Department for
Business, Energy
& Industrial Strategy

Advanced Gasification Technologies – Review and Benchmarking

Methodology for Techno-Economic Assessment of Advanced Gasification Technologies

Task 3 Report

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Contents

Management Summary

The following document provides the methodology for the Techno-Economic Assessment that will be adopted to assess the Advanced Gasification and counterfactual scenarios developed during Task 5.

The assessment will be based on both qualitative and quantitative parameters with the quantitative parameters being used to provide a Levelised Cost of End Product. The qualitative parameters will be used to provide context to the assessment.

Appendix A contains counterfactual benchmark unit costs for a range of products that could alternatively be produced by Advanced Gasification Technologies (AGTs) using biomass or waste as a feedstock. It is intended that these costs are used as context for the product cost figures generated from the economic analysis of AGT schemes, conducted separately in Task 5.

1 Introduction

This document provides the methodology for the Techno-Economic Assessment of the Advanced Gasification Technologies that will be developed and assessed in Task 5. It aims to address the requirements of the BEIS *Advanced Gasification Technologies – Review and Benchmarking* study as specified within Task Briefing Note 3 [1]:

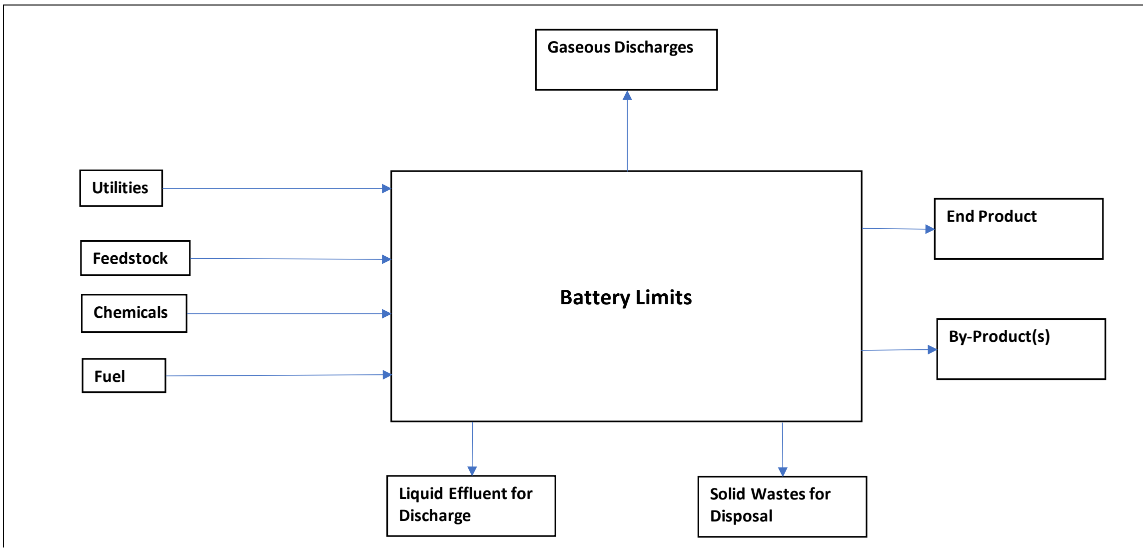
1. Develop the pricing methodology / standardised assumptions to be used across all technologies to provide the basis for the evaluation of the selected options. This will include such items as civils pricing, costing base date, finance rates, battery limits, general assumptions etc; and

2. Develop the evaluation matrix for completion under Task 5.

Task Briefing Note 3 also requires the development of counterfactual schemes which are the subject of a subsequent report.

2 Battery Limit

All scenarios will adopt the Battery Limits as identified in Figure 1.



The definitions of the terms identified in Figure 1 are provided in Table 1. These definitions will be adopted for all scenarios developed within this Task 3 and in Task 5.

Table 1 Definition of Battery Limits

Identifier	Description
Battery Limits	All on-site equipment, buildings and infrastructure required for the production of the required end-product. The specific limits for each parameter are as identified within this table.
Utilities	The Battery Limit is the on-site metering point for utilities and fuels (i.e. initial on-site meter for piped fuels and utilities; discharge point from on-site storage or weighbridge for tankered fuels) and includes all relevant infrastructure and equipment. The costs for the treatment, distribution, and supply up to the point of on-site metering are considered to be external to the Battery Limits.
Feedstock	The production, treatment, storage and transportation prior to the on-site metering point (i.e. weighbridge for solid materials) are outside of the Battery Limits.
Chemicals	Chemicals, including bulk chemicals (e.g. oxygen, hydrogen and nitrogen) and catalysts that are critical to the operation of the process. Excluded from the Battery Limits are the equipment required for production, treatment, storage and transportation of chemicals up to the point of on-site storage.
End Products	Depending on the process this will be either hydrogen, methane or liquid fuels. The Battery Limit will be the point of discharge from a suitable storage tank.
By-Product(s)	Secondary products that result from the process and have commercial value. Included within the Battery Limits are the initial storage and distribution arrangements up to the point of sale/ metering i.e. gas/ liquid meter or weighbridge.

Identifier	Description
Gaseous Discharges	The Battery Limits include all equipment, infrastructure, chemicals and consumables required for treating the process off-gases to a suitable standard for free release to the atmosphere. The Battery Limit ends at the discharge point from any on-site stacks. Where carbon dioxide (CO_2) capture is considered, the battery limit will be to the point where the CO_2 enters the off-site transportation pipeline. Separation, purification, compression and temperature adjustment of CO_2 is assumed to be within the battery limit.
Liquid Effluent for Discharge	The Battery Limits include all equipment, infrastructure, chemicals and consumables required for treating the process liquid effluent to a suitable standard for discharge and treatment at a third-party Wastewater Treatment Works. Where it is acceptable for low volumes of concentrated effluent to be treated by specialists, the Battery Limits are up to and including the transfer points to road tankers.
Solid Wastes for Discharge	Solid residues and wastes that require off-site disposal. The Battery Limits are restricted to the equipment and infrastructure up to the point of discharge from on-site storage.

2.1 Feedstocks

Feedstocks adopted for either the counterfactual or benchmarked schemes will be natural gas, municipal solid waste (MSW), commercial and industrial (C&I) waste, or biomass. The composition assumed in the schemes are defined below:

2.1.1 Waste

The waste stream adopted for the study will comprise both MSW and C&I waste. For the purposes of this study, the average waste composition estimate for MSW from 2017 [2] will be adopted. This is, summarised in Table 2 and has been derived using the Environment Agency's Waste and Resources Assessment Tool for the Environment (WRATE). WRATE is used to breakdown each of the waste materials into their chemical components.

Table 2 Chemical Composition Estimates for Waste for England, 2017

Parameter	Units	Values
Carbon	wt%	26.30
Hydrogen	wt%	3.69
Nitrogen	wt%	0.77
Sulphur	wt%	0.13
Chlorine	wt%	0.96
Oxygen	wt%	15.63
Moisture	wt%	34.65

Total ash[1]	wt%	17.86
Total	wt%	100
Ferrous metal	wt%	2.26
Non-ferrous metal	wt%	1.17
Net calorific value[2]	MJ/kg	9.7

Indoor reception facilities will be based on a hall with appropriate storage for four days operation at full throughput capacity. Reception facilities will include necessary noise, dust and odour control measures.

2.1.2 Biomass

As identified in the Task 2 report [3] biomass feedstock can come from a variety of sources but is most likely to come from either virgin wood or energy crops. For Task 5 it is proposed that woodchip from virgin wood or short rotation coppice (SRC) or wood pellets will be used. Woodchip and wood pellets are assumed to have moisture contents of 50% and 10% dry solids respectively. This will be more expensive than round wood and require screening but will remove the need for on-site shredding and drying.

Storage of biomass will be in external silos with conveyor offloading systems and will be provided to allow for 10 days of operation at full load.

2.2 End Products

2.2.1 Hydrogen

The Hydrogen product will be to BS ISO 14687:2019 [4].

2.2.2 Methane

Methane will be consistent with the requirements of the Gas Safety (Management) Regulations, 1996 [5] for inclusion in the National Transmission System (NTS).

