, a local electricity generator could be installed, which would operate only in case of emergency.

The security of thermal energy supplies can be achieved in several ways:

- adding a boiler burning biogas or /bioLPG to the plant,
- connecting to the natural gas grid and burning natural gas in a boiler, if cost effective alternatively biomethane

In the Tables the installation of one local CHP unit is foreseen and the electrical capacity of the CHP unit is determined by the estimated yearly consumption of electricity of the AD plant and upgrading units.

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The co-generated thermal energy (usually available in form of hot water) can be used to cover the heat requirements of the digesters. In the Tables no thermal energy consumption has been considered for the upgrading unit. Obviously, this approach is acceptable only for some of the upgrading technologies. In case of chemical absorption, the heat requirement is high, and this influences the thermal energy balances of the installation substantially.

In the Tables three alternatives were considered:

- Alternative A: local CHP for self-supply of energy electricity and heat
- Alternative B: external energy supply through importing electricity and natural gas from the respective grids.
- Alternative C: external electricity supply, local biogas or bioLPG boiler for heating the digesters.

Table 10: Basic data of the CHP unit

CHP data		
Electrical capacity	60	kW
Network connection	43.6	kW
Thermal energy production nominal capacity	24	kW
Conversion efficiency (to electricity)	35	%
Full load operating hours (calculated for 100%)	8600	h/year

The estimated energy consumption of the AD unit:

Table 11: Estimated energy consumption of the AD unit

AD unit estimated energy consumption		
Thermal energy consumption	1,905,430	kWh/year
Electricity consumption	2,705,484	kWh/year
Loss of electricity, %	154,110	kWh/year

The thermal energy consumption of the AD unit fluctuates with the time of the year. Such fluctuations are illustrated in the Table 12.

Table 12: Thermal energy balance of the AD unit

	%	own consumption, kWh	thermal energy sold, kWh
January	9.5	181,016	n/a
February	9.25	176,252	n/a
March	9.25	176,252	n/a
April	8.5	161,962	n/a
May	8.0	152,434	n/a
June	7.25	138,144	n/a
July	7.25	138,144	n/a
August	7.25	138,144	n/a
September	7.5	142,907	n/a
October	8.0	152,434	n/a
November	8.75	166,725	n/a

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December	9.5	181,016	n/a
Total	**100**	**1,905,430**	

Note: Table 13. includes an imaginary local utilisation of thermal energy for heating buildings in the cold months of the year.

Table 13: Thermal energy balance of the AD unit

Thermal energy balance	kWh/year	**%**
Thermal energy production	2,381,788	100
AD unit own consumption	1,905,430	80
Losses (5%)	100,286	5
Thermal energy utilised	1,905,430	80
Thermal energy not utilised	376,072	15

Note: The thermal energy balance estimate will be affected by the upgrading unit- which is very much technology specific.

Alternative A with local CHP

The biogas balance in Alternative A:

Table 14: Biogas balance - Alternative A

	Nm^3/year	Nm^3/hour
Gross biogas production	3,125,300	392
Biogas loss (0,5%)	15,627	1.8
Biogas to CHP	873,099	101.5
Biogas for upgrading	309,960	36
Biogas methane content	60%	
Gross methane production	1,155,968	135

Table 15: Electricity consumption of upgrading unit in Alternative A

Specific consumption	1.96	kWh/Nm^3 biogas
Biogas input	309,960	Nm^3 biogas input
Electricity consumption	608,806	kWh/year

Table 16: Electricity balance in Alternative A

Electricity balance	kWh/year	**%**
Gross electricity production	3,468,400	100
AD unit consumption	2,705,484	78
Upgrading unit consumption	608,806	17.5
Loss of electricity, %	154,110	4.5
Net electricity production	3,314,290	95.56

Alternative B without local CHP and biogas boiler:

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In Alternative B the necessary electrical energy and natural gas are imported, there is no CHP and no boiler consuming biogas. Correspondingly, the volume of biogas available for the upgrading unit will be higher than in Alternative A. This increases the electricity consumption of the upgrading unit accordingly:

Table 17: Electricity consumption of upgrading unit in Alternative B.

Specific consumption	1.96	kWh/Nm^3 biogas
Biogas input	419,331	Nm^3 biogas input
Electricity consumption	813,968	kWh/year

Table 18: Biogas balance in Alternative B - without local CHP and boiler

	Nm^3/year	Nm^3/hour
Gross biogas production	3,125,300	363
Biogas loss (0,5%)	15,627	1.8
Biogas to CHP and boiler	0	0
Biogas for upgrading	419,331	48.76
Biogas methane content	60%	
Gross methane production	1,614,205	188

Alternative C with local biogas boiler

In Alternative C part of the biogas is burned in boiler (to provide heating for the digesters), correspondingly the biogas volume available for the upgrading unit is lower.

Table 19: Electricity consumption of upgrading unit in Alternative C

Specific consumption	1.96	kWh/Nm^3 biogas
Biogas input	248,492	Nm^3 biogas input
Electricity consumption	487,045	kWh/year

The biogas balance in Alternative C:

Table 20: Biogas balance in Alternative C

	Nm^3/year	Nm^3/hour
Gross biogas production	3,125,300	363
Biogas loss (0,5%)	15,627	1.8
Biogas to boiler	704,994	82
Biogas for upgrading	248,492	29
Biogas methane content	60%	
Gross methane production	1,293,712	150

Table 21: Comparison of Feasibility indicators for energy supply alternatives

Alternative	A	B	C
Electricity	own CHP	imported	imported

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Thermal energy	own CHP	Natural gas	Biogas boiler
Methane production, million m^3/year	1,155,968	1,614,205	1,293,714
IRR (12 years), %	12.7%	17.2%	15.0%
NPV (10%, 12 years), EUR	€895,370	€2,261,464	€955,404

6.11 Conditioning, storage and delivery of products and by-products

6.11.1 Biomethane

The produced biomethane can be delivered to the market in several ways:

- injection into the natural gas grid network
  - pressurised pipe network, other regulatory technical standards, analytics, monitoring and scheduling, and reporting requirements are to be considered,
  - grid connection applications are subject to economic assessment, costs can differ substantially depending on volume, required pressure, distance, ecology, infrastructure and required control equipment,
  - the feasibility study must include investment and operational cost data specific for the location.
- compressed into composite trailers for road transport to central grid injection facilities or direct to end consumer, typically large energy user,
- liquified into road tanks for transportation to end users.

Grid injection:

To feed the produced biomethane into the gas network, appropriate technical components, which can be designed differently depending on the individual case, must be available and be competitive. The most important pieces of equipment include:

- connection pipeline,
- gas compression equipment
- intermediary gas storage
- gas pressure control, analyser instruments for quality, measuring and monitoring systems
  - Gas quality analysing and measuring system.
  - Odour injection equipment
- conditioning and gas mixing equipment (enrichment with propane)

In addition to the components for pressure control, quantity measurement and safety, further components are required, such as shut-off devices, filters and separators, thermometers, temperature sensors, manometers, pressure sensors, power supply data acquisition, data remote transmission, volume converters, and tariff devices.

For the planning, construction, equipment, and operation of a central grid injection facility for feeding biomethane into the natural gas grid network the applicable regulations and rules must be complied with. The costs of establishing the grid connection will vary and dependent on local constraints as mentioned above.

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Ireland has a Connections Agreement for AD biomethane projects to the natural gas grid that are favourable and supportive, setting out the commercials based on 30% of the grid connection cost would be borne by the developer, while the balance is recovered by GNI over a period of 15 years.

The cost of pipeline for grid connection is a crucial item in the investment budget which may mean locating the AD biomethane plant on a certain site unfeasible. The pipeline cost is a function of the distance between the plant and the gas network, the amount of biomethane produced and the complexity of the civil work requested (i.e., trenching and construction on public road versus farmland, crossing of rivers, motorways, railroads etc.).

In case the costs of constructing the pipeline connection and the grid injection station are prohibitive, the option of liquification or the delivery in compressed tankers should be considered.[7] Transportation via compressed composite trailer unit is a competitive alternative for transporting biomethane to central grid injection facility or to directly to off grid gas consumers.

The quality of the produced biomethane must meet the relevant CEN-EN 16723 standard, which specify the technical quality parameters both for grid injection and usage as vehicle fuel.

6.11.2 Carbon dioxide

The impurities in the biogenicCO_2 rich stream, coming from the biomethane/carbon dioxide separation unit can be removed in the biogenicCO_2 recovery unit producing pure biogenic CO_2. The biogenic CO_2 recovery section includes a liquefying step and cryogenic unit(s) with a series of elements for the compression, drying and purification of the gas stream. The liquefaction and the thermal treatment allow a first separation between condensable pollutants and biogenic CO_2 on the one hand, and non-condensable gases on the other hand. Upon cooling to minus 30-33 °C, the biogenic CO_2 separates from the non-condensable gases (N_2, O_2, and CH_4). In an additional distillation and condensation step, the biogenic CO_2 reaches high chemical purity CO_2 (99.9+%). The non-condensable gases must be released to avoid their accumulation, but a fraction of this stream can be fed back to the membrane section to minimise gas losses.

To produce food grade quality, biogenic CO_2 must meet the EIGA/ISBT standard of the European Industrial Gas Association and the International Society of Beverage Technologists. Correspondingly, the laboratory testing must prove that the product is completely bacteria and fungi-free, is odourless, tasteless, and colourless.

If to be marketed and commercialised as a product, pure biogenic carbon dioxide will be stored and delivered in liquid form in tanks.

6.11.3 Digestate (Bio Fertiliser)

The fermentation residue is a valuable by-product of the biomethane process as it contains, among others, phosphorus, potassium, and nitrogen, which are key components of mineral fertilisers.

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[7] *Biomethane grid injection or biomethane liquefaction: A technical-economic analysis G. Pasini, A. Baccioli∗, L. Ferrari, M. Antonelli, S. Frigo, U. Desideri, Biomass and Bioenergy 127 (2019) 105263*

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In anaerobic digestion facilities of this size the digestate is usually separated into two fractions, making the subsequent handling feasible and practical: the solid part can be transported longer distances and commercialised for organic fertiliser, while the liquid fraction, can be spread on cultivated land and for horticultural use. This means that they both have a monetary value, providing important additional revenue to the AD biomethane plant.

Table 22: Separation of digestate

Total volume	28,953 tn/year
Assumed density	32 kg/m^3
DM	55%
Liquid fraction DM	6%
Liquid fraction volume	11,268 tn/year
Solid fraction DM	55%
Solid fraction weight	3,895 tn/year
Separated water Fraction volume	14,924tn/year

Table 23: distribution of dry matter in the digestate fractions

Volume, to	DM	DM, to
Liquid Fraction 11,268 tn/yr	6%	608
Solid Fraction 3,895 tn/yr	55%	3,895
Separated water Fraction 13,790 tn/yr	0%	0

6.12 Site selection

The proposed site for the AD biomethane plant should be selected bases on an Appropriate Assessment of the site suitability, discussed at pre-planning and pre-feasibility study phase considering several factors:

- what are the relevant local regulations on minimum necessary safety distances of 150m to nearest residence?
- is the AD biomethane facility corresponding to the long-term development policies of the local authority?
- consideration and assessment of areas of sensitivity in relation to archaeology, hydrology, landscaping, and ecology.
- Road access to the proposed AD biomethane plant, traffic management, etc;
- are there long-term plans for road/rail/infrastructure constructions which impact the intended site?
- what are the technical conditions for connections to the electricity and gas grids for supplying energy to the biomethane installation and injection to the gas grid?
- what are the technical conditions for injecting the biomethane into the natural gas grid (pipeline length and diameter, required pressure, etc.)?
- is the space required for the AD biomethane plant, associated technologies and storing the feedstock and the digestate (as specified in the preliminary design offers by technology suppliers) available?

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- is there a reserve space for possible future expansion?
- is the site connected to the public road?
- what are the distances for the land spreading of the digestate - either solid or liquid fractions?

In course of the pre-feasibility study, in relation to site selection, consultations with local key stakeholders including the local community and other parties (municipality, authority for building permits and public roads, archaeology, hydrology, ecology, flood risk assessment, traffic management, electricity grid operator, natural gas grid operator, fire-fighting body, farmers, agricultural food companies) are necessary.

Without selecting the appropriate site for the project in the site assessment phase no meaningful feasibility study can be performed.

7 Market feasibility

7.1 Priorities in renewable energy policies

7.1.1 RED II

The RED II[8] is relevant to biomethane in several aspects:

- overall renewable energy target in final EU energy consumption,
- sectorial sub-targets: obligations on the renewable energy share in transport and heat sectors
- guarantees of origin to cover renewable gases,
- sustainability criteria for biogas

Biomethane can contribute to achieving the key RED II targets:

1. Member States shall collectively ensure that the share of energy from renewable sources in the Union's gross final consumption of energy in 2030 is at least 32 %.
2. The share of renewable sources in the transport fuel consumption should reach in 2030 at least 14%, including 3,5% from „advanced” fuels.
3. Each Member State shall endeavour to increase the share of renewable energy in the heating/cooling sector by an indicative 3.0 percentage points as an annual average calculated for the periods 2021 to 2025 and 2026 to 2030, starting from the share of renewable energy in that sector in 2020.

The Union’s 2030 renewables and energy efficiency targets have been expressed and agreed at EU level without underpinning binding targets at national levels. Instead, new working methods and new instruments have been established to enable the collective achievement of the objectives of the Energy Union. The EU Governance Regulation has created a unique system of energy and climate governance ensuring that the Union and its Member States can plan

[8] *Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources.*

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together and fulfil collectively these 2030 targets, as well as ensure a transition to a climate neutral economy that is fair and cost-effective for all. The RED II and the Governance Regulation[9] require Member States to establish 10-year integrated national energy and climate plans (further shortly NECP) for the period from 2021 to 2030.

The NECPs[10] specify the national contributions and the aggregated NECPs are sufficient for the collective achievement of the Union's 2030 targets set in 2018. With the European Green deal the European Commission took the commitment to put itself on track to become a climate neutral continent by 2050. To reach this ambitious goal the energy and climate objectives set by the Climate and Energy Package were no longer sufficient. For this reason, the entire climate and energy legislation underwent an extensive revision. A revised Renewable Energy Directive is currently being discussed by the co-legislators. The revision includes a higher Renewable energy target (40% in the Commission proposal), higher sectoral targets, a GHG savings target for the transport sector and stricter sustainability requirement for the biomass sector.

What will happen by 2030 will be largely determined by the national energy and climate plans. The NECPs play a key role in the EU's governance system to ensure that the member states join forces and deliver on the common objectives together. They should provide as much clarity and predictability as possible for the business and finance sector to stimulate necessary private investments. They will also facilitate Member States' programming of funding and investments in the next multi-annual financial framework 2021-2027. The governance process also provides an opportunity to update the plans in 2024 to reflect experience and to take advantage of new opportunities for the remainder of the decade.

7.1.2 The European Green Deal

As mentioned in the previous subchapter, The European Commission presented on December 11, 2019, the European Green Deal[11] aiming at delivering the EU political ambitious to shift the EU economy to climate-neutrality by 2050.

The 24-page proposal provides a roadmap setting legislation initiatives "*to boost the efficient use of resources by moving to a clean, circular economy and stop climate change, revert biodiversity loss and cut pollution*". It also outlines investments needed and financing tools available and explains how to ensure a just and inclusive transition.

The European Commission has presented exhaustive legislation proposals to revise all the energy, environment and climate legislative framework in the EU and put it up to speed to halt biodiversity loss, minimise air and water pollution and curb greenhouse gas emissions reaching a 55% saving by 2030. The so-called Fit-for-55 package includes:

Changes in the EU Emission Trading System

Each year, the EU ETS lowers the cap on emissions from particular economic sectors and sets the price for carbon dioxide emissions. The Commission suggests lowering the overall

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[9] *Regulation on the governance of the energy union and climate action (EU/2018/1999).*

[10] *https://ec.europa.eu/energy/en/topics/energy-strategy/national-energy-climate-plans*

[11] *Brussels, 11.12.2019 COM (2019) 640 final COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE EUROPEAN COUNCIL, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS*

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emission cap even more and quickening the pace at which emissions are being reduced each year. As for biomethane, this will be zero-rated under the system provided it complies with the Renewable Energy Directive rules.

Effort Sharing Regulation

The regulation establishes stronger emission reduction goals for the building, road, and domestic maritime transportation, as well as the agricultural, waste management, and small industrial sectors, for each Member State. Considering the different starting points and capacities of individual Member States, these figures are based on their GDP per capita and are adjusted to take account of cost-effectiveness.

Renewable Energy Directive (see previous chapter)

Energy Efficiency Directive

The proposal requires Member States to reduce their energy consumption, with particular focus on building sector and heating.

Regulation setting new CO_2 emission standards for cars and vans

The Commission proposal includes lower -CO_2 emission standards for passenger cars and vans to accelerate the transition to zero-emission mobility by requiring a 55% reduction in average emissions from new cars. The regulation sets a ban on internal combustion engin for new vehicles from 2035.

LULUCF – Land use land use change and forestry regulation

The regulation proposal sets a EU target for carbon dioxide removal from natural sinks, corresponding to 310 million tonnes of CO2 emissions by 2030. By 2035, the EU should achieve climate neutrality in the land use, forestry and agriculture sectors, including other agricultural emissions.

Revision of the Energy Tax Directive

The revision of the Energy Tax Directive proposed aligning the taxation of energy products with EU energy and climate policies, promoting clean technologies and removing the outdated exemptions and reduced rates that now encourage the use of fossil fuels.

Revision of the Energy Performance of Buildings Directive

The Commission proposal on this directive sets out how Europe can achieve a zero-emission and fully decarbonised building stock by 2050. The proposed measures aim at increasing the rate of renovation, particularly for the worst-performing buildings in each Member State. It will modernize the building stock, making it more resilient and accessible.

Gas Decarbonisation Package

The European Commission proposal on the package aims to facilitate the integration of renewable and low-carbon gases into the existing gas network. It proposes inter alia to ensure that renewable and low carbon gases have access to the gas wholesale market abolish costs for cross-border tariffs facilitating trade and reduce injection costs for those gases by 75%.

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7.1.3 REPowerEU

The geopolitical crises that lead to Russian's invasion of Ukraine, resulted in an extreme gas volatility. On Wednesday 18 May the European Commission published its plan setting out how the European Union can eliminate its dependency on Russian fossil fuels, called REPowerEU. As phase out of Russian coal imports has already been agreed and a gradual phase out of oil by end-2022 is currently under discussion, the REPowerEU plan focuses on how to phase out of Russian gas by 2027 in an orderly and affordable fashion. Notably, the REPowerEU includes a Biomethane Action Plan detailing tools and measures to scale up the sector and roll out 35 bcm of biomethane by 2030, including a Biomethane Industrial Partnership. The biomethane is among the ones prioritized by the European Commission in reaching a more sustainable and sovereign energy system. The Commission's action plan is structured along four main dimensions: 1) Energy Efficiency - Entailing a higher EE target and behavioral measures 2) Supply diversification – Common Purchasing of green hydrogen, LNG and gas from reliable trade partners 3) Energy transition acceleration – Higher Renewable Energy Ambitions reflected in stepped up targets 4) Investment and reforms – Revised Recovery and Resilience Plans, ad-hoc REPowerEU grants and calls under the main EU financing programmes. The European Commission reckons that delivering on the planned objectives will require an additional investment of €210 billion between 2022 and 2027. However, this would save almost €100 billion per year in reduced fossil-fuel imports.

The strategy includes a Biomethane Action Plan that aims at facilitating the increase in production of biogas and boost its subsequent conversion into bio-methane, respecting the criteria agreed in the REDII. The focus is on waste and residue-based capacity and on the development of sequential/cover crops and sustainable biomass in marginal land. The main weaknesses identified are lack of focus on transport and on cross border trading. The Plan's actions are grouped under 5 areas: (i) Promoting production, use and injection in the grid (ii) Providing Incentives for biogas upgrading into biomethane (iii) Promoting adaptation of existing infrastructure and the development of new infrastructure for biomethane through EU gas grid (iv) Address RND&I gaps (v) Access to finance. Higher renewable targets may drive biogas and biomethane demand. The Commission is proposing to increase the targets currently under discussion in the context of the Fitfor55 Package. Concerning transports, the advanced biofuels target is the only one remaining unchanged, while the increase of the Renewable Targets seems to be mainly covered by H2 and electrification.

7.1.4 Legislative measures supporting the biomethane market in **Ireland**

The main challenge for the development of the biomethane industry is the fact that the costs of biomethane production have been exceeding the market prices of the fossil alternative (natural gas). Considering the current Ukraine crisis, energy security and reliable supply and stable pricing of energy is now a priority for EU Member states. In the case of **Ireland**, support is required to develop an indigenous biomethane industry at scale and pace. The RGFI biomethane working group have put proposals to the Government of Ireland in an Integrated business case for biomethane that is fully aligned with EU, National policies, Climate Action Plan 2021/2022 and programme for Government.

The Government of **Ireland** Climate Action Plan 2021 has put particular importance of biomethane as a core measure and for the first time is recognised as a zero emissions renewable gas that has a key role in decarbonising multiple sectors of the economy. Further to this, gaps exist, while the positive externalities of renewable fuels are yet to be developed and commercialised or are not recognised on the market and the negative externalities of burning fossil fuels are also not fully recognised.

The governments of the EU Member States apply widely different financial support schemes for promoting the deployment of renewable energy sources, including biomethane. There is a clear tendency moving away from Feed-in-Tariffs via Feed-in-Premiums towards socialisation (Article 23) as financial support for operational costs. Examples of socialisation acceptance are available, such as the bio-fuels obligation scheme for the transport sector.

Support schemes available for biomethane producers in Ireland

The Department of the Environment, Climate and Communications has responded to the request from RGFI and industry collaboration to implement Article 23 (REDII) Renewable Heat Obligation Scheme (RHOS) by Q1 2023. DECC has completed an initial consultation on a proposed RHOS and has agreed to proceed to the next steps and accelerate the design phase with implementation target of RHOS by Q1 2023. The nest steps of the proposed structure and administration of the RHOS is expected that this will be in place by the end of 2022 in consultation with industry.

The Government of Ireland is favourable to providing Capital Grant funding to support the development of an indigenous biomethane industry, with the REPowerEU plan focus on ramping up biomethane production to address the energy security crisis. RGFI is in consultation with Government of Ireland on the provisions for capital funding in the upcoming budget 2022, and long-term provisions for capital funding of AD biomethane to 2030, in line with REPowerEU Plan and National Biomethane Strategy.

Financial support available for biomethane consumers (e.g. tax benefits).

There are four key dimensions to enabling an accelerated plan for biomethane production in addressing the energy security, energy storage and price stability, aligning with Governments objectives of scalability and pace in dealing with the current geopolitical and climate change crisis.

The four as follows.

1. Feedstock Mobilisation.
2. Accelerated planning & permitting.
3. Market conditions – dealing with barriers
4. Funding Structures – incl. relaxing of GPER thresholds

Currently there are Accelerated Capital Allowances for certain equipment and some vehicles, this will be reviewed and may be expanded to other incentives and tax reliefs.