2.2.3 Liquid Fuels

Liquid fuels will be diesel and aviation fuel but may also include methanol and ethanol. The necessary fuel standards that will be adopted are:

- ASTM D975 Standard specification for diesel fuel [6];
- ASTM D7566 Standard specification for aviation fuel containing synthesized hydrocarbons [7];

[1] Includes ferrous and non-ferrous metal
[2] Calculated using the Dulong Formula

- EN 15940:2016 Automotive Fuels – Paraffinic diesel fuel from synthesis or hydrotreatment – requirements and test methods [8];
- ASTM D1152 Standard Specification for Methanol (Methyl Alcohol) [9];
- ASTM D4806 Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel [10]; and
- IMPCA (International Methanol Producers and Consumers Association) Methanol Reference Specifications (2015) [11].

3 Methodology

The methodology for delivering the Techno-economic Assessment will adopt the following key stages:

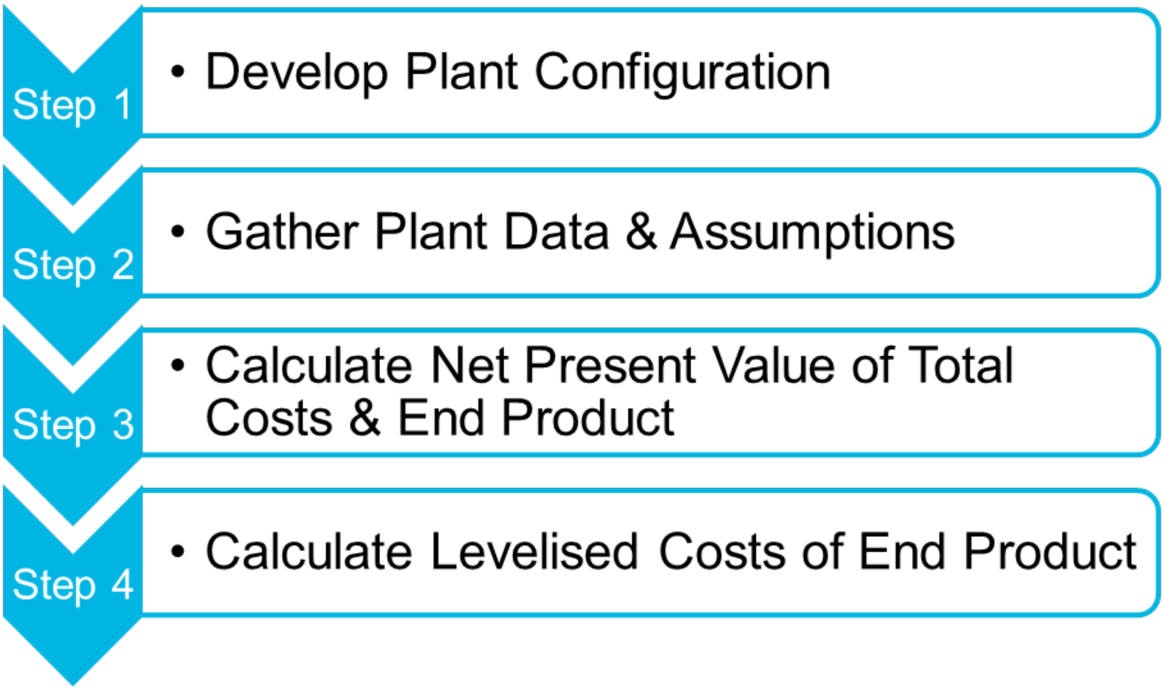


Figure 2 Methodology Approach

3.1 Develop Plant Configuration

Plant configurations will be developed for the arrangements (feedstock, end-product and plant scale) identified in Table 3 and each will be developed into a process block diagram (see the generic diagram illustrated in Figure 3) within the Battery Limits as identified in Section 2. This will allow the principal stages in the process to be identified.

Table 3 Options for Advanced Gasification Solutions

	Biomass		**Waste**	
Product	Small-scale	Large-scale	Small-scale	Large-scale
Methane	✓	✓	✓	✓
Hydrogen	✓	✓	✓	✓
Liquid Fuel	✓	✓	✓	✓

The size of the small scale and large-scale processes are illustrated in Table 4.

Table 4 Scale of processes

	Biomass		Waste	
	Small-scale	Large-scale	Small-scale	Large-scale
Gasifier Size (MW_{th})	100	664	37	200
Fuel Feed (tpa)	335,000	990,000	100,000	550,000

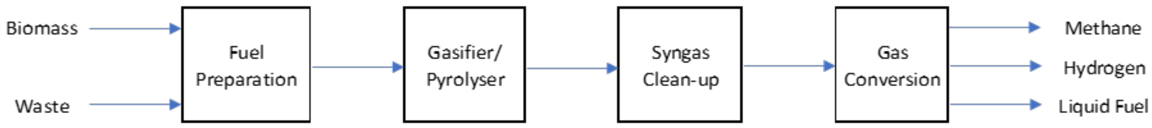


Figure 3 Generic Process Block Diagram for the Advanced Gasification Solution Options

This will result in 12 individual scenarios being modelled although it is acknowledged that a number of processing blocks will adopt similar technologies regardless of the solution being considered. For example, if MSW is the feedstock, it will be required to be converted into a refuse derived fuel (RDF) prior to being gasified regardless of the scale or end-product being produced. Similarly, for a particular product the gas clean-up and conversion steps may largely be the same whether the feedstock is biomass or waste, but the fuel preparation and the gasifier steps may differ.

3.2 Data Gathering & Modelling

It is proposed that the Techno Economic Assessment (TEA) will be based on developing Levelised Costs of End Product (LCOX) for each of the plant configurations and counterfactual scenarios. This will require specific processing information (see the evaluation criteria identified in Sections 4 and 5) to be gathered from technology suppliers and plant operators, supplemented by in-house engineering experience and publicly available literature sources.

Section 4 sets out the quantitative data that will be required to inform the LCOX that will be developed using Microsoft Excel.

The parameters that will inform the LCOX are summarised below:

Table 5 LCOX Parameters

Categories	Parameters
Plant Information	• Site • Plant Availability • Design Life
CAPEX	• Land Requirements • Engineering, Procurement & Construction Contract

Categories	Parameters
	• Consultancy • Planning & Other Regulatory • Developer • Start-up & Commissioning
OPEX	• Labour • Administration & Other Overheads • Feedstock • Maintenance • Fuel & Utilities • Consumables • Waste Disposal • Subsidiary Revenues

Section 5 provides qualification and context to the quantitative data.

3.3 Calculation of Net Present Values

The approach identified in this section and Section 3.4 uses the Levelised Cost methodology adopted by BEIS for the calculation of electricity generation costs [12 & 13].

Data gathered will be utilised to produce Net Present Values (NPV) in UK Sterling (as per Section 4.2) for capital (CAPEX) costs and operating (OPEX) costs of the project using the calculation identified in Equation 1. Where revenues are generated as a result of the process, other than revenue from the main product, these will be counted as negative values in the OPEX costs. Equation 2 calculates the total quantity of product produced over the period.

Equation 1 NPV of Total Costs

$$NPV\ of\ Total\ Costs\ (£) = \sum_{0}^{n} \frac{Total\ CAPEX + OPEX\ Costs\ for\ year\ n\ (£)}{(1 + discount\ rate)^n}$$

Equation 2 Discounted Sum of End Product

$$Discounted\ Sum\ of\ End\ Product\ (kg) = \sum_{0}^{n} \frac{End\ Product\ for\ year\ n\ (kg)}{(1 + discount\ rate)^n}$$

NPV’s will be developed using a calculation in Microsoft Excel.

A standard facility design life of 25 years has been assumed to determine the annual repayment cost.

3.4 Levelised Cost of End Product

The LCOX model will be developed in Microsoft Excel and will be based on a calculation where the individual system costs are evaluated and the total divided by the amount of product produced. It is proposed that the calculation will be on a weight basis (i.e.£/kg end product). The basic LCOX calculation will be:

Equation 3 Levelised Cost of End Product

$$LCOX\ (£/kg) = \frac{NPV\ of\ Total\ Costs\ (£)}{Discounted\ Sum\ of\ End\ Product\ (kg)}$$

The LCOX is the long-term price needed to achieve a required hurdle rate. For the project developer this is the price needed at commissioning to cover all project costs and achieve a required rate of return. In previous studies discount rates of between 3.5% and 10% have been adopted [12, 13 & 14] with the recent Carbon Capture Technology study adopting 7.8% and 8.9% [14]. For the purposes of this study a discount rate of 7.8% will be adopted in Equation 1 and Equation 2.