(duration, conditions, qualification, tender procedures, etc.).

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7.2 Domestic market

7.2.1 Technical and regulatory conditions for access into the domestic natural gas network

The Commission for Utilities Regulation (CRU) carried out public consultation on the harmonisation of renewable gas in the natural gas grid, as a result of the public consultation biomethane is being given priority in the gas grid and technical specifications have been agreed and harmonisation of tariffs for biomethane transported in the gas grid.

7.2.2 Possibilities of co-marketing biomethane in cooperation with the natural gas industry players.

Renewable Gas Forum Ireland has been very proactive in engaging with the key stakeholders in the manufacturing and processing sector with large users of natural gas. We have an industrial heat/thermal sectoral representation group being instrumental in engaging with Government and key state agencies to support the development of an indigenous biomethane industry to address demand for energy security, storage and stable pricing and biomethane to decarbonise thermal demand.

7.2.3 Maturity and development prospects for CNG/LNG in transport.

With the consumer sectoral representation approach has been very successful in delivering results to the manufacturing and processing industries for heat/thermal demand. RGFI has been approached to represent the Transport sector in relation to Government policy and legislation for biomethane (BioCNG/BioLNG) in transport. The transport sector already has a Biofuels Obligation Scheme in place, which needs to be adapted to include biomethane, BioCNG & BioLNG in transport and deliver at scale.

7.2.4 Government measures facilitating the consumption of renewables in transport, with special attention to “advanced” biomethane.

RGFI is engaging with industry participants in the transport sector to establish a credible representation of the transport sector and develop a strategy to progress policy and legislation that includes biomethane, BioCNG & BioLNG in transport.

The overall proposal is to establish a National Design and Coordination body led by RGFI to coordinate and develop a standardised approach to AD biomethane plant development that meets the Government of Ireland objectives of scalability and pace and in a sustainable, competitive and efficient manner, with continuous ongoing improvements.

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7.2.5 Interest for supplying biomethane for district heating purposes.

Through RGFI's engagement with Renewable Energy Ireland, we have promoted the concept of Community involvement in district heating with the involvement of Community Power who work closely with Sustainable Energy Communities (SEC's) to develop opportunities to include the supply of biomethane for district heating purposes, bringing bio-economy and circularity into rural and urban communities for a sustainable enduring solutions to renewable heat demands.

7.2.6 Interest of domestic industries for procuring biomethane

(for usage as raw material in the chemical industry, for high temperature for technologies, like steel industry)

RGFI has been working closely with the manufacturing and processing industries to develop an integrated business case for biomethane (KPMG/RGFI Integrated Business Case for Biomethane in Ireland 2019) for an enduring solution to renewable heat demand from domestic industries, with strong interest for indigenous sustainably produced biomethane. The current level of ambition of the domestic industries is to have 2.5TWh of biomethane in the gas grid by 2030.
Biomethane presents the lowest cost, least disruptive renewable heat solution for industrial users with thermal demand, where no other renewable heat technology can achieve the consistencies requires for manufacturing and processing industries, do not have a viable alternative, supported by the KPMG/Ervia 2018 report findings on decarbonising the heat demand.

7.3 Export market possibilities

In principle there are several ways of exporting biomethane into another European country:

a) **Direct physical deliveries in tanks compressed or liquified (road, rail, water)** – the administration is the same as for liquid biofuels.

b) **Physical deliveries in natural gas pipelines** – following the rules and procedures of natural gas transported in the gas pipelines.

c) **Virtual transfer of "renewable" value by means of Guarantees of Origin (GOs) –** regulated in RED II

d) **Mass-balancing in the natural gas network –** the ERGaR concept of cross-border biomethane administration and standardised approach to information and data contained therein.

a) **Direct physical deliveries in tanks** are available only in limited geographical circle around the biomethane production installation, and in limited volumes. This way of bringing biomethane to the market is very specific to local circumstances. Nevertheless, if demand over the border arises the feasibility study can be performed reflecting the concrete situation for volumes, forms of delivery and pricing.

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b) **Physical deliveries through natural gas pipelines** can be realised in accordance with the natural gas transport administration, following the rules and procedures which are valid for forwarding natural gas cross-border transfers (the transport/transit capacities must be booked, delivery schedules must be strictly met, etc.). Such deliveries are arranged today in practice, although the volumes are quite small yet. The burdensome and costly administration makes economic sense only if the biomethane imported is qualified for state aid/financial benefits. The ruling of the European Court of Justice in Case C-549/15 at the European Court of Justice (ECJ) E.ON Sweden vs. Swedish Energy Agency provides the legal basis for these transactions. The ECJ judgement confirmed that sustainable biomethane could be forwarded cross-border through the interconnected European natural gas pipeline network subject to proper mass-balancing administration and sustainability verification.

c) **Exporting Guarantees of Origin** may provide an additional income for biomethane producers and – correspondingly – the possibilities for exporting GOs should be addressed in the feasibility studies. However, it is very difficult to forecast the future income from selling GOs as long as no European forward market for these certificates is available for securing future prices.

GOs issued for biomethane consignments can be exported under the condition that the related biomethane volumes have not been placed on the domestic market as renewable gas. The RED II extended the system of Guarantees of Origin (further GO) to renewable gases in the expectation that this will create a European market for such gases, among them biomethane. As per definition the value of the GOs is determined by the market demand and customers willing to pay a premium (over natural gas) on a voluntary basis.

Respective quotes from RED:

"Guarantees of origin which are currently in place for renewable electricity should be extended to cover renewable gas. … This would provide a consistent means of proving to final customers the origin of renewable gas such as biomethane and would facilitate greater cross-border trade in such gas. It would also enable the creation of guarantees of origin for other renewable gas such as e-methane and bio hydrogen."

"Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources."

"A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another."

The information on financial support received is included on the list of obligatory content of GOs. This means that the RED II explicitly allows for issuing GOs for subsidised biomethane volumes. Nevertheless, the Member States are also entitled not to do so:
"Member States shall ensure that a guarantee of origin is issued in response to a request from a producer of energy from renewable sources, unless Member States decide, for the purposes of accounting for the market value of the guarantee of origin, not to issue such a guarantee of origin to a producer that receives financial support from a support scheme."

This right of the Member States must be taken into consideration when planning the sale of GOs for supported biomethane volumes. For example: presently GOs are issued for subsidised biomethane volumes in Denmark, in the UK, but not in Germany, France and the Netherlands. Governments may change their attitude in this respect any time.

An option available to Member States is to implement Article 23 of RED II by the latest date of 2026, placing an obligation on the shipper/supplier's sector to procure biomethane for onward supply to their customers. A Renewable Heat Obligation Scheme is a way of socialising the cost of producing biomethane across all consumers of gas, to decarbonise their heat/thermal demand.

Estimating future income from exporting GOs is challenging and calls for cautious approach. The declared function of GOs is informing the final consumers about the renewable origin of the energy carrier. It cannot be expected that the voluntary readiness of final consumers to pay for the green value in the future will provide the foundation for financing investments today – if no mature GO forward market is established, which would enable fixing future GO income for medium-long term.
The GOs cannot have an investment activity fostering impact also on economic considerations, per definition these GOs will always have a limited market value:

- the value will be determined (independently from the production costs) by the final consumers, who ***voluntarily*** decide on buying these GOs for demonstrating their environment/climate friendly attitude.
- the GO imports do not qualify for state financial support and for accounting towards national renewable energy commitments of the importing country.

d) Mass-balancing in the natural gas network - the ERGaR concept for administration of cross-border biomethane transactions

The main purpose of the European Renewable Gas Registry (ERGaR) association is to establish an independent, transparent, and trustworthy documentation scheme for mass balancing of biomethane distributed along the European natural gas system. In essence, ERGaR is to be seen as a network of national biomethane registries. Building on the activities of the national registries the common European documentation system enables cross-border trade of renewable gases via the European natural gas network while preventing double sale and double counting. The ERGaR administration is following the mass balancing methodology on a consignment-by-consignment basis.

In accordance with ERGaR's cross-border biomethane administration concept, the cooperation among the national biomethane registries issuing the biomethane Proofs of Origin has a central role in the transfer and mass-balancing of biomethane consignments along the European natural gas network.

It is to be noted that the ERGaR mass-balancing administration is different from the volume (energy) balancing processes of the network operators in the natural gas industry. The balancing in the gas industry is related only to balancing volumes in transportation, while the mass-balancing for biomethane must also cover tracking the sustainable and renewable ("green", "bio") quality from production through injection until withdrawal and usage of the product.

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The balancing in the gas industry begins with the injection and does not cover the origin and the production of biomethane. So, the balancing in the gas industry is aimed at

- establishing physical equilibrium between the injected and taken-out volumes and
- enabling security of supply to all end users and
- balancing any outages or oversupplies within the respective gas balancing areas in each country.

The physical balancing in the natural gas transportation and distribution systems has a continuous character; the equilibrium must be achieved at every moment. On the other hand, in case of biomethane the equilibrium between the injected and withdrawn volumes (expressed in energy units) is to be established within a set time frame.

7.4 Competition for feedstock and products

7.4.1 Competition for feedstock

AD biomethane project developers must be aware that some of the raw materials they are planning to process may have a competing usage which impacts both the availability and costs of the supplies to the anaerobic digestion unit. This potential for competition is mainly in the field of animal feed/fodder. To address and mitigate this from happening an AD Charter sets out the parameters for best practices and to not compete with animal feed. AD biomethane plants are designed to be complementary to all farming disciplines and promote incremental growth, sustainable feedstock such as multispecies swards and animal slurry management. Nevertheless, the feedstock demand of other biogas installations in the area may also put limitations on the raw material supply to the project under preparation.

Animal slurry

Solid manure (mostly with straw as bedding material) has been used as fertiliser and soil improver in agriculture for centuries. In view of the historical experience farmers are still interested in its application on the fields, so it would be misleading to believe that solid manure is available for the biomethane plants for free. However, with new regulations and requirements for animal manure to be stored/covered to mitigate methane emissions, the opportunity is that the AD plant processes the animal manures and in return the farmer receives a more usable fertiliser material. The spreading of raw animal manure/slurries is quickly becoming an outdated farm practice in the interest of protecting the environment. Among the operational costs, it may be prudent to factor in an additional transport cost in lieu of price to be paid to the animal farmers, Alternatively, a solid manure – solid faction of digestate exchange can be negotiated on organic fertiliser price with the farmers, which would be a mutually beneficial and stable solution.

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The situation with animal slurry is different. Spreading raw animal slurry on pastureland and tillage land is broadly practiced currently, however, National and EU policy is promoting the use of organic fertilisers, displacing artificial fertilisers and better management of surplus animal slurries to reduce GHG emissions in agriculture. Anaerobic digestion process provides an efficient solution for the treatment and processing of animal slurries and provides digestate bio-fertiliser. Further research is needed into the commercialisation of bio-fertiliser and related soil carbon sequestration.

Biodegradable organic material waste

Certain bio-waste streams, mainly from beverage and food processing, have a competing application, they can be also used as fodder (or component to fodder). If these materials (for example: spent grains from ethanol production, rape-seed press cake from biodiesel production, sugar-beet press cake etc.) find place on the animal feed market, the income may be higher than the value generated through anaerobic digestion.

The landfilling of biodegradable organic materials from households must be forbidden. The bulk of the separately collected bio-waste from households is currently still treated in composting plants. Due to the EU new waste legislation and developments in the biogas sector, an increasing amount of bio-waste material from this category can be expected for digestion.

The new waste legislation is clearly promoting the source separated collection of biodegradable materials and promotes anaerobic digestion as the preferred method of processing and recycling. Recycling targets combined with strict limitations on landfilling create serious challenges in those countries, regions and communities which still landfill the bulk of the municipal waste. The municipalities in Europe are expected to take strong measures towards source separated collection and recycling. Processing the biodegradable organic materials with high water content for biomethane as the target product will have no real competition in the future.

Silage

There are many primary residues that can supply biomass for bioenergy such as multispecies/grass silage of permanent grasslands (this material is usually used for hay or silage production and is subsequently applied in animal husbandry).

Grass silage could also originate from parks or other recreational areas, nature conservation areas and abandoned grasslands. In these cases, no competing use is to be considered but the costs of collection, transportation and storage must be covered.

Crop residues

Crop residues are parts of the crop that are not harvested during standard agricultural operations. Significant amounts of agricultural residues remain on the field after harvest. The utilisation of these residues (also called by-products from agriculture) depends on several factors, such as types of crops, crop rotation, crop mix, agricultural practices, harvesting techniques. There are considerable differences in Europe regarding cultivated area, types of crops and yields due to climate and soil conditions, accessibility, and farm practices.

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Straws from cereal, maize and rapeseed production are the main crop residues, which are already used for many different purposes. The majority of the available (cereal based) straw is used for animal husbandry. Straw can be collected for combined heat and power installations (CHPs), wheat straw is already used for bioethanol production, other innovative technologies such as biomass-to-liquid technologies are under development. The domestic market situation for wheat straw is to be analysed to see whether this material is available for the biogas plants at all and – if yes – assessment on volumes, availability, locations, and costs are feasible.

A substantial part of straw remains on the field for soil fertility purposes. In view of its characteristics maize straw is much more suitable for anaerobic digestion than wheat straw and has fewer competing usages – for these reasons among crop residues maize straw is the most prospective resource for the biomethane industry. Nevertheless, the AD biomethane plant must be ready to cover the costs of collecting, transporting, conserving, and storing maize straw.

Catch crops/cover crops/second crops.

Catch crops (cover crops, second crops) are cultivated on the same area of tillage land before or after the main crops. These crops are mostly used to bridge the time in between main crop cultivations when the area would otherwise just consist of delicate fallow land. In this context catch crops/cover crops help to prevent water and wind erosion, nutrient leakage and consequently soil deterioration.

Multispecies pasture to be considered as rotation crops, due to increased productivity of 13tDM.ha, and up to 58% reduction in nitrogen requirements.

7.4.2 Competition for the products

Biomethane

The consumers of biomethane are the same as the consumers of natural gas. Given the fact that the production costs of biomethane are above the prevailing market prices for natural gas, biomethane needs political and financial support to become attractive for the consumers. The financial support is addressed at different chapters of this paper. Regarding the price gap it is necessary to note the natural gas prices for consumers are at different levels in the European countries, correspondingly the price gap is not the same. Even more important is to recognise that the natural gas prices are different in the various market segments and if biomethane is supplied directly to the end users the wholesale costs can be substantially reduced.

The market segment for fuel used for heat with gas accounting for 41% or 22,736 GWh in 2019.

For biomethane designated as transport fuel the competition is from liquid biofuels, while both liquid and gaseous renewable fuels are counted towards meeting the biofuel/advanced biofuel quota targets. In this field the competition for biomethane is very direct: the marketing of biomethane must be financially attractive to fuel suppliers in comparison with meeting their commitments with liquid biofuels. In several European countries the biofuel/advanced biofuel quota obligations can be fulfilled by certificates issued for biomethane consignments supplied for transport. One example is the system of RTFO-RTFC in United Kingdom, another example is

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the GHG emission reduction commitment of transport fuel suppliers in Germany. In both cases non-fulfilment is penalised, and the amount of penalty is the ceiling for the prices of biofuel certificates.

Carbon dioxide

Examples of direct CO_2 utilization in the chemical industry are enhanced oil recovery (EOR) and enhanced coal-bed methane (ECBM) recovery. In the pharmaceutical and medical fields, CO_2 is used in a mixture with oxygen/air to promote deep breathing or for surgical dilation by means of intra-abdominal insufflations. Among the different CCU techniques, the use of CO_2 in the food market represents a relatively small but significant storage capacity and a moderate lifetime of storage. Its main use is in packaging, as preservative agent that increases the food shelf-life or for the carbonation of soft drinks, mineral water, and beer.

The fossil CO_2 supply chain is mostly based on fossil fuel combustion (carbon, natural gas, fuel oil, etc.); on gasification of solid fuels (carbon, oil shale, etc.); on extraction of CO_2 from geological reservoirs; and on CO_2 separation from petrochemical and chemical processes (such as syngas).[12]

Before taking a decision for additional investments resulting in production of (preferable food-grade) biogenic CO_2 the demand-supply situation on the domestic market must be carefully studied and considered.

Biogenic CO_2 will invariably become more sought after as the CO_2 derived from fossil sources becomes expensive due to carbon pricing and focus to move away from high carbon sources. In the opinion of RGFI, biogenic CO_2 will have a larger role to play as decarbonisation strategies and policies develop in the coming years. Currently, there is a white paper being finalised for submission to the EU Commission to support the development and suitable market conditions for Biogenic CO_2.

Digestate

Digestate can in the most part replace mineral fertilisers, but this is not a direct market competition situation. The value of digestate bio fertiliser can be calculated similarly to mineral fertilisers, i.e., based on the nutrient content, but the comparison is always depending on the location of the AD biomethane plant and its integration into the agricultural environment.

[12] *Simultaneous production of biomethane and food grade CO2 from biogas: an industrial case study by Elisa Esposito, Loredana Dellamuzia, Ugo Moretti, Alessio Fuoco, Lidietta Giorno and Johannes C. Jansen Energy Environmental Science. 2019, 12, 281*

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8 Commercial feasibility

8.1 Biomethane revenues

8.1.1 Revenue sources

The revenues of the biomethane producer related to the sale of the primary product (biomethane) may consist of several components:

- sales price of the molecules (corresponding to the prevailing prices on the market segment where the physical product is being delivered),
- Government policy on financial support via implementing Article 23, a Renewable Heat Obligation Scheme or other financial support scheme such as the Biofuel Obligation Scheme of the national government, if any,
- price premium paid voluntarily by the customer in respect of the „green” value (environment friendly, renewable, sustainable, etc.) of the product, if any,
- price premium paid by the customer in respect of the tax benefits the consumer is granted for purchasing renewable gas,
- income from the sale of Guarantees of Origin, if any,
- income from the sale of biofuel certificates, if any,
- income from the sale of ETS certificates, if any.

All these revenue components are subject to the conditions and regulations of the domestic market and no guidance can be given on European level on estimating, calculating these revenues. For this reason, the present General Guidance does not provide any details which would be valid to other markets all over Europe. Nevertheless, it is underlined that in the feasibility study performed for the given AD biomethane project all these potential income items must be considered, assessed, and addressed, even if not available now.

Under Article 23 of the Renewable Energy Directive II, **Ireland** must 'endeavour to increase the share of renewable energy in that (heating and cooling) sector by an indicative 1.3% as an annual calculated for the periods 2021 to 2025 and 2026 to 2030, starting from the share of renewable energy in the heating and cooling sector in 2020, expressed in terms of national share of final energy consumption. That increase shall be limited to an indicative 1.1% for Members States where waste heat and cold is not used.

The Department of the Environment, Climate and Communications have completed the public consultation process on the 29 October 2021, and it is anticipated that the Irish Government will be announcing the Renewable Heat Obligation Scheme and giving notice to the market of implementation in Q1 2023. Therefore, the final details, structure, administration, and costs associated are to be determined in the next phase of consultation, along with the financial support of bridging the funding gap in biomethane production (Contract for Difference) and natural gas price and other measures in bridging the funding gap, such as capital funding, carbon pricing, value of GoO's.

The Renewable Heat Obligation Scheme is an obligation on the shipper/supplier sector, at an arm's length from Government, not exchequer funding, socialising the costs across all gas consumers and therefore facilitate more flexibility in the trading of Guarantee of Original and ability to use against company carbon credits, EU ETS regulations and reporting.

The state aid in form of Feed-in-Tariff (FIT) is a special case: national governments supporting the domestic biomethane production in this way may put restrictions on the biomethane producer acquiring any other revenue in relation to the product in addition to the FIT. For example, the government may regulate that the subsidised biomethane must be brought to the market via a government designated company/organisation (i.e., DSO) and the producer is not entitled to market the product freely. Similarly, governments may rule that no Guarantee of Origin will be issued for FIT subsidised biomethane consignments.

In view of the variety of revenue sources in **The Example** we do not start the cash flow calculation from a biomethane sales price estimate. Instead, we apply the term about „biomethane total sales revenue" which includes all above listed (and potentially other available) elements. In **The Example** the calculations are performed with a reverse approach: instead of calculating feasibility indicators for a given sales price we calculate the „total sales revenue" necessary for achieving the targeted feasibility indicators.

The KPMG Biomethane Business Case for Ireland shows that in the case of a 20 GWh AD biomethane plant the sales revenue is 8.9c per kWh, from the KPMG/RGFI Cluster feasibility study in 2021.

For avoidance of different interpretations: any potential "gate fee" type income, received for taking over specific biodegradable materials waste streams are not considered as part of „total sales revenue". This income, if any, should be considered at calculating the total costs of feedstock substrate supplies (as an element decreasing these costs). Similarly, any income from the sale of by-products (digestate, carbon dioxide, electrical and thermal energy) must be considered as separate revenue sources and not as part of the sales revenues related to the primary product biomethane.

8.1.2 Support schemes

The summary on support systems with country specific data is provided in REGATRACE Deliverable 6.1. „Mapping the state of play of renewable gases in Europe" (www.regatrace.eu):[13]

The Renewable Heat Obligation Scheme (RHOS) is an obligation on the shipper/supplier sector, at an arm's length from Government, not exchequer funding, socialising the costs across all gas consumers and therefore facilitate more flexibility in the trading of Guarantee of Original and ability to use against company carbon credits, EU ETS regulations and reporting.

[13] *Further information on support systems is available:*

a) *Horschig at all. „Biogas Upgrading: A Review of National Biomethane Strategies and Support Policies in Selected Countries" published 2019, Licensee: MDPI Basel, Switzerland*
b) *Banja at all. „Renewables in the EU: an overview of support schemes and measures" JRC report JRC110415, published 2017*
c) *Renewable energy policy database and support www.res-legal.eu*

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Feed-in Tariff (FiT) = A Feed-in tariff is a technology-specific support scheme providing a technology-specific remuneration per unit of renewable energy. Public authorities define and guarantee the tariff for a specific time period. Typical advantages are:

- Long-term contract with producer (often 10 -20 years)
- Guaranteed grid access
- Payment levels based on the renewable energy generation costs.

Feed-in premium (FiP) = A Feed-in premium is a bonus to be paid above the prevailing, pre-specified benchmark market price. It is a technology-specific subsidy level per unit of renewable energy at a pre-set, fixed, or floating rate. The premium can be designed to estimate the avoided externalities of renewable energy generation, or to cover energy generation cost by the total payment. The two typical FiP designs are either a constant (fixed and predetermined) price or so-called sliding price allowing variations of the premium as a function of the prevailing price.

Quota/green certificates scheme (GC) = In a quota/GC system, the production of renewable energy is encouraged by an obligatory target stating a specific share of renewable energy in the mix of producers, consumers, or distributors. Often compliance is tracked by the trade of renewable energy certificates, which provide an additional supplementary revenue to electricity sales. Renewable energy generators benefit by selling their energy to the grid at market price and by selling certificates on the green certificates market.