3.4.1 Comments on LCOX Assessment

In the LCOX assessment for new and developing technologies there are three main issues to be aware of:

1. The difficulty in obtaining accurate data for cost components. Where possible this is being mitigated through the selection of technologies at a suitable Technology Readiness Level (i.e. TRL 6 and above) where some cost data should be obtainable;
2. Unexpected costs or contingencies. Following the realisation of a project the costs are often significantly greater than expected during the techno-economic assessment even if the assessment has been based on reliable data. This can be mitigated when comparing technologies at a similar stage in development but can introduce significant discrepancies when comparing developing with mature technologies. For this reason, it is proposed that a Contingency Factor is introduced and applied to the overall cost (as adopted by Lauer [15]). The level of project contingency will be determined by the clarity of cost breakdown and certainty. Contingency will be a minimum of 5% but is liable to be significantly higher with an appropriate contingency being applied based on the Technology Readiness Level of the configuration being considered; and
3. Amount of product produced. The quantity of product produced may be provided by technology suppliers but will be difficult to confirm due to the lack of operating data available, it needs to be realistic and account for conversion and other processing losses which will require engineering judgement on the information provided. Additionally, uncertainty around plant availability will have a significant impact on the amount of product produced.

4 Quantitative Assessment Criteria

4.1 Plant Information

4.1.1 Site

The site of the facilities will be located on a greenfield site in the North East of England. The North East of England has been selected due to the region's industrial nature, potentially more supportive local planning authority, as well as its good transport links and existing port facilities for the importation of biomass. It is assumed that the site has good connection to all necessary utilities (e.g. electricity, gas, water and sewerage), bulk chemicals (e.g. oxygen, hydrogen and nitrogen) and cooling water supply with the tie in points being at the Battery Limits.

The site is assumed to be on uncontaminated ground (i.e. no costs for remediation of contaminated soils have been assumed) requiring no demolition or site clearance and with no unexploded ordnance. The ground conditions will be assumed to be good to allow piling, with no issues with marshland, flood or coastal protection or underground aquifers.

Processing equipment, feedstock and product storage will be contained within buildings, wastewater or odour control treatment measures will be located outside. Process buildings will be insulated steel structures with external cladding. No architectural embellishments are assumed.

A standard design for site services, building requirements, storage areas, roads, pavements and landscaping will be adopted with costs assumed based on available civil engineering literature [16].

4.1.2 Plant Availability

An average plant availability of 85% will be assumed. This will account for:

- reduced availability during year 1 of operation due to Start-up, Commissioning and Training; and
- years where major planned and unplanned outages occur.

Plant availability is critical to the overall levelised cost of product and is potentially variable, particularly in the early years of commercial operation. The TEA will therefore allow for sensitivity analysis of varying availability to be undertaken.

4.1.3 Design Life

The design life (measured in years) is assumed to be the period following commissioning and first start-up through to final shut-down, site closure and clearance. This will include periods of major outages and process overhauls (these aspects are captured within the Maintenance costs in Section 4.3.4). During this period, the main plant components are assumed to perform at the designated capacity when operated within a defined range of operating conditions, on a specified feedstock and with an agreed planned maintenance programme. Unless otherwise identified by technology providers or EPC Contractors as less, a standard Plant Design Life of 25 years will be adopted.

4.2 CAPEX

The capital expenditure, CAPEX or Investment costs are the costs to the developer for project development, financing, establishment (e.g. land purchase, connections to utilities etc.), construction, commissioning and initial operation including all necessary consents, permits and authorisations. These are independent of operation or operation intensity and will be present regardless of whether the plants are operated or not.

The costs for consultancy, design and planning are a significant component of the capital cost (~5%), even if the technology is mature and well known. If the technology is novel, the cost can be considerably higher (up to 20 %) [15].

The cost estimates will be prepared to provide an estimate accuracy of around -30% to +50% although this will vary on a case-by-case basis depending on the technological complexity of the scheme and the available reference information.

All costs will be provided in Pounds Sterling (GBP), with the base year being 2025 (the anticipated commissioning date). All prices will be baselined to a 2025 cost basis and costs provided in other currencies will be converted to GBP using the annual average spot rate for 2019, as published by the Bank of England [17], as the base case (see below). Due to the potential volatility of exchange rates, sensitivity analysis will be allowed for within the TEA.

- £1 = $ 1.2766
- £1 = € 1.1405

As capital costs are paid during the construction phase of the project, and for consistency with previous benchmarking studies [14], all capital costs will be assumed to occur in the four years prior to first start-up, with costs allocated in the following percentages:

- 4 Years prior to Start-up: 15%
- 3 Years prior to Start-up: 35%
- 2 Years prior to Start-up: 40%
- 1 Year prior to Start-up: 10%

Plant commissioning will occur at the start of the first year of operation.

4.2.1 Land Requirements

This refers to the area occupied by the facility and will include all processing facilities, ancillary equipment, storage, buildings and necessary infrastructure up to and including the Battery Limits as defined in Section 2. This will be measured in square meters (m^2).

Industrial land in the North East of England ranges from £135,000 to £250,000 / hectare [18] and the average land cost of £192,500 / hectare (£19.25 / m^2) has been assumed.

4.2.2 Engineering, Procurement & Construction

It has been assumed that the projects will be delivered by a competitively tendered lump sum Engineering, Procurement and Construction (EPC) contract. This allows a fully commissioned plant to be developed (guaranteed to minimum performance standards) and handed over for an agreed amount.

The EPC contract will cover all facilities located at the site including the process, utilities, storage and administration facilities.

It is acknowledged that all scenarios are to be based on first-of-a-kind (FOAK) contract costs, but will also include an assessment reflecting the EPC costs assuming that the technology is commercially proven with a number of operating units i.e. an nth-of-a-kind (NOAK) approach.

It is assumed that costs for each of the process blocks identified within Figure 3 will be obtained through the engagement of the relevant technology providers and manufacturers to inform the Capital Cost model. Where this information is not made available estimates will be developed using costing methodologies consistent with Class IV of the Association of Cost Engineers. Similarly, this will be the approach adopted for generating costs for ancillary systems such as Piping, Control & Instrumentation and Electrical bulks.

First-fill quantities for chemicals, catalysts and other consumables will be captured within Commissioning/ Start-up costs.

Capital costs for groundworks, civils, buildings & structural components will be based on unit prices from published literature e.g. SPONs [16] or similar.

4.2.3 Consultancy

The contractor's engineering services costs (e.g. fees paid to third party consultants) incurred through the conceptual design, pre-Front End Engineering Design (pre-FEED) and FEED stages ranges between 0.5% and 3% [19] and for this study has been assumed to be 1% of the EPC contract value.

4.2.4 Planning & Other Regulatory

This covers the costs incurred in obtaining the necessary planning (including environmental impact assessments) and permitting (including all necessary environmental and waste permits) consents. It is considered that total consultancy fees of 5% of EPC Contract Cost is appropriate.

4.2.5 Developer's Costs

This covers the Developer's internal costs to develop the project from concept through to start-up, and includes costs associated with direct-hire personnel, taxes and insurances. A NOAK development on a greenfield site in a moderately industrial area, with a supportive local council and other stakeholders has been assumed. And as with previous benchmarking studies [14] this aspect is assumed to be 7% of the EPC Contract Cost.

4.2.6 Start-up & Commissioning Costs

These costs will be incurred in the months prior to first start-up and will cover having a trained operation and maintenance team on the facility during the commissioning and start-up process and the consumables that are used during the same period. There will also be a requirement for consumables to be held on-site to enable maintenance activities. Commissioning services are typically 3.5% of the investment cost of a process plant but can reach 25% for a technically challenging process [20]. Of this, typically 70% is for labour costs and 30% is for consumables.

4.3 OPEX

OPEX or operating and maintenance costs will consist of both fixed and variable components, these are defined as:

- Fixed Operating Costs: Labour; and Administrative & Other Overheads
- Variable Operating Costs: Feedstock, Maintenance, Fuel, Utilities, Consumables, Waste Disposal and Subsidiary Revenues

4.3.1 Labour

Labour costs take into account items such as national insurance, income tax, pension contributions, medical insurance and other in-house company benefits in addition to basic salary. This is an annual operating cost and will be dependent on the staff numbers required to adequately operate the plant. Each facility is assumed to be an advanced plant with high levels of control, automation and reduced staffing. The labour requirements will be developed on a case by case basis to allow for process complexity and facility scale to be accommodated. This will be undertaken by identifying a set number of key skills (e.g. senior management, shift leaders, shift operators, maintenance, technical support and day workers) for each scenario, determining the number of each skill set required and allocating a cost for each skill set.