Fiscal incentives= Tax exemptions or reductions are usually additional (and minor) support systems. Renewable energy generators receive certain tax exemptions (e.g., carbon taxes) as compensation for the competitiveness of the renewable energy market and its development. The impact of fiscal incentives is dependent on the applicable tax rate.

Investment support = An investment support is a fixed amount received before, during or shortly after the building phase of the plant. It is independent of the amount of renewable energy production.

8.1.3 Transport - Biofuel certificates

Some governments impose mandatory biofuel quotas or GHG emission reduction commitments on transport fuel suppliers. Such commitments can be met either by producing/purchasing/marketing physical biofuel volumes or by purchasing biofuel (or GHG emission reduction) certificates. The costs of these certificates are included in the fuel prices paid by the final consumers (by the motorists) and not by the state. For this reason, this is not a direct state aid to the producers but still a very important driver for producing and marketing biomethane.

It is to be noted that in the biofuel certificate systems biomethane is usually just one of the biofuels and is competing with the liquid biofuels on the certificate market. Because of a minor share of biomethane on the total biofuel market the biomethane specific supply/demand patterns have very limited impact on the biofuel certificate price movements. (*Italy is a special case, where the government introduced a biomethane specific scheme).*

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The new biofuel shares targets fixed in RED II will likely add to the future demand for biofuel certificates, including those issued for biomethane consignments. It is to be remembered that the fuels qualified as „advanced" in accordance with Annex IX. Part A of the RED II are counted double towards the targets and accordingly get two certificates.

Some of the biofuel certificates are already traded internationally but the European market is not mature enough to make reliable price forecasts for the exported certificates.

In Germany the regulation promoting the use of biofuels was changed in 2015, the GHG reduction commitment replaced the biofuel volume quota commitment. For 2020 the min. GHG emission reduction level is set at 6%. Non-performing fuel suppliers must pay a penalty of 470 EUR/tn CO_2 eq. GHG reduction, the penalty determines the theoretical upper limit for the market price of the GHG emission certificates. It is possible that other European governments follow this example and focus on GHG emission reduction effect rather than on physical volume shares. Due to the negative GHG emission intensity biomethane produced from manure enjoys clear benefits under such an approach.

In the Netherlands, according to the Energy for Transport compliance system transport fuel suppliers can meet their annual obligation through purchasing renewable energy units (HBEs: *hernieuwbare brandstofeenheden*).

In the United Kingdom the Renewable Transport Fuel Obligations (RTFO) can be fulfilled by acquiring Renewable Transport Fuel Certificates (RTFC).

8.1.4 Guarantees of Origin (GOs)

Respective quotes from the RED II:

"Guarantees of origin which are currently in place for renewable electricity should be extended to cover renewable gas. This would provide a consistent means of proving to final customers the origin of renewable gas such as biomethane and would facilitate greater cross-border trade in such gas. It would also enable the creation of guarantees of origin for other renewable gas such as hydrogen."

"Member States shall ensure that a guarantee of origin is issued in response to a request from a producer of energy from renewable sources, unless Member States decide, for the purposes of accounting for the market value of the guarantee of origin, not to issue such a guarantee of origin to a producer that receives financial support from a support scheme".

"Guarantees of origin issued for the purposes of this Directive have the sole function of showing to a final customer that a given share or quantity of energy was produced from renewable sources."

"A guarantee of origin can be transferred, independently of the energy to which it relates, from one holder to another."

"Member States or the designated competent bodies shall put in place appropriate mechanisms to ensure that guarantees of origin are issued, transferred and cancelled electronically and are accurate, reliable and fraud-resistant."

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The RED II extended the system of Guarantees of Origin to renewable gases in the expectation that this will create a strong European market for such renewable gases, among them biomethane. Per definition the value of the GOs is dependent on the willingness of the final customers to paying a premium (over natural gas) on a voluntary basis. This implies that in case of a GO price increase the demand for GOs is likely to decrease or diminish. By other words: the GO market will mostly be a buyer's and very rarely (if ever) a seller's market – a shortage of offer will not result in price increase (like it is usual with other commodities), For these reasons the forecast for future income from the sale of GOs must be conservative.

To establish the envisaged European market of renewable gas GOs will be difficult and time-consuming. The main obstacle is that different support systems and different export/import limitations are in force in different countries and in most cases the imported biomethane is not treated equally with the domestic production.

8.2 Other income streams projection

- Protein extraction from sustainable feedstock at the front end.
- Commercialisation of production and sale of digestate as organic fertiliser by-product
- Commercialisation of production and sale of Biogenic CO_2 carbon dioxide as by-product
- Monetising of soil carbon sequestration, i.e., carbon farming
- Development and Commercialisation of bio refinery to extract bio stimulants and bio actives from fermentation residues.
- sale of surplus electrical and thermal energy

8.2.1 Digestate – organic Fertiliser (Fermentation residue)

In view of the high volumes of fermentation residue (digestate) its disposal/utilisation requires careful attention in the preparation of feasibility studies. Digestate contains valuable nutrients, there are opportunities to commercialise this by-product as organic fertiliser, bio fertiliser and bio stimulants. The market is growing for organic fertilisers, and it is the opinion of RGFI that the market will improve further in the coming decade.

Table 24: Digestate fractions

	tn/year	DM %	DM tn/year
Fermentation residue total	28.953	16%	4,503
Liquid fraction	11,268	6%	608
Solid fraction	3,895	55%	3.895
Separated water Fraction	13,790	0%	0%

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Table 25: Estimated nutrient content of solid fraction in The Example

Estimated nutrient content	kg/tn	kg/year	value, EUR/kg
Nitrogen total	4.63	150,208	0.90€/kg
Phosphorus (P_2O_5)	1.02	33,220	2.00€/kg
Potassium (K_2O)	5.99	194,499	0.80€/kg
Total/average	**3.88**	**377,927**	**1.23€/kg**

The nutrient content data can be taken – for example – using the calculation model provided: https://www.lfl.bayern.de/iab/duengung/031516/index.php.

Table 26: Assumption of market value of digestate solid fraction

Nutrients average market value	1.23€/kg
Value of nutrients in solid fraction	233,460 €/year
Discount for non-standard quality	10%
Market value as discounted	210,114 €/year
Solid fermentation residue DM	55%
Solid fermentation residue volume	3,895tn/year
Solid fermentation residue value	20.00 EUR/tn

8.2.2 Sale of surplus thermal energy

Cash flow calculations may be performed under the assumption that part of the biomethane is consumed in a local CHP unit to secure electrical and thermal energies for the operation from renewable sources. It may also be assumed that part of the thermal energy not used for heating the digestate can be utilised in cold months for heating buildings. The value of so utilised thermal energy should be included in the revenues of the plant.

Table 27: Composition of revenues in The Example

Income source	EUR/year	%	Price	
Biomethane sales revenue	1.515,658		0.089	Euro/kWh
Thermal energy local utilisation	25,000		0.025	EUR/kWh
Digestate solid fraction (sales)	233,460		20	EUR/to
Total income	1,774,118			

8.3 Investment costs

The investment costs for an AD biomethane plant unit are greatly influenced by the local conditions, among them the following non-technological factors may have a substantial impact:

- Availability of storage facilities for raw materials and fermentation residue, resp. the necessity of constructing new storage capacities for these purposes,
- Conditions for establishing both the electricity and natural gas network connections (voltage, pressure, distance, etc.)
- Magnitude of costs of earth works, road construction, etc.
- Logistics for feedstock substrate supplies and digestate placement.

No final feasibility study should be produced without having the site of the installation identified. The impact of site selection can be quantified in the pre-feasibility study phase through comparing the preliminary cash-flow calculations for different alternatives.

The capital budget is composed of the Capital Costs (CAPEX) of the anaerobic digestion and upgrading units together with the auxiliary investments (like grid connection, utilities, etc.). Realistic and final feasibility study should be performed only based on the budget offers by the technology suppliers or EPC contractor(s). The preliminary cash-flow calculations provide a necessary and useful guidance for selecting the technology supplier(s) or EPC contractors. For example, comparing IRR for different technology solutions regarding differences in prices, material and energy balances, efficiencies, parasitic load, operations and maintenance, utility consumptions, payment terms, etc. will facilitate the selection of the most feasible technology.

The CAPEX budget estimate calculations included in the feasibility study must be complete, well detailed, prepared with proper diligence, containing reasonable reserves which will ensure that the project can be realized with the planned investment budget.

All relevant cost elements must be considered, among them the costs of

- the acquisition of the site,
- earth works,
- establishing the export and import network connections (electricity and natural gas),
- detailed engineering and design detail,
- permitting i.e., planning permission,
- construction, equipment, pipes etc. (including transportation to the site, potential customs clearance),
- instrumentation, control, and automation,
- first set of spare parts, operations and maintenance O&M Contract,
- gas analysis, local laboratory,
- internal roads,
- secure fencing,
- fire alarm and fire protection,
- weigh bridge and offices,
- welfare facilities,
- cost of licensing from DAFM and /or EPA,
- lightning protection,
- energy and material costs for start-up,
- technical documentation, handbook for operation, etc.

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Note: the above list is not exhaustive, only indicative. Careful attention is to be given to the fact, that the offers from the technology suppliers/EPC contractors may not include all the necessary items, which could cause additional costs and increase the total capital cost budget.

In **The Example** the following investments costs were included:

Table 28: Example of investment costs budget

Item	AD €'000s	Upgrading	Total €'000s
Pre-Construction Costs	70		
Construction – 1 digestion tank, pasteurisation tanks, membrane upgrading system	4,200	Incl.	
Civils (site clearance, building, foundations)	650		
Silage Clamps	200		
Grid Connection Costs	100		
Development Costs/ Contingency	257		
Development Overhead Costs	186		
Debt fees & Interest rollup	77		
Pre fund DSRA	148		
Other (Inc. Reserve)	100		
Total			5,988

Table 29: Specific investment costs

Net methane production 1 year	331,754	m^3
Net methane production first 10 years	20,009,704	m^3
Total investment	12,333,000	EUR
Investment per unit of net methane produced	**0.612**	**EUR/m^3**

Auxiliary investments will be needed in the period covered by the feasibility studies (i.e., 15 years). While calculating the auxiliary investments, in **The Example** it was assumed that proper, professional maintenance will be consequently provided throughout the operation, what limits the need for replacing parts of machinery.

In **The Example** the auxiliary investments (expressed in percentage of original investment value) were assumed as follows:

Table 30: Auxiliary investments

CHP unit year 8	6% of original investment
Technological machinery years 6-8	10% of original investment
Technological machinery years 12-15	15% of original investment
Measuring & steering equipment year 5	8% of original investment
Measuring & steering equipment year 10	12% of original investment

The forecast for the necessary auxiliary investments must be made in view of the requirements of the selected technology, machinery, and equipment.

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Auxiliary investments are likely not to be spread evenly among all the years, correspondingly the amount estimated for these financial expenditures will fluctuate year by year. Auxiliary investments may be financed from the operating income, thus reducing the cash flow.

In the cash flow calculation of any feasibility study the local (domestic/country specific) accounting rules must be followed. For example, the depreciation might be calculated with:

- 10 years for constructions, pipelines, road,
- 5 years for the CHP, technological machinery,
- 15 years for electricity network connection and gas grid connection,
- 3 years for measuring/steering equipment, engineering, etc.

The depreciation drops (correspondingly the tax base increases) from year x, while the machinery may make the biggest part of the total investment.

8.4 Operational expenses

8.4.1 Raw materials

The list and costs of raw materials for AD biomethane production is provided in Table 2.

8.4.2 Energy consumption (Parasitic Load)

The energy consumption, parasitic load of the combined biogas to biomethane plant consists of 3 elements:

- Electrical energy
- Thermal energy
- Vehicle fuel

The alternatives for energy supplies have been addressed in Chapter 7.5. In the alternative with biogas fuelled local CHP the own electrical energy consumption parasitic load of the technology units is covered by the installed CHP unit, i.e., autonomous electricity generation. (See the electrical energy balance in Chapter 7.5.)

It is to be noted that the actual electricity consumption depends on

- the selected fermentation technology, first on the consumption of the applied feed-in and mixing equipment and
- on the actual feedstock substrate qualities and composition.

The own thermal energy consumption of the AD biomethane plant is covered by the hot water generated through cooling the flue gas and the engine of the CHP units, i.e., out of the co-generated heat.

The transportation and loading of raw materials and the transportation of the digestate does require vehicle fuel – this consumption depends on the distances between the AD biomethane

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plant and the agricultural fields. The transportation costs related to transporting the feedstocks substrates are considered in the unit supply costs of these materials.

8.4.3 Personnel costs (Staff)

The AD biomethane plants do not require numerous personnel being present 24 working hours a day. The daily tasks are limited to the loading of the daily volumes of feedstock substrates, to daily checks of the installation, registering the operational parameters, logging data, and taking samples from time to time.

Usually, the local personnel do not include technicians trained for full service and maintenance of the machinery (CHP unit, agitators, mixers, etc.), the local staff does only daily routine checks and minor caretaking tasks and calls the Operations & Maintenance (O&M) service company when needed.

8.4.4 Operations & Maintenance

The maintenance of the machinery is the second biggest cost item among the operation expenses after feedstock supply costs. It is obviously important, that the preventive maintenance is carried out according to the respective schedules and the machinery is kept in best operating conditions all the time.

Maintenance costs for the CHP unit can be calculated at a rate of x Eurocent/kWh gross electricity cost of production. It is usual that the plant concludes a medium-term service contract with the nearest approved service contractor of the producer of the CHP units or with another local professional/authorised CHP company on a lump-sum/operating hour fee basis. The service provider takes care of all planned or unplanned service tasks, replacement of oils and parts. Such an Operations & Maintenance service contract gives the necessary assurance for the plant, that one of the most important parts of the installation is always kept at best operational conditions for efficiencies.

The other maintenance costs can be assumed using general market information. For example:

- maintenance of AD machinery: 2.5% of the invested value,
- maintenance of biomethane upgrading machinery: 5.0% of the invested value,
- constructions (digesters, roads, pipelines, etc.): 0.5% of the investment value.

In the first year of operation the maintenance might be assumed at 25% level compared to the following years (to take into account that the costs are lower in the guarantee period).

Table 31: Maintenance cost projection in The Example €’000s

CHP maintenance	0.006	EUR/kWh	120	EUR/year
Maintenance AD machinery	4%	on investment	239	EUR/year
Maintenance upgrading machinery	4.5%	on investment	270	EUR/year
Spare parts (incl. wear and tear)		EUR/year	150	EUR/year
Maintenance AD constructions	2%	on investment	119	EUR/year
Maintenance upgrading constructions	2.5%	on investment	149	EUR/year
Maintenance total			**1.047**	**EUR/year**

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8.4.5 Chemicals and other materials

The anaerobic digestion process of may require application of select chemicals: desulphurisation agents, anti-foam materials and potentially other chemicals.

8.4.6 Transportation of the liquid fraction of the digestate (fermentation residue)

The liquid fraction of the digestate (fermentation residue) should be applied preferably on the cultivated fields surrounding the location of the AD biomethane plant. The transportation cost for the liquid fraction will be calculated at €2.00 EUR/m^3. It is essential to include a realistic transportation cost estimate in the feasibility studies, which fully reflects the local circumstances (the possibilities of agricultural partners and the respective transport distances must be cleared in course of the assessment and preparation of the feasibility study).

8.4.7 Biotechnological service

It is in the elementary interest of the operator of the AD biomethane plant to keep the biological system in the optimum, most efficient and balanced condition, otherwise the biogas generation will fluctuate and fall below the potential of the raw materials. The professional biotechnological service includes the following elements:

- Regular laboratory analysis (twice a month) of the composition of the digestate fermentation mass from the digesters (volatile organic acids, etc.).
- Regular laboratory analysis (once a month) of the digestate fermentation residue for remaining biomethane potential (to control the efficiency of the degradation of the organic material);
- Laboratory analysis of every new feedstock.
- Continuous analysis of process parameters (biogas yield, biogas composition, material balances etc);
- Recommendations on changing process parameters, feedstock composition, etc.

8.4.8 Insurance

The costs of insurance must be included in the cash flow calculations of the feasibility study.

8.4.9 Banking expenses

Banking expenses must be included in the cash flow calculations of the feasibility study.

8.4.10 Administration and overhead expenses

Administration and overhead expenses must be included in the cash flow calculations of the feasibility study.

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Table 32: Forecast of operational expenses

	€'000s/year	Share
Costs of Sales		
Grass Silage	538	44.3%
Other feedstock	16	1.3%
Digestate	50	4.1%
Gas Injection Costs	90	7.4%
Gas Haulage Costs	65	5.4%
O&M Contract	120	9.9%
Farmer Operations Contract	40	3.3%
Lease	20	1.6%
Rates	20	1.6&
Insurance	25	2.1%
Professional/accounting fees	10	0.8%
Miscellaneous	45	3.7%
Electricity	175	14.5%
Total		100.00%

It is advised to include an unspecified, "reserve" cost position in every prudent feasibility study.

Showing the estimated operational expenses in relation to the volume of net biomethane production is an indicator which every addressee of the feasibility study will find interesting.

Table 33: Rough estimation of self-costs

Net biomethane production	1,895,735	Nm^3/year
Opex per unit of biomethane	0.634	EUR/Nm^3
Capex divided for 10 first year's production	3.16	EUR/Nm^3
Opex + Capex	3.8	EUR/Nm^3
Interest paid divided for first 10 years production	0.115	EUR/Nm^3
Rough estimation of self-costs	**0.94**	**EUR/Nm^3**

8.4.11 Cash flow projection

The cash flow projection can be produced for different time durations e.g. 2022 - 2037 is covered, with a contraction phase and biomethane production commencement. For the first year of operation the production level may be estimated at 90%.

If required, an inflation projection can be added, and different inflation rate can be applied to the different revenue and costs components.

The cash flow scheme of **The Example** includes the following steps:

- Revenues
- Direct and indirect costs

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- EBITDA
- Depreciation
- EBIT
- Interest paid on credit.
- Income threshold, amount subject to profit tax
- Taxation – corporate/partnership/sole trader - taxable profit
- Operational cash flow (interest paid, taxed)
- Investment cash flow
- Operational and investment cash flow
- Financing
- Credit service
- Financing cash flow
- Cash flow (aggregated operational, investment and financial cash flows)
- Feasibility indicators

Notes:

- The relevant domestic regulations regarding depreciation and taxation must be followed
- Companies and banks may apply different cash flow calculation schemes.
- Companies and banks may consider different feasibility indicators in their decision-making process.

8.5 Financing

The REGATRACE project provides a "Guidebook on securing financing for biomethane projects" (Deliverable 6.2). In deliverable 6.2 the potential different sources of financing are addressed. Therefore, this chapter on financing is limited to the question: how should financing be handled in the feasibility studies.

As a matter of fact, feasibility studies are crucial in securing financing for a project while they must demonstrate a level of competencies, due diligence and secure the necessary trust of the investors and financing institutions. The financing chapter of a feasibility study must be tailor-made to the project it covers. To enable fulfilling this role key issues must be studied and cleared in the pre-feasibility study phase, the most important among them:

- is there a non-repayable investment subsidy (RHOS) available and – if yes – under which conditions?
- is the project qualified for receiving an investment subsidy?
- what is the level of private capital which could be invested into the project and what is the expectation of private investors for repayment and profitability?
- are banks/financing institutions ready to provide commercial funding/credit in form of direct project finance or are securities are required from the stakeholders in the project?

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- finance (necessary Debt Service Coverage Ratio (DSCR), offered credit terms, such as interest rate, repayment period, grace period, supporting documentation).

Having collected the information on the above matters the feasibility study will determine whether the financing of the project is possible under the given circumstances.

The cash-flow calculation of the feasibility study applies the above listed information collected in the preparatory phase and supposed to confirm that the

- the project has acceptable feasibility indicators under the available conditions of financing,
- the credit service is guaranteed,
- the expectations of the private investors can be fulfilled.

Financing may be calculated under the following conditions:

- interest rate: 6 % per annum,
- repayment period: e.g., 15 years (excluding the grace period)
- grace period: e.g., 18 months, not considered in Ireland
- Interest in grace period: 18 months accrued and added to the capital.

Table 34: Key numbers for financing €'000s

Total investment cost	5,998,000 EUR
Own funds (0%)	0 EUR
Non-repayable investment subsidy (50%)	3,000,000 EUR
Credit amount capital	2,998,000 EUR
Interest rate	6%/year
Interest 6 months 2021	55,000 EUR
Interest 12 months 2022	205,000 EUR
Total credit incl. accrued interest	3,145,000 EUR
Credit service	68,000 EUR/year

Table 35: Estimation of credit service €'000s

Year	Outstanding capital	Capital repayment	Interest due	Credit service
1	2,998 EUR	0 EUR	247.9 EUR	51 EUR
2	2,998 EUR	162.5 EUR	206.1 EUR	68 EUR
3	2,835.5 EUR	153,684 EUR	159,072 EUR	69 EUR
	Total:			

Applying the above conditions, the cash flow calculation can confirm that at the assumed set of data the project would be capable of servicing the credit.

Note that for **Ireland**, the RGFI KPMG Biomethane Business Case 2019 shows that in the case of a 2 0GWh AD biomethane plant the sales revenue is 8.9c per kWh.

In case of revamping an existing biogas, plant and converting it to biomethane production the financing of the project is to be secured under different set-up:

- no state aid in form of non-repayable investment subsidy can be expected, albeit maybe eligible for RHO payments.

- it is likely that the banks/financing institutions will not require cash capital contribution form the stakeholders, while the existing plant will be accepted as security,
- the costs of revamping of the anaerobic digestion plant must be added to the investment costs of the new upgrading unit (together with the investments needed for natural gas grid connection).

8.6 Feasibility indicators

8.6.1 Internal Rate of Return (IRR)

The IRR is a key indicator and is the discount rate often used in capital budgeting that makes the net present value of all cash flows from a particular project equal to zero. The higher a project's internal rate of return, the more desirable it is to undertake the project. As such, IRR can be used to rank several prospective projects or potential alternatives an investor is considering. Assuming all other factors are equal among the various projects, the project with the highest IRR would probably be considered the best from an investment/commercial proposition perspective. One can think of IRR as the rate of growth a project is expected to generate. While the actual rate of return that a given project will in practice generate often differs from its estimated IRR rate, a project with a substantially higher IRR value (than other available options) would still provide a much better chance of good return on the investment.

For the purpose of comparisons, a min. 10% IRR may be considered as desirable - a set of conditions giving an IRR above 10% may be seen as offering satisfactory return on the investment, while an IRR value below 10% may be viewed as a warning signal, that the feasibility of the project might not satisfy the investors and/or the financing institutions.

The IRR expectation and the respective time frame should correspond to the local market conditions and the requirements of the investors and/or the financing institutions.