4.3.2 Administration & Other Overheads

These costs are for services not directly involved in the operation of the plant, such as management, insurance, business rates, taxes, rental and annual licence or permit charges. These services vary widely between companies and are also dependent on the complexity of the process.

This cost is typically assessed as a component of the investment CAPEX and can vary between 1% and 5% [15] depending on the size of the process and its complexity. For this study, an allowance of 2.5% is assumed.

Costs such as rents for land and buildings; equipment hire, royalties and annual licence fees are variable and dependent on the specific project, as a result the potential cost contribution is acknowledged but no costs are being allocated.

4.3.3 Feedstock

As identified in Section 2.1 the feedstock will be either waste (MSW or C&I) or biomass (wood chip, chipped SRC or wood pellets) and the costs within this criterion will be restricted to the feedstock costs at the battery limit i.e. CAPEX and OPEX costs associated with importation, unloading and transportation are accounted for within the cost per tonne of the feedstock supplied to the facility gate. Note that waste is assumed to generate revenue as a gate fee and this will be reflected as a negative value in the operating cost. This will be a variable operating cost and will exclude other operating costs such as labour, waste disposal, and utilities etc.

4.3.4 Maintenance

Maintenance costs cover the cost for routine cleaning, servicing and repair, planned and unplanned outages as well as major overhauls over the lifetime of the plant. This will include internal maintenance teams but will also include payments for service contracts to external contractors and/ or technology providers. Maintenance cost is related to the production intensity (e.g. repairs), the operating hours (e.g. servicing and overhauls) or where it is needed on a regular basis regardless of production intensity or operating hours (e.g. annual calibrations, building maintenance etc.).

Although maintenance cost can be related to the product (e.g. /kg), this requires a reasonable level of information from comparable plants (e.g. size, operation, technology) and as costs are not only related to production, the assessment will assume maintenance costs as a function of CAPEX. Indicative values from literature [14 & 15] will be adopted as follows:

Table 6 Estimated Maintenance Cost Contribution

Type of Equipment	Literature Annual Share of Investment	Selected Annual Share of Investment
Infrastructure	0.3 – 0.5%	0.5%
Buildings	0.8 – 1.2%	1.0%
Mechanical Equipment	2.0 – 3.5%	2.5%
Electrical Equipment	1.8 – 2.2%	2.0%
Gasification Conversion System	2.0 – 4.5%	3.0%
Other Equipment	1.5%	1.5%

The variation in maintenance costs is to account for the variation in maintenance effort needed for the different plant equipment e.g. higher maintenance requirements will be associated with rotating equipment compared to static equipment or civil infrastructure.

4.3.5 Fuel & Utilities

This is the cost for the supply of main and auxiliary fuels for the start-up and operation of the plant. This will include natural gas, diesel, fuel oil and electricity. This will be a combination of:

- The specific fuel or utility cost. This will be in accordance with the Retail Fuel Prices as specified in the Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal [22]. The values for the central value (industrial sector) for 2025 are adopted, i.e.:
  - Electricity: 12.8p/kWh
  - Gas: 2.69p/kWh
  - Oil: 55.3p/litre
- Consumption rate (in kWh or litres etc.).

An accurate estimate for fuel costs will rely on realistic estimates for process efficiency and availability.

Water supply charges will vary depending on the regional provider, therefore for a site in the North East of England this will be Northumbrian Water Ltd and typical costs are represented in Table 7.

Table 7 Typical Water Supply Charges

Item	Cost (2020)	Cost Estimate (2025)[3]
Annual Site Charge (£)	8,000	8,876
Meter Charge (£ per year per meter)	540	599
Wholesale water price (£ per m^3)	0.25	0.28

One water meter is assumed.

4.3.6 Chemicals & Consumables

This accounts for consumable items such as chemicals and catalysts used within the process. The main chemicals and catalysts together with an estimate of annual quantity will be identified for each process. The quantities required for each process will be determined from the supplier’s information and available literature and costs based on current market rates will be applied to provide an annual cost estimate. Where this information is unavailable an estimate from literature will be adopted. From Towler & Sinnott [21] it is estimated that consumables contribute approximately 3% of the total OPEX.

[3] Assuming a base year of 2018 with deflator values of 103.2 (2020) and 114.5 (2025). Taken from BEIS, 2019, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

4.3.7 Waste Disposal

This accounts for trade effluent discharged to an offsite wastewater treatment works and solid wastes (e.g. residues from feedstock pre-treatment; ash; spent materials and equipment). This will attract disposal costs and associated taxes. It is assumed that solid waste will be disposed of to landfill and will incur Landfill Tax at the standard rate of £94.15/tonne (as from 1 April 2020). Costs for landfill disposal in 2020 will vary depending on the material, as illustrated in Table 8.

Table 8 Typical Landfill Gate Fees

Landfill Component	Typical Range[4] (£/tonne)	Assumed Value (£/tonne)	Assumed Value 2025 (£/tonne)
Inert Waste	2 - 10	6	7
MSW	20 - 25	23	26
Hazardous Waste	40 - 80	60	67

Trade effluent disposal costs are based on the availability and operating charge of the utility provider. These costs are variable depending on the volume and composition of the discharged effluent. This is mainly based on Chemical Oxygen Demand and suspended solids concentration. Due to the variability of this charge an accurate estimation cannot be achieved, values within the literature [21] provide an estimate for wastewater discharges of $6/ 1000 gallons (US). Allowing for inflation and currency conversion this is estimated to be £1.53/m^3 and will be adopted for wastewater disposal costs. Where processes include for on-site wastewater treatment works (to reduce effluent to compositions appropriate for discharge to a trade effluent sewer), waste sludges will be produced. Waste sludges will be discharged as hazardous waste.

4.3.8 Subsidiary Revenues

Revenues obtained from gate fees for waste (MSW and C&I) and the sale of recovered resources or by-products will be incorporated into the variable OPEX cost.

Waste (MSW and C&I) will attract a revenue. This is estimated to be consistent with the gate fee to a merchant energy from waste plant. In 2019 the gate fee ranged between £88 and £115 [23] per tonne therefore the study will assume that the waste will generate a revenue of £99/tonne (2019 values) or £112/tonne in 2025.

Revenue from by-products will be based on commodity prices available in the literature.

[4] Personal communication A Judge, Tolvik Consulting Ltd. 1 September 2020

5 Qualitative Assessment Criteria

This section allows non quantitative information to be recorded. This is likely to be subjective but will allow identified issues, barriers or benefits to be recorded that can be used to provide context to the schemes developed in Task 5.

5.1 Qualitative Assessment Criteria

Opportunities for Cost Reduction will be linked to the current state of development and the likely scale up route to commercial deployment.

5.2 Scale Up Requirements

This will capture data on the necessary steps to take the technology and processing concept from its current stage of development through to widespread commercial deployment.

5.3 Technology Readiness Level

The Technology Readiness Level (TRL) is a scale that has been developed as a metric to indicate how far a technology, or concept, is away from its intended operational use or product’s readiness to be marketed. As illustrated in Figure 4 it is a nine level scale from TRL 1 (Basic Research Principles observed) to TRL 9 (Actual System Proven in Operational Environment).

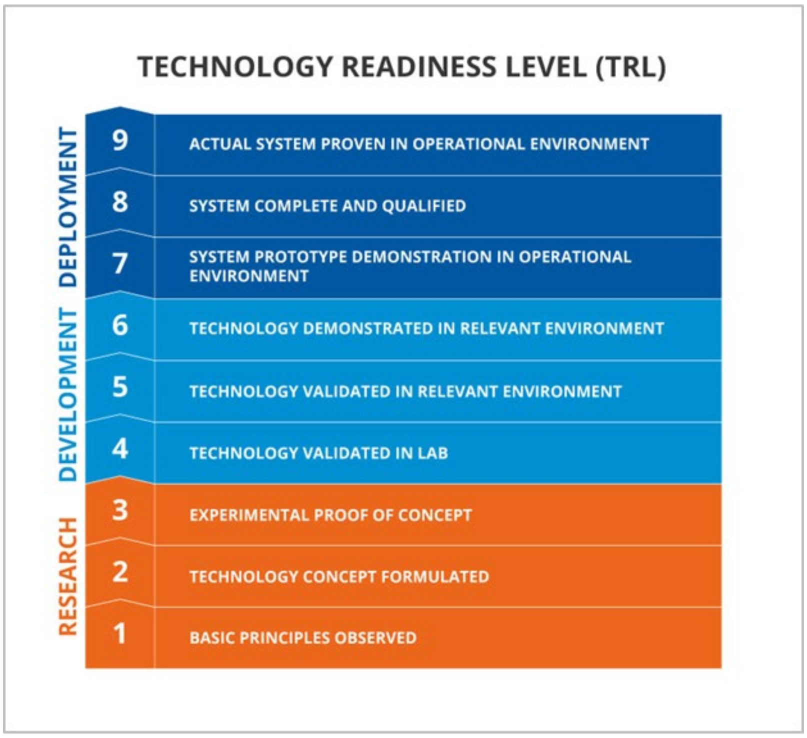


Figure 4 Technology Readiness Level

The assessment of TRL will be consistent with the NDA approach [24] where a System Map (or Process Block Diagram) is used to identify the overall purpose of the facility together with a list of plant items or equipment required to produce the end product. Once this is complete, TRLs for each block can be assigned with reference to Figure 4, by asking the question: “What stage is the equipment/ process block currently at?”

Where the systems consist of aggregated process blocks, the TRL of the aggregate system is the lowest individual TRL of the process blocks. Where required the guidance on TRL assessment from the European Space Agency TRL Handbook [25] will be followed.

5.4 Barriers to Commercial Deployment

Table 9 identifies the barriers to deployment that need to be considered and the typical questions that will need to be considered and addressed.

Table 9 Barriers to Commercial Deployment

Barrier to Deployment	Issues to consider
Political	Is the technology/ process politically acceptable and is there political will to develop the concept further? What are the planning and permitting implications of the facility?
Economic	Can the cost of the process be sufficiently reduced? Can alternative processes produce the product cheaper?

Barrier to Deployment	Issues to consider
	Are there emerging commercial constraints on existing production processes that make the technology/ concept attractive? Do subsidies exist either for the technology or its competitors?
Social	What is the social impact of the process?
Technical	How close to the theoretical limit is the technology operating? Can efficiencies be achieved?
Environmental	What quantity of gaseous/ liquid/ solid waste does the process produce? How hazardous are the wastes? Source of feedstock and its environmental impact? What is the greenhouse gas impact?
Legal	Does the regulatory framework exist to enable widespread deployment? Is there current legislation that limits deployment or favours other processes?

5.5 Track Record

This provides the opportunity to provide comment on the experience of the technology provider and potential EPC Contractors to design, procure, install, commission and operate the technology based on their previous experience of delivering the same or similar projects. This allows completely novel technologies and processes to be differentiated from those that are being developed from well-known technologies and used in novel applications.

5.6 Carbon Abatement

Understanding the overall net CO_2 abatement potential associated with the technologies under consideration is important. However, to conduct a full analysis and modelling of potential CO_2 emissions of the scenarios proposed, and compare them to other options, is a significant task which is not included in the scope of this assignment.

This study will calculate the potential mass of CO_2 that could be captured from any gaseous streams that are emitted from the production process, either as a result of converting the feedstock or from auxiliary fuel input. An estimate of the cost of CO_2 capture will be included in the Capex and Opex estimates used in the TEA.

The 12 plant configurations proposed in Section 3.1 for the TEA will produce different gaseous emission streams containing CO_2. The mass flow rates and compositions will vary between the streams and between the options. At present it is assumed that there will be two process streams containing CO_2 from each of the configurations, being:

1. CO_2 removed from the syngas prior to the upgrading process
2. Flue gas from the gasifier recycle heater (assumed to be fired on syngas)

The relative volume of these process steams, and CO_2 concentrations, will vary for each configuration, and there is the potential that the recycle heater will not be required in all cases.

The total amount of CO_2 to be captured from any of the AGT options under consideration will be dependent on uncertain factors including future carbon price and regulatory requirements. In particular, it is comparatively more expensive to capture CO_2 from smaller and more dilute process streams, such as the gasifier recycle heater.

For the purposes of this study the following assumptions will be made for the two exhaust gas streams.

CO_2 Generated During the Syngas Upgrading

As the last stage of syngas treatment prior to the upgrading it is anticipated that a Rectisol process will be included, to remove CO_2 and H_2S from the treated syngas. This process can be configured to separate the CO_2 and H_2S such that a clean CO_2 stream is produced. It is anticipated that this will require minimal processing prior to compression to the assumed export pressure.

Gasifier Recycle Heater Flue Gas

Where CO_2 is to be captured from this stream, it is anticipated that this gas stream will comprise of the order 15% CO_2, with other components being typical of flue gas from combustion of waste or biomass as applicable. Treatment of this flue gas prior to the CO_2 capture plant will be included within the main process. CO_2 capture will use an amine solvent process, with subsequent drying and compression to the assumed battery limit pressure. The capex and opex of this CO_2 capture will be derived from the 2018 Wood benchmark report [14], with scaling for the flue gas mass flow rate as appropriate. Where the relevant flue gas streams are too small to be scaled from this data, reference will be made to other sources, such as the Energy Systems Catapult May 2020 report ‘Energy from Waste Plants with Carbon Capture’ [26] or Element Energy, 2014 [27].

Where a gasifier recycle heater is used, an amine-based CO_2 capture stage on the exhaust will add significant cost, complexity and technical risk to the AGT process. Depending on the power of the heater used, the mass of CO_2 available for capture may also be very limited. For the purposes of this study, carbon capture from the gasifier recycle heater flue gas will only be considered if it represents more than 20% of the CO_2 emitted by the AGT process. This would still allow the production of products with negative associated CO_2 emissions.

Other emission streams containing CO_2 identified in the development of the configurations for the TEA will be assessed on a case by case basis to determine the mass of CO_2 contained within them and whether it would be reasonable to combine them with other sources of CO_2 prior to capture.

Export pressures of 110 bar and 25 bar will be assumed for large and small-scale exports of CO_2 respectively (to represent export directly to an off-shore transport and storage network, or to a local cluster network).

5.7 Greenhouse Gas Impact

Gaseous discharges to atmosphere will be assessed for their greenhouse gas impact. This will require converting the discharges into a CO_2 equivalent and will follow the BEIS guidance [22] using the factors in Table 10 below:

Table 10 Factors for converting greenhouse gases to their equivalent in carbon dioxide

Greenhouse Gas	Global Warming potential per unit mass (relative to CO_2)
Carbon Dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous Oxide (N_2O)	298
HFC – 134a	1,430
HFC – 143a	4,470
Sulphur hexafluoride	22,800

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A Abbreviations

AACE	Association for the Advancement of Cost Engineering
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
C&I	Commercial & Industrial
CO_2	Carbon Dioxide
EPC	Engineering, Procurement & Construction
FEED	Front End Engineering Design
FOAK	First of a Kind
GBP	Pound Sterling
LCOX	Levelised Cost of End Product
MSW	Municipal Solid Waste
NDA	Nuclear Decommissioning Authority
NOAK	Nth of a Kind
NPV	Net Present Value
NTS	National Transmission System
OPEX	Operating Expenditure
RDF	Refuse Derived Fuel
SRC	Short Rotation Coppice
TEA	Techno Economic Assessment
TRL	Technology Readiness Level
WEEE	Waste Electrical & Electronic Equipment

Appendix A Counterfactual Benchmarks

Contents

Management Summary

This document provides benchmark unit costs for a range of products that could alternatively be produced by Advanced Gasification Technologies (AGTs) using biomass or waste as a feedstock. It is intended that these costs are used as context for the product cost figures generated from the economic analysis of AGT schemes, conducted separately in Task 5.

The products being considered include hydrogen, methane and liquid fuels. For hydrogen and methane, benchmark costs are provided for different production methods. Details of assumptions, uncertainties and limitations of each of the benchmark costs have been provided throughout the report. These need to be understood and considered appropriately in relation to the use of the benchmark cost figures.

The benchmark costs presented are based on available market data or figures derived from third party sources. Third party data sources, providing estimated cost of production figures, have generally been used where available, particularly where the counterfactual benchmark is for an emerging technology itself (e.g. hydrogen from electrolysis). Elsewhere, market data has been used as the basis for the benchmarks. Market data has been used either where cost of production data is not publicly available or, as for many of the end products considered, there are existing established markets for production through conventional means (e.g methane, diesel and aviation fuel from fossil sources) and therefore end products from AGTs will need to be price competitive in these markets.

Table 1 contains benchmark cost ranges and representative points for the products under consideration.