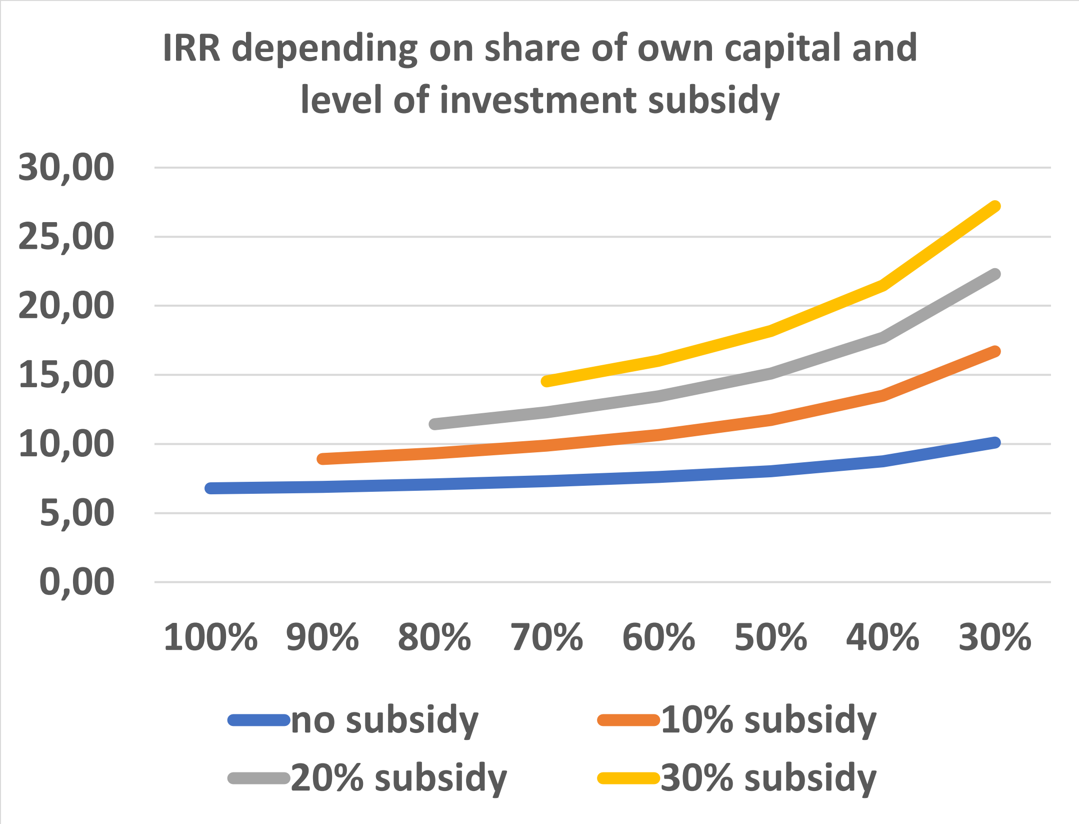

Figure 2: IRR depending on share of own capital and level of investment subsidy

8.6.2 NPV

Another feasibility indicator is the Net Present Value (NPV). The Net Present Value is the difference between the present value of cash inflows and the present value of cash outflows. By other words: the Net Present Value (NPV) of a project is the return on the investment (the sum of the discounted cash flows) less the cost of the investment.

NPV is used in capital budgeting to analyse the profitability of an investment or a project.

NPV compares the value of money (EUR) today to the value of that same money (EUR) in the future, taking a discount factor (for inflation and returns) into account.

About discount factor:

- In private industry, many companies use their own cost of capital (or a weighted average cost of capital) as the preferred discount rate.
- Government organizations typically prescribe a discount rate for use in the organization's planning and decision support calculations.
- Financial officers may use a higher discount rate for investments or decisions viewed as risky, and a lower discount rate when expected returns from a proposed action come with less risk. The higher "discount rate" is a hedge against risk because it puts relatively more emphasis (weight) on near-term returns compared to distant future returns.

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The present value of future cash flows requires the implementation of "time value of money" calculations. Cash flows are discounted for the selected number of years to equate future cash flows to current monetary levels. Discounting accounts for the idea that the value of EUR 1.0 today does not equal the value of EUR 1.0 received in one year because money in the present normally offers more earning potential (for example via interest/income bearing savings), than money yet unavailable. Cash flows received further in the future are therefore considered to have a lower present value than money received closer to the present.

If the NPV of a prospective investment calculated at the discount rate satisfying the investor is positive than the project can be accepted. However, if NPV is negative at a given discount rate than the project`s cash flow will result in a number below x%.

The discount rate applied for NPV calculation depends on relevant local considerations the requirements of the investors and/or the financing institutions.

8.6.3 Discounted Cash Flow (DCF) or Present Value (PV)

Discounted cash flow (DCF) is a valuation method used to estimate the value of an investment based on its future cash flows. DCF analysis attempts to figure out the value of a project today, based on projections of how much money it will generate in the future.

DCF analysis finds the present value of expected future cash flows using a discount rate. A present value estimate is then used to evaluate a potential investment. If the value calculated through DCF is higher than the current cost of the investment, the project could be considered.

Note: the difference between NPV and DCF/PV is that NPV is calculated using the DCF/PV and subtracting the cost of the investment.

8.6.4 Profitability Index (PI)

The profitability index (PI), alternatively referred to as value investment ratio (VIR), or profit investment ratio (PIR), describes an index that represents the relationship between the costs and benefits of a proposed project, using the following ratio:

$$\text{Profitability Index (PI)} = \frac{\text{PV of future cash flows}}{\text{Initial investment}}$$

The PI is helpful in ranking various project alternatives because it lets investors quantify the value created per each investment option. Under the above formula a profitability index of 1.0 is logically the lowest acceptable measure on the index, as any value lower than that number would indicate that the project's present value (PV) is less than the initial investment. As the value of the profitability index increases, so does the financial attractiveness of the proposed project.

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An alternative way of expressing and calculating the Profitability Index is to have Investment required + PV of future cash flows in the numerator and the Investment required in the Denominator. In this case any positive number could be acceptable.

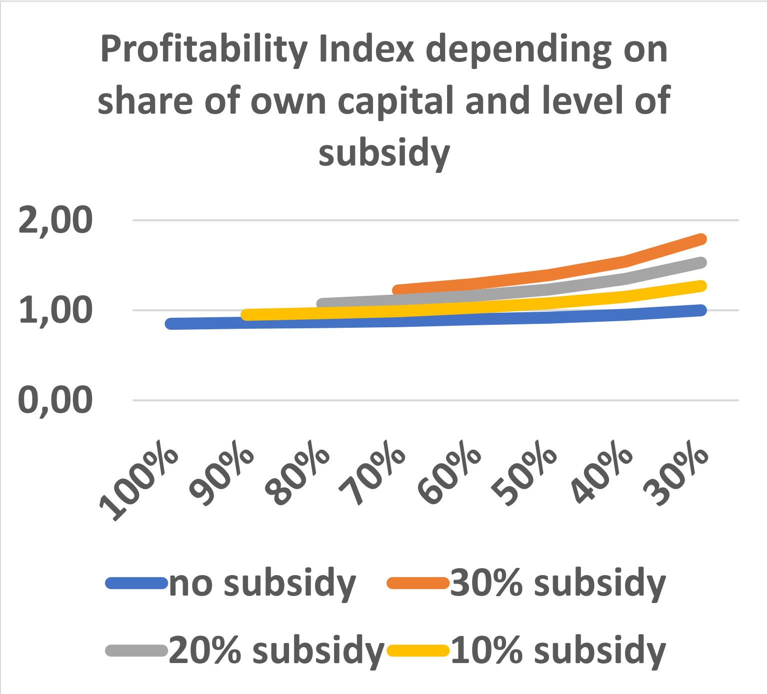

Figure 3: Profitability Index dependig on share of own capital and level of subsidy

8.6.5 Discounted Payback Period (DPBP)

The discounted payback period is another capital budgeting procedure used to determine the profitability of a project. A discounted payback period gives the number of years it takes to break even from undertaking the initial expenditure, by discounting future cash flows and recognizing the time value of money. The metric is used to evaluate the feasibility and profitability of a given project.

Note: the simplified „payback period formula", which simply divides the total cash outlay for the project by the average annual cash flows, doesn't provide as accurate an answer to the question of whether or not to take on a project because it assumes only one, upfront investment, and does not factor in the time value of money. (The simplified payback period is the amount of time for a project to break even in cash collections using nominal dollars.) Alternatively, the discounted payback period reflects the amount of time necessary to break even in a project based not only on what cash flows occur but when they occur and what discount factor is deemed appropriate.

The calculation of DPBP begins with the estimation of the periodic cash flows of a project shown by period in a table or Excel spreadsheet. These cash flows are then reduced by their present value discount factor to reflect the time value for money concept. This can be done – for example - using the present value function in Excel and a table in a spreadsheet program.

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Next, the future discounted cash inflows are netted against the initial investment outflow. The discounted payback period process is applied to each additional period's cash inflow find the point at which the inflows equal the outflows. At this point, the project's initial cost has been paid off, with the payback period reduced to zero.

A general rule to consider when using the discounted payback period is to accept projects that have a payback period that is shorter than the target timeframe. A company can compare its required break-even date for a project to the point at which the project will break even according to the discounted cash flows used in the discounted payback period analysis, to approve or reject the project.

8.6.6 Debit Service Coverage Ratio

The Debt Service Coverage Ratio (DSCR) is an important indicator for the financing institution; it shows how far the credit service (repayment of the credit together with the agreed interest) is secured.

$$\text{DSCR} = \frac{\text{EBITDA}}{\text{credit service amount}}$$

Note, that *the RGFI / KPMG Biomethane Business Case shows that in the case of a 20GWh AD biomethane plant the sales revenue is 8.9c per kWh.*

9 Overall risk assessment

The fourth element focuses on the major risks the proposed plan can entail. The overall risk assessment part of a feasibility study examines the different ways your organization can reduce the risk of embarking on the new action.

The overall risk assessment should answer the following questions:

- *What are the major risks associated with the construction and operation?*
- *What are the risks associated in selecting a suitable EPC/technology provider?*
- *What is the survival outlook for each of the above risks?*
- *How sensitive are the profits on different risk scenarios?*
- *What are the best ways to minimize these risks?*

The aim is to try to cover all the possibilities and create a risk assessment checklist, which deals with the probability of the risk and the impact it would have on the project. It's aimed at recognizing the risks that can make or break the project from the smaller, more manageable risks.

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In addition, at launching a new project, the overall risk assessment should also consider one final question. Answering the question "*When can the project be able to support itself without extra financing?*" is an important part of a feasibility study. Self-sufficiency is crucial for business success, as having to borrow can hinder the long-term viability of the activity.

The construction and operation of an AD biomethane plant involves environmental, health, safety, commercial and other risks. With the accumulated experience in the industry these risks are well understood and can be managed if not eliminated. The objective of risk management is to identify all potential risks and put in place suitable measures that will reduce these risks to acceptable levels.

Ensuring the health and safety of employees and the public, and the protection of the environment should be a priority when undertaking any activity, including the construction and operation of an AD biomethane producing installation.

The failure to identify and manage risks can result in a disproportionate number of accidents and incidents that have a negative impact on the environment, or on the health and safety of site employees and the public. This leads to a negative perception and impact on the industry, and as a result, lead to increased wariness of insurers and investors who work with the sector.

The effective risk management should result in:

- Prevention and/or management of pollution incidents and therefore avoidance or reduction of remediation costs.
- Prevention of accidents that could result in harm to employees, prosecution, and business disruption.
- Better staff retention, by demonstrating commitment to their safety and wellbeing.
- Reduced cost of insurance premiums and better insurance policies.
- Improved operational performance, delivering higher quality outputs.
- Better overall financial performance.