Table 11 Benchmark Costs

Product	Benchmark Range (£/kg)	Benchmark Representative Point (£/kg)	Source
Hydrogen from methane reforming	£0.60 - £1.50	£1.20	Aggregate of figures from third party studies.
Hydrogen from methane reforming with CCS	£1.00 – £2.20	£1.70	Aggregate of figures from third party studies.
Hydrogen from electrolysis	£2.40 - £13.30	£6.00	Aggregate of figures from third party studies.
Natural gas	£0.19 - £0.42	£0.28	BEIS 2019 Fossil Fuel Price Forecast
Methane from landfill gas	£0.55 - £0.75	£0.65	Figure from third party study
Methane from AD	£0.70 - £1.70	£1.10	Aggregate of figures from third party studies.
Diesel	£0.51 - £0.83	£0.65	Treasury Green Book

Product	Benchmark Range (£/kg)	Benchmark Representative Point (£/kg)	Source
Aviation fuel	£0.32 - £0.76	£0.49	Derived from BEIS 2019 Fossil Fuel Price Forecast
Methanol	£0.16 - £0.42	£0.32	Market data
Bioethanol (based on US commodity price)	£0.25 - £0.47	£0.38	Market data

All figures in Table 1 are presented on a £/kg in 2025 basis. The 2025 basis has been selected to be in line with the assumed commissioning date of the AGT plants being modelled in Task 5. Where available, price forecasts provided by BEIS have been used. Where information has been obtained from market data or third-party studies government inflator figures[5] have been used to convert the original figures (from different dates) to a common 2025 basis.

It is evident from the above table that there is significant variability in the prices of the products being considered. For example, even before the effects of the current pandemic the UK wholesale natural gas price varied by a factor of three over several different periods in the last 10 years. This variation directly affects hydrogen and methanol prices, as production of these fuels often relies on natural gas as a feedstock. Similar levels of price variation occur with crude oil-based products due to fluctuations in crude oil prices. The range provided for each counterfactual reflects this variability, with the representative value typically being a midpoint within this range.

Where available, counterfactual benchmarks are based on cost forecast data published by BEIS, or data that is consistent with that adopted in similar studies on behalf of BEIS. All benchmark data is based on a review of publicly available information and professional judgement in relation to the appropriateness of data sources. It is not a detailed commodity price forecast.

The robustness of any benchmark is dependent on the quality of the available input data. Data sources have been referenced and limitations to the data have been highlighted throughout the report. Where data has been taken from third party reports the assumptions used in the reports should be read and understood.

The figures provided within this report are intended to provide indicative reference costs against which to consider the cost of products from potential AGT projects, as will be derived in Task 5.

[5] Adopting the UK government deflator available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/938602/GDP_Deflators_Spending_Review_November_2020_update.xlsx

1 Introduction

This document provides benchmark unit costs for a range of products that could alternatively be produced by Advanced Gasification Technology (AGT) schemes using biomass or waste as a feedstock. It is intended that these costs are used as context for the product cost figures generated from the economic analysis of AGT schemes, conducted separately in Task 5.

The products being considered include hydrogen, methane and liquid fuels. For hydrogen and methane, benchmark costs are provided for different production methods. Details of assumptions, uncertainties and limitations of each of the benchmark costs have been provided throughout the report. These need to be understood and considered appropriately in relation to the use of the benchmark cost figures.

The benchmark costs presented are based on data published by BEIS, figures derived from third party sources or market data. Market data has been used either where cost of production data is not publicly available or, as for many of the end products considered, there are existing established markets for production through conventional means. Therefore, the end products from AGTs will need to be price competitive in these markets.

All benchmark data is based on a review of publicly available information and professional judgement in relation to the appropriateness of data sources. It is not a detailed commodity price forecast.

The robustness of any benchmark is dependent on the quality of the available input data. Data sources have been referenced and limitations to the data have been highlighted throughout the report. Where data has been taken from third party reports the assumptions used in the reports should be read and understood.

The figures provided within this report are intended to provide indicative reference costs against which to consider the cost of products from potential AGT projects, as will be derived in Task 5.

2 Benchmark Costs for Hydrogen

This section contains benchmark cost ranges and representative costs for hydrogen produced by methane reforming, methane reforming with carbon capture and storage (CCS) and electrolysis. Methane reforming has been selected as it is currently the most common method of hydrogen production. Methane reforming with CCS, and electrolysis have been selected as these methods of hydrogen production have the potential to result in lower CO_2 emissions than methane reforming, so may become more prevalent in the future.

The information in this section comes from a variety of studies that have been undertaken on behalf of BEIS or similar bodies, as referenced. However, a full review of the base assumptions used by the studies has not been conducted. In some instances, the base assumptions were not stated.

Some of the assumptions, such as gas, electricity and carbon price, have a significant impact on the cost of the hydrogen produced. Regardless of the method used to generate benchmark costs for the counterfactual products there will be significant uncertainty associated with the figures generated due to the inherent price uncertainty associated with the inputs required for production.

2.1 Hydrogen from Steam Methane Reforming

Steam methane reforming (SMR) is the most common large-scale production method for hydrogen. The technology used is mature and large scale SMR facilities are common in industrial processing facilities across the world.

The cost of hydrogen produced using SMR is highly dependent on the cost of the input feedstock. Natural gas is commonly used as a feedstock and other light hydrocarbons are also used. Indicative costs are presented in Table 2, figures quoted are inclusive of the cost of natural gas feedstock.

Table 12 Cost of Hydrogen from SMR without CCS

Reference	Cost of Production 2019	Forecast Cost of Production £/kg of H_2 in 2025
IEA Energy Perspectives[6]	\$0.7 - \$1.6/kg H_2 (£0.55 – 1.25/kg H_2)	£0.61 – 1.40
European Commission[7]	€1.5 /kg H_2 (£1.32/kg H_2)	£1.47

[6] IEA, September 2020, Energy Technology Perspectives 2020

[7] European Commission, July 2020, A hydrogen strategy for a climate-neutral Europe, COM(2020) 301 final

Reference	Cost of Production 2019	Forecast Cost of Production £/kg of H_2 in 2025
Benchmark Range		**£0.60 - £1.50**
Benchmark Representative Point		**£1.20**

Production of hydrogen using SMR generates CO_2 both from the feedstock and from the energy used to drive the process, and this CO_2 is released into the atmosphere. In the future CO_2 emissions may be taxed or controlled by other measures. Any such measures would increase the price of hydrogen production using SMR without CCS.

Other processes for producing hydrogen from hydrocarbons include partial oxidation (PO) and autothermal reformation (ATR). Each process has advantages and disadvantages in areas such as external energy use, process complexity, product yield and composition of product streams which will have a bearing on the hydrogen production cost.

2.2 Hydrogen from SMR with Carbon Capture and Storage

SMR could be combined with CCS technology to reduce the CO_2 emissions associated with the production of the hydrogen by between 55% and 90% depending on where in the process the carbon capture occurs[8]. At present this combination of technologies is very rare due to the lack of financial incentives for preventing the release of CO_2 into the atmosphere.

Due to the immature nature of SMR coupled with CCS there is additional uncertainty in relation to the benchmark cost provided. The uncertainties will be like those encountered on any CCS project and will include factors like the cost of CO_2 transport and storage infrastructure. Cost estimates for producing hydrogen from SMR with CCS are summarised in Table 3, figures quoted are inclusive of the cost of natural gas feedstock.

[8] IEAGHG, 2017, *Techno – Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS*, Technical Report 2017-02

Table 13 Cost of Hydrogen from SMR with CCS

Reference	Cost of Production 2019	Forecast Cost of Production £/kg of H_2 in 2025
Wood Study[9]	£172.5/kNm^3 (£1.92/kg H_2)	£2.14
IEA Energy Perspectives[10]	\$1.2 - \$2.0/kg H_2 (£0.94 – 1.57/kg H_2)	£1.05 – 1.75
European Commission[11]	€2.0 /kg H_2 (£1.75/kg H_2)	£1.96
Committee on Climate Change[12]	-	£1.26 – 1.97
Hynet[13]	£1.43 - £1.72/kg H_2	£1.60 - £1.92
Benchmark Range		**£1.00 - £2.20**
Benchmark Representative Point		**£1.70**

If this technology is developed there could be scope for optimisation of the hydrocarbon to hydrogen conversion process in relation to the addition of CCS. Without CCS there is no incentive to generate a process stream containing higher concentrations of CO_2. Optimisation of the process for conversion of methane to hydrogen to work in conjunction with CCS is likely to lead to cost reductions.

2.3 Hydrogen from Electrolysis

Production of hydrogen from electrolysis is less common than from SMR because of the higher cost. However, this technology is receiving increasing attention because it does not rely on fossil fuels and can produce hydrogen with low associated CO_2 emissions.

The cost of this approach to hydrogen production is highly dependent on the cost of input electricity and the cost of the electrolysis equipment. The cost of electrolysers is falling due to increased demand for the technology, leading to technology and supply chain developments.

[9] Wood, January 2020, Hydrogen Supply Programme – Novel Steam Methane / Gas Heated Reformer, Phase 1 Final Study Report,
[10] IEA, September 2020, Energy Technology Perspectives 2020
[11] European Commission, July 2020, A hydrogen strategy for a climate-neutral Europe, COM(2020) 301 final
[12] Committee on Climate Change, November 2018, Hydrogen in a Low Carbon Economy
[13] Hynet Low Carbon Hydrogen Plant, Phase 1 Report for BEIS, 2019

Furthermore, the cost of some low carbon electricity sources, such as offshore wind, is also reducing. Therefore, when considering a suitable benchmark cost for hydrogen produced using electrolysis it is important to remember that this cost is likely to reduce in the future.

Table 4 shows costs for hydrogen from electrolysis taken from different sources. The Gigastack and H2H EDF reports were completed as part of the BEIS Low Carbon Hydrogen Competition. The hydrogen cost ranges given within these reports are mainly due to the range of assumptions made in relation to the cost of electricity.

Table 14 Cost of hydrogen from electrolysis

Reference	Cost of Production (2019)	Forecast Cost of Production £/kg of H_2 in 2025
IEA Energy Perspectives[14]	\$3.2 - 7.7/kgH_2 (£2.51 – 6.03 kg/H_2)	£2.80 – 6.74
European Commission[15]	€2.5 – 5.5/kg H_2 (£2.19 – 4.82/kg H_2)	£2.45 - £5.39
Committee on Climate Change[16]		£3.51 - £3.62
Gigastack[17]	£5.38 - £8.37/kg H_2	£6.01 - £9.35
H2H EDF Energy[18]	£6.08 - £11.08/kg H_2	£6.79 - £13.27
Benchmark Range		**£2.40 - £13.30**
Benchmark Representative Point		**£6.00**

The production of hydrogen using electrolysis also has the potential to produce a stream of oxygen that could be used for other purposes. Consequently, this oxygen could provide an additional revenue stream and so improve the process economics.

The CO_2 emissions associated with the production of hydrogen by this route will be largely dependent on the CO_2 emissions associated with generating the electricity required to drive the electrolysis process. If low carbon sources of electricity are used, then the CO_2 emissions associated with the hydrogen produced will also be low.

14 IEA, September 2020, Energy Technology Perspectives 2020
15 European Commission, July 2020, A hydrogen strategy for a climate-neutral Europe, COM(2020) 301 final
16 Committee on Climate Change, November 2018, *Hydrogen in a Low Carbon Economy.* Values were developed assuming natural gas prices for the EU of 22 €/MWh, electricity prices between 35-87 €/MWh, and capacity costs of €600/kW.
17 Element Energy Ltd, January 2020, *Gigastack Bulk Supply of Renewable Hydrogen Public Report*
18 EDF Energy, 11th October 2019, *H2H Feasibility Report*, Hydrogen Supply Programme Tender Reference Number: TRN 1540/06/2018

3 Benchmark Costs for Methane

3.1 UK Natural Gas

The cost of natural gas has a significant impact on the benchmark costs for the products within this report as it is commonly used as a feedstock. For example, in the production of hydrogen from SMR, hydrogen from SMR with CCS and methanol.

The UK national balancing point (NBP) price is a common reference point for gas prices in the UK and includes all sources of gas brought to the UK. The sources of gas include national production, gas imported from other countries through pipelines and interconnectors and Liquified Natural Gas (LNG) delivered to the grid. By adopting the NBP, separate costs for UK produced natural gas and imported LNG are not possible, so it is proposed that a single counterfactual scenario is adopted rather than the two identified within the Task 3 Methodology report[19].

The BEIS 2019 fossil fuel price assumptions for 2025 are presented in Table 6 below and will be used as the counterfactual benchmark. Note that this price in £/kg is derived from the unit cost in pence/therm. Some of the conversion factors applied during the unit's conversion assume a gas composition. There is variation in gas composition across the gas network.

Table 15 Benchmark unit costs for Natural Gas

Parameter	Forecast Cost in 2025
BEIS 2025 Gas Price Forecast[20]	Low 36 p/therm (£0.19/kg)
	Central 53 p/therm (£0.28/kg)
	High 78 p/therm (£0.42/kg)
Benchmark Range	**£0.19 - £0.42/kg**
Benchmark Representative Point	**£0.28/kg**

When using benchmark costs for UK natural gas the volatility and unpredictability of gas prices must be acknowledged. Significant variations in market prices occur due to factors such as the development of new technologies, weather conditions and changes in the global political situation. Price variations over the last 10 years are shown in Figure 2 below, taken from Ofgem.

[19] AECOM & Fichtner, 2020, Advanced Gasification Technologies – Review and Benchmarking Methodology for the Techno-Economic Assessment of Advanced Gasification Technologies Task 3 Report
[20] BEIS 2019 Fossil Fuel Price Assumptions

Figure 5. Wholesale day ahead UK gas prices from May 2010 to May 2020 from Ofgem

3.2 Methane from Landfill Gas

Biogas containing methane is collected from landfill sites across the UK. This gas is generated from the bacterial decay of biodegradable materials, such as food waste, contained within the landfill. The biogas produced by landfills can be upgraded to biomethane.

Producing biomethane using this approach is limited and will reduce over time. This is due to the requirements of the Landfill Directive which restricts the amount of biodegradable municipal waste that can be disposed of in landfills. Additionally, the quantity of biogas produced by a landfill will decline over time as the organic material degrades.

Other aspects that impact the economics of producing biomethane from landfills include the biogas treatment and upgrading costs, the cost of transporting the biomethane to the grid injection point and the required grid connection costs.

Table 16 Cost of methane from landfill gas

Reference	Cost of Production 2015	Forecast Cost of Production 2025 (£/kg methane)
Department for Transport Report[21]	£0.45 – 0.62/kg	£0.55 – £0.75
Benchmark Range		**£0.55 - £0.75**
Benchmark Representative Point		**£0.65**

[21] Ricardo – AEA, March 2015, Biomethane for Transport from Landfill and Anaerobic Digestion, PPRO 04/91/63

3.3 Methane from Anaerobic Digestion

Biomethane can be produced by upgrading biogas produced in anaerobic digestion plants. Table 7 provides costs for biomethane produced using anaerobic digestion.

Table 17 Cost of methane from anaerobic digestion

Reference	Cost of Biomethane Production	Forecast Cost of Production 2025 (£/kg methane)
Department for Transport Report[22]	£0.61-£0.98/kg (2015)	£0.74 - £1.19
DECC Biomethane Injection[23]	£1.27/kg (2010)	£1.67
IEA Outlook for Biogas and Biomethane[24]	£0.67/kg (2020)	£0.75
Benchmark Range		**£0.70 - £1.70**
Benchmark Representative Point		**£1.10**

[22] Ricardo – AEA, March 2015, Biomethane for Transport from Landfill and Anaerobic Digestion, PPRO 04/91/63
[23] Department of Energy & Climate Change, 30 May 2014, RHI Biomethane Injection to Grid Tariff Review, URN 14D/173
[24] IEA, 2020, Outlook for biogas and biomethane – Prospects for Organic Growth

4 Benchmark Costs for Liquid Products

4.1 Diesel

The production of diesel fuel is achieved through the refining of crude oil. Therefore, the cost of diesel production will be significantly impacted by fluctuations in the price of crude.

Diesel will be one of several products manufactured in the refining process which will all have common production stages and costs. This makes it difficult to allocate specific production costs that can be solely attributed to the production of diesel. To accommodate these issues, it is proposed that the wholesale price of diesel is adopted.

The approach being proposed assumes uses the retail price of diesel in 2025 (based on 2018 prices) from the Supplementary Guidance to the Treasury Green Book[25] excluding fuel duty (which is charged at a fixed rate of 57.95 p/litre) and Value Added Tax (charged at 20%). Figures are presented in Table 8. It should be noted that the retail price will include a profit margin that has not been accounted for in the above calculation.