The ADBA Best Practice Checklist Risk Management[14] provides a comprehensive description of different risks related to the anaerobic digestion technology and the content can be applied to the biogas-biomethane facilities directly. The risk categories detailed on the ADBA paper are:

- catastrophic failure
- environmental risks
- health and safety risks
- commercial and reputational risks.

For project developers it is recommended to study the referred ADBA document "Best Practice Checklist Risk Management".

14 http://adbioresources.org/our-work/best-practice-scheme/best-practice-checklists

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In relation to a biomethane development project the risk management checklist can be specified to include the following items:

Collateral/bankability requirements

- How Is the off take of biomethane and by-products secured? (RHOS, long-term purchase agreements, direct marketing positions)?
- Are there long-term feedstock substrate supply agreements with sufficient penalties imposed upon default of feedstock supply to cover the losses that would be suffered?
- Is there sufficient insurance over the project risks?
- Is there a long-term land lease agreement if the property is not owned by the project developer?

Permitting and licensing requirements

- Has a basic desk top assessment or full Environmental Impact Assessment been completed?
- Is a waste management licence required if so has it been obtained?
- Has an air emissions licence been obtained?
- Is there a natural gas grid connection agreement?
- Does the project have a licence for AD biomethane production from DAFM? (if needed under the domestic legislation)?
- Does the project have a construction permit, planning permission from the local authority?

Technical considerations

- Does the EPC contractor have sufficient financial strength/experience/competencies/references?
- Is there a guaranteed performance ratio for the plant and structural elements? Is this guarantee financially secured? What is the guarantee period and what does it cover?
- Does the EPC contract provide for O&M training, has sufficient handover period been allocated?
- Is there a base warrantee on equipment of at least 2 years?
- Has the technical design been reviewed by a qualified independent party?

Contracting requirements

- Have the rights of project properly secured in the respective contracts (land lease, permitting, licences, offtake agreements)?
- Have the construction, O&M, off-take, and feedstock agreements been compiled by parties experienced in AD biomethane projects?
- Have the EPC, O&M, off-take, and feedstock contracts been validated by qualified external parties, ideally experienced in AD biomethane projects?

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Additional considerations

- Has the business model included at least 12 months commissioning time at zero revenue?
- Is there an environmentally responsible digestate management, land bank for application and nutrient management plan?

10 Sensitivity analysis

The Excel cash flow calculation provides a convenient tool for assessing the impact of different factors on the feasibility of the project.
While assessing the impact of a certain factor all other conditions remain unchanged and the investigated factor is altered. In this Guidance the impact of changes in the following factors are analysed:

- credit facility/commercial lending interest rate - 9% per annum credit interest rate
- AD biomethane plant costs x € 610,000/year
- Biomethane production – eligible for Renewable Heat Obligation Scheme
- feedstock substrate costs € 30/t
- efficiency of operation x full load 8,600 hours per year
- € 5,998m EUR investment costs KPMG have provided a budget estimate of c. € 6m for 20GWh AD biomethane plant. Figures from KPMG/RGFI Cluster Report 2021 and Integrated Business case 2019.
- 50% non-repayable investment subsidy

10.1 Credit interest rate

The sensitivity calculations are usually performed applying the expected sales price for the primary product (biomethane). With changing the input value for the investigated factor, the feasibility indicators (like IRR, NPV etc.) will change. KPMG have done an economic assessment and the interest rate fluctuates between 4 and 8%. As the numbers show, with increased credit interest rate the IRR falls below the required 10%, while lower interest rates impact the IRR positively.

Table 36: Impact of interest rate on IRR in The Example

	A	B
Interest rate %	IRR at biomethane price	Biomethane sales revenue required EURcent/kWh
8	6%	8.4c/kWh
6	8%	8.7c/kWh
5	9%	8.9c/kWh
4	10%	9.1c/kWh

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In column B a reversed approach is followed: the IRR remains the same (at the level of 10%) and the biomethane sales revenue necessary to secure this IRR is calculated. As can be seen about 2.6% higher biomethane sales revenue would be needed if the credit interest rate were increased to 8% (from 6%) and – on the contrary – the project could achieve the targeted feasibility at somewhat lower biomethane sales revenue.

In lack of established European biomethane market price information, this Guidance and **The Example** attached to it cannot be based on an estimated biomethane sales revenue. For this reason, the examples of the sensitivity analysis below follow the approach shown under B: the impact of the given factor is expressed through the changes in the biomethane sales revenue necessary for reaching the 10% IRR. By other words: the negative effect of a factor (for example higher credit interest rate) calls for higher sales revenues, while the positive effect (of lower credit interest rate) enables profitable operation at lower sales price.

10.2 Costs of raw material supplies

Table 37 shows the impact of potential changes in the total costs of raw material supplies to the AD biomethane plant. As compared to the base case higher feedstock substrate costs substantially increase the required biomethane sales revenue.

Table 37: Required biomethane sales revenue depending on substrate costs level

Cost level	no subsidy	10% subsidy	20% subsidy	30% subsidy
80%				
90%				
100%				
110%				
120%				
130%				

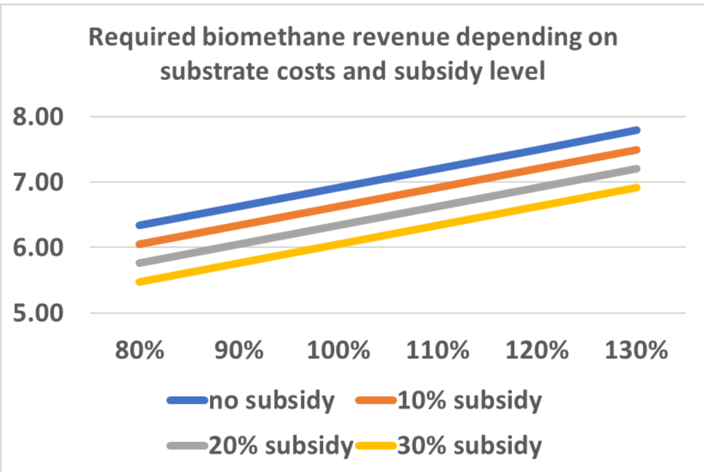

Figure 4: Required biomethane revenue depending on feedstock substrate costs and subsidy level

10.3 Investment costs

In **The Example** the alterations to the investment cost budget in the range of minus 20% - plus 30% were looked at. The comparison with the base case suggests that with the increase of the investment costs (in comparison with the assumed € 8,715,000 EUR) substantially higher biomethane sales revenues would be needed for maintaining the feasibility of the project. The impact of higher investment costs is logically higher in cases of lower or no investment subsidy. For example, if the investment budget had to be increased to € 11.3 million EUR) and no investment subsidy were available, 7.88 Eurocent/kWh biomethane sales revenue should be generated for achieving the 10% IRR.

Table 38: Required biomethane sales revenue depending on investment costs level.

costs level	no subsidy	10% subsidy	20% subsidy	30% subsidy
80%	6.31	6.08	5.86	5.64
90%	6.61	6.35	6.09	5.85
100%	6.92	6.63	6.34	6.05
110%	7.24	6.91	6.59	6.27
120%	7.56	7.20	6.84	6.49
130%	7.88	7.49	7.10	6.71

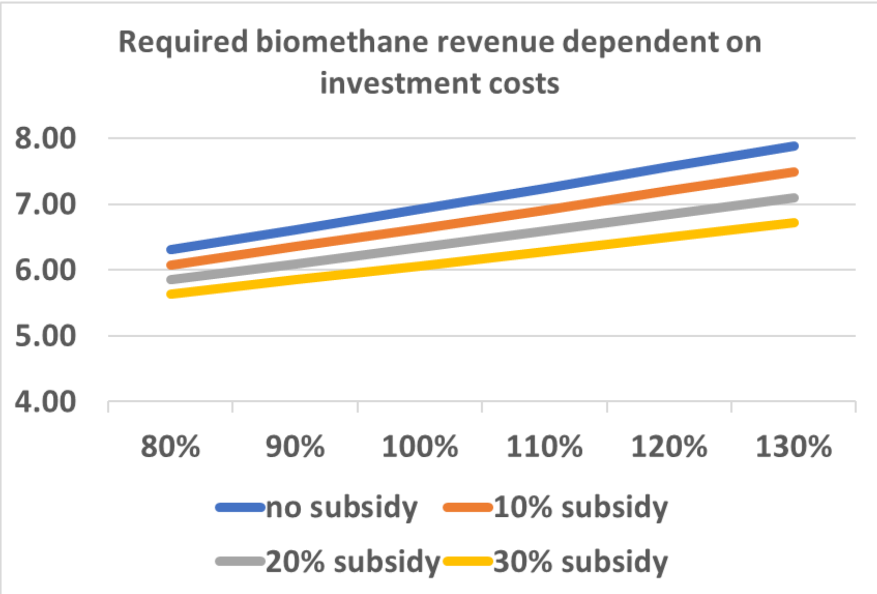

Figure 5: Required biomethane revenue dependent on investment costs

10.4 Investment subsidy

The tables above already illustrate the effect of non-repayable investment subsidy on the feasibility. At € 8,715,000 EUR investment costs and € 1,150,000 EUR feedstock substrate costs the needed biomethane sales revenue is € 6.05 Eurocent/kWh if 30% investment subsidy is provided. On the other hand, € 6.92 Eurocent/kWh biomethane sales revenue would be needed if no investment subsidy were available.

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10.5 Efficiency of operation

Among the sensitivities the potential malfunctioning and disruptions of operations must also be considered. The simplest way of expressing efficiency is to assume a loss of biomethane production due to operational reasons. The correlation between loss of efficiency and worsening of profitability is evident. Without loosening the expectation on the feasibility indicator (10% IRR) the lost production can be compensated only through increasing the necessary biomethane sales revenue, as shown in Table 39.

Table 39: Effect of efficiency of operation on feasibility

Loss of production	biomethane sales revenue
%	required Eurocent/kWh
0	6.05
2	6.18
4	6.31
6	6.44
8	6.59
10	6.73

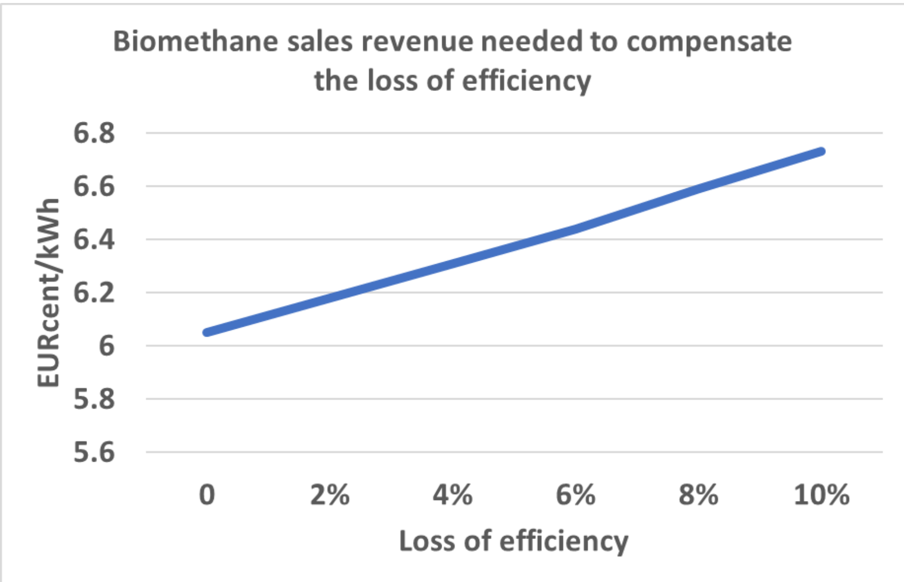

Figure 6: Biomethane sales revenue needed to compensate the loss of efficiency

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