[25] BEIS, 2019, Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

Table 18 Price of Diesel

Parameter	Low	Central	High
Retail Price of Diesel Engine Road Vehicle (DERV) diesel (p/litre)[26]	120.1	134.2	152
Fuel Duty (p/litre)	57.95	57.95	57.95
VAT (p/litre)	20.02	22.37	25.33
Wholesale Price (p/litre)	42.13	53.88	68.72
Benchmark Range (£/kg)	**£0.51**	----	**£0.83**
Benchmark Representative Point (£/kg)		**£0.65**	

4.2 Aviation Fuel

The Department for Transport models the price of standard, fossil origin, aviation fuel using the price of crude oil as the basis for the estimate[27]. Figures in Table 9 have been derived using this formula and the BEIS 2019 Fossil Fuel Price assumptions.

Table 19 Price of Aviation fuel

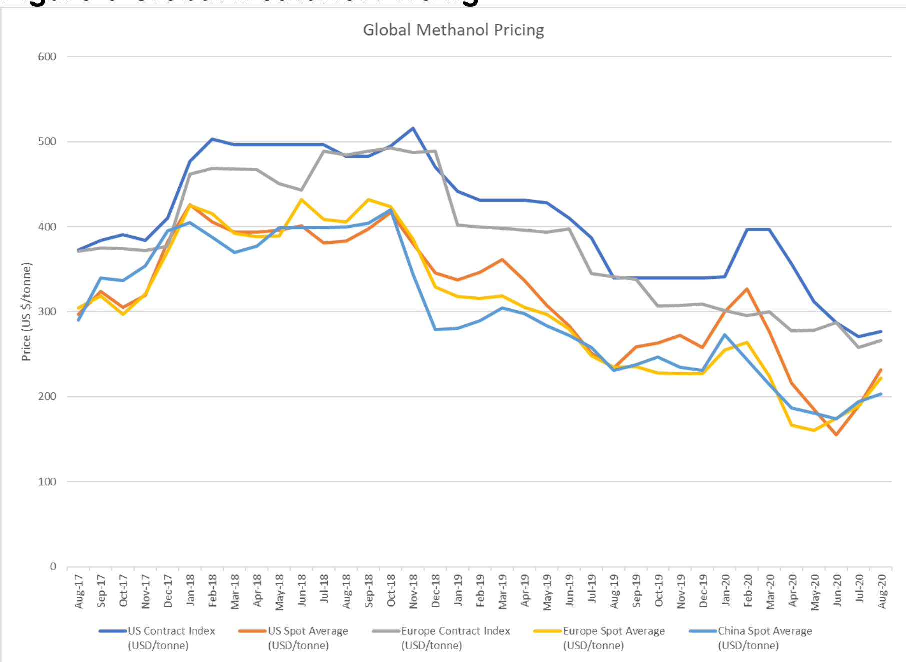
[26] Green Book 2019 prices amended for the GDP Deflator Index.
[27] Spot price of jet fuel (in $/litre) is calculated based on the following calculation: 0.03 + 0.007*oil price ($).

Parameter	Forecast Cost of Crude Oil in 2025	Forecast Cost of Aviation Fuel in 2025
Crude oil forecast[28]	Low - 43 USD/bbl Central – 68 USD/bbl High – 106 USD/bbl	
Aviation fuel forecast		Low – 0.33 USD/l (£0.32/kg) Central – 0.51 USD/l (£0.49/kg) High – 0.77 USD/l (£0.76/kg)
Benchmark Range (£/kg)		**£0.32 - £0.76**
Benchmark Representative Point (£/kg)		**£0.49**

4.3 Methanol

Figure 2 illustrates how the global price of methanol[29] has fluctuated in recent years. In Europe the average spot price has fluctuated from £0.13/kg (US$161/tonne) in May 2020 to £0.34/kg (US$432/tonne) in June and September 2018. This gives a range of £0.16 - £0.42 in 2025 prices.

Figure 6 Global Methanol Pricing



Although these are market prices rather than production costs, they illustrate a wide variability in the methanol market. As the principal route for methanol synthesis is through steam

[28] BEIS 2019 Fossil Fuel Price Assumptions
[29] Data from Methanol Market Services Asia via the Methanol Institute - https://www.methanol.org/methanol-price-supply-demand/ accessed 16/09/20.

methane reforming the production costs, as with several of the counterfactual products, will be susceptible to the variability of the natural gas price.

For the purposes of this study the average methanol market price (not production cost) from the Methanex European Contract Price for 2019 has been adopted as the last full year of available data whilst excluding the adverse impact of the Covid-19 pandemic[30]. This is estimated to be €328.75/tonne (£0.29/kg) and forecasting to 2025 gives an estimate of £0.32/kg. Methanol prices are presented in Table 10. Using a 2019 average price does not consider future market trends for methanol.

[30] https://www.methanex.com/our-business/pricing accessed 15/09/20

Table 20 Price of Methanol

Parameter	Based on 2020 prices £/kg	Forecast Cost in 2025 £/kg
Methanex European Contract Price Range August 2017 – August 2020	£0.13 - £0.34	£0.16 - £0.42
Average Methanex European Contract Price for 2019	£0.29	£0.32
Benchmark Range (£/kg)		**£0.16 - £0.42**
Benchmark Representative Point (£/kg)		**£0.32**

4.4 Bioethanol

The cost of bioethanol production will be dependent on several factors, including the cost of the feedstock used. These factors will vary from year to year and with geographic location. Figure 4 shows ethanol market price data over approximately a 5-year period published by Trading Economics[31], y-axis is USD/gallon.

[31] tradingeconomics.com/commodity/ethanol

Figure 7. Ethanol market price

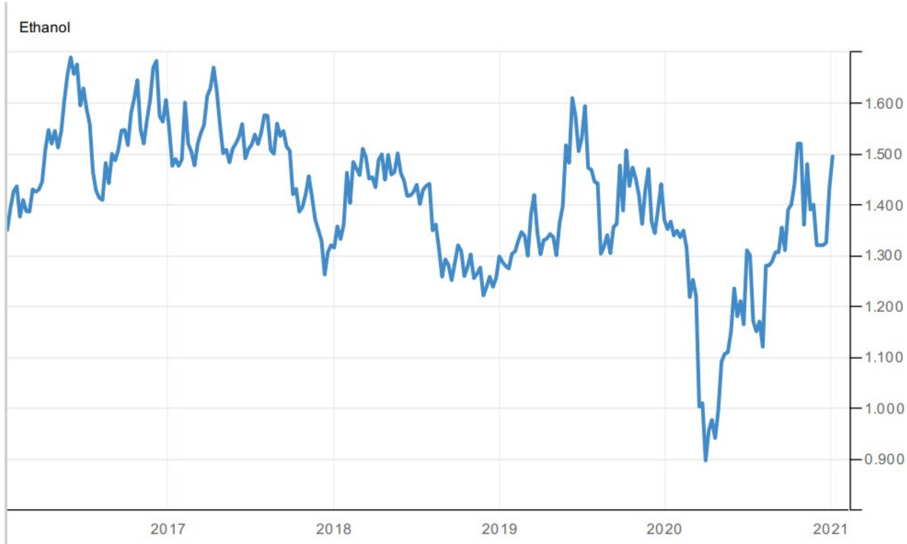


Table 21 Price of Ethanol

Parameter	Based on 2020 prices	Forecast Cost in 2025 £/kg
Ethanol market price Range July 2017 – November 2020	0.90 – 1.70 (USD/gal) £0.24 – 0.45/kg	£0.25 - £0.47
Financial Times Contract Price Representative Value	£1.40 (USD/gal) £0.37/kg	£0.38
Benchmark Range (£/kg)		**£0.25 - £0.47**
Benchmark Representative Point (£/kg)		**£0.38**

The figures in Table 10 are based on the US commodity price for ethanol and may differ from the production cost of bioethanol in the UK.

B Conversions

Exchange Rates

£1	€1.1405
£1	US$1.2766

C Abbreviations

AGT	Advanced Gasification Technology
ATR	Autothermal Reformation
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CCS	Carbon Capture & Storage
CO_2	Carbon Dioxide
DECC	Department of Energy & Climate Change
DfT	Department for Transport
EU	European Union
H_2	Hydrogen
IEA	International Energy Agency
LCOH	Levelised Cost of Hydrogen
MSW	Municipal Solid Waste
NBP	National Balancing Point
PEM	Proton Exchange Membrane
PO	Partial Oxidation
RTFO	Renewable Transport Fuel Obligation
SMR	Steam Methane Reforming
VAT	Value Added Tax

This publication is available from: www.gov.uk/government/publications/advanced-gasification-technologies-review-and-benchmarking